STATE OF NEW HAMPSHIRE
BEFORE THE
PUBLIC UTILITIES COMMISSION

In the matter of
Public Service Company of
New Hampshire
Petition for Permanent Rate Increase

Docket No. DE 09-035

DISTRIBUTION RATE CASE

DIRECT TESTIMONY OF
George R. McCluskey

Analyst, Electric Division

January 15, 2010

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DIRECT TESTIMONY
OF
GEORGE R. McCLUSKEY

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is George McCluskey, and my business address is the New Hampshire Public Utilities Commission ("Commission"), 21 South Fruit Street, Suite 10, Concord, NH 03301.

Q. WHAT IS YOUR POSITION WITH THE COMMISSION?

A. I am an Analyst within the Electric Division.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL EXPERIENCE.

A. A copy of my resume is included as Staff Exhibit-GRM 1.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. On June 30, 2009, Public Service Company of New Hampshire (PSNH or Company) filed proposed new tariff pages seeking an increase in distribution revenue requirements of $51 million effective 8/1/2009, equivalent to a system average rate of return (ROR) on rate base of 7.59%.[1] The proposed $51 million increase would mean a 4.2% average increase on total bills and a 20.95% average increase on distribution bills. In fact, PSNH is proposing an across the board increase of 20.95% in distribution class revenue requirements. PSNH also seeks to alter its rate design, in part by increasing customer charges and distribution demand charges and decreasing distribution energy charges. In support of its rate design proposals, PSNH filed the direct testimony of Stephen Hall. It also filed a technical statement prepared by Charles Goodwin that describes the methodology used to develop the Company's embedded distribution cost of service study (COSS). The results of the COSS were submitted as exhibits to Mr. Goodwin's technical statement.

My testimony addresses three key issues. The first is the method used to classify costs in Mr. Goodwin's embedded COSS. The second is the development of the proposed class revenue requirements. The third issue is the appropriateness of the proposed rate design and delivery service tariff changes contained in Mr. Hall's testimony. This testimony is presented on behalf of the Staff of the Electric Division.

Q. HOW IS STAFF'S TESTIMONY ORGANIZED?

A. This introduction is followed by a brief description of the Company's filing as it relates to cost of service and rate design issues. The third section includes Staff's analysis of the embedded COSS including the proposed classification of certain

[1] PSNH actually requested a ROR of 8.108%, equivalent to an increase of $68.2 million inclusive of ice storm and reliability enhancement costs. PSNH proposed to collect the $17 million difference through a step adjustment effective 7/1/10. On December 15, 2009, updated its request to increase distribution revenues to $50.9 million effective 8/1/09 and $67.6 million effective 7/1/10.

distribution-related plant to the customer-related category based on the minimum distribution system (MDS) method. This section also includes Staff's recommendations for class revenue requirements. The fourth section contains Staff's analysis of the proposed rate design changes and the fifth section contains an analysis of the proposed changes in the delivery service tariff.

II. COMPANY FILING

Q. PLEASE PROVIDE A BRIEF OVERVIEW OF THE COMPANY'S FILING AS IT RELATES TO COST OF SERVICE AND RATE DESIGN.

A. Pursuant to the Commission's filing requirements the Company included its embedded COSS for the twelve months ending December 31, 2008 and a supporting technical statement prepared by Charles Goodwin. According to Mr. Goodwin, the COSS provides a cost based determination of the amount of the distribution revenue requirement attributable to each rate class.

A key result of the COSS is that class rates of return during the test year varied significantly among rate classes. Specifically, the ROR for Primary General Service Rate GV was 18.97%, Large General Service Rate LG 13.65%, General Service Rate G 8.8%, and Residential Service Rate R 0.53%.[2] These returns compare with a system average ROR of 3.89%. Despite these significant differences, the Company is not proposing to re-allocate distribution revenue requirements among the classes in order to mitigate subsidization concerns. Instead, the Company is proposing an across the board increase in distribution

[2] See PSNH Petition, Volume III – Standard Filing Requirements and Workpapers, June 30, 2009, Pages 000051-52.

class revenue requirements. Accordingly, class rates of return will not move closer to the system average under the Company's proposal.

Q. WHY HAS THE COMPANY PROPOSED AN ACROSS THE BOARD INCREASE?

A. The Company states that its primary ratemaking goal is not to assign costs to those that cause them but to provide bill stability for customers so as to avoid controversy.

Q. STAFF INDICATED THAT THE COMPANY IS SEEKING AN INITIAL DISTRIBUTION REVENUE INCREASE THAT WOULD RAISE THE SYSTEM AVERAGE ROR TO 7.59%. WHAT EFFECT WOULD THIS INCREASE HAVE ON THE CLASS RATES OF RETURN REFERENCED ABOVE?

A. The Company has calculated that the class rates of return would increase to: 26.48% for the Rate GV, 20.09% for Rate LG, 14.0% for Rate G and 3.29% for Rate R.[3]

Q. WHAT CONCERNS DOES STAFF HAVE WITH MR. GOODWIN'S COSS?

A. Staff has two key concerns. The first relates to the proposed classification of distribution-related plant in FERC Accounts 364 through 367 as customer-related using the MDS method. The theory behind MDS is that distribution plant (poles, lines, transformers) is designed not just to serve customers' demand for electricity, but also to connect customers to the distribution system regardless of their need to use electricity. In other words, it assumes that customers would pay to connect to the distribution system even if they have zero demand for electricity.

[3] See PSNH Response to Staff 02-81 which is attached as Staff Exhibit-GRM 2.

Some experts have likened this to charging customers a fee to enter a grocery store to have an opportunity to shop.

Our second concern focuses on the contrast between the disparate rates of return earned by PSNH's rate classes and the proposed across the board increase in class distribution revenues.

Q. PLEASE DESCRIBE THE MDS METHOD.

A. As noted, the MDS method is based upon the assumption that the utility incurs certain costs solely for the purpose of connecting each customer in its service territory. Estimating these costs requires determining the average book cost for the minimum size pole, conductor, cable and any other components of equipment or service that is installed by the utility.

