THE STATE OF NEW HAMPSHIRE

BEFORE THE

NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION

Docket No. DE 09-035

DIRECT TESTIMONY OF

Gary A. Long

Request for Permanent Delivery Rates

June 30, 2009

I. INTRODUCTION

Q. Please state your name, position and business address.

A. My name is Gary A. Long. I am the President and Chief Operating Officer of Public Service Company of New Hampshire (PSNH). My business address is 780 North Commercial Street, Manchester, New Hampshire.

Q. Have you previously testified before this Commission?

A. Yes, I have testified on many occasions in various regulatory proceedings on behalf of PSNH.

Q. Are there other witnesses in this proceeding that are sponsoring pre-filed direct testimony in support of this rate request?

A. Yes.

Robert A. Baumann, Director – Revenue Regulation and Load Resources is presenting testimony on PSNH's revenue requirements, storm cost recovery and storm reserve and the drivers of the need for permanent rate relief.

George J. Eckenroth, Director – Corporate Financial Policy, is presenting testimony on PSNH's return on equity, capital structure and overall cost of capital.

Stephen R. Hall, Manager of Rate and Regulatory Services, is presenting testimony on PSNH's proposed tariff, rate design and the impact of PSNH's proposed permanent rates on each customer class.

Stephen M. Johnson, Director – Energy Delivery, is presenting testimony on PSNH's proposed modifications to the Reliability Enhancement Program approved by the Commission in Docket No. DE 06-028, PSNH's last distribution rate case.

Q. Did you previously submit pre-filed testimony in this docket concerning PSNH's request for temporary rates?

A. Yes, I did. In this testimony, I will be incorporating my previous testimony by reference to the extent necessary.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide an overview of the challenges PSNH is facing which have resulted in the need to request a permanent rate increase. In this testimony, I will discuss PSNH's desire to establish a more permanent and longer lasting solution to those challenges, including a discussion of the need to address attrition. I will also discuss PSNH's interest in pursuing a policy to modernize its distribution system to make it ready for what I refer to as the new energy economy.

II. BUSINESS ENVIRONMENT

Q. Please provide a brief summary of PSNH's business environment.

A. In my testimony filed on April 17, 2009 in this docket, I provided a description of PSNH's business environment. I will not repeat that detailed description here, but I will provide a summary of the difficulties PSNH is encountering in its efforts to continue to provide reliable delivery service to its customers. PSNH is faced with the need to replace the aging equipment that comprises the bulk of PSNH's distribution system. This need, combined with the lack of overall kilowatt-hour sales growth, has caused significant erosion in PSNH's earnings. Beyond these factors, PSNH must recover the costs associated with the December, 2008 ice storm. While we are reluctant to request an increase in distribution rates, we are finding it increasingly difficult to provide high quality service and still achieve the most recently allowed rate of return. Therefore, in this filing, we are requesting the Commission to approve a longer lasting solution, including dealing with the issue of attrition of earnings that has occurred and that is expected to continue absent specific rate relief proposals discussed in this filing.

III. ATTRITION

Q. What is attrition?

A. Attrition has been defined by the New Hampshire Supreme Court as "an erosion in the earning power of a revenue-producing investment. This erosion is a complex phenomenon, the result of operating expenses or plant investment, or both, increasing more rapidly than revenues. If attrition occurs, the result would be that the rate of return realized in the future would be below that which rates were designed to produce." [1]

Q. Has PSNH experienced attrition since the last rate case?

A. Yes, it has. Mr. Baumann's attachment RAB-4 filled on April 17, 2009 in the Temporary Rates proceeding in this docket shows PSNH's actual distribution cost of capital Return on Equity since December 31, 2005. As shown on that graph, PSNH has not been able to earn its allowed rate of return. This is exactly the situation described by the Supreme Court – i.e., the rate of return realized is below that which rates were designed to produce. ROE improves in the quarterly periods immediately following implementation of permanent rates, but even in those periods, it falls short of the ROE allowed by the Commission.

[1] *New England Telephone & Telegraph Co. v. State of New Hampshire,* 113 N.H. 92, 97 (1973)

Q. Why has PSNH been unable to earn its allowed ROE?

A. Two main contributors to PSNH's low earned ROE are the additions to rate base to meet system requirements and the decline in overall kilowatt-hour sales. Part of the problem is the use of an historical five-quarter average rate base for determining revenue requirements, which matches historic periods of revenue recovery and rate base but understates the current and forward looking level of rate base. By using a five-quarter average rate base, new rates are already out of date before they even go into effect. Absent unprecedented sales growth or a significant cessation in new distribution system investment, the situation only gets worse with time.

Q. Was the use of a five-quarter average rate base addressed during the last rate case?

A. Yes, it was. The Commission Staff and Office of Consumer Advocate recognized the problem associated with using historical average rate base and agreed, through the settlement agreement in the last rate case, to use an end of period rate base for determining revenue requirements and to provide for a step increase six months after the implementation of permanent rates. Those steps allowed PSNH to continue to earn at a level closer to its allowed ROE for a brief period of time following implementation of the step increase. However, PSNH's ROE declined soon thereafter and has continued to decline since then. While the step increase mitigated the level of decline in ROE, it did not fully address the issue of attrition.

Q. Why is it necessary to address attrition in this case?

A. Attrition is an issue that has been present for several years and, notwithstanding the efforts of the parties in the last rate case, has persisted. Based on the results of PSNH's performance through March 31, 2009, attrition is a continuing problem. Based on

PSNH's most recent sales projections and our system needs, we expect attrition to continue and, in fact, worsen. The existence of attrition has necessitated the filing of distribution base rate increase requests on more frequent intervals than PSNH would like. This cycle of frequent rate cases creates uncertainty for our customers. In addition, rate cases consume significant time and resources, not only those of PSNH but also those of the Commission and the OCA. We would like to break the cycle of filing for a rate case every three years (or even fewer) and develop a more comprehensive solution to the problem.

Q. Why is it so important to address attrition at this point in time?

A. PSNH is encountering many competing issues, which if experienced separately could possibly be dealt with individually. Taken together, however, the compounding effect presents a severe problem for PSNH which cannot be managed using traditional regulatory methods.

Q. Please describe these issues.

A. Earlier, I referenced the fact that PSNH's sales have actually declined since the last rate case. Our current projections show no relief from this phenomenon. The table below shows PSNH's actual billed delivery sales since 2005 (the test year in the last rate case) and forecasted sales through 2012:

Year	GWh Sales	% Change
2005	8,059	0.4%
2006	8,036	-0.3%
2007	8,126	1.1%
2008	8,027	-1.2%
2009	7,819	-2.6%
2010	7,828	0.1%
2011	7,910	1.0%
2012	7,978	0.9%

As shown in the table, by 2008, PSNH's sales level had dropped below the level in the test year used for the last rate case. Beyond this, PSNH's projected sales for the next three years are expected to be below the level of sales in 2008, the test year used in this case. These figures do not contemplate further sales declines brought about by even more funding becoming available for increased energy conservation, energy efficiency and customer-owned generation, which we believe is the long-term policy direction of the state and the country.

At the same time that we are seeing reduced growth in revenues due to a decline in sales, we are experiencing increased need to invest in our system. For example, as discussed in Mr. Johnson's testimony, the average age of PSNH's distribution substation transformers is nearly 50 years old, the average age of bulk substation transformers is over 30 years old, and about half of PSNH's 400,000 poles are at least 30 years old. This means that PSNH will incur increased maintenance costs as well as increased costs to actually replace failing system components. The cost of new equipment is much higher than the depreciated book cost of existing equipment, which is the basis for setting rates. Thus, whenever older equipment is replaced, there is a corresponding increase in PSNH's revenue requirements. For example, replacing a pole that was originally installed for $206 in 1973 and is now nearly fully depreciated (i.e., its book cost is much less than $206) cost $926 in 2008.

On top of just maintaining our existing system, PSNH is incurring spending as required to meet new customer and community needs. Even though overall sales have declined, we are still seeing localized new business and new demands from the communities we serve requiring us to install new services, enhance existing services, or move facilities due to roadway infrastructure construction and repairs. In addition to these ongoing requirements is a pressing need to look at the future and newer technologies. Smart grid technologies such as Distribution System Control and Data Acquisition (DSCADA) can provide real benefits for customers in terms of improved reliability and system efficiency once we make the initial investment. Mr. Johnson's testimony discusses our plans for GIS deployment as part of the REP program in his testimony, but GIS is only the tip of the iceberg in preparing for the future. Advanced metering infrastructure (AMI) could provide the mechanisms for customers to better control and manage their energy consumption which in the end could reduce energy costs for everyone. We have not proposed spending for all of these purposes, but we are fully aware of the growing industry trend to move in that direction. Finally, PSNH is interested in pursuing renewable distributed generation in an effort to advance federal and state policy initiatives and to manage costs over the long term

In summary, PSNH is faced with declining sales, ongoing general business needs, aging infrastructure and a dramatically different future. We believe that now is the time for PSNH and the Commission to begin grappling with these issues.

Q. How will addressing attrition help this situation?

A. As Mr. Baumann's testimony shows, a significant contributor to PSNH's inability to meet its authorized ROE is the addition of rate base beyond the rate year. By addressing this issue, it will not only keep PSNH financially sound, but it will also assure that customers are properly paying for infrastructure to provide reliable service.

Q. How will addressing attrition benefit customers?

A. An attrition adjustment will help PSNH remain financially sound, thus providing benefits when PSNH needs to access the capital markets. As Mr. Eckenroth discusses in his testimony, the nation's (and indeed the world's) capital markets have undergone dramatic change, and are continuing to operate at an unprecedented level of stress and uncertainty. The availability of credit has tightened and the price of credit has increased. To support a viable capital program, PSNH must be able to demonstrate that its regulators recognize the need to keep PSNH financially sound.

Q. What are you requesting from the Commission in this case?

A. We are requesting that the Commission and parties acknowledge the problem of attrition and consider mechanisms to address it. Unless PSNH is able to solve the problem of attrition, it could have insufficient financial wherewithal to enable it to pursue some of the capital projects that will be needed for the new energy economy and infrastructure replacement.

Q. What types of mechanisms could be used to address attrition?

A. There are several ratemaking mechanisms that could be used to address attrition. The use of end of period rate base is one method that, as I discussed earlier, provides some level of relief. Other mechanisms include, but aren't limited to, an adder to allowed ROE to recognize that it's not possible to earn the allowed rate of return; an ROE collar where rates are adjusted based on the difference between earned and allowed return; decoupling to address the impact of lack of sales growth and energy conservation; the use of a forward-looking test year for the purpose of determining rate base; and the use of step increases to periodically adjust the rate base amount on which return is based. Many other mechanisms could likely be used and Mr. Baumann's testimony describes a mechanism to adjust rates to enable PSNH to recover the increased investment in rate base.

PSNH is not wedded to any specific mechanism. Rather, we are hoping to work cooperatively with the parties in an effort to develop a solution to the problem. We would like to avoid the need to continually plan for and file rate cases.

IV. SUMMARY AND RECOMMENDATIONS

Q. Please summarize your proposal to the Commission.

A. PSNH is requesting that the Commission consider its request for permanent rates in the broader context of the changing industry and the need to invest capital in the distribution system to meet the needs of customers. We encourage the establishment of collaborative discussion with the Commission's Staff and the Office of Consumer Advocate so that the parties can jointly develop creative solutions to address the decline in PSNH's financial performance that has occurred shortly after the implementation of permanent rates following the last two rate cases. During the last rate case, PSNH was encouraged by the willingness of the parties to resolve issues cooperatively. We look forward to continuing similar discussion during the course of this case.

Q. Does this complete your testimony?

A. Yes, it does.

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Docket No. DE 09-035

DIRECT TESTIMONY OF

Stephen M. Johnson

June 30, 2009

I. INTRODUCTION

Q. Please state your name, business address and position.

A. My name is Stephen M. Johnson. I work at PSNH Energy Park, 780 North Commercial Street, Manchester, New Hampshire. I am the Director – Energy Delivery for Public Service Company of New Hampshire ("PSNH" or the "Company").

Q. Have you previously testified before this Commission?

A. No. I have, however, participated in technical sessions in a variety of NHPUC dockets including the settlement discussions during PSNH's last rate case, Docket No. DE 06-028.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to discuss the Company's Reliability Enhancement Program ("REP"). I will review the current status of existing REP programs and the anticipated expenditures for capital and operation and maintenance (O&M) in support of those programs. I will also review the positive impact of the REP program on PSNH's distribution system reliability and proposed changes to the REP funding to allow us to further improve reliability through additional, targeted capital and O&M expenditures.

II. PSNH'S RELIABILITY ENHANCEMENT PROGRAM

Q. Please provide a summary of the Reliability Enhancement Program.

A. The Reliability Enhancement Program was established as a 5-year effort under the settlement agreement approved by the Commission in Order No. 24,750 in Docket No. DE 06-028. The REP became effective July 1, 2007 concurrent with the effectiveness of permanent rates under the settlement agreement. The REP provides PSNH with $10 million in annual distribution revenue to improve reliability through enhanced, targeted capital and O&M expenditures. Our interest in this program came about as a result of the assessment of PSNH's Distribution Reliability and System Planning performed by the SHAW Group, Stone & Webster Management Consultants. This assessment was a result of a settlement agreement in the prior rate case (Order No. 24,369, Docket No. DE 03-200) and completed in December 2005.

Q. What kinds of activities or programs are included in the REP?

A. In very broad terms, the REP consists of O&M activities and actions directed at:

Distribution Line Vegetation Management

Distribution Inspection and Repairs (National Electrical Safety Code)

Line and Substation maintenance activities

For Capital, the programs amount to $10 million per year and include:

New Technology upgrades, replacements and installations

Obsolete Equipment replacement

Distribution Circuit rehabilitation

Underground Cable Replacement

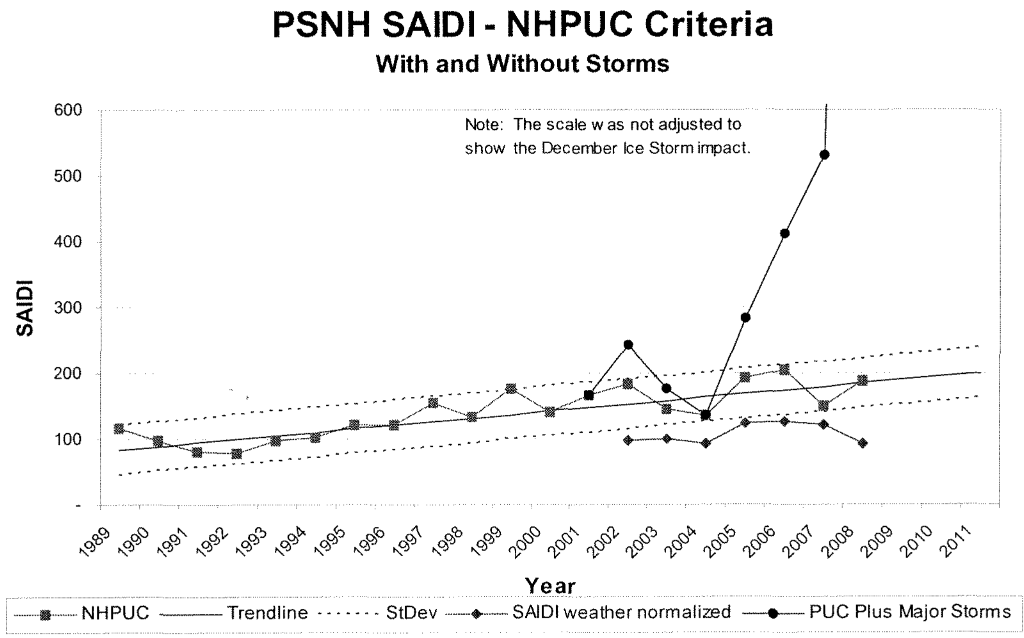
Q. What progress has been made on the REP?

