FILED
January 20, 2023
INDIANA UTILITY
REGULATORY COMMISSION

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**

INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR

PUBLIC'S EXHIBIT NO. 11

TESTIMONY OF OUCC WITNESS GLENN A. WATKINS

JANUARY 20, 2023

Respectfully submitted,

____

Kelly Earls, Attorney No. 29653-49
Deputy Consumer Counselor
OFFICE OF UTILITY CONSUMER COUNSELOR
115 W. Washington St. Suite 1500 South
Indianapolis, IN 46204
Email: KeEarls@oucc.in.gov
infomgt@oucc.in.gov

TABLE OF CONTENTS

VERIFIED DIRECT TESTIMONY OF GLENN A. WATKINS
ON BEHALF OF
INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Glenn A. Watkins. My business address is 6377 Mattawan Trail, Mechanicsville, Virginia 23116.

Q. WHAT IS YOUR PROFESSIONAL AND EDUCATIONAL BACKGROUND?

A. I am President and Senior Economist with Technical Associates, Inc., which is an economics and financial consulting firm with offices in the Richmond, Virginia area. Except for a six-month period during 1987 in which I was employed by Old Dominion Electric Cooperative, as its forecasting and rate economist, I have been employed by Technical Associates continuously since 1980.

During my career at Technical Associates, I have conducted marginal and embedded cost of service, rate design, cost of capital, revenue requirement, and load forecasting studies involving numerous electric, gas, water/wastewater, and telephone utilities. I have provided expert testimony on more than 250 occasions in Alabama, Arizona, Delaware, Georgia, Illinois, Indiana, Kansas, Kentucky, Maine, Maryland, Massachusetts, Michigan, Montana, Nevada, New Jersey, North Carolina, Ohio, Pennsylvania, Vermont, Virginia, South Carolina, Washington, and West Virginia.

I hold an M.B.A and B.S in economics from Virginia Commonwealth University and am a Certified Rate of Return Analyst. A more complete description of my education and experience as well as a list of my prior testimonies is provided in my Attachment GAW-1.

Q. HAVE YOU PREVIOUSLY PROVIDED TESTIMONY BEFORE THIS COMMISSION?

A. Yes. In addition to Northern Indiana Public Service Company's ("NIPSCO" or "Company") last two rate cases (Cause Nos. 45159 and 44688), I have provided testimony on behalf of the Office of Utility Consumer Counselor ("OUCC") in several rate cases including Indianapolis Power & Light Company, Indiana Michigan Power, and Duke Energy Indiana rate cases.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. Technical Associates has been engaged by the OUCC to assist in its evaluation of the Company's proposed class revenue increases and rate design as it relates to Residential and Small Commercial customers. The purpose of my testimony, therefore, is to comment on NIPSCO's proposals on these issues and to present my findings and recommendations based on the results of the studies I have undertaken on behalf of the OUCC.

II. SUMMARY OF TESTIMONY

Q. PLEASE PROVIDE A SUMMARY OF YOUR FINDINGS AND RECOMMENDATIONS IN THIS CASE.

A. The approval of Rate 831 in the Company's last general rate case (Cause No. 45159) allowed several large industrial customers to leave NIPSCO's generation system for the majority of their capacity and energy needs. While NIPSCO's investment in generation plant was designed and built to meet the needs of all customers including those of its large industrial customers (before they left the system), a major policy issue is how to fairly and equitably assign the revenue erosion resulting from the Rate 831 customers leaving the NIPSCO system for generation needs. I have conducted various analyses indicating that maintaining the status quo of allocating generation plant across classes is not justified, fair, or reasonable. As a result, I recommend that, in general, all classes should receive an equal percentage increase of any overall increase authorized by the Commission in this case.

With regard to Residential and Small Commercial customer charges, the Company proposes significant increases to these fixed charges. I have conducted independent studies of the reasonable level of customer charges based on costs that would indicate that a reduction to these fixed charges are appropriate. However, in the interest of gradualism and rate continuity, I recommend that the Residential and Small Commercial fixed monthly customer charges be maintained at their level.

III. OVERVIEW OF NIPSCO'S RATE INCREASE REQUEST

Q. PLEASE PROVIDE AN OVERALL SUMMARY OF NIPSCO'S REQUESTED REVENUE INCREASE IN THIS CASE.

A. NIPSCO is requesting an overall $291.8 million revenue increase in this case and states that this represents a 19.1% increase in overall revenues.[1] While this percentage is correct in that the current revenues reflect various riders and trackers that have been implemented or increased since the last rate case. However, the Company's request reflects a 35.4% increase over the rates approved in its last general rate case. This difference is attributable to the implementation and escalation of various trackers and riders since the last rate case. As such, under the Company's proposal, customers' electric bills would increase by more than 35% since the Commission authorized in rates in Cause No. 45159.

IV. DETERMINATION OF CLASS REVENUE RESPONSIBILITY

Q. PLEASE PROVIDE A BRIEF OVERVIEW AND HISTORY OF NIPSCO'S INVESTMENT IN ITS GENERATING ASSETS.

A. NIPSCO's forecasted test year gross investment in production (generation plant) is $3.040 billion.[2] This investment is comprised primarily of large base load coal units as well as natural gas and hydro units and was designed and built to meet the collective loads and energy requirements of its total customer base which included the large loads

[1] This increase excludes the Company's proposed Variable Cost Tracker ("VCT").
[2] Per Witness Taylor's class cost of service study (Minimum Standard Filing Requirements 1-5-15).

and energy requirements of large industrial customers. As observed in Cause No. 43526, the Commission found that "NIPSCO's system was designed, planned, and built in material part to serve the loads of its energy intensive industrial customers."[3]

In NIPSCO's last general rate case (Cause No. 45159), several of NIPSCO's largest industrial customers were allowed to bypass the Company's generation system for the majority of their load and energy requirements with the implementation of Rate 831. Before these large industrial customers left NIPSCO's system for generation, the large industrial load was approximately 895 MW.[4] As a result of the largest industrial customers leaving NIPSCO for the majority of their firm load requirements, this load has been reduced to about 240 MW, wherein the Rate 831 customers' load responsibility is projected to be 185 MW. Similarly, these large industrial customers relied on NIPSCO's generation system for approximately 7,353 GWh of their energy requirements before the Rate 831 customers left the system[5] which has been reduced to approximately 1,620 GWh in the current case.[6]

As a result of these large Rate 831 customers leaving NIPSCO's system for the majority of their firm generation needs, there was a huge loss of revenue from these customers. In NIPSCO's last case (Cause No. 45159), this revenue erosion was not absorbed by shareholders, but rather, spread across all remaining captive ratepayers.

Assuming that Rate 831 is continued in this case, the issue confronting the Commission is not one of "cost causation" since NIPSCO's generation costs have been incurred to meet both captive customers' loads as well as the large loads of Rate 831 customers, but rather, how the revenue erosion resulting from Rate 831 customers leaving the system should be fairly and reasonably assigned across all remaining captive customers. That is, there is no doubt that NIPSCO's investment in its current generation assets are the result of the Company's need to meet the prior large industrial loads that have now left the

[3] Cause No. 43526, Final Order, page 85.
[4] 4-CP load including Rates 732, 733, and 734. Per NIPSCO Witness Gaske Workpapers, Attachment 17-E Class Allocation Factors (Cause No. 44688).
[5] Per NIPSCO Witness Gaske Workpapers, Attachment 17-E Class Allocation Factors (Cause No. 44688).
[6] Per NIPSCO Witness Taylor Workpaper: NIPSCO Electric External Allocators_WORKPAPERS.

system. As such, the remaining captive customers have not "caused" this level of investment to be incurred, and as a result, the underlying question is how to fairly and equitably assign NIPSCO's current level of generation investment across the remaining captive customers given the significant revenue erosion resulting from Rate 831 customers leaving the system.

Because this Commission has found that peak loads are the appropriate metric to assign cost responsibility associated with generation plant, if the relationships of peak load across all remaining captive customers have remained relatively constant before and after the exit of Rate 831 customers, this could be an appropriate approach to assign cost responsibility in this case. As a result, I have investigated the changes in the relative contributions to load before and after the Rate 831 customers exited the system.