Q. BEFORE BEGINNING THE ANALYSIS OF THE COMPANY'S FILING, PLEASE SUMMARIZE STAFF'S RECOMMENDATIONS.

A. Staff recommends:

1. Rejecting the proposal to classify distribution plant based on the minimum distribution system method.
2. Classifying distribution plant as demand-related.
3. Using cost causation as the primary determinant of class revenue requirements.
4. Moving class rates of return closer to the system average in order to mitigate inter-class subsidies.
5. Increasing customer-charges by a smaller percentage than proposed and increasing demand charges by a larger percentage than proposed.
6. Modifying the proposed tariff provision regarding the rental of pole-mounted apparatus.
7. Modifying the proposed master metering provision so that it conforms to the Commission's rules
8. Approving as filed the proposal to eliminate for government units and civic groups the option to pay excess outdoor lighting costs over an extended period.
9. Approving as filed the proposed midnight outdoor lighting service option.

III. STAFF ANALYSIS OF EMBEDDED COSS

1. Minimum Distribution System (MDS) Method

Q. STAFF SAID THAT A KEY PURPOSE OF ITS TESTIMONY IS TO ADDRESS COST CLASSIFICATION AND ALLOCATION ISSUES IN PSNH'S TECHNICAL STATEMENT ON COST OF SERVICE. PLEASE EXPLAIN CLASSIFICATION AND ALLOCATION.

A. Many of the costs that PSNH incurs in providing electric service to its customers are joint costs. Joint costs are the costs of shared facilities such as distribution substations and lines that serve multiple customers. In order to determine the cost to serve each class, these joint costs must be shared among the customer classes that use the facilities. The first step in this process is called functionalization. Distribution utility costs are booked into functional accounts such as substations and overhead and underground lines. Classification is the further division of these functional costs into categories bearing a relationship to a measurable cost-defining service characteristic. Electric utilities traditionally use the classification categories of customer, energy, and demand. Once the costs are classified, they can be allocated to customer classes. Allocation is the apportionment of joint costs among rate classes based on each class's relative share of a measurable cost-defining service characteristic such as kilowatt-hours or peak demand in kilowatts. Costs classified as customer-related are allocated based on the number of customers, sometimes weighted by some cost information. Energy-related costs are allocated on relative energy usage. Demand-related costs are allocated on relative demands.[4]

Q. HOW DID THE COMPANY CLASSIFY ITS DISTRIBUTION PLANT?

A. As noted, distribution plant is typically booked into functional accounts including substations, primary lines, line transformers, secondary lines, service drops, and meters. Meters and service drops were classified by the Company as customer-related together with approximately fifty percent of primary and secondary distribution lines on the ground that the costs of these assets are also driven by numbers of customers. The other parts of primary and secondary lines were classified as demand-related together with substations.

Q. WHAT IS THE COMPANY'S BASIS FOR ASSERTING THAT THERE IS A CUSTOMER-RELATED COMPONENT TO DISTRIBUTION PLANT COSTS?

A. The portion of primary and secondary lines classified as customer-related was determined based on the MDS method. This method, according to PSNH, was endorsed by the National Association of Regulatory Utility Commissioners ("NARUC") Electric Utility Cost Allocation Manual (NARUC Manual).

Q. DOES STAFF AGREE THAT THE NARUC MANUAL ENDORSES THE MDS METHOD?

A. No, we do not. Inclusion of a particular cost-of-service method in the NARUC Manual is not evidence that NARUC recommends the method or that an industry-wide consensus exists as to the appropriateness of the method. Indeed, the preface to the Manual specifically states that one of its objectives was that "[t]he

[4] This explanation is based on testimony submitted in 2009 by Lowell E. Alt on behalf of the Rocky Mountain Power Company before the Utah Public Service Commission.

writing style should be non-judgmental; not advocating any one particular method but trying to include all currently used methods with pros and cons." If that extract is not considered sufficiently clear as to the Manual's purpose, the following should remove any doubt:

> This manual only discusses the major costing methodologies. It recognizes that no single costing methodology will be superior to any other, and the choice of methodology will depend on the unique circumstances of each utility. Individual costing methodologies are complex and have inspired numerous debates on application, assumptions and data. NARUC Manual, page 22

Thus, contrary to the Company's assertion, the NARUC Manual does not endorse any particular costing methodology.

Q. THE NARUC MANUAL WAS PREPARED ALMOST TWO DECADES AGO. DOES IT CONTINUE TO SERVE A PURPOSE?

A. While it continues to serve the purpose of explaining costing methodologies, it does not reflect the more recent decisions that regulators have made about cost classification and allocation issues. In 2000, the NARUC Committee on Energy Resources and the Environment hired the Regulatory Assistance Project (RAP) to examine these and other issues. RAP's paper, which is entitled: Charging for Distribution Utility Services: Issues in Rate Design, discusses among other things the classification of distribution-related costs and states at page 30:

> There are a number of methods for differentiating between the customer and demand components of embedded distribution plant. The most common method used is the basic customer method, which classifies all poles, wires, and transformers as demand-related and meters, meter reading, and billing as customer-related. This general approach is used in more than thirty states.

That is, this more current study not only recognizes the validity of the basic customer method but it also finds that it is used in a majority of states.

Q. WHAT METHODOLOGY IS TYPICALLY USED IN NEW HAMPSHIRE?

A. Other than PSNH, Staff is not aware of any New Hampshire electric, gas or water utility that uses the MDS method for classifying distribution plant. The predominant cost classification methodology is the basic customer method. As noted, this method classifies metering, meter-reading, billing, and service line costs as customer-related and distribution plant costs as demand-related.

Q. DID THE COMMISSION AUTHORIZE PSNH TO USE THE MDS METHOD TO CLASSIFY COSTS?

A. Not explicitly. Although the COSS filed by PSNH in Docket DE 06-028 was based on the MDS method, cost classification was not addressed in the Company's pre-filed testimony or in the testimony submitted by Staff. In addition, cost classification was not addressed in the settlement agreement filed by the parties and approved by the Commission. In short, the Commission has not previously considered the validity of the MDS method for classifying PSNH distribution plant. We note, however, that the Commission did authorize the New Hampshire Electric Cooperative in 1995 to use the zero intercept method to classify distribution plant. See Order No. 21,693, June 20, 1995, Docket 93-124. The zero intercept method is a variant of the MDS method.

Q. DOES STAFF BELIEVE THE MDS METHOD IS VALID?

A. No, we do not. The MDS is a fabricated system that bears no relation to the way costs are actually incurred by distribution companies to serve customers. A customer will connect to a utility's distribution system only if it expects to use electricity, and the utility will incur distribution system costs only if that usage adds to the distribution system peak demand.

Q. DID STAFF OR THE COMPANY RE-CALCULATE THE CLASS RATES OF RETURN BASED ON THE ASSUMPTION THAT DISTRIBUTION PLANT IS A DEMAND-RELATED COST AND ALLOCATED TO CUSTOMERS BASED ON THE ALLOCATORS USED BY THE COMPANY?