A. Actual results for O&M expense activities for the initial 18 months of the REP through December 31, 2008 show $12.2 million expended on the targeted activities. For that same 18 month period PSNH invested $15 million in various REP capital projects. A requirement of the REP is an annual report of current activities and those for the next budget year which is submitted by April 1 of each year. That report has been filed in 2008 and 2009 and contains much more detail about the tasks and projects conducted under the REP program. In general, PSNH's REP program meets its objectives for performance and cost-effective expenditures.

III. POSITIVE IMPACT OF THE REP ON PSNH'S RELIABILITY

Q. What is the value of this program on electric system reliability?

A. A typical way to measure electric system reliability in the industry is using the system average interruption duration index ("SAIDI") which measures how long the average customer served is without power over the course of a year. SAIDI is measured in minutes of outage time. PSNH's SAIDI reliability is shown in the graph below:

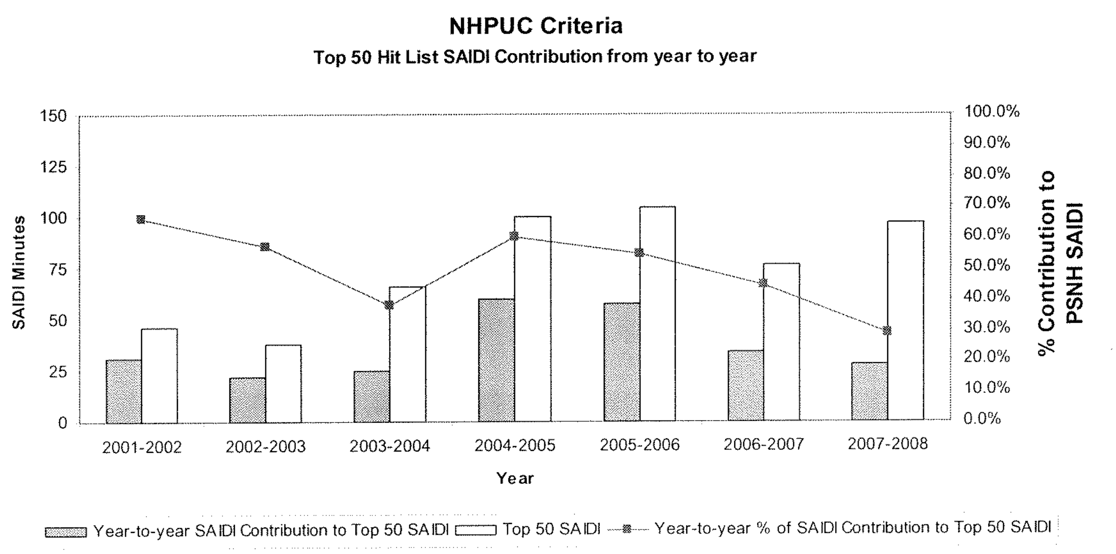


As shown above, the NHPUC reported SAIDI has remained below the all time high that occurred in 2006, the last year before the REP began. The impact of major storms (including the 2008 December Ice storm) is outside of NHPUC reported data and is shown only for reference. Weather events which meet the NHPUC criteria for "major storms" are allowed to be excluded from the calculation of NHPUC reported SAIDI.

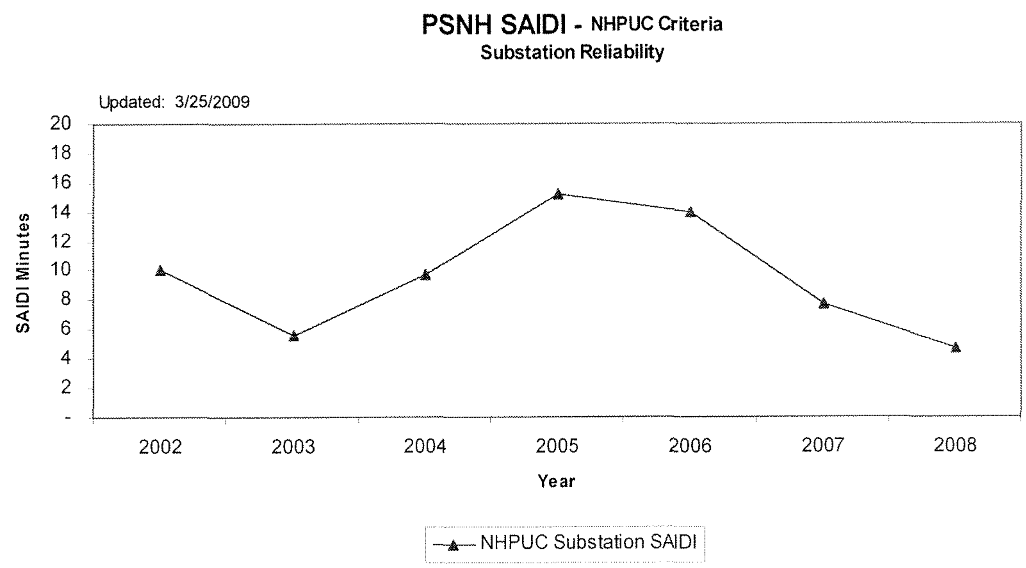
In addition to the standard method used to determine NHPUC SAIDI described above, PSNH also determines a weather-normalized SAIDI. Days where 100 outages or more occur in a 24 hour period are separated from NHPUC reported SAIDI and the result is our typical day to day routine or "weather adjusted" reliability. As shown in the above graph, the data indicate an improving trend in this area. In 2008, PSNH had 20 days with 100 or more outages, not including those days with "major storms". Historically, we experience half as many "100 or more outage" days in a normal year.

Q. Are there other ways to demonstrate how the reliability of PSNH's distribution system has improved due to the REP?

A. Yes there are. For many years PSNH has tracked the reliability performance of the 50 worst performing distribution circuits and ranked them from highest to lowest in SAIDI contribution to the total company SAIDI. We have found that of the 600 circuits in our system, these 50 have a high proportion of the SAIDI minutes we experience in a year. We have used a variety of the REP programs, both capital and expense, on these circuits in order to improve their reliability and we are clearly seeing an improving trend. The total SAIDI minutes and percent contribution for these circuits in each year is declining. The amount of SAIDI minutes due to circuits remaining on the list from one year to the next is also declining. The chart below helps to illustrate this improvement:



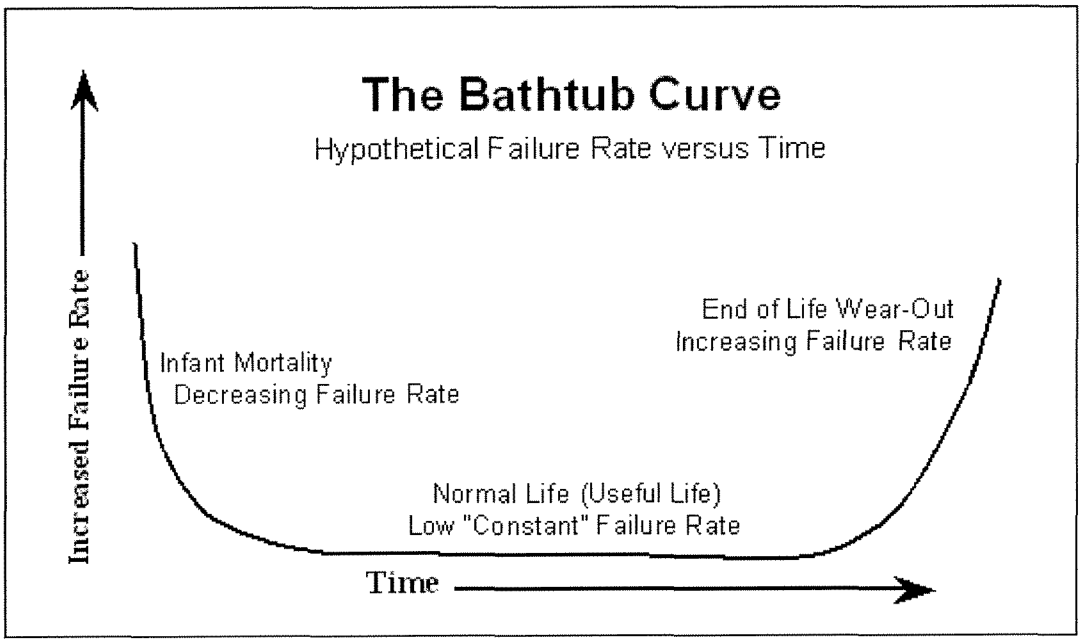
PSNH is also continuing to see an improvement in reliability relating to distribution substations. We believe this reflects our ongoing REP O&M activities focusing on planned maintenance, combined with REP-funded capital projects such as breaker and distribution substation transformer upgrades and brown glass insulator replacements. This improvement is shown in the following graph of substation SAIDI.



Q. What other value does the REP program provide to PSNH and its customers?

A. Additional value of the REP program includes proactive replacement of older and problematic equipment and proactive maintenance of equipment which ensures proper operation, instead of facing a costly emergency replacement of equipment and a potentially lengthy outage.

PSNH is no different than many utilities in that in the years following World War II, there were major capital investment programs to meet the growing needs of customers. This aging equipment has performed well over the years but is nearing the end of its useful life. A common way to display failure rate approximation is the "bathtub curve" shown below. It is used in many industries and for various components of a system. The concept shows that a product or component has higher failure rates and different modes of failure early in life (failure "right out of the box") and late in life (when it becomes worn out).



Shown below is PSNH's age profile for substation transformers. You can see the majority of our transformers are now over 45 years old; the oldest is vintage 1930. The potential for failure increases with advanced age. Shown in red are three transformers at our South Manchester Substation.

The REP capital program provided us the opportunity to rebuild the South Manchester substation which included the 1934-vintage transformers, circuit breakers and other components dating from the 1920's. The substation feeds load in primarily residential areas in Southeast Manchester. The substation capacity was increased from 6MW to 10.5MW allowing for load growth in addition to providing for backup ties to other substations, which improves reliability and provides greater flexibility to maintain circuits.

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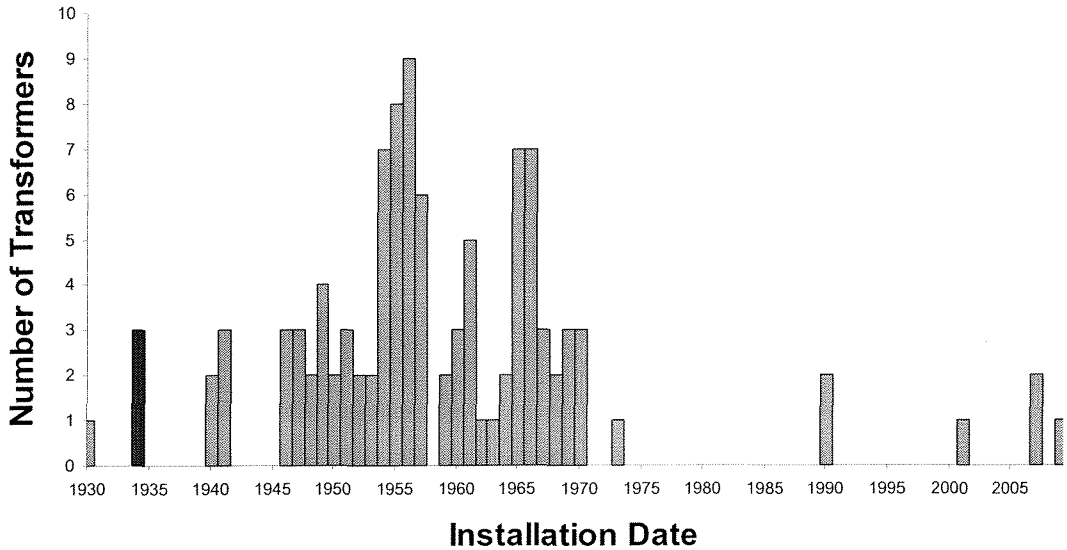
PSNH Distribution Substation Transformer Age Profile



Another example of managing the aging equipment population is proactive change-out of older and problematic equipment. Sometimes this is necessitated by a known manufacturing defect, and at other times it is a generic mode of failure that appears earlier than anticipated or due to specific application conditions. For example, utilities have long used porcelain as insulators on all voltages. There is a known failure for these products due to moisture combined with freeze and thaw cycles leading to cracking and fracture of the porcelain insulators.

The REP capital program allowed PSNH to address this problem by funding the programmatic change-out of these porcelain insulators with the goal of ultimately eliminating them from all distribution lines. The table below shows our progress to date in this effort. Note that the porcelain change out efforts shown commenced at the time REP began in July 2007 (thus a partial year), but that 2008 was a full year with $2.0M of capital budgeted for this task. This is a multi-year effort and PSNH's goal is to change these out, removing the old insulator and replacing it with a modern polymer insulator product, system-wide over a 10-year period.

	Disc Insulators	Cutouts	Lightning Arrestors
Total population	**92,000**	**48,000**	**11,000**
Changed out in 2007	1,888	701	146
Changed out in 2008	6,101	913	213
Changed out to date	7,989	1,614	359

A third example is the replacement of equipment that is unique and one of a kind such as what was done at PSNH's Gorham Substation. The Company's last remaining 1952 vintage Westinghouse circuit breaker was replaced under the REP capital program. In addition to its age, it was the last of only two of this specific type in use at PSNH. Retiring these unique breakers eliminated a one of a kind requirement for training and in house skill retention. We also disposed of spare parts, unique tools, repair manuals and operating instructions. This is a prime example of how maintenance issues can be reduced with removal of obsolete equipment.

IV. CURRENT REP BUDGET AND PROGRAM ALLOCATION

Q. How do the capital and O&M expenditures under the REP program relate to the $10 million included in PSNH's rate level?

A. Under the current program, PSNH's plan is to complete $10 million of capital investment each year. Pursuant to the settlement agreement approved by the Commission in Order No. 24,750, annual REP capital expenditures were to be in excess of what would have typically been budgeted under normal business practices (prior to the REP initiative). In order to ensure that the amount PSNH invested annually in REP capital was truly incremental, PSNH tracked all reliability capital with the understanding that only $10 million is REP and the rest is assumed to fall under "normal" business investment.

For each $10 million of REP capital investment placed in service, PSNH estimates that $1.2 million in revenue requirements per year is needed to support this incremental rate base. In order to support REP capital, the REP O&M budget funded by the $10 million of total REP revenue was first reduced by the total capital-related revenue requirement. Thus, for the first program year ending June 2008, $8.8 million of REP revenue was allocated towards O&M expense activities ($10 million total less $1.2 million capital support). In the second program year ending June 2009, the funding allocated towards REP O&M activities from the $10 million of revenue was reduced by year 1 capital revenue requirements of $1.2 million in addition to the year 2 capital revenue requirements of $1.2 million. This allows for a net amount of $7.6 million to be spent on REP O&M during the second program year. This O&M erosion process continues through the life of the existing REP program. Over time, the amount of revenue available to perform O&M expense activities is significantly reduced. Attached is a table from PSNH's annual REP report that demonstrates this O&M erosion over five program years. Note this is on a "program year" basis (i.e., split year) and not on a calendar year basis.