Q. PLEASE EXPLAIN YOUR INVESTIGATION OF THE CHANGES IN THE RELATIVE CONTRIBUTIONS BEFORE AND AFTER RATE 831 CUSTOMERS EXITED THE SYSTEM FOR THE MAJORITY OF THEIR GENERATION NEEDS.

A. In evaluating each class's relative contributions to peak loads, I conducted various analyses of the changes in the Company's estimated class peak loads before and after Rate 831 customers left the system. Specifically, I actively participated in the Company's 2015 rate case (Cause No. 44688) which was the case immediately preceding the Rate 831 customers leaving NIPSCO's system for generation. As a result, I was able to evaluate the absolute and relative changes in class loads, energy usages, and number of customers before and after the construct of Rate 831. The following table provides these changes and absolute percentage changes between the 2015 and current rate cases:

TABLE 1
Changes In 4-CP, MWh Sales, & Number of Customers

Rate Case	Total	Resid.	Gen'l Svc.[7]	Ind. & RR[8]	Large Ind.[9]	Off-Peak	Muni Power	Light[10]	Inter-Depart.
4-CP									
2015	3,004,713	909,747	1,050,350	12,330	895,380	120,952	3,866	904	11,185
2022	2,458,833	1,159,173	810,481	8,708	240,395	224,825	4,590	807	9,856
% Chg.	-18.17%	27.42%	-22.84%	-29.38%	-73.15%	85.88%	18.71%	-10.73%	-11.88%
MWh Sales									
2015	17,129,661	3,435,718	5,197,275	116,555	7,353,846	871,581	29,402	79,983	45,303
2022	10,913,899	3,452,198	4,089,883	104,612	1,620,258	1,532,103	33,011	55,263	26,570
% Chg.	-36.29%	0.48%	-21.31%	-10.25%	-77.97%	75.78%	12.27%	-30.91%	-41.35%
No. of Cust.									
2015	468,464	402,973	55,092	15	16	143	681	9,500	46
2022	487,998	419,221	56,337	13	16	260	409	11,696	46
% Chg.	4.17%	4.03%	2.26%	-13.33%	0.00%	81.82%	-39.94%	23.12%	0.00%

Sources: 2015 data (Cause No. 44688): NIPSCO's CCOSS, Attachment 170 IAC 1-5-15(e).
2022 data (current case), per Witness Taylor's Workpaper "NIPSCO Electric External Allocators_WORKPAPERS."

As can be observed above, the Company has estimated that the Residential class's 4-CP demand has increased by more than 27%, while the number of customers has only increased by 4%, and Residential energy sales have remained essentially flat between these rate cases. At the same time, the General Service, Industrial & Railroad, Large Industrial, and Lighting classes have all seen declines in their estimated 4-CPs. The increases in the Off-Peak and Municipal Power classes 4-CPs can be explained by the increases in their energy usage. Based on these estimates, this means the Residential class's load factor (at the meter) has declined from 44.9% to 35.6%.[11]

Q. IS THERE A POSSIBLE EXPLANATION FOR THE SIGNIFICANT INCREASE IN THE RESIDENTIAL CLASS' 4-CP LOAD AND ATTENDANT REDUCTION IN LOAD FACTOR BETWEEN THE 2015 AND CURRENT RATE CASES?

A. Possibly, yes. Because the Residential class's loads are very weather sensitive, I examined the temperatures on each of the peak days utilized for the 2015 and current rate

[7] Includes Rates X20, X21, X22, X23, X24, and 543.
[8] Includes Rates X25, X42, and X44.
[9] Includes Rates 831, X32, X33, and 634.
[10] Includes Rates X50, X55, and X60.
[11] The load factors are expressed at the meter such that the 4-CP demands reflect line losses.

cases. The following table shows the average and maximum temperatures during each of the four summer monthly peak days between the two rate cases:

TABLE 2
Temperatures in Northern Indiana WFO, IN

Current Case			2015 Case		
Peak Day	Avg. Temp	Maximum Temp	Peak Day	Avg. Temp	Maximum Temp
6/11/2021	76.0	86.0	6/30/2014	76.5	83.0
7/6/2021	79.0	87.0	7/22/2014	75.5	86.0
8/24/2021	80.0	90.0	8/25/2014	79.0	90.0
9/13/2021	76.0	85.0	9/5/2014	78.0	91.0
Average	77.8	87.0		77.3	87.5

Source: National Weather Service.

As can be seen above, there are no material differences in the temperatures on the peak days between the 2015 and current rate cases. As such, it cannot be said that the Residential class's peak loads for the current case were due to an abnormal heat wave compared to the 2015 case.

Q. WHAT ARE YOUR CONCLUSIONS REGARDING NIPSCO'S SIGNIFICANT REDUCTION IN THE ESTIMATED RESIDENTIAL LOAD FACTOR BETWEEN THE 2015 AND CURRENT CASES?

A. The reduction in the estimated Residential load factor from 44.9% to 35.6% cannot be explained by abnormally hot temperatures during the current test year. Furthermore, and due to the residual impacts of the COVID-19 Pandemic wherein many workers were working from home during 2021, and thereby increasing their total energy usage, it would be expected that the Residential load factor would increase due to a higher level of energy consumption. At this point, there is no logical explanation for the increase in the estimated Residential loads and reduction in the Residential load factors. I will discuss NIPSCO's procedures to estimate class coincident peak ("CP") loads later in my testimony.

Q. PLEASE CONTINUE WITH YOUR INVESTIGATION AND ANALYSIS OF THE CHANGES IN PEAK LOAD RESPONSIBILITY ACROSS CLASSES.

A. For embedded cost allocation purposes, it is the relative class percentages of any allocation factor that are most important. In other words, it is the class percentages of the total system that are only important in allocating costs. Therefore, I investigated each class's 4-CP allocation factor percentages between the 2015 case and the current case and calculated each class's relative percent change in the 4-CP allocation factors which are provided in the table below:

TABLE 3
Changes In Class 4-CP Allocation Factor Percentages

Rate Case	Total	Resid.	Gen'l Svc.[12]	Ind. & RR[13]	Large Ind.[14]	Off-Peak	Muni Power	Light[15]	Inter-Depart.
4-CP									
2015	100.00%	30.28%	34.96%	0.41%	29.80%	4.03%	0.13%	0.03%	0.37%
2022	100.00%	47.14%	32.96%	0.35%	9.78%	9.14%	0.19%	0.03%	0.40%
Relative % Change	--	55.70%	-5.71%	-13.70%	-67.19%	127.15%	45.07%	9.08%	7.68%
MWh Sales									
2015	100.00%	20.06%	30.34%	0.68%	42.93%	5.09%	0.17%	0.47%	0.26%
2022	100.00%	31.63%	37.47%	0.96%	14.85%	14.04%	0.30%	0.51%	0.24%
Relative % Change	--	57.71%	23.51%	40.87%	-65.42%	175.90%	76.22%	8.44%	-7.95%
No. of Customers									
2015	100.00%	86.02%	11.76%	0.00%	0.00%	0.03%	0.15%	2.03%	0.01%
2022	100.00%	85.91%	11.54%	0.00%	0.00%	0.05%	0.08%	2.40%	0.01%
Relative % Change	--	-0.13%	-1.83%	-16.80%	-4.00%	74.54%	-42.35%	18.19%	-4.00%

As indicated above, the Residential class's 4-CP allocation factor has increased from 30.28% to 47.14%, which indicates a relative percentage increase of 55.70% between the two cases. At the same time, we can see that the General Service, Industrial & Railroad, and Large Industrial classes relative responsibilities of the 4-CP allocation factor have declined. The increases in the relative allocation factors for the Off-Peak and Municipal Power classes can be explained by the substantial increase in energy usage of these customers.

[12] Includes Rates X20, X21, X22, X23, X24, and 543.
[13] Includes Rates X25, X42, and X44.
[14] Includes Rates 831, X32, X33, and 634.
[15] Includes Rates X50, X55, and X60.

Q. WHAT ARE YOUR FINDINGS CONCERNING THE SIGNIFICANT INCREASE IN THE RESIDENTIAL 4-CP ALLOCATOR COMPARED TO THE REDUCTIONS TO OTHER CLASS FACTORS BETWEEN THE 2015 CASE AND THE CURRENT RATE CASE.