A. Yes. As the table below shows, the resulting class rates of return are much more uniform than the rates of return that resulted from using the MDS method. Rate GV has the highest return at 11.73% whereas Rate LG at 6.36%, Rate G at 8.37% and Rate R at 6.52% are much closer to the system average ROR of 7.59%.[5] These data suggest that the MDS method results in proportionately more distribution plant being allocated to the residential class and proportionately less to the other classes compared to the basic customer method. In other words, the MDS method is the chief cause of the disparate class rates of return.

TABLE I
Class Rates-of-Return

	Rate R	Rate G	Rate GV	Rate LG	Rate B	Overall
MDS Method	3.29%	14.00%	26.48%	20.09%	13.82%	7.59%
Basic Customer Method	6.52%	8.73%	11.73%	6.36%	2.08%	7.59%

Q. IS THERE ANOTHER REASON FOR OPPOSING THE MDS METHOD?

A. Yes. As we have just seen, the MDS method is the principal cause of the disparate class rates of return that result from the COSS. Amazingly, however,

[5] See PSNH Response to Staff 05-11 which is attached as Staff Exhibit-GRM 3.

the Company is opposed to basing the class revenue targets on the results of its COSS. Instead of recommending class revenue targets that would move class rates of return closer to the system average, the Company is proposing to lock in the disparate rates of return. The reader would be excused at this point for asking why a utility would vigorously advocate a particular costing methodology but just as vigorously oppose implementing the results. The answer is that the MDS method affects not only the class rates of return but also the costs classified as customer-related. In fact, it substantially increases the costs classified as customer-related; a result the Company utilizes to support its proposal to shift costs from kWh-related charges to customer charges. To sum up, the Company is asking the Commission to accept the results of the COSS as support for its *intra-class* rate design proposals, which incidentally benefit the Company financially, but ignore those results when it comes to formulating *inter-class* rate design proposals. Staff believes this position is untenable and should be rejected.

Q. IS IT STAFF'S OPINION THAT CLASS REVENUE TARGETS SHOULD REFLECT CLASS RATES OF RETURN CALCULATED USING THE BASIC CUSTOMER METHOD?

A. Yes, it is.

2. Class Revenue Requirements

Q. IF THE COMMISSION AGREES WITH STAFF AND REJECTS THE MDS METHOD, WHAT CLASS REVENUE REQUIREMENTS SHOULD BE ADOPTED?

A. To be consistent with the principle of cost causation (i.e., assign costs to those who cause them), the class revenue requirements approved in this case should reflect the results of the COSS. That is, rate classes that produce higher than average returns should receive smaller than average increases in their revenue requirements while rate classes that produce lower than average returns should receive higher than average increases. Another way of saying this is that class rates of return should be moved closer to the system average.[6] In this proceeding, that would mean lower than average increases for rate classes GV and G and higher than average increases for rate classes LG and R.[7] However, because Rate GV is the only class with a ROR substantially different from the average, we recommend that the revenue requirement for that class be set such that the class ROR is within 1.5% points of the system average. The revenue requirements for all other classes should be increased by an equal percentage consistent with the above constraint.

Q. DOES MR. GOODWIN BELIEVE THAT STAFF'S APPROACH TO SETTING CLASS REVENUE TARGETS IS REASONABLE?

A. Not in this proceeding. However, in two cases before the Connecticut Department of Public Utility Control, he effectively took the same position. In testimony filed on behalf of Connecticut Light and Power Company in a 2007 case, Mr. Goodwin stated that:

> Both the Company and the Department have expressed a desire to better reflect the COSS results (both class ROR and rate design) in future rate proceedings. However, it is simply unrealistic to expect that distribution

[6] Note that because Staff is not proposing to move to equal rates of return in one step, our recommendation combines the cost causation and rate stability goals.

[7] Staff believes the increase for Rate B should be subject to further review of the Company's COSS.

> rates will conform to full cost-based rates in one step, while maintaining some level of rate continuity among and within rate classes. The process of moving closer to cost-based rates should start now in this proceeding, but it will likely take a series of rate adjustments over time before actual rate design will mirror full cost-based rates.

He went on to say that:

> The Company has addressed the challenge of rate design in this proceeding with three primary objectives in mind. The first is that, with class rates of return ("ROR") so widely disparate, equalized class ROR cannot be achieved. Therefore, CL&P's rate design proposal is looking to narrow, not eliminate, the disparity among class ROR.

In testimony filed on behalf of Yankee Gas Services Company in a 2006 case, Mr. Goodwin stated the following:

> [T]otal firm and seasonal rates were designed in Phase 1 to recover $194.844 million of Distribution revenues. This exhibit confirms that the proposed rate design recovers precisely the same level of revenue. The exhibit also shows in the far right-hand column the resulting overall class revenue increase or decrease in total Distribution revenue under Yankee's proposal. Those rate classes that currently contribute lower than the system average ROR will realize increases in Distribution components, while those classes currently above the system average ROR will realize decreases under this proposal.

Q. IF THE COMMISSION DISAGREES WITH STAFF AND DECIDES THAT IT IS APPROPRIATE TO USE THE MDS METHOD FOR COST CLASSIFICATION PURPOSES, WHAT APPROACH SHOULD BE USED TO ESTABLISH CLASS REVENUE REQUIREMENTS?

A. Again, to be consistent with the principle of cost causation, revenues must be reallocated from classes that have higher than average ROR to classes that have lower than average ROR. Since the MDS-based COSS indicates that all rate classes other than Rate R have higher than average ROR, those classes should be awarded smaller revenue increases than the increase awarded to Rate R. In this way, the ROR for each class will be moved closer to the system average ROR.

Q. WHAT ROR TARGETS DOES STAFF RECOMMEND?

A. The table below shows for each of the major rate classes the difference between the proposed ROR and the system average. What is clear from this table is that under the Company's proposal Rate R will continue to be heavily subsidized by the other classes, particular Rates GV and LG. In order to mitigate this subsidy and move in the direction of having each class pay its fair share of the cost of service, we recommend the class revenue requirements for Rates G, GV, LG and B be set such that the difference between the class ROR and the system average is no greater than half the difference shown in the table. The resulting revenue shortfall from rates G, GV, LG and B would be re-allocated to Rate R. Very roughly, we estimate this would raise the ROR for Rate R to about 5.5%, equivalent to a distribution revenue increase of 28% instead of the proposed 21%. To continue the movement towards equalized class rates of return, Staff also recommends that the proposed $17 million step increase effective 7/1/10 be collected based on the relative percentage increases in revenue requirements that result from this phase of the proceeding.