	ACTUAL	Reliability Enhancement Program Revenue Allocation Plan			
	PROGRAM YR 1	YEAR 2	YEAR 3	YEAR 4	YEAR 5
REP AREA	12 Mo End 6/30/08	12 Mo End 6/30/09	12 Mo End 6/30/10	12 Mo End 6/30/11	12 Mo End 6/30/12
Vegetation Management	$ 2,758,418	$ 2,974,000	$ 2,856,000	$ 2,976,000	$ 3,085,000
NESC Inspect/Repair	$ 2,824,686	$ 2,233,000	$ 2,440,000	$ 2,090,000	$ 915,000
O&M Activities	$ 2,949,570	$ 2,393,000	$ 1,104,000	$ 134,000	$ -
Total O&M	$ 8,532,674	$ 7,600,000	$ 6,400,000	$ 5,200,000	$ 4,000,000
CAPITAL Financing	$ 1,200,000	$ 1,200,000	$ 1,200,000	$ 1,200,000	$ 1,200,000
PRIOR YEAR CAP	$ -	$ 1,200,000	$ 2,400,000	$ 3,600,000	$ 4,800,000
REVENUES	$ 9,732,674	$ 10,000,000	$ 10,000,000	$ 10,000,000	$ 10,000,000

Vegetation Management and NESC Inspection/Repair are escalated in time assuming 100% contractor
NESC Inspect/Repair is reduced in Year 5 after completing 1st cycle in 4 years, next cycle is twice as long
O&M Activities are reduced annually due to allocation of revenues to continue "Base" activities and Capital

Q. What is the forecast for REP expenditures?

A. PSNH's April 1, 2009 REP report contains a detailed forecast of capital and O&M expenditures through the end of 2009 as well as overall budget estimates for the 5-year effort. We expect to be able to execute our plans through the end of 2009. However, beginning in 2010, and absent this rate proceeding, PSNH would need to curtail O&M

activities with even more reductions in subsequent program years due to the additional deployment of the $10 million revenue stream in order to support the REP capital placed in service. Notwithstanding this, PSNH's plan is to continue a steady capital investment of $10 million per year for each year of the existing REP program.

Q. What changes need to be considered for continuation of an effective REP?

A. When the programs and actions were determined during the previous rate case settlement, the long-term effect of declining net revenue available for O&M programs was not fully appreciated. In addition to the revenue requirements to support the capital effort, the cost to maintain individual programs can escalate over time which further compresses program allocations. While some of the programs may decline in cost over time due to establishing longer maintenance cycles with the replacement of aging infrastructure, this cost reduction does not offset the increased cost to support capital investment and the inflation effects and make it more difficult to stay within REP's fixed revenue stream.

Most of the O&M expense activities will require sustainability beyond the life of the REP and, as such, do not work well within the current declining funding framework. The amounts needed to maintain the system while actively replacing aging plant do not decline as the available revenue does; over a long time horizon funding requirements for maintenance remain the same. While the average age of plant will slowly decline over time, for the foreseeable future PSNH's reliability-based O&M expenditures will substantially be based on the system in place now and therefore will require a stable revenue stream for sustainability.

Q. What do you mean by sustainability?

A. Some programs require expenditure of funds each year in order to obtain the intended results. For example, during settlement discussions on the REP, vegetation management was deemed a "base" O&M expense activity with an expectation that the activities should be established and maintained as an ongoing business practice. The intent was that we would reduce our average trimming cycle from 5 years to 4.5 years. This requires the same incremental volume of work every year and will continue long after the original REP was planned to expire. Another example is O&M expense for switch maintenance. It is cyclical and requires repeated performance over the life cycle of the switch.

Q. Are there any programs that do not require sustainability?

A. Yes, within the REP we just completed an O&M expense program to retrofit all of our substations with animal guards. This was completed ahead of schedule and on budget.

Now that it is complete, there is no further action needed and maintenance of animal guards is very modest. This can be easily incorporated into PSNH's routine maintenance practices.

Another example is an O&M expense for a substation grounding study to benchmark and determine "step and touch" potential conditions throughout our system, especially where bulk transformers had been installed. "Step and touch" potential refers to safety requirements where a person could be shocked while standing in a substation and touching an equipment cabinet or fence while a short circuit occurred locally or elsewhere. While still ongoing, this effort will be completed and the information obtained will be used for future design of equipment. The associated revenue requirement for this program will end in the next few years, because once it's completed, there will be no need to continue to incur the expense.

Q. Is this issue the same for capital?

A. Not to the same degree. Since the capital portion of our plan for the REP is funded at $10 million per year, the inflation effect is there but not the revenue requirements for that capital plan.

It is also important to recognize that the O&M plans generate capital work. National Electric Safety Code (NESC) inspections and pole inspection and treatment are prime examples. During such pole inspections, if a damaged or unsafe pole is found, then this O&M activity will cause capital to be invested to replace the damaged pole. Therefore, these O&M activities can 'drive' or create the need for additional capital investments as they are performed and, hence, the capital component also needs to be sustained. PSNH inspects 22,000 poles annually, and while many of them prove to be adequate to remain in service, others require chemical treatment to avoid decay and insects, and still others are deemed unfit to remain in service and must be replaced or reinforced, causing a capital expenditure.

Other capital items are actually long-term replacement programs that extend beyond the original life of the REP, such as porcelain insulator change-outs and substation brown glass insulator replacements. There is too much to do on a short time horizon, both physically and financially. These are programs that need steady funding for the long term until all of the components are replaced.

Q. What is the best option to ensure continued REP O&M funding?

A. In order to maximize available funds for O&M activities, the total REP capital investment that has accumulated should be placed into PSNH's distribution rates rather than continuing to be supported and tracked within the current REP program. By the end of program year 2 on June 30, 2009, there will be $20 million of accrued REP capital (equating to $2.4 million of ongoing revenue requirements) that is in service and benefiting PSNH's customers. The $15 million of REP capital placed in service as of the end of the 2008 test year has been included in the rate base amounts described in Mr. Baumann's testimony. However, this is only a partial solution to the issue of REP O&M erosion. It will be necessary to propose some further amendments to the program and to fully reflect all REP capital in PSNH's distribution rates in order to maximize the long-term benefit of the REP for PSNH's customers.

V. ISSUES NOT ADDRESSED IN CURRENT REP

Q. Are there other issues to consider regarding continuation of the REP program framework?

A. Yes. The REP provides a highly valuable portfolio of activities that improve service to our customers. It addresses activities that PSNH had underway that needed improvement, activities that were not being performed but were required, and activities that needed funding to manage them in a programmatic fashion. The REP provided a reliable funding mechanism to allow these much needed improvements to occur and required annual reporting in order to ensure that the work was being performed as planned. We now need to make sure these and other reliability activities can continue on a long-term basis.

The Stone and Webster Assessment from 2005 identified the value of a Geographic Information System ("GIS"), pointing to its ability to provide improved Outage Management. Their recommendation included the use of mobile technology in the workforce and streamlining data capture to reduce duplication. These interrelated activities can both be accomplished if a GIS is in place. PSNH has studied the implementation of this kind of system and our research shows that it would require a multi-year (5 or more) effort to implement and achieve significant operational gains.

It is expected that the total GIS program implementation would cost $10-15 million of capital with associated O&M expense activities of $1-2 million. Ongoing operating and support costs for portions or the entire GIS have not been estimated yet but there would be an increase in annual expenses to maintain and support a GIS. This project needs specific revenue support to be able to execute successfully and effectively over its lengthy implementation period; hence, we propose adding it as an REP program.

Having successfully restored service after the major storm in December, 2008, PSNH has identified additional programs which should be included in the REP. The damage to the system has been repaired; however, the effects of this storm will be with us for a very long time. The impact on vegetation management O&M programs is an additional $500,000 annually to deal with damage to trees that may not be visible but renders them weaker and declining in health over time. In addition we believe further short-term vegetation management funding for takedown and danger conditions ($600,000) is required as well as a short-term increment of $500,000 for 34.5 kV right-of-way (ROW) "full-width" clearing. For capital, PSNH would establish a program to change out distribution lines which have non-standard small conductors and move some lines out of narrow distribution ROWs.

Q. Can you provide more detail on your plan to implement a GIS at PSNH?

A. Yes. In simple terms, a GIS is a computer database that captures information about the components in our electric distribution system and then ties them to where they are on a geographically referenced mapping system. This allows spotting of poles, transformers and other equipment on a map with a very high degree of accuracy as well as displaying how the system is electrically connected together. A GIS then allows inquiry features such as "what towns are served by a specific circuit and how many of our customers are in each town." It also allows information to pass electronically to other applications such as circuit models for load and voltage calculations. Ultimate levels of a sophisticated GIS provide for interactive activities including in-the-field circuit layout and design, work management job packaging and dispatch, as well as refined outage management.

We expect that the first stage of a GIS would involve definition of the overall scope and the desired end products followed by determining technology requirements, vendor selection and overall implementation plan. Initial deliverables would include establishing PSNH's overhead maps onto a land base, connecting the new GIS to existing internal databases including Customer Information and Vegetation Management with outputs to automate engineering models and analysis tools.

Next steps would include capturing underground systems, incorporating switching and distribution operating information (DSCADA), as well as right-of-way lines. Integration with other readily available GIS data from other entities would also be performed, such as for wetlands and property ownership information that is available from federal, state, and municipal agencies. We would also explore ways share our information to others.

Subsequent steps are to move the GIS to desktop/infield design of line extensions and system upgrades. An outage management system and work management opportunities would then become practical expansions of this system.

IV. PROPOSED CHANGES TO REP

Q. What changes are necessary to REP in order to ensure continuation of the existing reliability programs as well as allow for certain expanded programs?

A. First and foremost, the REP is having a positive impact and is now showing results. Significant progress is being made and it would be very unfortunate to be unable to sustain the efforts we have started.

Second, capital expended to date is in service and, as described earlier, has been incorporated into test year rate base and included in Mr. Baumann's total distribution revenue requirement. As reported in our second annual report to the Commission filed on April1, 2009, REP capital through 18 months ending 12/31/08 is $15 million with an additional $10 million accumulating through year end 2009.

Third, the current REP O&M activities should be considered a part of normal business practices and, therefore, the $8.2 million of test year REP O&M expense has been included in the test year revenue requirement. The intent of this inclusion is to transition the existing REP amount into PSNH's standard distribution rates in order to sustain these O&M efforts on an ongoing basis, not just for the five-year horizon included in the original REP. The activities performed under the REP during the last two years are now considered standard business practice by PSNH.

Fourth, PSNH is requesting to re-establish the REP increment at $4 million of annual revenue to provide for expanded reliability initiatives and to allow for the development of a GIS at PSNH.

Q. You mentioned moving REP capital into rate base. What do you mean by that?

A. As mentioned earlier, PSNH will have invested $25 million in REP capital at the end of 2009 that has been supported by the program. This includes distribution investment that is installed and used and useful and should be recognized as part of PSNH's distribution rates and supported through those rates directly rather than through the REP funding. Inclusion of this investment in distribution rates will occur as part of the normal revenue requirements computation in the rate case proceeding. Once rates are set, the activities would no longer need to be specifically tracked through REP.

Q. What type of programs should be sustained and considered base activities?

A. REP activities that have now become ongoing maintenance practices should be considered part of PSNH's base business and therefore recovered through distribution rates. Based upon the 2008 test year O&M expense of $8.2 million, PSNH proposes that the following programs be recovered through base distribution rates:

All programs for Vegetation Management	$3.2 million
All programs for Inspection and Repair	$2.8 million
All programs for Line and Substation Maintenance	
(Excluding animal protection at substations)	$2.2 million

Animal protection installed at substations was $540,000 in 2008 and is now complete. All other programs are cyclical maintenance programs that require sustained effort as normal business practice. The animal protection funding has been included as an increment to the Vegetation Management portfolio which includes mid-cycle trimming, take downs, and reducing the trimming cycle.

Q. How will this change affect the REP capital programs?

A. As mentioned earlier, the O&M programs can have an impact on the amount of capital required within the REP. With essentially all the expense programs in the current REP portfolio in distribution rates, the resulting "base REP" capital requirements need to be supported by a revenue source. Under PSNH's proposal, the revenue to support base REP capital would be within the new $4 million/year REP increment. Experience to date shows the capital programs related to performing O&M are as follows:

Project	**Amount ($000)**
Reject Pole Replacement	$1,750
Pole Reinforcement	$ 150
NESC Capital Repairs	$ 500
Airbreak Switch Replacement	$ 200
Direct Buried Cable Replacement	$1,250
Direct Buried Cable Injection	$ 150
TOTAL	**$4,000**

This means an accumulation of capital and associated revenue requirements occurs going forward in time as a direct result of REP-based O&M expenditures, and these accumulated capital amounts need permanent revenue support. A new REP funding increment as well as periodic adjustment to PSNH's distribution rates to recognize these known capital additions would allow the new REP funding to be effective and to continue at a sustainable level.

Q. Are there any other changes that should be considered?

A. Yes, PSNH believes we should clearly specify the capital projects that fall under the REP umbrella. Currently we are managing $10 million of capital additions above normal business allocations on an all inclusive reliability portfolio. PSNH's preferred use of the REP increment for capital is to assure steady progress on system upgrades and elimination of obsolete equipment and the long term gain in reliability that provides. Normal business practice had proven to be insufficient to allow substantial or regular progress on these kinds of efforts.

Projects that are long term due to the number of components in service are good candidates for an REP. An example is our distribution line porcelain change-out program discussed earlier. We expect at the current REP funding level porcelain change-out will be a 10+ year effort. Absent REP we would more likely have a modest replacement program and deal with this problem on an operational basis, as failures and outages occur over the life of the equipment. Specifying this project specifically in the REP projects portfolio means steady funding to assure completion.

We also are proposing a Geographic Information System as part of this identified capital within a new REP for a similar reason where it is expected to take a long period of time to implement and requires steady funding.

Q. What do you propose for other REP capital projects?

A. PSNH proposes including the capital projects in the following table as specifically tracked projects with revenue support within the new $4 million/year REP increment.