A. The resulting allocation factors and relative percent changes shown in Table 3 before and after Rate 831 customers left the system are simply a matter of arithmetic. However, NIPSCO's estimates in no way reflect how its generation costs were, or currently are, incurred. As a result, the current 4-CP class cost allocation factors should not be considered in evaluating class cost responsibility for this case.

Q. HOW DID THE COMPANY ESTIMATE CLASS CONTRIBUTIONS TO EACH OF THE FOUR SUMMER MONTHLY CP DEMANDS?

A. For purposes of assigning generation cost responsibility, the Company proposes to utilize the anticipated firm load commitments of the Rate 831 customers of 185 MW. Then, for all captive rate classes, the Company estimated each class's monthly CP load for the four summer months during 2021. However, because NIPSCO does not have hourly interval demand data for every customer on its system, the Company was forced to estimate CP demands for those rate classes that do not have hourly demand data utilizing load surveys and sampling techniques.[16] Although NIPSCO knows the total system peak load for each hour, the sum of the estimated class peak loads do not equal the system peak load even when line losses are reflected. As a result, there is a material sampling error for each of the four hours which were material as shown in the table below:

TABLE 4
Coincident Peak Sampling Error During 2021 Four Summer Months
(kW)

Month	System Peak @ Generation	Sum of Estimated Class Peaks @ Generation	Sampling Error Amount	Sampling Error Percent
June	2,814,565	2,413,844	400,721	14.24%
July	2,807,333	2,528,327	279,006	9.94%
August	3,163,128	2,878,757	284,371	8.99%
September	2,702,034	2,940,387	(238,353)	-8.82%

[16] The sampling techniques were utilized for Rate 811, 820, 821, 822, 823, 824, and Interdepartmental.

NIPSCO then allocated these sampling errors to those classes without hourly interval demand meters in order for the sum of the class's CPs to equal the system CP for each month.

Q. DO YOU KNOW WHAT CAUSED THESE LARGE SAMPLING ERRORS?

A. No. NIPSCO's estimated class CP loads for those classes that required sampling techniques were based on a sample number of customers for each class and then expanded (extrapolated) in order to estimate the entire class's population of customers. In this regard, it is not known whether the sample for each estimated class reasonably reflects the characteristics of the population for each specific class.

Q. DOES THE LARGE CP SAMPLING ERROR GIVE YOU CAUSE FOR CONCERN AS IT RELATES TO NIPSCO'S ESTIMATED CLASS 4-CPS??

A. Yes. While it is reasonable to expect a small sampling error, NIPSCO's sampling errors range from -9% to +14% causes concern for the veracity of the Company's ultimate estimated class 4-CP demands.

Q. GIVEN THAT NIPSCO'S CALCULATED 4-CP CLASS ALLOCATION FACTORS BEAR NO RESEMBLANCE TO HOW THE COMPANY'S GENERATION INVESTMENTS WERE INCURRED COUPLED WITH YOUR CONCERNS REGARDING THE SAMPLING ERRORS WHICH ARE PRESENT FOR MOST RATE CLASSES, WHAT IS YOUR RECOMMENDATION AS TO HOW CLASS REVENUE RESPONSIBILITY SHOULD BE ASSIGNED IN THIS CASE?

A. Because the revenue erosion associated with Rate 831 customers leaving NIPSCO's generation system has nothing to do with a shift in the cost causation of generation plant, the arithmetic associated with assigning cost responsibility based on questionable estimates of coincident peak demands to the remaining captive customer classes is at best, meaningless, and results in an unfair assignment of generation costs to particular classes. Therefore, it is my opinion that the only equitable solution is to generally assign class revenue responsibility on an equal percentage basis until such time as all or most of

NIPSCO's current legacy plant is retired and removed from rate base; i.e., until such time as NIPSCO's generation plant is more in equilibrium with its native load.

Q. HOW DOES THE COMPANY PROPOSE TO ASSIGN ITS REQUESTED $291.8 MILLION OVERALL REVENUE INCREASE?

A. Company Witness John Taylor sponsors NIPSCO's proposed class revenue distribution approach which is discussed on pages 38 and 39 of his direct testimony. Mr. Taylor's approach results in the following proposed class revenue increases:

TABLE 5
NIPSCO Proposed Class Revenue Distribution
($000)

	Current Revenues			Proposed Increase		
Rate Description	Rate Revenue [17]	Other Revenues	Total Revenue	Increase	Rate Revenue % Increase	Total Revenue % Increase
Rate 811-Residential	$549,946	$8,714	$558,660	$106,656	19.39%	19.09%
Rate 820-C&GS Heat Pump	$935	$12	$947	$271	29.01%	28.64%
Rate 821-GS Small	$260,842	$2,983	$263,825	$47,848	18.34%	18.14%
Rate 822-Comml SH	$945	$10	$954	$181	19.17%	18.98%
Rate 823-GS Medium	$140,976	$1,591	$142,567	$30,145	21.38%	21.14%
Rate 824-GS Large	$184,248	$2,164	$186,412	$40,960	22.23%	21.97%
Rate 825-Metal Melting	$8,063	$80	$8,143	$1,477	18.32%	18.14%
Rate 826-Off-Peak	$160,514	$1,669	$162,182	$34,295	21.37%	21.15%
Rate 831-Ind. Pwr Svc.	$139,320	$4,431	$143,751	$16,799	12.06%	11.69%
Rate 832-Ind. Svc.-LLF	$14,731	$159	$14,890	$3,391	23.02%	22.77%
Rate 833-Ind. Svc.-HLF	$22,284	$262	$22,546	$5,607	25.16%	24.87%
Rate 841-Muni. Power	$4,413	$35	$4,448	$807	18.28%	18.14%
Rate 842-Int WW Pump.	$110	$1	$111	($54)	-49.20%	-48.89%
Rate 543-Sta. Pwr. Ren.	$2,433	$15	$2,448	($1,201)	-49.34%	-49.04%
Rate 844-Railroad	$1,911	$17	$1,928	$552	28.89%	28.64%
Rate 850-Street Lighting	$6,666	$33	$6,699	$1,918	28.78%	28.64%
Rate 855-Traffic Lighting	$1,082	$7	$1,089	$198	18.25%	18.14%
Rate 860-Dusk-to-Dawn	$2,638	$22	$2,660	$762	28.87%	28.64%
Interdepartmental	$4,038	$40	$4,078	$1,168	28.92%	28.64%
System Total	$1,506,095	$22,245	$1,528,340	$291,780	19.37%	19.09%

Q. PLEASE EXPLAIN MR. TAYLOR'S PROPOSED 49.3% RATE REDUCTION TO RATE 543 – STATION POWER RENEWABLE.

[17] Includes base rate (non-fuel and fuel), TDSIC, and DSM revenues.

A. As set forth on page 18 of Mr. Taylor's direct testimony, this is a proposed new rate schedule. Currently, the customers that would be moved to proposed Rate 543 are served under Rate 824 – General Service Large. However, the Company's studies indicate that these customers have a different character of service than other customers served on the current Rate Schedule 824 wherein these proposed Rate 543 customers' calculated rate of return ("ROR") at current rates is significantly large (49.26%). As a result, NIPSCO proposes this new Rate 543 which would reduce the revenue collected from these customers by approximately $1.2 million.

Q. DO YOU HAVE ANY OBJECTION TO NIPSCO'S PROPOSED RATE 543?

A. No.

Q. PLEASE EXPLAIN MR. TAYLOR'S PROPOSED RATE REDUCTION TO RATE 842 – INTERMITTENT WASTEWATER PUMPING.

A. This is a very small rate class with rate revenues slightly above $100,000 per year. These customers utilize NIPSCO's system in a very consistent manner across hours, days, and months of the year such that Mr. Taylor's CCOSS found that a significant rate reduction is warranted for this rate schedule. As a result, Mr. Taylor proposes 49.2% rate reduction to this rate schedule.