TABLE 2
PSNH Proposed Class ROR

	Rate R	Rate G	Rate GV	Rate LG	Rate B	System
PSNH Proposed	3.29%	14.00%	26.48%	20.09%	13.81%	7.59%
Difference vs System	-4.30%	6.41%	18.89%	12.50%	6.22%	0.00%

IV. RATE DESIGN

Q. HAS STAFF REVIEWED PSNH'S PROPOSED RATE DESIGN IN THIS CASE?

A. Yes. Mr. Hall's approach to rate design is quite simple:

- Increase each class revenue requirement by the proposed system average increase.
- For each class, increase the customer and demand charges by specified amounts (i.e., 34% and 28% respectively) and adjust the energy-related (i.e., kWh-related) charges by an equal percentage such that the class revenue target is met.

Q. DOES STAFF SUPPORT THE PROPOSED RATE DESIGN?

A. No. For the reasons stated above, we recommended that class rates of return be moved closer to the system average resulting in class revenue requirements increasing by different percentages.

In addition, the classification of all primary and secondary distribution plant as demand-related per our recommendation results in fewer customer-related dollars to be collected through customer charges and more demand-related dollars to be collected through demand charges. For this reason, we recommend that customer-charges be increased by a smaller percentage than proposed and demand charges by a larger percentage while keeping the proposed increase in energy charges at roughly the same level.

Q. WHAT PERCENTAGE INCREASES DOES STAFF RECOMMEND?

A. We recommend that the percentage increase in customer charges be no higher than the percentage increase in distribution revenue approved by the Commission.

For rate classes that have demand charges, the demand charges could be increased by a larger percentage provided the additional revenue to be generated by the higher charge is offset by a corresponding reduction in energy charges. For rate classes that do not have demand charges, the energy and customer charges would increase at the same percentage.

V. DELIVERY SERVICE TARIFF CHANGES

Q. IS PSNH PROPOSING ANY CHANGES TO ITS DELIVERY SERVICE TARIFF?

A. Beyond the intra and inter class changes described above, PSNH is proposing four tariff changes that relate to:

(i) Rental of pole mounted apparatus;
(ii) Separate metering of multi-unit dwellings;
(iii) Outdoor lighting payment arrangements for government units and civic groups;
(iv) Midnight outdoor lighting service option.

1. <u>Rental of Pole-Mounted Apparatus</u>

Q. PLEASE SUMMARIZE THE PROPOSED TARIFF CHANGES THAT ADDRESS THE RENTAL OF POLE-MOUNTED APPARATUS.

A. PSNH is requesting that it be given the option to refuse to rent pole-mounted transformers to GV and LG customers "because it has no control over the maintenance of support structures or the area surrounding those structures." In addition, PSNH is proposing to add language to its tariff that authorizes it to terminate existing apparatus rental agreements with GV and LG customers and remove pole-mounted transformers upon 90 days written notice to customers. PSNH states that it would only utilize the authority to terminate existing rental agreement when a customer-owned structure supporting a PSNH owned pole-mounted transformer is deemed insufficient or threatened by trees or other hazards and the customer refuses to replace the support structure and/or remove the hazard.

Q. DOES STAFF SUPPORT THE PROPOSAL TO REFUSE TO RENT TO GV AND LG CUSTOMERS?

A. Not as written. The proposed tariff language gives PSNH the unfettered ability to refuse any rental request without specifying the reasons on which the refusal is based. At a minimum, any new provision must require PSNH to identify the alleged hazard and provide the customer an opportunity to remove it before the rental request is refused. Providing the customer the option to rent a pad-mounted transformer from PSNH does not address these weaknesses.

Q. REGARDING THE PROPOSAL TO TERMINATE EXISTING RENTAL AGREEMENTS FOR POLE-MOUNTED APPARATUS, HOW MANY SUCH AGREEMENTS DOES PSNH HAVE?

A. PSNH states that it currently has 1,199 agreements for pad-mounted and pole-mounted transformers for customers served under Rate GV and 62 rental agreements for pad-mounted and pole-mounted transformers for customers served under Rate LG. According to PSNH, information relating to the number of rental agreements for pole-mounted versus pad-mounted transformers "is not readily available."

Q. WHAT DOES STAFF RECOMMEND?

A. Absent information on the number of customers that could potentially be impacted by this proposed tariff change, Staff is reluctant to recommend approval. In addition, the proposed tariff language does not require: (i) the Company to identify the alleged hazard and to request its removal prior to issuing a termination notice; or (ii) specify who is responsible for any un-recovered cost of the disconnected transformers. These problems should be rectified.

Q. HAVE THERE BEEN INSTANCES WHERE CUSTOMERS THAT RENT POLE-MOUNTED TRANSFORMERS HAVE REFUSED TO REMOVE A HAZARD?

A. PSNH states that is not aware of any instances over the last five years where a customer has refused to remove a hazard. This fact highlights the importance of requiring the Company to make a determined effort to have the hazard removed prior to issuing a termination notice.

2. <u>Separate Metering of Multi-Unit Dwellings</u>

Q. WHAT IS THE BASIS FOR THE PROPOSED TARIFF CHANGE?

A. PSNH contends that the proposed change in its tariff relating to master metering does not represent a change in policy. Rather, it is its attempt to clarify the policy it has utilized since the early 1980's. That policy is currently contained in PSNH's "Requirements for Electric Service Connections" and in its Delivery Service Tariff by reference and reads as follows:

> "In accordance with State law and the rules of the New Hampshire Public Utilities Commission, master metering of electric service is prohibited in buildings with more than one dwelling unit: (a) which are constructed new after November 18, 1980; or (b) which undergo renovations after that date in which the cost of renovations exceeds 50 percent of the value of the building; or (c) which are converted to electric space and/or water heating after that

date. This separate metering shall register all electric energy used for the dwelling unit over which the occupant of the dwelling unit has direct control. Motels, hotels, dormitories, time share condominiums and assisted living facilities are excluded from this requirement."