Project	**Amount ($000)**
Distribution line Porcelain Change out	$2,000
34.5 KV Substation Breaker Replacement	$ 500
Enhanced Tree Trimming	$2,000
Pole Top DSCADA Replacement	$ 500
Substation RTU Replacement	$ 325
Enable SCADA to Windsor Backup	$ 135
Dist. line Wire upgrade/eliminate narrow ROW	$ 400
Reliability Improvements Annual	$1000
GIS Implementation	$2,000
TOTAL	**$8,860**

(NOTE: The Reliability Improvements Annual comprises various smaller individual actions to address individual circuits, unfused lateral installations, mid-line recloser installations and other distribution line capital activities)

Q. Would there also be O&M expense component in the new REP in addition to the capital items?

A. Yes, PSNH would propose that the O&M expense be focused on those with a known time frame that can be scheduled within a limited REP term and declining revenue allocation structure. The following activities have been identified:

Expense Program	**Amount ($000)**
CASCADE Database field survey - S/S and Dist Line	$ 200
Replace pre 1984 RTE Elbow Terminators	$ 250
Substation Switch Maintenance	$ 300
Inspect and Reclaim 34.5kv ROW width	$ 500
Takedowns and cycle impact due to storm	$ 600
GIS O&M Expense, 5 years 10% of capital	$ 200
O&M expense related to other tracked capital projects	$ 450
TOTAL	**$2,500**

Q. In summary, how do the capital and O&M amounts discussed above relate to the new $4 million/year REP increment?

A. The following chart provides a high-level summary of how the $4 million/year in additional REP funding (revenue requirements) will be allocated to capital and O&M (over 4 years):

NEW RELIABILITY ENHANCEMENT PROGRAM ALLOCATION PLAN

CAPITAL ADDITIONS	Year 1	Year 2	Year 3	Year 4
GIS Capital Project	$ 2,000,000	$ 2,000,000	$ 2,000,000	$ 2,000,000
New REP Capital Projects	$ 6,860,000	$ 6,926,750	$ 7,134,553	$ 7,348,589
Capital related to Base REP	$ 4,000,000	$ 4,120,000	$ 4,243,600	$ 4,370,908
Annual Capital Additions	$ 12,860,000	$ 13,046,750	$ 13,378,153	$ 13,719,497
note Revenue Required is 12% of Capital Additions				
Cumulative Revenue Required for CAP ADDS	**$ 1,543,200**	**$ 3,108,810**	**$ 4,714,188**	**$ 6,360,528**
O&M EXPENSE				
GIS O&M Expense	$ 200,000	$ 200,000	$ 200,000	$ 200,000
O&M Related to other Tracked CAP ADDS	$ 407,250	$ 414,253	$ 426,681	$ 439,481
New REP O&M Programs	$ 1,850,000	$ 1,800,000	$ 250,000	$ 150,000
Revenue Requirements for O&M Programs	**$ 2,457,250**	**$ 2,414,253**	**$ 876,681**	**$ 789,481**
NEW REP *Total* Revenue Requirements	**$ 4,000,450**	**$ 5,523,063**	**$ 5,590,869**	**$ 7,150,009**
CAPITAL ADJUSTMENT INTO BASE RATES				
Capital Adjustment to Rate Base after Year 1	$ -	$ 12,860,000	$ -	$ -
Revenue Requirements Adjustment after Year 1	$ -	$ (1,543,200)	$ (1,543,200)	$ (1,543,200)
Capital Adjustment to Rate Base after Year 3	$ -	$ -	$ -	$ 13,046,750
Revenue Requirements Adjustment after Year 3	$ -	$ -	$ -	$ (1,565,610)
NEW REP *Net* Revenue Requirements	**$ 4,000,450**	**$ 3,979,863**	**$ 4,047,669**	**$ 4,041,199**

Assuming the test year activities and $8.2 million of revenue associated with the original REP O&M programs are part of base rates, and using the current REP framework, we can structure a successful new REP for a term of 4 years that would include the following:

- Identified annual capital additions would amount to just over $12.8 million per year. This includes the GIS project at $2 million and other specifically tracked capital of $6.8 million, plus capital related to base REP of $4 million. This capital plan is estimated to accumulate revenue requirements of $1.5 million per year, and add another $1.5 million each succeeding year.

- A distribution rate adjustment for additional capital placed into service would occur at the completion of program year 1 (June 30, 2011) to account for REP-related capital, thus freeing up the REP revenue to be used for additional capital expenditures under the REP program. An additional capital adjustment could occur at the end of the third year recognizing at least one more year of accumulated capital and again freeing up revenue requirements for the final year of the REP.
- O&M expense activities amount to $2.5 million in the first year and decline rapidly to work in concert with the revenue requirements due to the capital plan.
- REP incremental revenue required on an annual basis would be able to be maintained at $4 million per year over and above $8.2 million REP O&M activities now in base rates.

We have included inflation effects on the long term programs in both O&M and capital.

Q. Please summarize what you are requesting with respect to the Reliability Enhancement Program.

A. We are requesting that the existing program O&M be considered standard business practice and therefore no longer under the REP umbrella. We are also requesting that the Commission allow PSNH an additional $4 million per year in revenue requirements for new REP activities (both capital and O&M) that I describe above. Finally, in order to continue the new REP program at a fully funded level for a period of four years, we are requesting that the Commission allow PSNH to adjust its distribution rates as of July 1, 2011 to recover the REP capital that it spends through the end of the first year (i.e., through June 30, 2011), and to allow a similar adjustment at the end o the third year (July 1, 2013).

Q. Does that complete your testimony?

A. Yes, it does.

THE STATE OF NEW HAMPSHIRE
BEFORE THE

NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION

Docket No. DE 09-035

DIRECT TESTIMONY OF

Robert A. Baumann

Request for Permanent Distribution Rates

June 30, 2009

TABLE OF CONTENTS

ATTACHMENTS

I. INTRODUCTION

Q. Please state your name, position and business address.

A. My name is Robert A. Baumann. I am Director, Revenue Regulation & Load Resources for Northeast Utilities Service Company ("NUSCO"). NUSCO provides centralized services to the Northeast Utilities ("NU") operating subsidiaries, including Public Service Company of New Hampshire ("PSNH" or the "Company"). My business address is 107 Selden Street, Berlin, Connecticut. Additional biographical information is provided in Attachment RAB-1.

Q. Have you previously testified before this Commission?

A. Yes. I have testified on numerous occasions before the Commission.

Q. What is the purpose of your testimony?

A. I am submitting this testimony in support of PSNH's distribution revenue requirement as it relates to, and supports PSNH's request for a change in permanent retail distribution rates effective August 1, 2009. The foundation for the calculation of this permanent rates request builds on the Company's request for temporary rates that was filed on April 17, 2009 ("temporary rates filing"), with a limited number of additional adjustments.

Finally, my testimony will address the issue of "attrition" as introduced in Mr. Long's testimony and propose a regulatory framework that would deal with some of the negative financial impacts that attrition has had on PSNH in the past and will continue to have in the future.

Q. For purposes of PSNH's filing, what are the test year and the pro forma test year periods?

A. The test year in PSNH's filing is the 12 months ended December 31, 2008 and the test year pro forma period is the 12 months ending December 31, 2009.

Q. Does this filing contain all of the tariff filing requirements described in Part Puc 1604 of the Commission's Rules?

A. Yes. PSNH has filed the appropriate filing requirements in this submittal. On February 23, 2009, PSNH filed a Motion for Waiver of certain Provisions of Puc 1604.01(a). On April 3, 2009, the Commission granted PSNH's request for waiver and determined that granting the waiver is in the public interest and would not disrupt the orderly and efficient resolution of matters before the Commission.

II. PERMANENT DISTRIBUTION RATES REQUEST

Q. Please explain why the Company is requesting authority to implement Permanent Distribution Rates effective August 1, 2009.

A. Consistent with my testimony in the temporary rates filing, this proposal for permanent rates is necessary to address significant distribution cost increases since PSNH's last rate case that have not been offset by revenue growth. The current insufficient level of revenue has adversely impacted the actual financial results of the Company in the test year and has continued to expose the Company to additional financial degradation into 2009. Temporary rates would provide PSNH with an immediate increase in revenues and therefore timely address, in part, the current financial degradation.

Three years ago PSNH filed and was allowed both temporary and permanent rate changes in Docket No. DE 06-028 effective July 1, 2006 and July 1, 2007 respectively. The final approved permanent rates contained an allowed distribution Return on Equity (ROE) of 9.67% and were based on an adjusted 2005 test year. As part of the DE 06-028 approval, PSNH was also allowed a modest "step" increase to rates which was effective January 1, 2008 to reflect nonrevenue producing capital additions through December 31, 2007. Since that time, PSNH has continued to meet its obligation to serve by continuing to invest significantly in PSNH's distribution infrastructure system to maintain and improve current and future service to customers. As a result, the value of PSNH's rate base has and will continue to increase well beyond the level allowed in the last rate case, on which the current distribution rates were based. In addition, operation and maintenance costs have continued to increase beyond the levels embedded in current rates, while delivery sales have decreased over the same time period. The increase in investments to our infrastructure as well as the continued increase to our O&M costs have resulted in a significant decline in the Company's actual earned distribution ROE. As of December 31, 2008, the actual 2008 distribution ROE for PSNH, as reported to the Commission, was 6.26%, and as of March 31, 2009 the actual distribution ROE dropped to 5.54% for the 12 month period. These values remain well below past and current industry standards of a fair and reasonable return, and well below the 9.67% level authorized by the Commission in the 2006 case. With no temporary rate relief in 2009, PSNH projects a calendar year 2009 distribution ROE of approximately 4% and continued decline into 2010.

Q. Explain how the current rate setting structure has contributed to the weak financial results of PSNH?

A. When PSNH's base rates are reset in a general rate case proceeding, the overall starting point for those rates is an historic five-quarter average rate base and a projected pro forma income statement based on limited known and measurable cost adjustments. Using this methodology, the setting of new base rates automatically creates significant financial risk and uncertainty for PSNH as new rates are set on financial information, much of which is backwards looking (rate base) and some of which is set on a cost structure that is current at the time the rate filing is prepared, but will be out of date by the time new rates take effect. The current regulatory lag between filing a case and securing a final decision results in rates that do not recover the actual level of costs during the time that the rates are in effect.

In Docket No. DE 06-028, the Permanent Rates Settlement approved by the Commission recognized the "lag" problem and partially addressed the issue through a modest "step" increase to rates associated with some growth in rate base. While the numbers we are filing today are not requesting additional revenue requirements beyond the proforma test year 2009, we would request that the issue of "lag", and the revenue shortfall it creates, be addressed within the Permanent rates review and adjudication process as all interested parties meet in technical sessions throughout the process. This would allow for a full understanding of the "lag" issues and possible solutions going forward, and would give all interested parties the opportunity to have a voice in a possible solution. This significant issue goes to the heart of our unsatisfactory financial results that PSNH is facing currently and most likely will face in the future, if not addressed effectively in this docket.

Q. Describe in more detail the elements behind the "unsatisfactory financial results" you refer to above.

A. Simply stated, the current regulatory practice in New Hampshire does not allow PSNH the opportunity to earn its allowed ROE for any sustainable period of time. Even in the past, when the Commission has allowed a level of revenue requirements that are supported by a reasonable rate of return, PSNH has been unable to earn that intended return due to attrition. Fair and reasonable levels of rate base and costs of service that are part of the rate setting calculation are quickly over-taken by increasing costs and additional capital additions, which are often times not offset by the level of sales and associated revenue increases. These constant cost increases subsequent to the setting of new rates, coupled with inadequate sales growth have immediate negative impacts to PSNH's financial returns. This in turn creates inconsistent and inadequate earnings for PSNH.

Q. Does PSNH have a going forward proposal to address the regulatory disconnect described above?

A. Yes. It is our intent to introduce into this permanent rate case request a dialogue among all interested parties which could lead to the creation of a ratemaking framework in New Hampshire that deals head on with the issue of attrition. We believe that a successful regulatory framework can be put into place, on a going forward basis, which would address the key concepts and goals noted below:

1. Lower the frequency of permanent base rate requests.
2. Create rate paths that are supported by actual costs incurred by PSNH.
3. Create an ongoing recovery methodology that is straightforward and easily verifiable.
4. Create protections for customers that assure fair, reasonable and cost based rates.

Q. Describe in more detail the framework that you are suggesting to put into place.

A. We believe that periodic rate adjustments supported by verifiable financial information would create a future rate path that would slow the frequency of permanent rate requests and afford PSNH the opportunity to earn a sustainable and reasonable rate of return. Less frequent rate case requests would decrease the administrative burden of a full rate case and create additional time for all parties to address new initiatives that present themselves over time. Any such rate adjustment would be supported by actual financial data which would always be available for review by the Commission and by other interested parties.

We would propose that on an annual year-end basis, PSNH would file actual net capital balances consistent with the most currently allowed rate base data, and that these values would be used to calculate rate adjustments effective on July 1 of the following year. Specifically, the filing would include actual gross plant less accumulated depreciation, or net plant, offsetting accumulated deferred income tax (ADIT) and depreciation expense. This would be a very important and material step towards the attrition issue. The plant investment data would be verifiable, and these assets would be used and useful at the time rate recovery began. PSNH's capital program is well documented and supported by a strong commitment to reliability for our customers. The Commission and all other interested parties would be afforded the opportunity to review the capital costs embedded in this annual filing, which would also be supported by our year end audited financial statements that are filed with the FERC and SEC.

With respect to O&M costs, we would propose at this time that PSNH would continue to monitor and address theses costs through our internal operations and that these costs not be included as a part of the periodic annual rate adjustments. The risks associated with higher O&M costs would continue to remain with PSNH and could be offset by any future sales increases, if they were to occur. PSNH's sales levels are being negatively impacted by the current economic conditions, conservation and customer usage patterns as well as through other demand and supply side programs aimed at reducing customer usage.

Finally, a new regulatory framework such as we have proposed may result in less frequently filed permanent rate cases. If such a framework were adopted, we believe that the Commission should closely monitor the Companies actual ROE levels on an ongoing basis. We certainly would be willing to discuss a framework for an earnings sharing mechanism based on actual ROEs. PSNH currently files a rolling twelve month actual ROE calculation with the Commission and OCA at the end of each calendar quarter (NHPUC Form F-1).

Q. Do you believe that your suggested regulatory framework is in keeping with past recovery practices?

A. Yes. PSNH believes that our proposed periodic rate adjustments are consistent with the step increase that was part of the settlement approved by the Commission in the 2006 rate case, which was supported by all parties. Our proposal is also consistent with cost based ratemaking that has been the historic cornerstone of all past and current recovery mechanisms. Such a fundamental change in the regulatory framework in New Hampshire would be a fair and balanced first step approach to the issue of attrition.

Q. Would this suggested regulatory framework solve the attrition experienced by PSNH?

A. No. Although it would significantly mitigate the expected attrition in ROE, this method would not mitigate higher expenses or lower kWh sales. PSNH is willing to consider other attrition solutions with the parties to the proceeding, but this particular proposal would significantly contribute to a solution.

Q. Describe the supporting historical rate base and return data that is attached to this testimony.

A. Attachment RAB-3 illustrates graphically the historical "lag" in rate base by comparing the level of rate base allowed in rates to the comparable actual rate base values over the past three years. The chart clearly illustrates the tens of millions of dollars of rate base lag that PSNH's rates have contained over recent years.

Attachment RAB-4 illustrates graphically the short-fall in the actual earned ROEs when compared to the allowed and/or recommended ROEs over the same three year historical period as in Attachment RAB-3. This chart also gives a clear picture of the continuing gap between allowed and actual ROEs.

Q. What is the Company's overall rate proposal?

A. In this filing PSNH is requesting an increase for Permanent distribution rates of $51 million to be effective August 1, 2009. We recognize that if our temporary rates request of approximately $36 million were to go into effect on August 1, 2009, and that the Permanent rates request were to be suspended for up to one year, the final allowed Permanent rates request would be subject to recoupment. We would propose that the recoupment value would be the difference between the final allowed temporary and permanent rate levels effective August 1, 2009 and would be recovered through rates beginning July 1, 2010 over a 12 month period. The recoupment period would be the 11 month period August 2009 – June 2010. This would re-synchronize the distribution rate change with the existing rate charges for the ES, SCRC and TCAM back to a pattern of mid-year changes that is in effect today.

In addition to the Permanent rates request noted above, PSNH is requesting an additional step increase in rates effective July 1, 2010. This step increase is approximately $17 million and would establish recovery of estimated 2009 net capital additions to rate base and associated depreciation expense and ADIT. Prior to implementing that increase, PSNH would provide information documenting the amount of capital additions and associated depreciation expense. In addition, this step increase would include funding of a new Reliability Enhancement Program (REP) as described in Mr. Johnson's testimony, increase depreciation expense related to the application of a Capital Recovery Calculation (CRC), as well as an increase to the current annual accrual for major storm costs.