Q. DO YOU AGREE WITH MR. TAYLOR'S PROPOSED 49.2% RATE REDUCTION TO RATE SCHEDULE 842?

A. Not in the magnitude that Mr. Taylor recommends. As explained earlier in my testimony, NIPSCO's proposed overall increase in this case represents an approximate 35% increase in customers' rates from those that were approved in the last rate case. Given this large impact on all other customers' bills, it is my opinion that an almost 50% reduction in these customers' bills are not fair and reasonable such that I recommend limiting any rate revenue reduction to Rate 842 to 25%.

Q. BASED ON THE COMPANY'S REQUESTED OVERALL $291.8 MILLION INCREASED, HOW DO YOU RECOMMEND THAT THIS INCREASE BE ASSIGNED TO ALL OTHER RATE CLASSES?

A. With the exception of Rate 842 and the proposed Rate 543, I recommend that all other classes receive an equal percentage increase in revenues as shown in the table below:

TABLE 6
OUCC Proposed Rate Revenue Distribution

Rate Description	Present Rate Revenue	OUCC Proposed Rate Revenue Increase	
		Amount	Percent
Rate 811-Residential	$549,946	$107,172	19.49%
Rate 820-C&GS Heat Pump	$935	$182	19.49%
Rate 821-GS Small	$260,842	$50,832	19.49%
Rate 822-Comml SH	$945	$184	19.49%
Rate 823-GS Medium	$140,976	$27,473	19.49%
Rate 824-GS Large	$184,248	$35,906	19.49%
Rate 825-Metal Melting	$8,063	$1,571	19.49%
Rate 826-Off-Peak	$160,514	$31,280	19.49%
Rate 831-Ind. Pwr Svc.	$139,320	$27,150	19.49%
Rate 832-Ind. Svc.-LLF	$14,731	$2,871	19.49%
Rate 833-Ind. Svc.-HLF	$22,284	$4,343	19.49%
Rate 841-Muni. Power	$4,413	$860	19.49%
Rate 842-Int WW Pump.	$110	($27.49)	-25.00%
Rate 543-Sta. Pwr. Ren.	$2,433	($1,201)	-49.34%
Rate 844-Railroad	$1,911	$372	19.49%
Rate 850-Street Lighting	$6,666	$1,299	19.49%
Rate 855-Traffic Lighting	$1,082	$211	19.49%
Rate 860-Dusk-to-Dawn	$2,638	$514	19.49%
Interdepartmental	$4,038	$787	19.49%
System Total	$1,506,095	$291,780	19.37%

Q. PLEASE PROVIDE A COMPARISON OF NIPSCO'S AND OUCC'S PROPOSED CLASS REVENUE INCREASES UTILIZING THE COMPANY'S PROPOSED $291.8 MILLION OVERALL INCREASE.

A. The following table provides a comparison of NIPSCO's and OUCC's proposed class revenue increases utilizing an overall increase of $291.8 million:

TABLE 7
Comparison Of NIPSCO & OUCC Proposed Revenue Increase

	$ Increase		% Rate Increase	
Rate Description	NIPSCO	OUCC	NIPSCO	OUCC
Rate 811-Residential	$106,656	$107,172	19.39%	19.49%
Rate 820-C&GS Heat Pump	$271	$182	29.01%	19.49%
Rate 821-GS Small	$47,848	$50,832	18.34%	19.49%
Rate 822-Comml SH	$181	$184	19.17%	19.49%
Rate 823-GS Medium	$30,145	$27,473	21.38%	19.49%
Rate 824-GS Large	$40,960	$35,906	22.23%	19.49%
Rate 825-Metal Melting	$1,477	$1,571	18.32%	19.49%
Rate 826-Off-Peak	$34,295	$31,280	21.37%	19.49%
Rate 831-Ind. Pwr Svc.	$16,799	$27,150	12.06%	19.49%
Rate 832-Ind. Svc.-LLF	$3,391	$2,871	23.02%	19.49%
Rate 833-Ind. Svc.-HLF	$5,607	$4,343	25.16%	19.49%
Rate 841-Muni. Power	$807	$860	18.28%	19.49%
Rate 842-Int WW Pump.	($54)	($27)	-49.20%	-25.00%
Rate 543-Sta. Pwr. Ren.	($1,201)	($1,201)	-49.34%	-49.34%
Rate 844-Railroad	$552	$372	28.89%	19.49%
Rate 850-Street Lighting	$1,918	$1,299	28.78%	19.49%
Rate 855-Traffic Lighting	$198	$211	18.25%	19.49%
Rate 860-Dusk-to-Dawn	$762	$514	28.87%	19.49%
Interdepartmental	$1,168	$787	28.92%	19.49%
System Total	$291,780	$291,780	19.37%	19.37%

Q. TO THE EXTENT THE COMMISSION ULTIMATELY AUTHORIZES AN INCREASE LESS THAN $291.8 MILLION, HOW SHOULD THIS INCREASE BE SPREAD ACROSS CLASSES?

A. I recommend that the rate reductions to Rate Schedules 842 and 543 be maintained as set forth in Table 6 and that all other classes receive an equal percentage increase in rate revenues.

V. <u>RESIDENTIAL AND SMALL COMMERCIAL RATE DESIGN</u>

Q. DOES NIPSCO PROPOSE SIGNIFICANT INCREASES TO FIXED MONTHLY CUSTOMER CHARGES FOR THE RESIDENTIAL AND SMALL COMMERCIAL RATE CLASSES?

A. Yes. NIPSCO proposes to increase the current Residential customer charge from $13.50 to $17.00 per month, or by 25.9%. Similarly, the Company proposes to increase the Small Commercial customer charges (Rates 820, 821, and 822) from $30.00 to $34.50

per month, or by 15.0%.

Q. HOW DOES NIPSCO SUPPORT ITS SUBSTANTIAL INCREASES TO FIXED MONTHLY CUSTOMER CHARGES IN THIS CASE?

A. On page 47 of his direct testimony, Witness Taylor states:

> The customer charges provide for recovery of a portion of the Company's fixed costs, which are incurred solely because of the existence of customers connected to the system. These costs, such as the expense of reading meters and billing, occur regardless of whether electricity is used and are not related to demands placed on the system. The proposed customer charge increases will also help to ensure recovery by the Company of a greater portion of its fixed costs of providing service. Inasmuch as customer costs are not related to usage, they should be recovered to the extent possible through a tariff mechanism that does not depend upon volumetric billing.

In short, Mr. Taylor is of the opinion that fixed costs that do not vary with (energy) usage should optimally be recovered from fixed charges. This will be discussed in more detail later in my testimony.

Q. HAS MR. TAYLOR CALCULATED WHAT HE CLAIMS ARE CUSTOMER COSTS FOR THE RESIDENTIAL CLASS?

A. Yes. As stated on page 46 of his direct testimony, Mr. Taylor has calculated Residential customer costs to be $25.55 per month.

Q. IS MR. TAYLOR'S CALCULATED RESIDENTIAL CUSTOMER COST OF $25.55 WITHIN THE RANGE OF REASONABLENESS?

A. No. Customer costs should only reflect those costs required to connect and maintain a customer's account. This is appropriate because these are the only costs that directly vary with number of customers. Other costs that are included in Mr. Taylor's analysis do not vary with number of customers, but rather, are simply the result of placing various rate base and expense items into a classification costing bucket that he refers to as "customer." In this regard, it should be understood that Mr. Taylor first places NIPSCO's total costs by rate base and operating income accounts into one of more of three separate buckets: customer, demand, and/or energy. However, Mr. Taylor's classification has nothing to do with whether a particular cost varies with number of customers but are the result of various classification methods and the result of internal allocations from previously assigned costs.

Q. CAN YOU PROVIDE EXAMPLES OF COSTS THAT MR. TAYLOR HAS INCLUDED AS "CUSTOMER" THAT DO NOT VARY DIRECTLY WITH NUMBER OF CUSTOMERS?