This language, according to PSNH, mirrors the language that was contained in the Commission's rule, N.H. Code Admin. Rules Puc 303.02, in effect prior to October 18, 2005. That rule has since been updated to the following:

> Puc 303.02 Master Metering.
> (a) A utility shall install master metering of electric service consistent with its tariffs if the installation is consistent with the International Energy Conservation Code 2000 as adopted in RSA 155-A:1,IV, except as set forth in (b) below.
> (b) No utility shall install master metering at a multi-tenant building containing any residences if the occupants of any unit receiving electric service through the master meter have temperature control over any portion of the electric space heating, electric air conditioning or electric water heating service for the unit.
> (c) Section (b) above shall not apply to hotels, motels, dormitories and time-sharing interests in condominiums as defined in RSA 356-B:3.

This new language indicates that a utility shall install master metering consistent with its tariff which, for PSNH, is the language contained in its Requirements for Electric Service Connections. However, the current language contained in the Requirements for Electric Service Connections references the Commission's rules. Because PSNH contends that this amounts to a circular reference it proposes to add the following to its Delivery Service Tariff.

> "Each dwelling unit of a new or renovated domestic structure with more than one dwelling unit will be metered separately and each meter will be billed as an individual Customer."

Q. DOES STAFF ACCEPT THE ARGUMENT THAT THE LANGUAGE IN THE COMPANY'S REQUIREMENTS FOR ELECTRIC SERVICE CONNECTIONS IS CIRCULAR?

A. No. That document is clear that master metering must be installed in accordance with the rules of the Commission. Moreover, the current version of those rules prohibits master metering only in a limited number of circumstances. Those circumstances are when the occupants of any unit receiving electric service have: temperature control over any portion of the electric space heating; electric air conditioning; or electric water heating service. All other units can be supplied with electricity through a master meter. In contrast, the Company's proposed language would require all units in new or renovated domestic structures to be metered separately.

Q. WHAT DOES STAFF RECOMMEND?

A. Staff recommends that the master metering provision in the Company's tariff be modified to conform to the Commission's rules.

3. <u>Payment of Excess Outdoor Lighting Costs</u>

Q. HOW DOES STAFF RESPOND TO THE PROPOSAL TO ELIMINATE FOR GOVERNMENT UNITS AND CIVIC GROUPS THE OPTION TO PAY EXCESS COSTS OVER AN EXTENDED PERIOD?

A. Excess costs under Rate OL are defined as any costs incurred in connection with new installations, extensions and replacements which exceed the costs of a standard outdoor lighting fixture located on existing poles with overhead wiring. Based on the Company's statement that government units and civic groups have not availed themselves of this provision over the past ten years, Staff recommends that the proposal be approved.

4. <u>Midnight Outdoor Lighting Service Option</u>

Q. WHAT IS THE MIDNIGHT OUTDOOR LIGHTING SERVICE OPTION?

A. The midnight option employs a time clock photocell to turn the outdoor light on or off at specified times whereas the all-night option is limited to turning the light on at dusk and off at dawn using a simple light sensitive photocell.

Q. DOES STAFF SUPPORT THIS PROPOSAL?

A. Yes.

Q. DOES STAFF ALSO SUPPORT THE PROPOSED RATES FOR THE MIDNIGHT OPTION?

A. Staff supports the proposed rate design, which includes separate charges to recover the cost of distribution service and the incremental costs to purchase and install the additional equipment.

Q. DOES THAT COMPLETE STAFF'S TESTIMONY?

A. Yes.

Staff Exhibit-GRM 1

GEORGE R. McCLUSKEY

NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION
Analyst

George McCluskey is a ratemaking specialist with over 30 years experience in utility economics. Since rejoining the New Hampshire Public Utilities Commission ("NHPUC") in 2005, he has worked on default service and standby rate issues in the electric sector and cost allocation issues in the gas sector. While at La Capra Associates, a Boston-based consulting firm specializing in electric industry restructuring, wholesale and retail power procurement, market price and risk analysis, and power systems models and planning methods, he provided strategic advice to numerous clients on a variety of issues. Prior to joining La Capra Associates, Mr. McCluskey directed the electric utility restructuring division of the NHPUC and before that was manager of least cost planning in the economics division, directing and supervising the review and implementation of electric and gas utility least cost plans and demand-side management programs. He has testified as an expert witness in numerous electric and gas cases before state and federal regulatory agencies.

ACCOMPLISHMENTS

Recent project experience includes:

Staff of the New Hampshire Public Utilities Commission – Expert testimony before NHPUC regarding distribute energy resources in a case involving Unitil Energy Systems.

Staff of the New Hampshire Public Utilities Commission – Expert testimony before NHPUC regarding lead/lag studies and rate design in a base rate case involving EnergyNorth Natural Gas.

Staff of the New Hampshire Public Utilities Commission – Expert testimony before Maine Public Utilities Commission regarding interstate allocation of natural gas capacity costs in case involving Northern Utilities.

Staff of the Arkansas Public Service Commission – Analysis and case support regarding Entergy Arkansas Inc.'s application to transfer ownership and control of its transmission assets to a Transco. Also analyzed Entergy Arkansas Inc.'s stranded generation cost claims.

Massachusetts Technology Collaborative – Evaluated proposals by renewable resource developers to sell Renewable Energy Credits to MTC in reponse to 2003 RFP.

Pennsylvania Office of the Consumer Advocate – Analysis and case support regarding horizontal and vertical market power related issues in the PECO/Unicom merger proceeding. Also advised on cost-of-service, cost allocation and rate design issues in FERC base rate case for interstate natural gas pipeline company.

Staff of the New Hampshire Public Utilities Commission – Expert testimony before the NHPUC regarding stranded cost issues in Restructuring Settlement Agreement submitted by Public Service Company of New Hampshire and various settling parties. Testimony presented an analysis of PSNH's stranded costs and made recommendations regarding the recoverability of such costs.

Town of Waterford, CT – Advisory and expert witness services in litigation to determine property tax assessment for nuclear power plant.

Washington Electric Cooperative, VT – Prepared report on external obsolescence in rural distribution systems in property tax case.

New Hampshire Public Utilities Commission - Expert testimony on behalf of the NHPUC before the Federal Energy Regulatory Commission regarding the Order 888 calculation of wholesale stranded costs for utilities receiving partial requirements power supply service.

Ohio Consumer Council - Expert testimony regarding the transition cost recovery requests submitted by the American Electric Power Co., including a critique of the discounted cash flow and revenues lost approaches to generation asset valuation.