Finally, as noted above, PSNH is proposing a new regulatory framework that would address the issue of attrition and its negative impact on the financial results of the Company.

III. PERMANENT RATES DISTRIBUTION REVENUE REQUIREMENT

Q. Based on your detailed calculation of the Company's Distribution revenue requirements using the 2008 test year, is there a test year revenue deficiency evidenced by the supporting calculations?

A. Yes. A calculation of a revenue deficiency using actual 2008 test year financial data adjusted only for known and measurable changes results in a distribution revenue deficiency for PSNH's distribution business of approximately $30 million. In addition, as the chart below illustrates, there are additional items that have been included in the requested Permanent revenue requirements as proposed by PSNH. They relate to additional test year rate base levels and associated depreciation, recovery of the

December 2008 ice storm costs and a higher requested ROE than is currently allowed in rates (10.5% vs. 9.67%). The overall calculation supporting this revenue deficiency is contained in the supporting schedules, which are attached to my testimony.

Q. What is the total requested permanent distribution revenue requirements in this filing?

A. As noted above, the total level of Permanent rates being requested effective August 1, 2009 is an increase of $51 million. In table form this requested increase is summarized as follows:

Test year deficiency with **average** test year rate base	$ 20	million
Other known and measurable proforma cost increases	10	
Storm cost recovery (over 5 years) – December 2008 storm	9	
Increase in rate base from average to end of test year levels	4	
Increase in depreciation expense – to end of test year levels	3	
Increase in ROE from current allowed of 9.67%, to 10.5%	5	
Total requested Permanent rates effective August 1, 2009	$ 51	million

Q. Describe the $10 million component associated with the test year proforma cost increases noted in the table above.

A. In keeping with Commission rules, we have proformed the test year data for only known and measurable cost changes. Specifically, the $10 million is primarily made up of known increases for property taxes ($3 million), pension costs ($3 million), payroll costs ($2 million) and medical costs ($1 million). The property tax expense in this filing represents the expected level of state and local taxes that PSNH will begin to pay in the second quarter of 2009. This value reflects the liability that will be accrued monthly on PSNH's books. The pension and medical expenses are supported by the latest known and measurable actuarial values. Finally, the payroll expenses represent the latest known actual pay levels and full time employees at the end of the test year.

Q. Describe the $9 million component associated with storm costs noted in the table above.

A. New Hampshire and surrounding states suffered a severe ice storm in December 2008 that demanded an extensive response from PSNH. The total costs incurred to restore service to our customers throughout our service territory have been estimated to be in excess of $60 million after insurance. Our permanent rates filing assumes recovery of these costs, with carrying charges, over a five (5) year period beginning August 1, 2009. The temporary rates filing preliminarily assumed a six (6) year recovery period.

Q. How did you calculate the storm costs?

A. The values that we have included in the revenue requirements are based on actual data with some estimated data as well. All estimated data will be trued up to actual data in subsequent months and will be made available to the Commission for their review. We would recommend that the Commission conduct its audit review of the updated storm costs when they are filed. It is currently our plan to update all storm costs to actual during the June 30, 2009 quarterly closing process. The total net cost embedded in this rate filing for the December 2008 storm is $66.4 million. This value is derived by adding the total storm costs deferred on the Company's books as of December 31, 2008 ($62.7 million) to an estimated amount for directly related operating expenditures that will be incurred in 2009 ($7.0 million), and carrying costs ($9.4million), netted against an estimated insurance payment ($12.7 million). A detailed supporting calculation is contained as Attachment RAB-2 to this testimony.

Q. Why are you changing from the 6 year recovery period as filed in the temporary rates application to the 5 year period in this filing?

A. Our requested temporary increase was tempered by the desire to keep overall rates flat or lower on July 1, 2009 when you combine the temporary distribution rate change with the ES and SCRC rate changes. Our total requested temporary increase, when combined with the estimated net decrease in the ES and SCRC rates also scheduled for July 1 at the time of filing, resulted in no increase to the average residential customer rates and a 1% decrease in overall average rates on July 1, 2009. A recovery period less than 6 years would not have met that desired outcome for temporary rates.

Q. Describe the $4 million component associated with end of test year rate base noted in the table above.

A. For reasons noted previously, we are requesting that permanent rates effective August 1, 2009 be set using a test year end actual rate base versus a test year five-quarter average rate base.

Q. Describe the $3 million component associated with end of test year depreciation levels noted in the table above.

A. Consistent with an end of test year rate base, we are requesting that permanent rates be set with depreciation expense levels adjusted to an end of test year expense level which would allow for full recovery of depreciation expense in the following rate year.

Q. Describe the $5 million component associated with a requested increase to the allowed ROE as noted in the table above.

A. We are requesting an increase to the current allowed ROE from 9.67% to 10.5%. This increase is supported by the testimony of George J. Eckenroth which is contained in PSNH's filing.

Q. Describe the additional $17 million step in rates that PSNH is requesting to be effective July 1, 2010.

A. PSNH is requesting an additional step increase in rates effective July 1, 2010. This step is approximately $17 million and would establish recovery of estimated 2009 capital additions to rate base and associated depreciation expense. In addition, this step increase would include funding of a new Reliability Enhancement Program (REP), an increase to the current annual accrual for major storm costs and an increase to the overall level of depreciation supported by the latest Capital Recovery Calculation (CRC). In table form this requested increase is summarized as follows:

2009 capital additions to rate base and associated depreciation	$ 5	million
Reliability Enhancement Program	4	
Increase in annual storm expense accrual ($1.7 to $4.4 million)	2	
Capital Recovery Calculation (CRC)	6	
Total	$ 17	million

Q. **Describe the $5 million component associated with the recovery of 2009 capital additions to rate base and associated depreciation expense noted in the table above.**

A. For reasons noted previously, PSNH is requesting that permanent rates on July 1, 2010 be set using an actual rate year end (2009) rate base versus a test year five-quarter average rate base. These values will be known, measurable and in service as of July 1, 2010.

Q. **Describe the $4 million component associated with a new Reliability Enhancement Program noted in the table above.**

A. Our request contains a new REP program that is presented in the testimony of Stephen M. Johnson which is contained in the Company's filing.

Q. **Describe the $2+ million component associated with the requested increase in the annual accrual for major storms from the current level of $1.7 million to $4.4 million noted in the table above.**

A. Our request increases the annual accrual to the major storm reserve, to cover future major storm costs. The requested level is supported by an average of past historical major storm levels from 2004 through 2007. Values for 2008 were not contained in our average due to the severity and uniqueness of the December 2008 ice storm.

Q. **Describe the $6 million component associated with the application and recovery of additional annual depreciation expense resulting from the most current Capital Recovery Study (CRC) noted in the table above.**

A. PSNH is requesting an increase in depreciation expense related to the application of a Capital Recovery Calculation on the existing depreciation methodology. Support for our request is contained in the Technical Statement of Dale R. Urban which is included in this filing.

Q. Are there any other specific adjustments that you would like to present at this time?

A. Yes. We have recently learned of a new legislative initiative that has raised 2009 unemployment taxes on an emergency basis to fund the state unemployment trust fund, and which is likely to raise them further into 2010. As of today, we do not have a financial impact resulting from this law. As the State of New Hampshire considers its own budget needs and associated tax structure, any changes to State policy or practice may increase PSNH's operating costs. When issues like this become known and measurable we will be updating our filing accordingly.

In addition, PSNH is reviewing its leases related to its fleet of vehicles and the future viability of lease versus purchases. This review was made necessary by dramatic changes in vehicle lease programs as a result of the upheaval in the capital markets which is discussed by Mr. Long. Once we understand the impacts of this issue we will update the case accordingly.

Q. Describe the overall link to PSNH's financial statements as presented in this filing.

A. Consistent with the unbundling of PSNH's rates, we have provided supporting schedules that reconcile total company income and rate base to PSNH's books and records. In addition, we have provided schedules that support the segmentation of these total company balances. The distribution segment forms the beginning basis of our revenue requirements calculation. We then provided a series of known and measurable adjustments to the actual test year distribution segment in formulating the adjusted test year financials. The adjusted test year income statement (operating income) and five-quarter average rate base were then used in the computation of the distribution revenue deficiency calculation.

Q. Please explain the Summary of Adjustments to the Income Statement in Schedule 1 Attachment, Page 1.

A. This schedule shows the net effect on the test year operating income statement resulting from all of the known and measurable pro forma adjustments contained in PSNH's filing. Each adjustment that supports this summary schedule contains additional explanations and analysis related to each particular adjustment to the income statement. Please refer to the Attachment RAB-5 for detailed discussion of all proforma income statement adjustments which were included in this Temporary Rates filing.

Q. Does this conclude your testimony?

A. Yes, it does.

Biography of Robert A. Baumann

Mr. Baumann graduated from Lafayette College in 1974 with a Bachelor of Arts degree in Economics. In 1976 he received a Masters Degree in Business Administration from the University of Connecticut. From 1976 to 1981, Mr. Baumann was employed by the international accounting firms of Touche Ross and Company and Coopers & Lybrand. He received his designation in Connecticut as a Certified Public Accountant in 1979.

Mr. Baumann assumed his current position of Director – Revenue Regulation and Load Resources in 2001. In 1981, he joined Northeast Utilities (NU) in the Revenue Requirements Department and has worked in various regulatory capacities for all of the operating subsidiaries of NU. His current responsibilities include all revenue requirement issues associated with Public Service Company of New Hampshire, all NU regulatory issues related to generation, load, and standard offer contracts for all of the NU operating subsidiaries as well as all regulatory issues associated with the Purchase Gas Adjustment Clause for Yankee Gas Services Company, an NU affiliate. He has provided testimony on many occasions before state commissions in New Hampshire, Connecticut and Massachusetts as well as before the Federal Energy Regulatory Commission.

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE
DISTRIBUTION SEGMENT RATE CASE

PROFORMA ADJUSTMENT - SUPPORTING SCHEDULE

MAJOR ICE STORM COSTS

(Thousands of Dollars)

Line			Distribution Segment
1	**Part 1 - Summary of December 2008 major ice storm costs (1)**		
2	Storm costs, net of amounts capitalized, deferred to a 186 account at December 31, 2008	$	62,709
3	Additional costs expected to be incurred during 2009 to complete restoration		10,000
4	*Portion of 2009 costs PSNH expects to capitalize*		(3,000)
5	Estimated insurance proceeds		(12,709)
7	Return on the average balance over the recovery period (see page 2 of 2)		9,359
8	Total December 2008 major ice storm costs, incl return on the average balance	$	66,359
9	Unrecovered balance Acct 182.ST (Deferred Major Storm Costs) at June 30, 2009	$	5,486
10	Plus : Return, including tax gross up, for the July 2009 through June 2010 (DE 08-071)		431
11	Unrecovered revenue requirements for Acct 182.ST at June 30, 2009	$	5,917
12	Total (Line 8 and Line 11)	$	72,276
13	**Part 2 - Recovery of costs through permanent rates**		
14	Estimate of major storm recovery through temporary rates (2)	$	12,268
15	Remainder to be recovered through permanent rates (Line 12 less Line 14)	$	60,008
16	Annual recovery of deferred major storm costs over 4 years--permanent rates	$	15,002
17	Less amortization for Acct 182.ST, and return		5,917
18	Revenue requirements increase in recovery of deferred major storm costs	$	9,085

19 (1) The numbers shown represent PSNH's best estimate as of December 31, 2008. These
20 amounts, including returns, will be updated during 2009 as additional actual information
21 becomes available.

22 (2) See temporary rates filing, DE 09-035 as filed April 17, 2009--reference page 000102

23 Amounts shown above may not add due to rounding.

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE
DISTRIBUTION SEGMENT RATE CASE

MAJOR ICE STORM COSTS

(Quarter Ending)

(Thousands of Dollars, excluding Percentage Data)

1 Return on the December 2008 major ice storm costs (1)

2	Mar 09	June 09	Sept 09	Dec 09	Mar 10	June 10 (2)	Sept 10	Dec 10	Mar 11	June 11	Sept 11	Dec 11	Mar 12	June 12	Sept 12	Dec 12	Mar 13	June 13	Sept 13	Dec 13	Mar 14	June 14	Total Return
3 Beginning balance	62,709	67,049	58,652	57,725	56,786	55,837	54,877	51,731	48,549	45,331	42,077	38,785	35,455	32,088	28,682	25,238	21,754	18,230	14,667	11,062	7,416	3,729	
4 Additional 2009 costs, net	3,500	3,500																					
5 Insurance proceeds		(12,709)																					
6 Amortization			(1,588)	(1,588)	(1,588)	(1,588)	(3,750)	(3,750)	(3,750)	(3,750)	(3,750)	(3,750)	(3,750)	(3,750)	(3,750)	(3,750)	(3,750)	(3,750)	(3,750)	(3,750)	(3,750)	(3,750)	
7 Balance prior to return	66,209	57,840	57,064	56,136	55,198	54,249	51,126	47,980	44,799	41,581	38,326	35,034	31,705	28,338	24,932	21,487	18,004	14,480	10,916	7,312	3,666	(21)	
8 Average balance to calculate return	66,459	62,444	57,858	56,931	55,992	55,043	53,001	49,855	46,674	43,456	40,201	36,910	33,580	30,213	26,807	23,363	19,879	16,355	12,791	9,187	5,541	1,854	
9 Def taxes calculated at 39.55%	(25,494)	(24,697)	(22,883)	(22,516)	(22,145)	(21,769)	(20,962)	(19,718)	(18,460)	(17,187)	(15,900)	(14,598)	(13,281)	(11,949)	(10,602)	(9,240)	(7,862)	(6,468)	(5,059)	(3,633)	(2,192)	(733)	
10 Net def costs to calculate return	38,966	37,747	34,975	34,414	33,847	33,273	32,039	30,138	28,214	26,269	24,302	22,312	20,299	18,264	16,205	14,123	12,017	9,887	7,732	5,553	3,350	1,121	
11 x Return (1)	2.15%	2.15%	1.89%	1.89%	1.89%	1.89%	1.89%	1.89%	1.89%	1.89%	1.89%	1.89%	1.89%	1.89%	1.89%	1.89%	1.89%	1.89%	1.89%	1.89%	1.89%	1.89%	
12 Return on def major storm costs	839	813	660	650	639	628	605	569	533	496	459	421	383	345	306	267	227	187	146	105	63	21	9,359
13 Ending balance, including the return	67,049	58,652	57,725	56,786	55,837	54,877	51,731	48,549	45,331	42,077	38,785	35,455	32,088	28,682	25,238	21,754	18,230	14,667	11,062	7,416	3,729	(0)	
14 182ST $5.917M amortization, incl return			(1,479)	(1,479)	(1,479)	(1,479)																	