A. Yes. The following table provides examples of rate base and expense items that Mr. Taylor has included within his Residential customer cost analysis:

TABLE 8
Examples of Taylor Inappropriate Residential Customer Costs
($000)

	Cust.	Total	% Cust.
Rate Base (Gross Plant)			
Intangible Plant	$9,341	$43,933	21.26%
Dist. Structures	$1,357	$7,575	17.91%
Dist. Secondary Poles	$71,312	$100,738	70.79%
Dist. Secondary OH Lines	$51,635	$83,870	61.57%
Dist. Secondary UG Conduit	$800	$1,025	77.99%
Dist. Secondary UG Conductors	$79,393	$101,790	78.00%
Dist. Line Transformers	$248,088	$248,088	100.00%
General Plant	$16,696	$68,159	24.50%
Common Plant	$68,075	$201,739	33.74%
Total	$546,696	$856,916	63.80%
O&M			
Dist. OH Lines Operations	($94)	($437)	21.55%
Dist. UG Lines Operations	$550	$2,341	23.48%
Misc. Distribution Operations	$3,610	$8,077	44.70%
Dist. Maint. OH Lines	$5,357	$24,858	21.55%
Dist. Maint. UG Lines	$252	$1,073	23.48%
Dist. Maint. Transformers	$14	$14	100.00%
Uncollectibles	$3,384	$3,384	100.00%
Advertising	$580	$580	100.00%
A&G	$25,039	$106,097	23.60%
Total	$38,691	$145,986	26.50%

As can be seen above, Mr. Taylor's customer cost analysis inappropriately includes at least $546.7 million of plant and $38.7 million of O&M expenses. In addition to these plant amounts, Mr. Taylor's calculations also include the similar level of depreciation expenses.

Q. WITH RESPECT TO MR. TAYLOR'S INCLUSION OF VARIOUS DISTRIBUTION PLANT AMOUNTS SUCH AS STRUCTURES, POLES, AND LINES, DO THESE COSTS DIRECTLY VARY WITH NUMBER OF CUSTOMERS?

A. No. NIPSCO has installed its distribution poles and lines throughout its service territory in order to meet its current and future customer energy needs. This system is in place and does not vary with the addition (or deletion) of number of customers.

Q. WITH RESPECT TO MR. TAYLOR'S INCLUSION OF DISTRIBUTION LINE TRANSFORMERS PLANT, DO THESE COSTS DIRECTLY VARY WITH NUMBER OF CUSTOMERS?

A. Not entirely. While it is true that the addition of a new customer may sometimes require a new dedicated transformer, several customers are often served by the same transformer. More importantly is the fact that transformers are demand-related in that their purpose is to reduce voltage and are sized and placed based on the expected total demand placed on that transformer.

Q. WITH RESPECT TO GENERAL AND COMMON PLANT, DO THESE COSTS VARY DIRECTLY WITH NUMBER OF CUSTOMERS?

A. No. These are simply overhead costs incurred by the Company in order to provide electric service as a business enterprise. These costs do not vary with number of customers but are simply the result of internal allocation procedures that he used to place these costs into one of the three classification buckets.

Q. WITH RESPECT TO THE DISTRIBUTION O&M EXPENSES SHOWN IN TABLE 8, DO ANY OF THESE COSTS VARY DIRECTLY WITH NUMBER OF CUSTOMERS?

A. No.

Q. WITH RESPECT TO UNCOLLECTIBLES EXPENSE, IS IT APPROPRIATE FOR 100% OF THIS EXPENSE TO BE INCLUDED AS A CUSTOMER COST?

A. No. The Company's incurrence of uncollectibles expense is the result of revenue not collected from customer charges as well as variable energy charges. As such, while it is appropriate to include a portion of uncollectible expenses as customer-related, it is not appropriate to include the full amount of this expense item.

Q. WITH RESPECT TO ADVERTISING AND ADMINISTRATIVE & GENERAL EXPENSES, IS IT APPROPRIATE TO INCLUDE A PORTION OF THESE COSTS AS CUSTOMER-RELATED?

A. No. As is the case with general and common plant, these are simply overhead costs.

Q. DO YOU AGREE WITH MR. TAYLOR'S OPINION THAT FIXED CHARGES THAT DO NOT VARY WITH ENERGY USAGE SHOULD BE RECOVERED FROM FIXED CHARGES?

A. No. There is not a single economic theory that supports Mr. Taylor's contention.

Q. DOES NIPSCO'S PROPOSAL TO COLLECT A SUBSTANTIAL PORTION OF RESIDENTIAL BASE RATE REVENUE FROM FIXED MONTHLY CHARGES COMPORT WITH THE ECONOMIC THEORY OF COMPETITIVE MARKETS OR THE ACTUAL PRACTICES OF SUCH COMPETITIVE MARKETS?

A. No. The most basic tenet of competition is that prices determined through a competitive market ensure the most efficient allocation of society's resources. Because public utilities are generally afforded monopoly status under the belief that resources are better utilized without duplicating the fixed facilities required to serve consumers, a fundamental goal of regulatory policy is that regulation should serve as a surrogate for competition to the greatest extent practical.[18] As such, the pricing policy for a regulated public utility should mirror those of competitive firms to the greatest extent practical.

[18] James C. Bonbright, et al., *Principles of Public Utility Rates*, p. 141 (Second Edition, 1988).

Q. PLEASE BRIEFLY DISCUSS HOW PRICES ARE GENERALLY STRUCTURED IN COMPETITIVE MARKETS.

A. Under economic theory, efficient price signals result when prices are equal to marginal costs.[19] It is well known that costs are variable in the long-run. Therefore, efficient pricing results from the incremental variability of costs even though a firm's short-run cost structure may include a high level of sunk or "fixed" costs or be reflective of excess capacity. Indeed, competitive market-based prices are generally structured based on usage; i.e. volume-based pricing. As an example, a colleague of mine often uses the following analogy: an oil refinery costs well over a billion dollars to build such that its cost structure is largely comprised of sunk, or fixed, costs. However, these costs are recovered one gallon at a time.

Q. PLEASE BRIEFLY EXPLAIN THE ECONOMIC PRINCIPLES OF EFFICIENT PRICE THEORY AND HOW SHORT-RUN FIXED COSTS ARE RECOVERED UNDER SUCH EFFICIENT PRICING.

A. Perhaps the best known micro-economic principle is that in competitive markets (i.e., markets in which no monopoly power or excessive profits exist) prices are equal to marginal cost. Marginal cost is equal to the incremental change in cost resulting from an incremental change in output. A full discussion of the calculus involved in determining marginal costs is not appropriate here. However, it is readily apparent that because marginal costs measure the changes in costs with output, short-run "fixed" costs are irrelevant in efficient pricing. This is not to say that efficient pricing does not allow for the recovery of short-run fixed costs. Rather, they are reflected within a firm's production function such that no excess capacity exists and that an increase in output will require an increase in costs -- including those considered "fixed" from an accounting perspective. As such, under efficient pricing principles, marginal costs capture the variability of costs, and prices are variable because prices equal these costs.

[19] Strictly speaking, efficiency is achieved only when there is no excess capacity such that short-run marginal costs equal long-run marginal costs. In practice, there is usually at least some excess capacity present such that pricing based on long-run marginal costs represents the most efficient utilization of resources.

Q. PLEASE EXPLAIN HOW EFFICIENT PRICING PRINCIPLES ARE APPLIED TO THE ELECTRIC UTILITY INDUSTRY.

A. Universally, utility marginal cost studies include three separate categories of marginal costs: demand, energy, and customer. Consistent with the general concept of marginal costs, each of these costs vary with incremental changes. Marginal demand costs measure the incremental change in costs resulting from an incremental change in peak load (demand). Marginal energy costs measure the incremental change in costs resulting from an incremental change in kWh (energy) consumption. Marginal customer costs measure the incremental change in costs resulting from an incremental change in number of customers.

Particularly relevant here is understanding what costs are included within, and the procedures used to determine, marginal customer costs. Since marginal customer costs reflect the measurement of how costs vary with the number of customers, they only include those costs that directly vary as a result of adding a new customer. Therefore, marginal customer costs only reflect costs such as service lines, meters, and incremental billing and accounting costs.

Q. PLEASE EXPLAIN HOW THIS THEORY OF COMPETITIVE PRICING SHOULD BE APPLIED TO REGULATED PUBLIC UTILITIES, SUCH AS NIPSCO.

A. Due to NIPSCO's investment in system infrastructure, there is no debate that many of its short-run costs are fixed in nature. However, as discussed above, efficient competitive prices are established based on long-run costs, which are entirely variable in nature.