EXPERIENCE

New Hampshire Public Utilities Commission (2005 to Present)
Analyst, Electric Division

La Capra Associates (1999 to 2005)
Senior Consultant

New Hampshire Public Utilities Commission (1987 – 1999)
Director, Electric Utilities Restructuring Division
Manager, Lease Cost Planning

Utility Analyst, Economics Department

Electricity Council, London, England (1977-1984)
Pricing Specialist, Commercial Department
Information Officer, Secretary's Office

EDUCATION:

Ph.D. candidate in Theoretical Plasma Physics, University of Sussex Space Physics Laboratory.
Withdrew in 1977 to accept position with the Electricity Council.

B.S., University of Sussex, England, 1975.
Theoretical Physics

Public Service Company of New Hampshire
Docket No. DE 09-035

Data Request STAFF-02

Dated: 08/28/2009
Q-STAFF-081
Page 1 of 3

Witness: **Charles R. Goodwin**
Request from: **New Hampshire Public Utilities Commission Staff**

Question:
Assuming the Commission approves the proposed rates and charges – contained in Electric Delivery Service Tariff NHPUC – No. 7 – what effect would these new charges have on the rate class rates of return and the overall rate of return shown in Exhibit 3, pages 1 & 2?

Response:
Please see the pages 2 and 3 of this response for the overall rate of return and the rates of return by each rate class with the proposed new charges contained in Electric Delivery Service Tariff NHPUC - No. 7. These pages replicate pages 1 & 2 of Exhibit 3, but with proposed revenue shown on lines 21, 24 and corresponding Income Tax effect on line 35.

Public Service Company of New Hampshire
Cost of Service Study
Proforma - Twelve Months Ending December 31, 2008
(All Amounts in $000)

Table 1A

Line	Account IN/OUT	Description	LINE REFERENCE	Allocator	TOTAL RETAIL	Rate R Total	PL/SH	QR	CWH	LCS/ COPE	Rate G Total	PL/SH	QR	CWH	LCS/ COPE
2															
3	A	B		C	D	E	F	G	H	I	J	K	L	M	N
4															
5		SUMMARY OF RESULTS													
6															
7	RB_PLT	Net Plant	Pg. 9, Ln 7		888,876	589,764	571,860	11,569	132	6,204	166,454	165,991	237	8	218
8															
9		DEDUCT:													
10															
11	RB_DED	Total Rate Base Deduction	Pg. 9, Ln 20		(167,295)	(110,227)	(106,820)	(2,208)	(29)	(1,170)	(32,432)	(32,339)	(48)	(1)	(43)
12															
13		ADD:													
14															
15	RB_ADD	Total Rate Base Addition	Pg. 9, Ln 45		55,537	37,090	35,671	931	17	471	10,440	10,395	24	1	20
16															
17	RB	TOTAL RATE BASE	Pg. 9, Ln 47		777,118	516,627	500,711	10,291	120	5,505	144,462	144,047	213	7	195
18															
19		OPERATING REVENUES													
20															
21	440-447	Sales Revenue		ASALES_REV	294,560	163,123	157,942	4,647	125	409	70,670	70,467	168	2	34
22	440-447UN	Unbilled Sale Revenue	Pg. 11, Ln 9	AUN_REV	(1,248)	(717)	(659)	(51)	(1)	(6)	(315)	(313)	(1)	-	(1)
23	440-447Resale	Sales Revenue/Resale Customers	Pg. 11, Ln 10	A360	4,957	2,201	2,011	120	-	69	1,146	1,143	1	0	2
24	447DistCR	Dist. Credit Sp. Pricing Cust.		ASALES_REV	480	266	257	8	0	1	115	115	0	0	0
25	REV_OTH_ELEC	Total Other Revenue	Pg. 11, Ln 38		12,009	6,762	6,743	12	0	6	1,650	1,648	1	0	1
26															
27	REV	Total Revenue	Pg. 11, Ln 40		310,758	171,634	166,295	4,735	124	480	73,267	73,059	170	3	35
28															
29		OPERATING EXPENSES													
30															
31	EXP_O&M	Total O&M Expense	Pg. 17, Ln 22		152,454	101,173	97,230	2,613	52	1,278	28,953	28,819	72	2	60
32	EXP_DEP	Total Depreciation Expense	Pg. 19, Ln 41		38,679	26,033	25,241	515	8	269	7,081	7,058	12	0	10
33	EXP_AMORT	Total Amortization Expense	Pg. 19, Ln 45		6,265	4,252	4,013	158	4	78	1,190	1,182	5	0	4
34	EXP_TAX_OTI	Total Taxes Other than Income Tax	Pg. 21, Ln 28		30,207	20,133	19,460	437	6	229	5,645	5,626	10	0	9
35	4_CUR_TAX	Total Current Adjusted Taxes			(11,063)	(20,163)	(19,314)	(105)	15	(760)	3,399	3,408	17	(0)	(26)
36	411NUPER	NUSCO Permanent Difference		RB_PLT_D_O	(222)	(147)	(143)	(3)	(0)	(1)	(41)	(41)	(0)	(0)	(0)
37	Post_Tax_Adj_DIT	Provision for Deferred Income Tax	Pg. 25, Ln 18		35,178	23,340	22,632	458	5	246	6,588	6,569	9	0	9
38	Post_Tax_Adj_ITC	Investment Tax Credit Adjustment	Pg. 25, Ln 20		(132)	(88)	(85)	(2)	(0)	(1)	(25)	(25)	(0)	(0)	(0)
39															
40	OPERATING _EXPENSE	Operating Expense	Lns 31 thru 38		251,366	154,534	149,033	4,072	91	1,338	52,789	52,596	125	2	65
41															
42	NET_RETURN	OPERATING INCOME	Ln. 27 - Ln 40		59,392	17,101	17,262	664	34	(858)	20,478	20,463	45	0	(30)
43															
44	426	Donations, net of tax		NET_RETURN	293	84	85	3	0	(4)	101	101	0	0	(0)
45	431	Return on Customer Deposit		NET_RETURN	131	38	38	1	0	(2)	45	45	0	0	(0)
46															
47	OP_INC_ADJ	Adj. to the Operating income	Ln 44 + Ln 45		424	122	123	5	0	(6)	146	146	0	0	(0)
48															
49	Adj_OP_INC	Adjusted Operating Income	Ln 42 - Ln 47	Formula	58,968	16,979	17,138	659	33	(852)	20,332	20,317	45	0	(30)
50															
51		RATE OF RETURN	Ln 49/Ln 17		7.59%	3.29%	3.42%	6.40%	27.97%	-15.48%	14.07%	14.10%	20.98%	2.96%	-15.15%
52															

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Public Service Company of New Hampshire
Cost of Service Study
Proforma - Twelve Months Ending December 31, 2008
(All Amounts in $000)