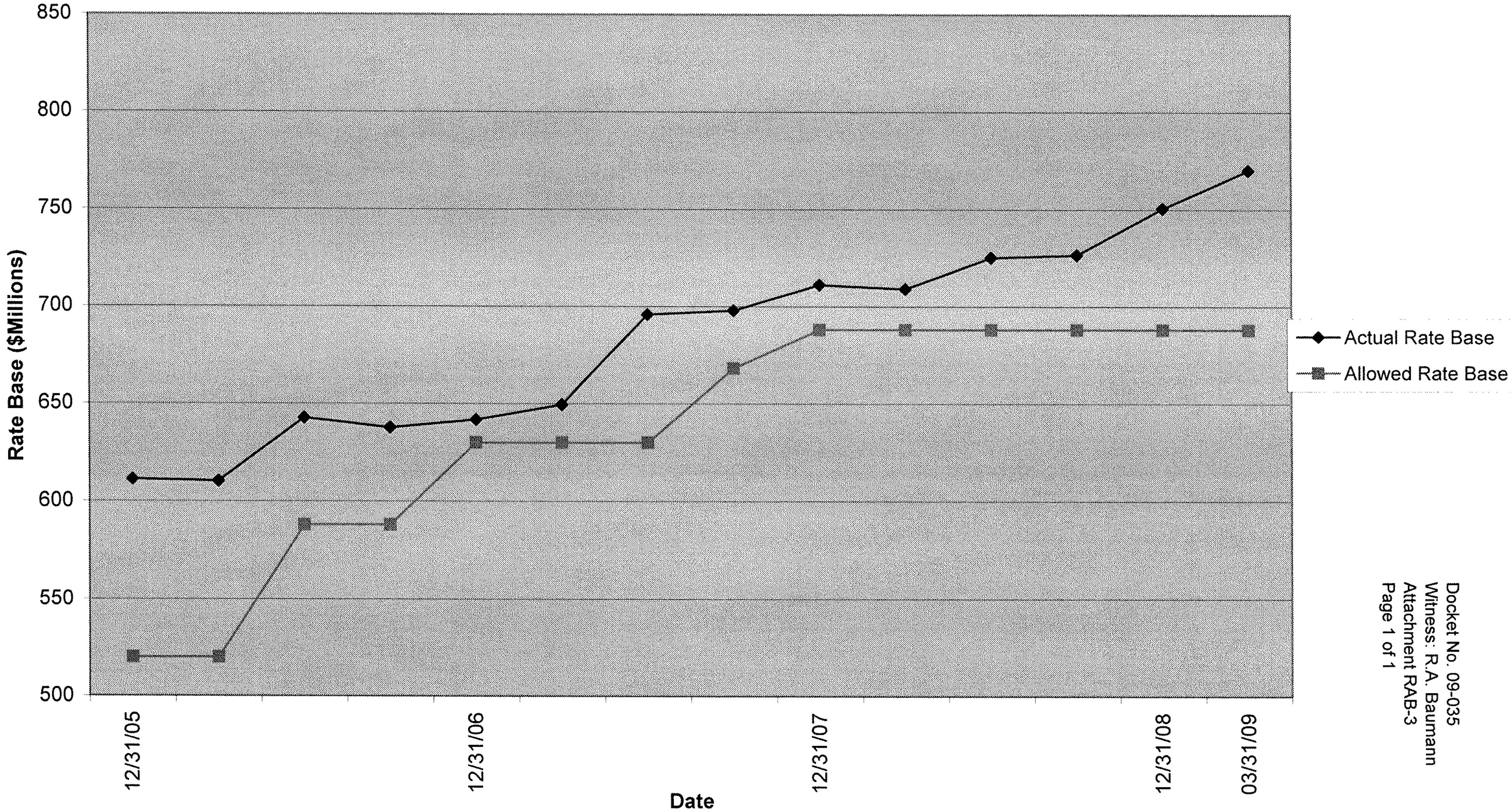
15 (1) 7.55% annual return (including the gross revenue conversion adjustment on the equity return for taxes) previously used in
16 DE 06-028 and DE 08-071 in determining the return on deferred major ice storm costs.

17 (2) The ending balance for June 2010 is consistent with the information provided in PSNH's temporary rate filing in DE
18 09-035, dated April 17, 2009 (reference attachment RAB-2, page 2 of 2). Adjustments for 2009 costs and insurance
19 proceeds in both the temporary and permanent have been estimated based upon information currently available. This
20 calculation will be updated as additional information becomes available.

21 Amounts shown above may not add due to rounding.

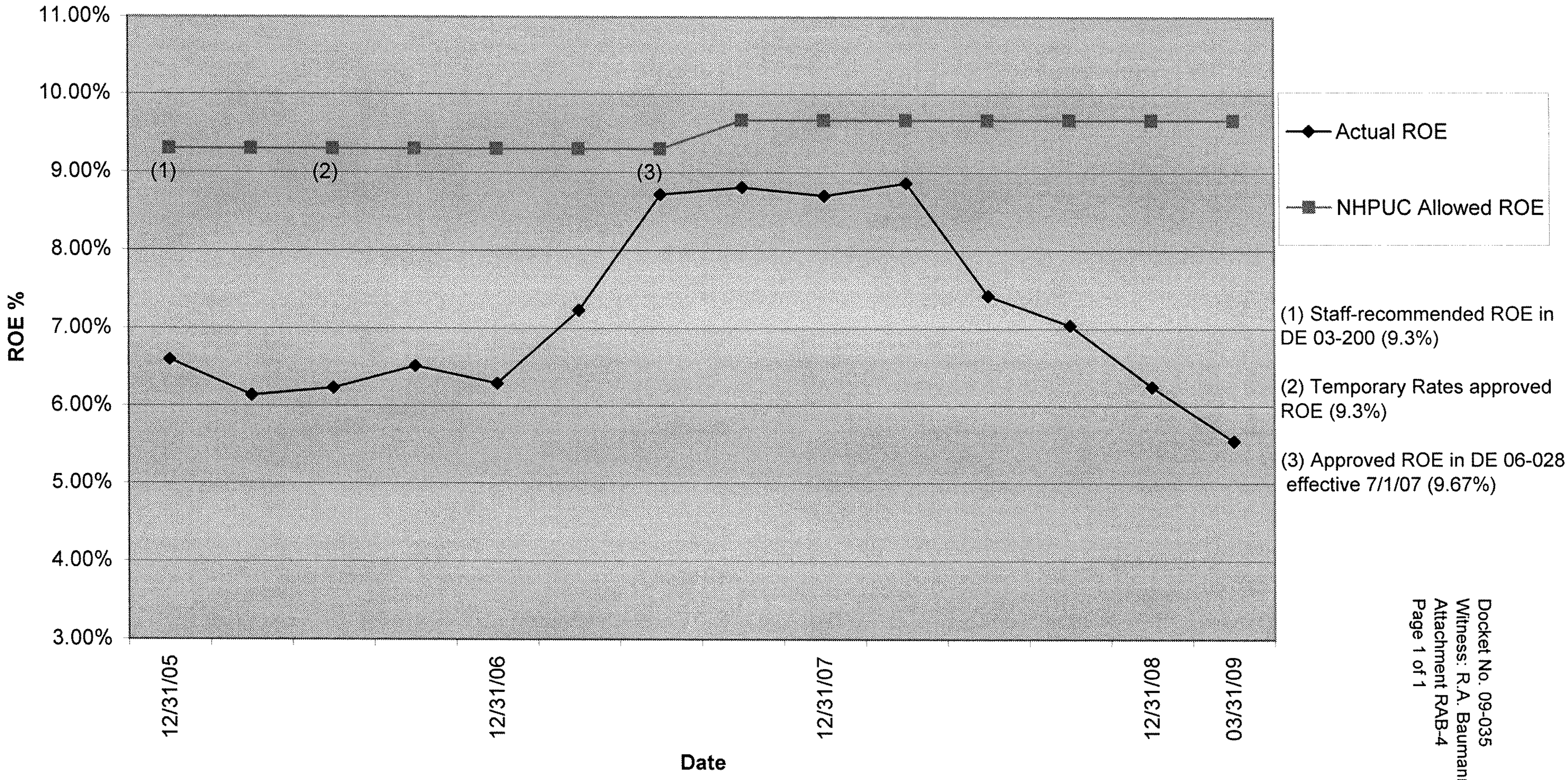
Docket No. 09-035
Witness: R.A. Baumann
Attachment RAB-3
Page 1 of 1

End of Period Actual vs. Allowed Rate Base



000037

ROE Percent
Based on 5 Quarter
Rate Base and Cost of Capital Data



Docket No. 09-035
Witness: R.A. Baumann
Attachment RAB-4
Page 1 of 1

PSNH

REQUEST FOR PERMANENT RATES

PRO FORMA INCOME STATEMENT ADJUSTMENTS

The following adjustments can be found in Schedule 1 Attachment:

Page 2 – Special Pricing Revenue

This pro forma adjustment reflects the decrease in distribution operating revenues to reflect special pricing arrangements which will terminate and revert to billing under standard tariff rates by December 31, 2009 (within twelve months of the end of the test year).

Page 3 – Billed Retail Distribution Revenue

This pro forma adjustment relates to PSNH's retail distribution rates which decreased on July 1, 2008. This adjustment states retail revenues at the July 1, 2008 rate level for the entire year.

Page 4 – Field Collection Revenues

This pro forma adjustment increases PSNH's retail distribution revenue to reflect Field Collection revenues that were mistakenly booked to the wrong segment from January thru July 2008.

Expense Adjustments

Page 5 – Uncollectible Expense

This pro forma adjustment decreases test year operating expense to reflect a decrease in the allocation to the Distribution Segment.

Page 6 – Verizon Out-of-Period O&M Credit Associated with Tree Trimming

This pro forma adjustment eliminates a non-recurring out-of-period O&M credit associated with the reimbursement for tree trimming costs from Verizon.

Page 7 – Tilton Area Work Center O&M Costs

This pro forma adjustment eliminates non-recurring O&M costs associated with fire damage at the Tilton Area Work Center in 2008.

Page 8 – Amortization of Software Maintenance Agreement

This pro forma adjustment reflects the increase in test year operating expenses for the amortization of contract costs associated with call center technology software support and maintenance.

Page 9 – Postage Expense Increase

This pro forma adjustment increases test year operating expense to reflect higher postage expense effective May 12, 2008 and May 11, 2009.

Page 10 – Payroll Expense

This pro forma adjustment changes test year payroll expense to reflect the impact of retirements, annualization of new employee salaries, and to reflect pay increases for exempt, non-exempt and union employees, along with payroll-related overheads.

Page 11 – Other Post Employment Benefits (OPEB)

This pro forma adjustment reflects an increase in OPEB expense based on most current actuarial studies.

Page 12 – Pensions

This pro forma adjustment reflects the increased pension expense based on most current actuarial studies.

Page 13 – Property Taxes

This pro forma adjustment reflects the increased test year operating expense for higher levels of property tax expense based on 2009 property tax levels.

Page 14 – Medical Benefits

This pro forma adjustment reflects the increase in test year operating expenses for increased medical benefits based on information supplied by the PSNH's actuaries.

Page 15 – Hydro Quebec Support Costs

This pro forma adjustment reflects the increase in test year operating expenses for 2009 Hydro Quebec support costs.

Page 16 - Rate Reduction Bond (RRB) Servicing Fees

This pro forma adjustment increases test year operating expenses related to the decrease in RRB servicing fee revenues.

Page 17 - Amortization of Deferred Environmental Remediation Costs

This pro forma adjustment reflects the amortization of deferred environmental remediation costs for environmental remediation costs deferred after June 30, 2007.

Page 18 - Major Storms Reserve

This pro forma adjustment increases test year operating expenses to reflect a proposed increase in the major storms reserve.

Page 19 - Rent Expense

This pro forma adjustment reflects an increase in test year operating expenses relating to PSNH's share of increased rent costs for Corporate Center facilities.

Page 20- FairPoint O&M Credit Associated with Tree Trimming

This pro forma adjustment decreases test year operating expenses to reflect the billing for shared maintenance work costs to FairPoint.

Page 21 - Depreciation Expense

This pro forma adjustment reflects an increase in test year depreciation relating to technical adjustments to the depreciation calculation and net capital additions.

Page 22 - Current and Deferred Income Taxes

This pro forma adjustment adjusts both Current and Deferred income taxes based on pro forma changes in pre-tax operating income.

THE STATE OF NEW HAMPSHIRE

BEFORE THE

NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION

Docket No. DE 09-035

DIRECT TESTIMONY OF

Stephen R. Hall

Request for Permanent Delivery Rates

June 30, 2009

I. INTRODUCTION

Q. Please state your name, position and business address.

A. My name is Stephen R. Hall. I am Rate and Regulatory Services Manager for Public Service Company of New Hampshire ("PSNH"). My business address is PSNH Energy Park, 780 North Commercial Street, Manchester, New Hampshire.

Q. Have you previously testified before the Commission?

A. Yes, I have testified on numerous occasions before the Commission over the past twenty-nine years. A listing of my educational background and experience is contained in Attachment SRH-1.

Q. Did you previously submit pre-filed testimony in this docket concerning PSNH's request for temporary rates?

A. Yes, I did. In this testimony, I will be incorporating my previous testimony by reference to the extent necessary.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present PSNH's tariff pages containing permanent rates designed to recover the revenue requirements described in Mr. Baumann's testimony. I will list PSNH's revenue pro forma adjustments that I previously discussed in my temporary rates testimony. I will describe the allocation of revenue requirements to customer class and the resulting rate design that PSNH used to calculate permanent rates. I will describe PSNH's tariff and the changes that PSNH is proposing to some of the tariff language, terms and conditions, including a description of a new type of street lighting service that PSNH is proposing.

II. REVENUE AND EXPENSE PRO FORMA ADJUSTMENTS

Q. Please describe PSNH's revenue pro forma adjustments.

A. PSNH's revenue pro forma adjustments are contained in Schedule 1 Attachment to Mr. Baumann's testimony. These adjustments decrease PSNH's test year distribution revenue by $ 287,000. PSNH revised the revenue pro forma adjustments from the temporary rate filing to take into account a minor rounding difference of $5,000 in the adjustment which stated distribution revenue at the rate level effective July 1, 2008. This pro forma, a decrease of $199,000 in the temporary rate filing, has been revised slightly to a decrease of $194,000. The other revenue pro forma adjustment, a decrease of $93,000 due to the expiration of special pricing arrangements, is unchanged from the amount described in my testimony on temporary rates.

III. PROPOSED TARIFF PAGES AND REVENUE ALLOCATION

Q. Please describe generally the rates and charges contained in Attachment SRH-2.

A. Attachment SRH-2 is PSNH's proposed Electricity Delivery Service Tariff – NHPUC No. 7, which contains the rates and charges necessary to recover PSNH's cost of providing delivery service to customers. The tariff contains the currently-effective Energy Service rate, Stranded Cost Recovery Charge rates and Transmission Cost Adjustment Mechanism rates. All of those rates are subject to change on August 1, 2009 as a result of PSNH's filings in Dockets DE 08-113, DE 08-114, and DE 09-114, respectively. Once the final rates in each of those dockets have been determined, the tariff will be updated to incorporate the rates ultimately approved.

We've also included a "blacklined" version of the tariff in Attachment SRH-3 as well as a summary of the tariff changes in Attachment SRH-4.

Q. What is PSNH's proposed overall distribution revenue target?

A. PSNH's proposed overall distribution revenue target is $295,039,000, which is the total of the current retail billed distribution revenue, as pro formed, of $243,931,000 plus the revenue deficiency of $51,108,000 discussed in Mr. Baumann's testimony.

Q. Please reconcile the difference between the $243,931,000 pro formed retail billed revenue and the pro formed distribution operating revenue shown in Mr. Baumann's schedules.

A. Mr. Baumann's Schedule 1, Page 1 shows total pro forma distribution operating revenue of $259,824,000, which includes not only billed distribution revenue, but an additional $15,893,000 of unbilled revenue, wholesale revenue and other operating revenues (late payment charges, miscellaneous service revenue, transformer rental revenue, and other electric revenue).