Marginal cost pricing only relates to efficiency. This pricing does not attempt to address fairness or equity. Fair and equitable pricing of a regulated monopoly's products and services should reflect the benefits received for the goods or services. In this regard, those that receive more benefits should pay more in total than those who receive fewer benefits. Regarding electricity usage, the level of kWh consumption is the best and most direct indicator of benefits received. Thus, volumetric pricing promotes the fairest pricing mechanism to customers and to the utility.

The above philosophy has consistently been the belief of economists, regulators, and policy makers for generations. For example, consider utility industry pricing in the 1800s, when the industry was in its infancy. Customers paid a fixed monthly fee and consumed as much of the utility commodity/service as they desired (usually water). It soon became apparent that this fixed monthly fee rate schedule was inefficient and unfair. Utilities soon began metering their commodity/service and charging only for the amount actually consumed. In this way, consumers receiving more benefits from the utility paid more, in total, for the utility service because they used more of the commodity.

Q. IS THE ELECTRIC UTILITY INDUSTRY UNIQUE IN ITS COST STRUCTURES, WHICH ARE COMPRISED LARGELY OF FIXED COSTS IN THE SHORT-RUN?

A. No. Most manufacturing and transportation industries are comprised of cost structures predominated with "fixed" costs. These fixed costs are primarily comprised of investments in plant and equipment and are also known as "sunk" costs. Indeed, virtually every capital intensive industry is faced with a high percentage of so-called fixed costs in the short-run. Prices for competitive products and services in these capital-intensive industries are invariably established on a volumetric basis, including those that were once regulated, e.g., motor transportation, airline travel, and rail service.

Accordingly, NIPSCO's position that its fixed costs should be recovered through fixed monthly charges is incorrect. Pricing should reflect the Company's long-run costs, wherein all costs are variable or volumetric in nature, and users requiring more of the Company's products and services should pay more than customers who use less of these products and services. Stated more simply, those customers who conserve or are otherwise more energy efficient, or those who use less of the commodity for any reason, pay less than those who use more electricity.

Q. HOW ARE HIGH FIXED CUSTOMER CHARGE RATE STRUCTURES CONTRARY TO EFFECTIVE CONSERVATION EFFORTS?

A. High fixed charge rate structures actually promote additional consumption because a consumer's price of incremental consumption is less than what an efficient price structure would otherwise be. A clear example of this principle is exhibited in the natural gas transmission pipeline industry. As discussed in its well-known Order 636, the FERC's adoption of a "Straight Fixed Variable" ("SFV") pricing method[20] was a result of national policy (primarily that of Congress) to encourage increased use of domestic natural gas by promoting additional interruptible (and incremental firm) gas usage. The FERC's SFV pricing mechanism greatly reduced the price of incremental (additional) natural gas consumption. This resulted in significantly increasing the demand for, and use of, natural gas in the United States after Order 636 was issued in 1992.

FERC Order 636 had two primary goals. The first goal was to enhance gas competition at the wellhead by completely unbundling the merchant and transportation functions of pipelines.[21] The second goal was to encourage the increased consumption of natural gas in the United States. In the introductory statement of the Order, FERC stated:

> The Commission's intent is to further facilitate the unimpeded operation of market forces to stimulate the production of natural gas... [and thereby] contribute to reducing our Nation's dependence upon imported oil… .[22]

With specific regard to the SFV rate design adopted in Order 636, FERC stated:

> Moreover, the Commission's adoption of SFV should maximize pipeline throughput over time by allowing gas to compete with alternate fuels on a timely basis as the prices of alternate fuels change. The Commission believes it is beyond doubt that it is in the national interest to promote the use of clean and abundant gas over alternate fuels such as foreign oil. SFV is the best method for doing that.[23]

Recently, some public utilities have begun to advocate SFV residential pricing. The companies claim a need for enhanced fixed charge revenues. To support their claim, the companies argue that because retail rates have been historically volumetric based, there

---

[20] Under Straight Fixed Variable pricing, customers pay a fixed charge that is designed to recover all of the utility's fixed costs.
[21] Federal Energy Regulatory Commission, Docket Nos. RM91-11-001 and RM87-34-065, Order No. 636 (Apr. 9, 1992), p. 7.
[22] *Id.* p. 8 (alteration in original).
[23] *Id.* pp. 128-129.

has been a disincentive for utilities to promote conservation or encourage reduced consumption. However, the FERC's objective in adopting SFV pricing suggests the exact opposite. The price signal that results from SFV pricing is meant to promote additional consumption, not reduce consumption. Thus, a rate structure that is heavily based on a fixed monthly customer charge sends an even stronger price signal to consumers to use more energy.

Q. ARE CONSERVATION AND EFFICIENCY GAINS A NEW RISK TO PUBLIC UTILITIES?

A. No. Conservation through efficiency gains has been ongoing for many years and is not a new risk. As a result, even though average residential electric usage per appliance has been declining, utilities have remained financially healthy and have continued their investments under volumetric pricing structures. Also, FERC's movement to straight fixed variable pricing for pipelines was unquestionably initiated to promote additional demand for natural gas, not less, and did in fact do so.

Q. DO THE COMPANY'S PROPOSED RESIDENTIAL AND SMALL COMMERCIAL CUSTOMER CHARGES MOVE FULLY TO SFV PRICING FOR DISTRIBUTION-RELATED COSTS?

A. No. However, the concepts discussed above relating to SFV pricing explain why the inclusion of fixed costs within fixed charges are contrary to conservation efforts. In this regard, it is clear that Mr. Taylor is advocating the movement towards SFV pricing wherein he states on page 50 of his direct testimony: "The proposed rate design makes some movement towards SFV pricing but does not fully move to SFV pricing."

Q. AS A PUBLIC POLICY MATTER, WHAT IS THE MOST EFFECTIVE TOOL THAT REGULATORS HAVE TO PROMOTE COST EFFECTIVE CONSERVATION AND THE EFFICIENT UTILIZATION OF RESOURCES?

A. Unquestionably, one of the most important and effective tools that this, or any, regulatory Commission has to promote conservation is by developing rates that send proper pricing signals to conserve and utilize resources efficiently. A pricing structure that is largely fixed, such that customers' effective prices do not properly vary with consumption, promotes the inefficient utilization of resources. Pricing structures that are weighted heavily on fixed charges are much more inferior from a conservation and efficiency standpoint than pricing structures that require consumers to incur more cost with additional consumption.

Q. A CUSTOMER'S TOTAL ELECTRIC BILL IS COMPRISED OF A BASE RATE COMPONENT, A FUEL ADJUSTMENT CLAUSE ("FAC") RIDER; AND VARIOUS OTHER RIDERS. THESE FUEL AND OTHER RIDERS ARE VOLUMETRICALLY PRICED AND REPRESENT A SIGNIFICANT PORTION OF A CUSTOMER'S BILL. DOES THE VOLUMETRIC PRICING OF THESE COMPONENTS ELIMINATE THE NEED FOR A PROPER PRICING SIGNAL FROM BASE RATES?

A. No, certainly not. The fact that significant revenue may be collected volumetrically through trackers does not lessen the need for reasonable design of the underlying base rates.

Q. NOTWITHSTANDING THE EFFICIENCY REASONS AS TO WHY REGULATION SHOULD SERVE AS A SURROGATE FOR COMPETITION, ARE THERE OTHER RELEVANT ASPECTS TO THE PRICING STRUCTURES IN COMPETITIVE MARKETS *VIS A VIS* THOSE OF REGULATED UTILITIES?

A. Yes. In competitive markets, consumers, by definition, have the ability to choose various suppliers of goods and services. Consumers and the market have a clear preference for volumetric pricing. Utility customers are not so fortunate in that the local utility is a monopoly. The only reason utilities are able to seek pricing structures with high fixed monthly charges is due to their monopoly status. In my opinion, this is a critical consideration in establishing utility pricing structures. Competitive markets and consumers in the United States have demanded volumetric based prices for generations. Hence, a regulated utility's pricing structure should not be allowed to counter the collective wisdom of markets and consumers simply because of its market power.