Table 1A

1	Account IN/OUT	Description	LINE REFERENCE	Allocator	TOTAL RETAIL	Rate GV	Rate LG	Rate B	Rate OL	Rate EOL
2										
3	A	B		C	D	O	P	Q	R	S
4										
5		SUMMARY OF RESULTS								
6										
7	RB_PLT	Net Plant	Pg. 9, Ln 7		888,876	62,414	33,371	3,887	16,100	16,886
8										
9		DEDUCT:								
10										
11	RB_DED	Total Rate Base Deduction	Pg. 9, Ln 20		(167,295)	(11,239)	(6,021)	(680)	(3,506)	(3,188)
12										
13		ADD.								
14										
15	RB_ADD	Total Rate Base Addition	Pg. 9, Ln 45		55,537	3,716	2,054	211	998	1,028
16										
17	RB	TOTAL RATE BASE	Pg. 9, Ln 47		777,118	54,890	29,403	3,418	13,592	14,725
18										
19		OPERATING REVENUES								
20										
21	440-447	Sales Revenue		ASALES_REV	294,560	34,164	16,629	1,470	4,716	3,787
22	440-447UN	Unbilled Sale Revenue	Pg. 11, Ln 9	AUN_REV	(1,248)	(105)	(87)	(12)	(12)	-
23	440-447Resale	Sales Revenue/Resale Customers	Pg. 11, Ln 10	A360	4,957	937	575	71	14	13
24	447DistCR	Dist. Credit Sp. Pricing Cust.		ASALES_REV	480	56	27	2	8	6
25	REV_OTH_ELEC	Total Other Revenue	Pg. 11, Ln 38		12,009	2,819	631	26	57	63
26										
27	REV	Total Revenue	Pg. 11, Ln 40		310,758	37,871	17,774	1,558	4,784	3,869
28										
29		OPERATING EXPENSES								
30										
31	EXP_O&M	Total O&M Expense	Pg. 17, Ln 22		152,454	10,631	6,113	564	2,254	2,766
32	EXP_DEP	Total Depreciation Expense	Pg. 19, Ln 41		38,679	2,337	1,233	141	1,104	751
33	EXP_AMORT	Total Amortization Expense	Pg. 19, Ln 45		6,265	398	230	21	70	104
34	EXP_TAX_OTI	Total Taxes Other than Income Tax	Pg. 21, Ln 28		30,207	2,027	1,081	123	618	579
35	4_CUR_TAX	Total Current Adjusted Taxes			(11,063)	5,391	1,860	82	(686)	(945)
36	411NUPER	NUSCO Permanent Difference		RB_PLT_D_O	(222)	(15)	(8)	(1)	(5)	(4)
37	Post_Tax_Adj_DIT	Provision for Deferred Income Tax	Pg. 25, Ln 18		35,178	2,470	1,321	154	637	668
38	Post_Tax_Adj_ITC	Investment Tax Credit Adjustment	Pg. 25, Ln 20		(132)	(9)	(5)	(1)	(3)	(3)
39		Provision for Deferred Income Tax								
40	OPERATING _EXPENSE	Operating Expense	Lns 31 thru 38		251,366	23,231	11,824	1,082	3,989	3,917
41										
42	NET_RETURN	OPERATING INCOME	Ln. 27 - Ln 40		59,392	14,641	5,950	476	794	(48)
43										
44	426	Donations, net of tax		NET_RETURN	293	72	29	2	4	(0)
45	431	Return on Customer Deposit		NET_RETURN	131	32	13	1	2	(0)
46										
47	OP_INC_ADJ	Adj. to the Operating income	Ln 44 + Ln 45		424	105	42	3	6	(0)
48										
49	Adj_OP_INC	Adjusted Operating Income	Ln 42 - Ln 47	Formula	58,968	14,536	5,908	472	789	(47)
50										
51		RATE OF RETURN	Ln 49/Ln 17		7.59%	26.48%	20.09%	13.82%	5.80%	-0.32%
52										

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Public Service Company of New Hampshire
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Data Request STAFF-05

Dated: 11/25/2009
Q-STAFF-011
Page 1 of 3

Witness: **Charles R. Goodwin**
Request from: **New Hampshire Public Utilities Commission Staff**

Question:
Reference response to Staff 2-81. Please re-calculate the class rates-of-return based on the following changes:

(i) all primary and secondary distribution system costs classified as demand-related; and
(ii) such demand-related costs allocated to classes using appropriate NCP allocators.

Response:
The Company firmly believes that the requested COSS scenario is an inappropriate and unrealistic hypothetical. Using only the NCP allocator for these major distribution system costs suggests there is only a demand driven cost element and that the existence of customers on the system has no impact on the cost of providing service via these assets. Regardless of the customer demand on the system, the Company would be required to make an investment in poles, wires, transformers and the like in order to provide service to its customer base. It is in recognition of this customer-related responsibility that utility cost-of-service-studies classify these types of distribution assets as both customer and demand related. PSNH is unaware of any utility or jurisdiction that does not recognize this duel classification in COSS.

In terms of responding to this extreme hypothetical, this run provides the class rates of return using the Staff 2-81 COSS, and revising the allocation for distribution system costs (i.e., Accounts 364, 365, 366 and 367, as well as related expense items for these accounts).

Public Service Company of New Hampshire
Cost of Service Study
Proforma - Twelve Months Ending December 31, 2008
(All Amounts in $000)