Q. Please describe how you allocated revenue to each class for the purpose of calculating PSNH's proposed distribution rates.

A. Revenue was allocated to each class in the same manner as the revenue allocation for PSNH's proposed temporary rates. Specifically, revenue was allocated to classes by increasing each class's current revenue component by the same percentage amount, as shown on Attachment SRH-5.

Attachment SRH-6 is PSNH's "Report of Proposed Rate Changes". This report shows the proposed distribution rate changes on a class-by-class basis, compared to the rate level currently in effect. The report shows an overall increase of $51.1 million or 4.2% attributable exclusively to the proposed permanent distribution charges. Since the SCRC, Energy Service and TCAM rates for effect on August 1, 2009 are not yet certain, all of the revenue amounts in this report (in both the current and proposed columns) are premised upon the currently-effective SCRC, Energy Service and TCAM charges.

IV. RATE DESIGN

Q. Is PSNH proposing any changes to rate design?

A. Yes, we are. PSNH is proposing modest increases to its customer charges and demand charges, and correspondingly reducing its energy (kilowatt-hour) charges in order to more closely match the cost of providing service. We are not proposing any reallocation of revenue responsibility between classes.

Q. Did you rely on PSNH's cost of service study to design your rates?

A. Yes, to a certain extent. The cost of service study is included in Volume III and is described in the technical statement of Charles R. Goodwin. The cost of service study shows that the customer-related costs attributable to providing service to several customer classes and subclasses (Residential, General Service Rate G, Load Controlled Service and Large General Service Rate LG) are significantly higher than what the level of the customer charge would be absent any changes to rate design. It also shows that demand charges for general service classes are relatively close to the cost of service. A summary of the unitized costs is shown on Attachment SRH-7.

In this proceeding, we are not proposing a rigorous re-design of PSNH's rates. Rather, we are proposing minor changes to customer and demand charges to more closely align those charges with the cost of providing service as determined in the cost of service study.

Q. Will your proposed changes completely align PSNH's customer and demand charges with the costs shown in the cost study?

A. No, they will not. We are seeking to make a very gradual change to our rate design to avoid a significant bill impact on individual customers. We will continue to examine rate design during the next few rate cases and will assess whether additional changes to rate design should be made during those future cases. By making modest, gradual changes to rate design, we are hoping to more closely align our rates to costs over time without significantly impacting any particular customer's bill amount. Moreover, the embedded cost of service study provides only one measurement of the individual rate components. In order to perform a rigorous rate re-design, one might want to consider other measurements as well, such as a marginal cost of service study.

Q. Other than more closely aligning your rates with cost of service, are there other benefits to your proposed rate re-design?

A. Yes. Higher customer and demand changes and lower energy charges will provide PSNH with a modicum of additional revenue to the extent that customers engage in significant conservation efforts. This positive effect is a small step toward addressing the problem of attrition discussed in Mr. Long's testimony. To the extent that PSNH's kilowatt-hour sales continue to decrease, the rate design that we are proposing will slightly offset the revenue loss that would otherwise occur if all rates and charges were increased by the same proportion. Conversely, to the extent that kilowatt-hour sales increase, PSNH would not realize as much of an increase in revenue under the proposed rate design.

Q. Please continue with your description of your rate design.

A. The first step in designing rates was to allocate revenue to each class of service. Attachment SRH-5 shows the calculation of proposed distribution revenue by rate class. Once each class's revenue level was determined, we set customer and demand charges at specific levels, calculated the amount of revenue that will be received through those charges, and subtracted the result from the total class revenue requirement. The remaining class revenue requirement was then achieved by adjusting all class kilowatt-hour charges by an equal percentage.

The results of PSNH's rate design changes are shown in Attachment SRH-8. This attachment contains a summary of PSNH's current rate level, rates and charges at the proposed rate level if all rates and charges were increased by an equal percentage amount (i.e., without any rate design changes), and the proposed redesigned rates and charges. To summarize the results of PSNH's rate design, all of the customer charges and meter charges for all classes of service were increased by the same approximately percentage. For all rate classes that have demand charges, those demand charges were also all increased by the same approximate percentage, Compared to charges without any rate design changes, energy charges were reduced to reflect the additional revenue to be obtained from higher customer and demand charges.

A description of the calculation for each rate class and sub-class follows. In each case, the comparison is between rates increased by a uniform percentage (no rate design changes) and the proposed, redesigned rates.

Residential Delivery Service Rate R: We increased the customer charge from the $10.80 per month level that results from proportionally adjusting all rates and charges to $12.00 per month. The increase in revenue that will result was used to reduce the energy charge from 3.525 cents per kWh to 3.315 cents per kWh.

Uncontrolled Water Heating: The meter charge was increased from $3.81 per month to $4.25 per month, and the energy charge was reduced from 1.727 cents per kWh to 1.625 cents per kWh.

Controlled Water Heating: The meter charge was increased from $6.71 per month to $7.50 per month, and the energy charge was reduced by 0.006 cents per kWh. Although the cost of service study indicates a lower meter charge due to the age of the meters used to provide this service, we are proposing increasing the meter charge by the same approximate percentage as the proposed increase to the meter charge for uncontrolled water heating to keep the pricing for the two rates relatively consistent.

Residential Time-of-Day Delivery Service Rate R-OTOD: The customer charge was increased by the same approximate percentage as the increase to the Rate R customer charge, and energy charges were decreased by the same percentage as the decrease to the Rate R energy charge. Since this is such a small group of customers, they are included in the Residential Power and Light and Space Heating column of the embedded cost of service study. Therefore, pricing for Rate R-OTOD was changed consistently with the pricing for Rate R.

General Delivery Service Rate G: The customer charge for single phase service was increased from $12.17 per month to $13.50 per month; the customer charge for three phase service was increased from $24.35 to $27.00 per month; and the demand charge was increased from $7.37 per kW to $7.80 per kW. Energy charges were reduced by approximately 6.8% in recognition of the additional revenue to be derived from the higher customer and demand charges.

Space Heating: The meter charge was increased from $2.43 per month to $2.70 per month and the energy charge was reduced from 2.989 cents per kWh to 2.636 cents per kWh.

General Time-of Day Delivery Service Rate G-OTOD: This small group of customers was included in the Rate G Power and Light and Space Heating column of the embedded cost of service study. As a result, the customer, demand and energy charges were changed commensurately with the changes to the corresponding charges for Rate G.

Load Controlled Delivery Service Rate LCS: Customer charges for the radio-controlled and switch options were increased from $7.77 per month to $8.75 per month; the customer charge for the 8-, 10-, or 11-hour option was increased from $6.71 to $7.50 per month. Since the majority of these customers are Residential, the energy charges were reduced by the same percentage as the remaining Residential energy charges.

Primary General Delivery Service Rate GV: The customer charge was increased from $163.90 per month to $180.00 per month; demand charges were increased by the same approximate percentage as the demand charge for Rate G; and energy charges were decreased as required to achieve the class revenue target. In the cost of service study, no distribution costs are allocated to energy. PSNH bills energy charges for distribution service in order to maintain continuity between rate classes and smooth the transition when a customer's load increases or decreases sufficiently to require the customer to take service under a different rate class.

Large General Delivery Service Rate LG: The customer charge was increased from $498.15 to $550.00 per month; the demand charge was increased by the same approximate percentage as the Rate G and Rate GV demand charges, from $4.02 to $4.25 per kVa, and energy charges were reduced as required to achieve the class revenue target. As in the case of Rate GV, there are no distribution costs allocated to energy in the cost study, and energy charges are set at a level that provides for rate continuity between classes.

Backup Delivery Service Rate B: The administrative charge was increased from $280.86 per month to $310.00 per month; the translation charge was increased from $46.80 per month to $52.00 per month; and the demand charge (for customers taking service below 115 kV) was increased from $3.77 per kVa to $4.00 per kVa. Customers are billed for energy under the otherwise applicable standard tariff rate schedule, so energy charges for Rate B customers will change based on the changes in energy charges in Rates GV and LG.

We did not make any changes to the design of the outdoor lighting service rates (Rates OL and EOL). Rather, the prices per luminaire were all increased by the same percentage amount.

Q. Will any changes need to be made to rate design if the Commission approves a different level of distribution revenue?

A. Yes, changes might be needed to maintain relative relationships between rate classes and to moderate bill impacts on customers. We would need to examine the effect of any changes from the proposed revenue level and possibly make minor adjustments to some customer and/or demand charges. Beyond this, changes might be necessary to the extent that there is any recoupment or reimbursement of the difference between the level of permanent and temporary rates. I believe that the best way to address any such changes is through discussions and technical sessions with the parties once a final rate level has been determined by the Commission.

V. DELIVERY SERVICE TARIFF

Q. Is PSNH proposing any changes to the language, terms or conditions of the tariff?

A. Yes, we are.

Q. Have you included anything in this filing that will assist the Commission and the parties in identifying all of the proposed changes?

A. Yes, we have. We have provided three separate documents: a copy of the Delivery Service Tariff in its final form (Attachment SRH-2); a copy of the Delivery Service Tariff that highlights all of the new sections and blacklines all of the deleted sections (Attachment SRH-3); and a narrative entitled "Summary of Changes to PSNH's Currently Effective Tariff No. 6" that identifies and describes all of the tariff changes (Attachment SRH-4).

Q. Please describe the proposed tariff changes and the reasons for each change.

A. There are four proposed tariff changes. Three of the four changes are described below, while the forth change is described in Section VI.

1) <u>Pole-mounted Apparatus Rental Under Primary General Service Rate GV and Large General Delivery Service Rate LG</u>

PSNH is proposing to add language to the Apparatus section of Primary General Service Rate GV and Large General Delivery Service Rate LG to indicate that PSNH is not required to rent pole-mounted apparatus. Customers receiving delivery service under Rate GV or Rate LG are currently responsible for furnishing, owning and maintaining all the necessary substation foundations, structures, and all controlling, regulating, transforming and protective apparatus. Upon a customer's request, PSNH will rent either pole-mounted or pad-mounted transforming apparatus to the customer at a charge of 18% per year of the equipment cost. PSNH would like to have the option to refuse to rent pole-mounted transformers because PSNH has no control over the maintenance of the support structures or the area surrounding the support structures. PSNH will determine, on a case by case basis, whether or not a pole-mounted transformer can be rented from PSNH based on immediate hazards that may be present (such as trees and proximity to parking and delivery areas) and environmental considerations (such as the proximity to water supplies and water ways, including drains that lead to water ways). In situations where PSNH refuses to rent a pole-mounted transformer, the customer would have the option of renting a pad-mounted transformer from PSNH, assuming it can be installed in accordance with PSNH's environmental requirements and it is a standard size transformer that PSNH stocks in its inventory.

In addition to adding language to indicate that PSNH is not required to rent pole-mounted apparatus, PSNH is also proposing to add language to indicate that PSNH is authorized to terminate an existing apparatus rental agreement and to remove a pole-mounted transformer upon 90 days written notice to a customer. PSNH would only utilize this authorization in the event 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 to remove the hazard.

2) Meters Section of the Terms and Conditions for Delivery Service

PSNH is proposing to add language to the Meters section of the Terms and Conditions for Delivery Service section of PSNH's Tariff to clarify that each 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. This language describes the metering policy PSNH has utilized since the early 1980's in compliance with the rules of the Public Utilities Commission.

3) Removal of the Option to Pay Excess Costs Over a Sixty Month Period from Outdoor Lighting Delivery Service Rate OL

PSNH is proposing to remove the option available to governmental units and civic groups to pay for excess costs associated with new installations, extensions and replacements under Rate OL, including interest at the Prime Rate over a period not to exceed sixty months. This tariff language has been in place since the early 1970's and is an outdated policy. PSNH is not aware of any instances over the past ten years where a governmental unit or civic group has paid excess costs under Rate OL over a time period. In its place, PSNH is proposing that all customers pay excess costs as a lump sum prior to the installation or replacement of the equipment under Rate OL. This is consistent with the policy used to collect excess costs under PSNH's existing and proposed line extension policies.

VI. MIDNIGHT OUTDOOR LIGHTING SERVICE OPTION

Q. Is PSNH proposing a new lighting service option?

A. Yes, we are. PSNH is proposing to add a midnight outdoor lighting service option to Outdoor Lighting Delivery Service Rate OL and Energy Efficient Outdoor Lighting Delivery Service Rate EOL.

Q. Please briefly describe the midnight outdoor lighting service option that PSNH is proposing.

A. Under the proposed midnight outdoor lighting service option (midnight option), a customer can receive partial night's lighting service (from dusk to midnight) for energy-efficient luminaires (i.e. high pressure sodium and metal halide). In order to receive service under the midnight option, the existing all-night photocell which turns the luminaire on at dusk and off at dawn will be removed and replaced with a photocell capable of turning the luminaire on at dusk and off at midnight.

Q. Why is PSNH proposing a midnight option?

A. PSNH is proposing a midnight option because municipal outdoor lighting service customers have expressed an interest in partial night outdoor lighting service as a way to reduce their electric service bills and to reduce their kilowatt-hour consumption, thereby reducing their carbon footprint. In addition, the New Hampshire legislature passed House Bill 585, which encourages outdoor lighting efficiency at the municipal and state level and requires utilities to offer a partial night option for unmetered outdoor lighting service. PSNH worked with the legislature on House Bill 585 and made a commitment to seek the Commission's approval of a partial night rate option in the near future following passage of the bill. Offering a partial night outdoor lighting service option is also consistent with PSNH's commitment to assist customers in managing their cost of electricity, to support energy-efficiency initiatives, and to support New Hampshire's clean energy goals and protecting the natural environment.

Q. If a customer has more than one luminaire, will the customer be allowed to select the midnight option for a portion of the luminaires?

A. Yes. A customer will be able to select the midnight option for either a portion of their luminaires or for all of their luminaires.

Q. Please describe the rates under the midnight service option.

A. The distribution rates under the midnight service option are the same as the rates under the all-night service option, because the fixture (excluding the photocell), lamp and maintenance costs do not change under the midnight option. The distribution rates are flat monthly charges for each luminaire. However, transmission, stranded cost recovery, energy service, system benefits charge and consumption tax rates are applied to the monthly kilowatt-hours associated with each luminaire. Monthly kilowatt-hours under the midnight option will be lower, reflecting the number of dark hours in each month from dusk to midnight. Therefore, municipalities will receive lower monthly charges for all rates that are billed on a kilowatt-hour basis, since the monthly kilowatt-hours used for each luminaire under the midnight option will be lower than under the standard all-night service.

Q. Are customers required to pay any costs up-front before they can receive service under the midnight service option?

A. Yes. Since the additional equipment and installation cost associated with the new photocell are not reflected in the distribution charges under the midnight service option, customers requesting midnight service are required to pay for these costs prior to the installation of the new photocell. The following is a summary of the requirements of service under the midnight option:

1) Customers requesting a modification of service from the all-night option to the midnight option are responsible to pay the estimated installed cost of the new photocell. The estimated installed cost includes the cost of the additional equipment required, labor, vehicles and overheads. If such a request is concurrent with PSNH's existing schedule for lamp replacement and maintenance, the customer is only responsible to pay for the estimated cost of the new photocell, since PSNH would already be at the location to replace the lamp and perform any required maintenance.

2) Customers requesting a modification of service from the midnight option to the all-night option are responsible to pay the estimated installation cost of the all-night option photocell. The estimated installation cost includes the cost of labor, vehicles and overheads. If such a request is concurrent with PSNH's existing schedule for lamp replacement and maintenance, no additional costs are required to modify service from the midnight option to the all-night option.