Q. HAVE YOU CONDUCTED ANY STUDIES OR ANALYSES TO INDICATE THE LEVELS AT WHICH NIPSCO'S RESIDENTIAL AND SMALL COMMERCIAL CUSTOMER CHARGES SHOULD BE ESTABLISHED?

A. Yes. In designing public utility rates, there is a method that produces reasonable fixed monthly customer charges and is consistent with efficient pricing theory and practice. This technique considers only those costs that vary as a result of connecting a new customer and which are required in order to maintain a customer's account. This technique is a direct customer cost analysis and uses a traditional revenue requirement approach. Under this method, capital cost provisions include an equity return, interest, income taxes, and depreciation expense associated with the investment in service lines and meters. In addition, operating and maintenance provisions are included for customer metering, records, and billing.

Under this direct customer cost approach, there is no provision for corporate overhead expenses or any other indirect costs as these costs are more appropriately recovered through energy (kWh) charges.

Q. HAVE YOU CONDUCTED DIRECT CUSTOMER COST ANALYSES APPLICABLE TO NIPSCO'S RESIDENTIAL AND SMALL COMMERCIAL CLASSES?

A. Yes. I conducted a direct customer cost analysis of NIPSCO's residential and small commercial classes. The details of this analysis are provided in my Attachment GAW-2. As indicated in this Attachment and based on the Company's requested return on equity of 10.40%, the Residential direct customer charge is $6.99 per month, while the Small Commercial direct customer cost is $10.49 per month. In this regard, fixed charges are virtually risk-free in that they reflect guaranteed revenue recovery. As a result, and for illustrative purposes, when a return on equity of 9.50% is utilized, the resulting Residential customer cost is $6.75 per month, while the Small Commercial customer cost is $10.16 per month.

Q. WHY IS IT APPROPRIATE TO EXCLUDE CORPORATE OVERHEAD AND OTHER INDIRECT COSTS IN DEVELOPING RESIDENTIAL CUSTOMER CHARGES?

A. Like all electric utilities, NIPSCO is in the business of providing electricity to meet the energy needs of its customers. Because of this and the fact that customers do not subscribe to NIPSCO's services simply to be "connected," overhead and indirect costs are most appropriately recovered through volumetric energy charges.

Q. BASED ON YOUR OVERALL EXPERIENCE AS WELL AS THE STUDIES AND ANALYSES YOU HAVE CONDUCTED FOR THIS CASE, WHAT IS YOUR RECOMMENDATION REGARDING THE APPROPRIATE CUSTOMER CHARGES FOR NIPSCO'S RESIDENTIAL AND SMALL COMMERCIAL CUSTOMERS?

A. Even though my direct customer cost analyses indicates that significant reductions to current fixed monthly customer charges applicable to Residential and Small Commercial customers are appropriate, in the interest of rate continuity, gradualism, and impacts on individual customer bills, I recommend that the current monthly customer charge of $13.50 for Residential and $30.00 for Small Commercial (Rates 820, 821, and 822) be maintained at their current level. In this regard, the large $6.51 to $6.75 difference between my calculated Residential direct customer cost of $6.75 to $6.99 and the current Residential customer charge of $13.50 per month provides a significant level of costs available to recover indirect and general overhead costs associated with residential service. Similarly, for Small Commercial customers, this difference is $19.51 to $19.84 ($30.00 minus $10.49 or $10.16).

Q. PLEASE BRIEFLY SUMMARIZE WHY YOUR RECOMMENDATION TO MAINTAIN THE CURRENT LEVEL OF CUSTOMER CHARGES IS APPROPRIATE.

A. It must be remembered that my proposed rate design will allow the Company a reasonable opportunity to recover all of its costs and earn a fair rate of return. Utility's advocate higher fixed customer charges in order to minimize their risks by guaranteeing revenue recovery through fixed charges. Whether electricity rates are largely volumetric priced or largely based on fixed charges, the reality is that the utility will collect its required revenues. This is particularly relevant in this case since the Company has adjusted actual test year energy usages (kWh) for normal weather. Rate designs structured largely based on volumetric charges promote conservation, are efficient, and are in accordance with pricing practices in competitive markets.

Finally, no cross-subsidization issues are created across customers within the same class as long as the fixed customer charge recovers the incremental cost of connecting and maintaining each customer's account. Indeed, the incremental cost of connecting and maintaining a Residential customer's account is under $7.00 per month. My recommendations to maintain the current customer charge of $13.50 for Residential customers and $30.00 for Small Commercial customers is considerably higher than this incremental cost.

Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes.

BACKGROUND & EXPERIENCE PROFILE
GLENN A. WATKINS
PRESIDENT/SENIOR ECONOMIST
TECHNICAL ASSOCIATES, INC.

EDUCATION

1982 - 1988	M.B.A., Virginia Commonwealth University, Richmond, Virginia
1980 - 1982	B.S., Economics; Virginia Commonwealth University
1976 - 1980	A.A., Economics; Richard Bland College of The College of William and Mary, Petersburg, Virginia

POSITIONS

Jan. 2017-Present	President/Senior Economist, Technical Associates, Inc.
Mar. 1993-Dec. 2016	Vice President/Senior Economist, Technical Associates, Inc. (Mar. 1993-June 1995 Traded as C. W. Amos of Virginia)
Apr. 1990-Mar. 1993	Principal/Senior Economist, Technical Associates, Inc.
Aug. 1987-Apr. 1990	Staff Economist, Technical Associates, Inc., Richmond, Virginia
Feb. 1987-Aug. 1987	Economist, Old Dominion Electric Cooperative, Richmond, Virginia
May 1984-Jan. 1987	Staff Economist, Technical Associates, Inc.
May 1982-May 1984	Economic Analyst, Technical Associates, Inc.
Sep. 1980-May 1982	Research Assistant, Technical Associates, Inc.

EXPERIENCE

I. Public Utility Regulation

A. Costing Studies -- Conducted, and presented as expert testimony, numerous embedded and marginal cost of service studies. Cost studies have been conducted for electric, gas, telecommunications, water, and wastewater utilities. Analyses and issues have included the evaluation and development of alternative cost allocation methods with particular emphasis on ratemaking implications of distribution plant classification and capacity cost allocation methodologies. Distribution plant classifications have been conducted using the minimum system and zero-intercept methods. Capacity cost allocations have been evaluated using virtually every recognized method of allocating demand related costs (e.g., single and multiple coincident peaks, non-coincident peaks, probability of loss of load, average and excess, and peak and average).

Embedded and marginal cost studies have been analyzed with respect to the seasonal and diurnal distribution of system energy and demand costs, as well as cost effective approaches to incorporating energy and demand losses for rate design purposes. Economic dispatch models have been evaluated to determine long range capacity requirements as well as system marginal energy costs for ratemaking purposes.

B. Rate Design Studies -- Analyzed, designed and provided expert testimony relating to rate structures for all retail rate classes, employing embedded and marginal cost studies. These rate structures have included flat rates, declining block rates, inverted block rates, hours use of demand blocking, lighting rates, and interruptible rates. Economic development and special industrial rates have been developed in recognition of the competitive environment for specific customers. Assessed alternative time differentiated rates with diurnal and seasonal pricing structures. Applied Ramsey (Inverse Elasticity) Pricing to marginal costs in order to adjust for embedded revenue requirement constraints.

GLENN A. WATKINS

C. Forecasting and System Profile Studies -- Development of long range energy (Kwh or Mcf) and demand forecasts for rural electric cooperatives and investor owned utilities. Analysis of electric plant operating characteristics for the determination of the most efficient dispatch of generating units on a system-wide basis. Factors analyzed include system load requirements, unit generating capacities, planned and unplanned outages, marginal energy costs, long term purchased capacity and energy costs, and short term power interchange agreements.

D. Cost of Capital Studies -- Analyzed and provided expert testimony on the costs of capital and proper capital structures for ratemaking purposes, for electric, gas, telephone, water, and wastewater utilities. Costs of capital have been applied to both actual and hypothetical capital structures. Cost of equity studies have employed comparable earnings, DCF, and CAPM analyses. Econometric analyses of adjustments required to electric utilities cost of equity due to the reduced risks of completing and placing new nuclear generating units into service.