Table 1A

#	Account IN/OUT	Description	Allocator	TOTAL RETAIL	Rate R Total	PL/SH	QR	CWH	LCS/ COPE	Rate G Total	PL/SH	QR	CWH	LCS/ COPE
3	A	B	C	D	E	F	G	H	I	J	K	L	M	N
5		SUMMARY OF RESULTS												
7	RB_PLT	Net Plant		888,876	502,592	476,198	16,951	132	9,311	205,639	205,029	300	12	297
9		DEDUCT:												
11	RB_DED	Total Rate Base Deduction		(167,295)	(93,215)	(88,312)	(3,157)	(29)	(1,717)	(40,126)	(40,007)	(59)	(2)	(57)
13		ADD:												
15	RB_ADD	Total Rate Base Addition		55,537	31,985	30,232	1,142	17	593	12,774	12,724	27	1	23
17	RB	TOTAL RATE BASE		777,118	441,362	418,118	14,937	120	8,188	178,287	177,746	268	11	263
19		OPERATING REVENUES												
21	440-447	Sales Revenue	ASALES_REV	294,560	163,123	157,942	4,647	125	409	70,670	70,467	168	2	34
22	440-447UN	Unbilled Sale Revenue	AUN_REV	(1,248)	(717)	(659)	(51)	(1)	(6)	(315)	(313)	(1)	-	(1)
23	440-447Resale	Sales Revenue/Resale Customers	A360	4,957	2,201	2,011	120	-	69	1,146	1,143	1	0	2
24	447DistCR	Dist. Credit Sp. Pricing Cust.	ASALES_REV	480	266	257	8	0	1	115	115	0	0	0
25	REV_OTH_ELEC	Total Other Revenue		12,009	6,206	6,178	18	0	10	1,912	1,909	1	0	1
27	REV	Total Revenue		310,758	171,078	165,730	4,741	124	483	73,529	73,321	170	3	35
29		OPERATING EXPENSES												
31	EXP_O&M	Total O&M Expense		152,454	87,842	83,342	2,966	52	1,482	35,116	34,973	76	2	65
32	EXP_DEP	Total Depreciation Expense		38,679	21,711	20,551	748	8	404	9,045	9,016	15	1	14
33	EXP_AMORT	Total Amortization Expense		6,265	3,850	3,600	164	4	82	1,377	1,369	5	0	4
34	EXP_TAX_OTI	Total Taxes Other than Income Tax		30,207	17,107	16,179	599	6	323	7,016	6,992	12	0	11
35	4_CUR_TAX	Total Current Adjusted Taxes		(11,063)	(8,097)	(6,386)	(651)	15	(1,075)	(2,104)	(2,080)	10	(1)	(34)
36	411NUPER	NUSCO Permanent Difference	RB_PLT_D_O	(222)	(124)	(117)	(4)	(0)	(2)	(52)	(52)	(0)	(0)	(0)
37	Post_Tax_Adj_DIT	Provision for Deferred Income Tax		35,178	19,890	18,846	671	5	368	8,138	8,114	12	0	12
38	Post_Tax_Adj_ITC	Investment Tax Credit Adjustment		(132)	(74)	(70)	(2)	(0)	(1)	(31)	(31)	(0)	(0)	(0)
40	OPERATING _EXPENSE	Operating Expense		251,366	142,105	135,944	4,491	91	1,580	58,506	58,303	130	3	71
42	NET_RETURN	OPERATING INCOME		59,392	28,973	29,786	250	34	(1,097)	15,022	15,018	40	(0)	(36)
44	426	Donations, net of tax	NET_RETURN	293	143	147	1	0	(5)	74	74	0	(0)	(0)
45	431	Return on Customer Deposit	NET_RETURN	131	64	66	1	0	(2)	33	33	0	(0)	(0)
47	OP_INC_ADJ	Adj. to the Operating income		424	207	213	2	0	(8)	107	107	0	(0)	(0)
49	Adj_OP_INC	Adjusted Operating Income	Formula	58,968	28,766	29,573	249	33	(1,089)	14,915	14,911	40	(0)	(36)
51		RATE OF RETURN		7.59%	6.52%	7.07%	1.66%	27.97%	-13.30%	8.37%	8.39%	14.86%	-1.05%	-13.52%

Public Service Company of New Hampshire
Cost of Service Study
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Table 1A

	Account IN/OUT	Description	Allocator	TOTAL RETAIL	Rate GV	Rate LG	Rate B	Rate OL	Rate EOL
1									
2									
3	A	B	C	D	O	P	Q	R	S
4									
5		SUMMARY OF RESULTS							
6									
7	RB_PLT	Net Plant		888,876	96,902	54,802	6,538	12,384	10,018
8									
9		DEDUCT:							
10									
11	RB_DED	Total Rate Base Deduction		(167,295)	(17,948)	(10,190)	(1,196)	(2,778)	(1,842)
12									
13		ADD:							
14									
15	RB_ADD	Total Rate Base Addition		55,537	5,715	3,296	365	779	622
16									
17	RB	TOTAL RATE BASE		777,118	84,670	47,908	5,707	10,386	8,798
18									
19		OPERATING REVENUES							
20									
21	440-447	Sales Revenue	ASALES_REV	294,560	34,164	16,629	1,470	4,716	3,787
22	440-447UN	Unbilled Sale Revenue	AUN_REV	(1,248)	(105)	(87)	(12)	(12)	-
23	440-447Resale	Sales Revenue/Resale Customers	A360	4,957	937	575	71	14	13
24	447DistCR	Dist. Credit Sp. Pricing Cust.	ASALES_REV	480	56	27	2	8	6
25	REV_OTH_ELEC	Total Other Revenue		12,009	3,034	764	43	33	18
26									
27	REV	Total Revenue		310,758	38,086	17,907	1,575	4,759	3,824
28									
29		OPERATING EXPENSES							
30									
31	EXP_O&M	Total O&M Expense		152,454	15,816	9,334	963	1,680	1,703
32	EXP_DEP	Total Depreciation Expense		38,679	4,038	2,290	272	917	406
33	EXP_AMORT	Total Amortization Expense		6,265	554	327	32	53	72
34	EXP_TAX_OTI	Total Taxes Other than Income Tax		30,207	3,219	1,822	214	489	340
35	4_CUR_TAX	Total Current Adjusted Taxes		(11,063)	657	(1,082)	(282)	(168)	13
36	411NUPER	NUSCO Permanent Difference	RB_PLT_D_O	(222)	(24)	(14)	(2)	(4)	(2)
37	Post_Tax_Adj_DIT	Provision for Deferred Income Tax		35,178	3,835	2,169	259	490	396
38	Post_Tax_Adj_ITC	Investment Tax Credit Adjustment		(132)	(15)	(8)	(1)	(2)	(1)
39		Provision for Deferred Income Tax							
40	OPERATING _EXPENSE	Operating Expense		251,366	28,080	14,837	1,455	3,454	2,927
41									
42	NET_RETURN	OPERATING INCOME		59,392	10,005	3,070	119	1,305	897
43									
44	426	Donations, net of tax	NET_RETURN	293	49	15	1	6	4
45	431	Return on Customer Deposit	NET_RETURN	131	22	7	0	3	2
46									
47	OP_INC_ADJ	Adj. to the Operating income		424	71	22	1	9	6
48									
49	Adj_OP_INC	Adjusted Operating Income	Formula	58,968	9,934	3,048	119	1,296	891
50									
51		RATE OF RETURN		7.59%	11.73%	6.36%	2.08%	12.47%	10.12%
52									