E. Accounting Studies -- Performed and provided expert testimony for numerous accounting studies relating to revenue requirements and cost of service. Assignments have included original cost studies, cost of reproduction new studies, depreciation studies, lead-lag studies, Weather normalization studies, merger and acquisition issues and other rate base and operating income adjustments.

II. Transportation Regulation

A. Oil and Products Pipelines -- Conducted cost of service studies utilizing embedded costs, I.C.C. Valuation, and trended original cost. Development of computer models for cost of service studies utilizing the "Williams" (FERC 154-B) methodology. Performed alternative tariff designs, and dismantlement and restoration studies.

B. Railroads -- Analyses of costing studies using both embedded and marginal cost methodologies. Analyses of market dominance and cross-subsidization, including the implementation of differential pricing and inverse elasticity for various railroad commodities. Analyses of capital and operation costs required to operate "stand alone" railroads. Conducted cost of capital and revenue adequacy studies of railroads.

III. Insurance Studies

Conducted and presented expert testimony relating to market structure, performance, and profitability by line and sub-line of business within specific geographic areas, e.g. by state. These studies have included the determination of rates of return on Statutory Surplus and GAAP Equity by line - by state using the NAIC methodology, and comparison of individual insurance company performance vis a vis industry Country-Wide performance.

Conducted and presented expert testimony relating to rate regulation of workers' compensation, automobile, and professional malpractice insurance. These studies have included the determination of a proper profit and contingency factor utilizing an internal rate of return methodology, the development of a fair investment income rate, capital structure, cost of capital.

Other insurance studies have included testimony before the Virginia Legislature regarding proper regulatory structure of Credit Life and P&C insurance; the effects on competition and prices resulting from proposed insurance company mergers, maximum and minimum expense multiplier limits, determination of specific class code rate increase limits (swing limits); and investigation of the reasonableness of NCCI's administrative assigned risk plan and pool expenses.

GLENN A. WATKINS

IV. Anti-Trust and Commercial Business Damage Litigation

Analyses of alleged claims of attempts to monopolize, predatory pricing, unfair trade practices and economic losses. Assignments have involved definitions of relevant market areas(geographic and product) and performance of that market, the pricing and cost allocation practices of manufacturers, and the economic performance of manufacturers' distributors.

Performed and provided expert testimony relating to market impacts involving automobile and truck dealerships, incremental profitability, the present value of damages, diminution in value of business, market and dealer performance, future sales potential, optimal inventory levels, fair allocation of products, financial performance; and business valuations.

MEMBERSHIPS AND CERTIFICATIONS

Member, Association of Energy Engineers (1998)
Certified Rate of Return Analyst, Society of Utility and Regulatory Financial Analysts (1992)
Member, American Water Works Association
National Association of Business Economists
Richmond Association of Business Economists
National Economics Honor Society

NORTHERN INDIANA PUBLIC SERVICE COMMISSION
Customer Cost Analysis

		Residential	Total Small Commercial
Gross Plant			
369	Services	$282,406,950	$40,591,294
370	Meters	$73,318,637	$19,527,229
	Total Gross Plant	**$355,725,587**	**$60,118,523**
Depreciation Reserve			
	Services	$158,198,633	$22,738,418
	Meters	$27,274,070	$7,226,806
	Total Depreciation Reserve	**$185,472,703**	**$29,965,224**
Total Net Plant		**$170,252,884**	**$30,153,299**
Operation & Maintenance Expenses			
586	Dist Oper - Meter	$1,169,571	$309,901
587	Customer Installations	$1,840,272	$519,839
597	Meters Maintenance	$462,711	$122,604
902	Meter Reading Expenses	$708,541	$180,112
903	Records & Collections	$7,199,111	$1,223,664
	Total O & M Expenses	**$11,380,206**	**$2,356,120**
Depreciation Expense			
	Services	$4,235,320	$608,757
	Meters	$2,343,370	$620,922
	Total Depreciation Expense	**$6,578,690**	**$1,229,679**
Revenue Requirement			
	Interest	$3,290,079	$582,702
	Equity return	$10,363,635	$1,835,492
	State Income Taxes	$675,928	$119,713
	Federal Income Taxes	$2,754,890	$487,916
	Revenue For Return	17,084,532	3,025,823
	O & M Expenses	$11,380,206	$2,356,120
	Depreciation Expense	$6,578,690	$1,229,679
	Subtotal Customer Revenue Requirement	$35,043,428	$6,611,622
	Total Revenue Requirement	**$35,043,428**	**$6,611,622**
	Number of Customers	419,221	52,701
	Number of Bills	5,030,652	632,412
	Monthly Cost Before Bad Debts & Utility Receipts Ta:	$6.97	$10.45
	Bad Debts + Utility Receipts Tax Rate	0.3802%	0.3802%
	TOTAL MONTHLY CUSTOMER COST	$6.99	$10.49

AFFIRMATION

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

____
Glenn A. Watkins
President & Senior Economist of Technical Associates, Inc.
Consultant for the
Indiana Office of Utility Consumer Counselor

Cause No. 45772
NIPSCO

January 17, 2023______________________
Date

Certificate of Service

This is to certify that a copy of the Indiana Office of Utility Consumer Counselor's Testimony Filing has been served upon the following parties of record in the captioned proceeding by electronic service on January 20, 2023.

Petitioner
Bryan Likins
Tiffany Murray
Debi McCall
NIPSCO, LLC
blikins@nisource.com
tiffanymurray@nisource.com
demccall@nisource.com

Nicholas Kile
Lauren Box
Lauren Aguilar
Hillary Close
BARNES & THORNBURG
nicholas.kile@btlaw.com
lauren.box@btlaw.com
laguilar@btlaw.com
hillary.close@btlaw.com

Walmart-Intervenor
Eric E. Kinder
Barry A. Naum
Steven W. Lee
SPILMAN THOMAS & BATTLE, PLLC
ekinder@spilmanlaw.com
bnaum@spilmanlaw.com
slee@spilmanlaw.com

IMUG-Intervenor
Robert M. Glennon
ROBERT GLENNON & ASSOC., P.C.
robertglennonlaw@gmail.com
With a copy to:
Ted.sommer@lwgcpa.com

U.S. Steel-Intervenor
Nikki Shoultz
Kristina Wheeler
BOSE MCKINNEY & EVANS, LLP
nshoultz@boselaw.com
kwheeler@boselaw.com
With a copy to:
lbood@boselaw.com

CAC-and Earthjustice –Intervenor
Jennifer A. Washburn
CITIZENS ACTION COALITION
jwashburn@citact.org
With a copy to:
sfisk@earthjustice.org
sdoshi@earthjustice.org
mozaeta@earthjustice.org
rkurtz@citact.org

NLMK-Intervenor
Anne Becker
LEWIS & KAPPES, P.C.
abecker@lewis-kappes.com
with a copy to:
atyler@lewis-kappes.com
etennant@lewis-kappes.com

NLMK Co-counsel
James W. Brew
STONE MATTHEIS XENOPOULOS & BREW
jbrew@smxblaw.com
With a copy to:
AMG@smxblaw.com

IG NIPSCO-Intervenor
Todd A. Richardson
Joseph P. Rompala
Aaron A. Schmoll
LEWIS-KAPPES, P.C.
trichardson@lewis-kappes.com
jrompala@lewis-kappes.com
aschmoll@lewis-kappes.com
with a copy to:
atyler@lewis-kappes.com
etennant@lewis-kappes.com

Midwest Industrial User's Group
James W. Hortsman
JAMES W. HORTSMAN LAW GROUP, LLC
jhortsman@hortsman.com

ChargePoint, Inc.-Intervenor
David T. McGimpsey
DENTON BINGHAM GREENBAUM LLP
david.mcgimpsey@dentons.com
With a copy to:
Connie.bellner@dentons.com

RV Group-Intervenor
Keith L. Beall
Clark, Quinn, Moses, Scott & Grahn, LLP
kbeall@clarkquinnlaw.com

Kelly Earls, Attorney No. 29653-49
Deputy Consumer Counselor
OFFICE OF UTILITY CONSUMER COUNSELOR
115 W. Washington St. Suite 1500 South
Indianapolis, IN 46204
Direct Line: 317.233.3235
Email: KeEarls@oucc.in.gov
infomgt@oucc.in.gov