3) Customers requesting the installation of a luminaire at a new location under the midnight option are required to pay for the incremental cost of the midnight option photocell.

Q. Does PSNH plan to utilize fixed price estimates per luminaire for the estimated installed cost, the additional equipment cost and the equipment installation cost?

A. Yes. PSNH is proposing to utilize fixed price estimates per luminaire for the estimated installed cost, the additional equipment cost and the equipment installation cost and will update the fixed price estimates each year based upon current costs. Attachment SRH-9 contains PSNH's current estimate of the installed cost, the additional equipment cost and the equipment installation cost per luminaire. PSNH plans to update the estimates using current costs upon the Commission's approval of the midnight service option and will update the estimates annually.

Q. Can a customer request a modification of their lighting service option at any time or is PSNH proposing to utilize a specific enrollment period each year?

A. PSNH is proposing to utilize a specific enrollment period each year to handle municipal and state roadway lighting customer requests to modify their lighting service from the all-night option to the midnight option. The open enrollment period is defined as the calendar months of January and February. Therefore, these customers may request a modification of their lighting service from the all-night option to the midnight option during this period only. Customer requests received after the enrollment period will be implemented during the next enrollment period, unless PSNH determines that it is feasible and practicable to implement the request prior to the next enrollment period. All other customer requests, as well as customer requests to modify their lighting service from the midnight option to the all-night option will be handled throughout the year at PSNH's discretion with consideration given to minimizing travel and set-up time.

Q. Why is PSNH proposing to utilize a specific enrollment period each year?

A. PSNH is proposing to utilize a specific enrollment period each year to limit the number of requests received from cities or towns to modify individual luminaires or a few luminaires several times a year. PSNH would prefer to handle modifications of service from the all-night option to the midnight option on a group basis once a year to limit travel and set-up time; thereby resulting in a more efficient use of its limited resources and lower costs to customers.

Q. If traffic control is required by a city or town during a modification of service from the all-night option to the midnight option or from the midnight option to the all-night option, is the customer required to provide and to pay for the cost of traffic control?

A. Yes. In the event traffic control is required by a city or town during a modification of the service option, the customer is responsible for coordinating and providing traffic control and for paying all costs associated with traffic control. If the customer requesting the modification of service is a residential or General Service Rate G customer, PSNH may coordinate and provide traffic control on the customer's behalf and the customer will be responsible to reimburse PSNH for all costs associated with the traffic control provided by PSNH.

Q. What savings will customers realize under the midnight service option?

A. Attachment SRH-10 contains a comparison of the annual charges per luminaire under the all-night option and the midnight option under Rate OL and Rate EOL based on rates effective January 1, 2009. As shown, customers receiving service under the midnight option will save from $16.20 to $308.26 annually per luminaire. The annual percentage savings ranges from 16.0% to 40.6% under Rate EOL and from 9.9% to 31.4% under Rate OL.

Q. What is the simple payback to convert from the all-night option to the midnight option?

A. Attachment SRH-10 contains a calculation of the simple payback to convert from the all-night option to the midnight option for each luminaire. As shown, if a customer schedules a conversion from the all-night option to the midnight option that is not concurrent with PSNH's existing plans for lamp replacement and maintenance, the simple payback ranges from seven months to ten years using PSNH's current installed cost estimate of $160 per luminaire. If a customer schedules a conversion from the all-night option to the midnight option concurrent with PSNH's existing schedule for lamp replacement and maintenance, the simple payback ranges from one month to 15 months.

Q. Does this conclude your testimony?

A. Yes, it does.

QUALIFICATIONS OF STEPHEN R. HALL

CURRENT POSITION AT PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE

Rate and Regulatory Services Manager

Responsible for regulatory relations at PSNH, including the interface with the NHPUC Staff on regulatory matters. Also responsible for various aspects of rate design, new service offerings, special contract development, rate policy and planning, special rate projects and related regulatory matters.

EDUCATIONAL BACKGROUND

Bachelor of Science Degree in Mathematics from the University of New Hampshire in 1977.

Master of Business Administration Degree from the University of New Hampshire in 1979.

Various managerial short courses offered by the Company.

PRIOR WORK POSITIONS AND EXPERIENCE

At PSNH

Assistant Rate Research Analyst, 1979
Rate Administrator, 1981
Rate Research Analyst, 1982
Staff Rate Research Analyst, 1983
Rate Research and Administration Supervisor, 1985
Rate Projects Manager, 1986
Rate Research and Administration Manager, 1989

PREVIOUS TESTIMONY

Testified before the NHPUC in every fuel adjustment, ECRM and FPPAC proceeding from June 1980 through December 1993. Also submitted testimony and/or testified in the following proceedings:

Docket No.	Docket Subject	Subject of Testimony
NHPUC		
DE 09-114	Transmission Cost Adjustment Mechanism	TCAM Pricing
DE 08-077	Lempster Wind Contracts	Rebuttal of Constellation Testimony
DE 08-071	Major Storm Cost Reserve	Pricing for MSCR Increase
DE 08-069	Transmission Cost Adjustment Mechanism	TCAM Pricing
DE 07-122	Hemphill Settlement	Cost Recovery for Payments to Hemphill
DE 07-108	Least Cost Plan	Rebuttal of Staff Testimony
DE 07-096 & 07-097	ES & SCRC Settlement	Description of Settlement Agreement
DE 06-061	Energy Policy Act	Implementation of Standards for TOU Rates
DE 06-028	Delivery Rate Case	Tariff Changes, Rate Design
DE 04-072	Least Cost Plan	Standards for Least Cost Plans
DE 03-186	(Seabrook) Florida Power and Light	Criteria for Granting Public Utility Status
DE 03-200	Delivery Rate Case	Tariff Changes, Rate Design
DE 03-078	Wausau Papers	Special Pricing
DE 03-064	Fraser N.H. LLC Special Contract	Pricing for Incremental Load
DE 02-166	Transition Service	Transition Service Pricing
DE 02-127	Stranded Cost Recovery Charge	Stranded Cost Reconciliation
DE 02-064 through DE 02-074	Hydro IPP Negotiations	Hydro IPP Settlements
DE 01-227	Sale of Vermont Yankee	Sale Approval
DE 00-211	Smith Hydro Valuation	Public Interest of Hydro Divestiture
DE 01-089 through DE 01-091	IPP Renegotiations	IPP Settlement
DE 00-009	ConEd/NU Merger	Merger Settlement Agreement
DR 98-139	FPPAC BA & Special Contracts	Special Contracts
DR 98-014	FPPAC	FPPAC BA/Special Contracts
DR 96-390	Seacoast Mills Special Contract	Load Retention
DR 96-171	Heidelberg Special Contract	Load Retention
DR 96-138	Wausau Special Contract	Load Retention
DR 96-121	OSRAM SYLVANIA, Inc.	Load Development
DR 96-113	Unitrode Special Contract	Economic Development
DR 96-068	Isaacson Special Contract	Load Retention
DR 96-058	Elliott Rose of Madbury Special Contract	Load Development
DR 96-035	Praxair, Inc. Special Contract	Load Retention
DR 95-321	American Tissue Mill Of NH	Spec. Contract Business Retention
DR 95-320	Hitchiner Mfg., Inc./Metal Casting Tech.	Load Retention
DR 95-318	Bay Ridge Special Contract	Load Retention
DR 95-303	Wyman-Gordon Special Contract	Economic Development

Docket No.	Docket Subject	Subject of Testimony
NHPUC		
DR 95-270	Textron Special Contract	Business Retention
DR 95-250	Retail Competition Pilot Program	Retail Competition
DR 95-230	MPB Special Contract	Business Retention
DR 95-214	Kollsman Special Contract	Business Retention
DR 95-205	Teradyne, Inc.	Business Retention/Economic Development
DR 95-149	Nashua Foundries, Inc.	Business Retention
DR 95-131	New England Wood Pellet Spec. Contract	Economic Development
DR 95-129	Rehrig Pacific Special Contract	Economic Development/Load Retention
DR 95-113	Elliott & Williams Roses Spec. Contract	Load Retention
DR 95-103	Tourist Village Special Contract	Load Retention
DR 95-070	Owens-Brockway Special Contract	Business Retention/Economic Development
DR 95-064	NH Ball Bearings Special Contract	Business Retention
DR 95-048	Batesville Casket Co. Spec. Contract	Business Retention
DR 95-012	Summit Packaging Systems Spec. Contract	Business Retention
DR 94-311	Nashua Corp. Special Contract	Business Retention
DR 94-309	CE-KSB Pump Co. Special Contract	Interruptible Service
DR 94-293	Polyvac, Inc. Special Contract	Load Retention/Economic Development
DR 94-255	Anheuser Busch Special Contract	Load Retention
DR 94-252	Freudenberg-NOK Special Contract	Economic Development
DR 94-193 through DR 94-200	PSNH Ski Areas Special Contracts	Load Retention
DR 94-135	Monadnock Paper Mills Spec. Contract	Load Retention
DR 94-132	Lockheed Sanders Special Contract	Business Retention/Economic Development
DR 94-074	Wyman-Gordon Special Contract	Business Retention
DR 94-057	Excalibur Special Contract	Load Retention
DR 94-033	OSRAM Special Contract	Load Retention
DR 93-247	Radio-Controlled Option Under Rate LCS	Space Heating Rate
DR 93-243	Gilford Special Contract	Load Retention
DR 93-103	Freudenberg-NOK Special Contract	Economic Development
DR 93-042	Bronze Craft Special Contract	Pilot Load Management Program
DR 92-232	CE-KSB Pump Special Contract	Interruptible Service
DR 89-058	Wentworth Special Contract	Rate WI
DR 88-191	Wildcat Special Contract	Rate WI
DR 88-190	Gunstock Special Contract	Rate WI
DR 88-179	Bretton Woods	Rate WI
DR 88-167	DRED	Rate WI
DR 87-197	Rate WI Tariff Schedule	Interruptible Service
DR 90-131	Rate WI Tariff Schedule	Interruptible Service
DR 89-171	Rate WI Tariff Schedule	Interruptible Service
DR 88-126	Rate WI Tariff Schedule	Interruptible Service
DR 84-131	Rate WI Tariff Schedule	Interruptible Service
DR 82-333	Rate Increase Request	Rate Design
DR 79-187	Rate Increase Request	Rate Design

FERC

ER 86-133	Recovery of Schiller Conversion Costs	Resale Fuel Adjustment Rate

Maine Public Utilities Commission

DR 81-9	Retail Fuel Adjustment	Fuel Adjustment Rate

Rev 6/5/09

THE STATE OF NEW HAMPSHIRE

BEFORE THE

NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION

Docket No. DE 09-035

DIRECT TESTIMONY OF

George J. Eckenroth

Request for Permanent Delivery Rates

June 30, 2009

TABLE OF CONTENTS

I. INTRODUCTION

Q. Please state your name, position, and business address.

A. My name is George J. Eckenroth. I am the Director of Corporate Financial Policy for Northeast Utilities Service Company. I am providing this testimony on behalf of Public Service Company of New Hampshire ("PSNH" or the "Company"). My business address is 107 Selden Street, Berlin, Connecticut.

Q. Have you previously testified before this Commission?

A. Yes. I have testified on numerous occasions before this Commission. A list of my background and experience is attached as Attachment GJE - 1.

Q. What is the purpose of your testimony?

A. The purpose of this testimony is (1) to describe current capital market conditions as they pertain to companies in general and to electric utilities in particular; (2) discuss PSNH's financial condition; (3) recommend an appropriate capital structure for PSNH; and (4) recommend an overall rate of return ("ROR"), also known as a Weighted Average Cost of Capital ("WACC"), for PSNH that reflects the cost of capital for each component of its distribution ratemaking capitalization.

II. SUMMARY

Q. Please summarize your testimony.

A. The United States economy, as well as the global economy in general, is in a period of extraordinary instability. These conditions have resulted in exceptionally high risk aversion by investors, which is reflected in historically high risk premiums on both debt and equity. These high risk premiums have raised the cost of capital for all companies, including electric utilities. Meanwhile, PSNH's credit metrics have been weakening to a degree that has provoked published comments by the major rating agencies. Further, the rating agencies, which have been criticized for their laxness that may have contributed to the current credit crisis, undoubtedly will be stricter in some of their practices in the future.

In order to ensure that PSNH has access to the financial markets under these conditions, certain steps are needed. First, PSNH's ratemaking capital structure needs to be strengthened. Second, PSNH needs an allowed return on equity ("ROE") that is consistent with the current requirements of investors. Third, PSNH needs rates that are set at a level that permits PSNH a realistic opportunity to earn its allowed ROE over the period that new rates will be in affect.

I have utilized three well-established methods to estimate the appropriate allowed ROE for PSNH. Each of these methods supports an ROE well in excess of 11 percent. I recognize, however, that a sharp increase in allowed ROE may be problematic to PSNH's customers under current challenging economic conditions. Further, allowed ROEs in recent regulatory decisions around the country have averaged closer to 10.5 percent. For that reason, I am recommending a 10.5 percent allowed ROE rather than the 11.5 percent or higher ROE that my analyses would fully support. With a 10.5 percent ROE and my recommended capital structure, PSNH's appropriate WACC is 8.11 percent.

Proposed Ratemaking Capital Structure
and the Weighted Cost of Capital

		Cost	
	Ratio	Embedded	Weighted
Long-Term Debt	48.88%	5.61%	2.74%
Common Equity	51.12%	10.50%	5.37%
			8.11%

III. CURRENT MARKET CONDITIONS

Q. Please describe current capital market conditions and their effects on the cost of capital

A. Security prices have declined severely as we have faced the most serious credit crisis since the 1930s. The debt and equity markets remain extremely volatile due to the ongoing financial crisis and the economic downturn. Investors remain apprehensive about committing long-term capital.

This can be seen most clearly with the use of a risk premium-type model. Using such a model, the cost of debt will equal a benchmark interest rate, such as the yield on 30-year treasury bonds, plus a risk premium or "credit spread" to compensate investors for the incremental risk of corporate securities relative to those issued by the U.S. government. The table below shows that the credit spread on BBB/Baa bonds has increased from 133 basis points in May 2007 to 425 basis points as of May 2009. Over the same period, 30-year Treasury bonds yields have decreased only 67 basis points. This 292 basis point increase in the credit spread greatly outweighed the 67 basis point decline in treasury yields, resulting in a net increase in the cost of debt of 225 basis points.

	May-07	May-09	Basis Point Change
30-year Treasury Yields [1]	4.90%	4.23%	-67
Bond spreads for BBB/Baa rated utility bond	1.33%	4.25%	292
All-in Bond Yields [2]	6.23%	8.48%	225

Source: [1]Federal Reserve Statistical Release H15
[2] Mergent Bond Record for May '07and Barclays Capital for May '09

It is evident from this data that intensified concerns about risks in the capital markets have triggered an increase in the credit spreads and confirms that investors have reassessed their tolerance for risk. As Standard & Poor's ("S&P") observed in December 2008:

> The Standard & Poor's composite spreads widened to new five-year highs yesterday, leaving the investment-grade spread at 554 basis points (bps) and the speculative grade spread at 1,598 bps, both well more than triple their five-year moving averages. ... [W]ith speculative-grade defaults on the rise, a higher preponderance of credit downgrades, and a general malaise about the future of the economy, we expect spreads to remain at their elevated levels for some time until confidence is restored to the market.[1]

It is apparent that investors have not recovered, either financially or psychologically, from the effects of the financial crisis, and may not recover for many years to come.

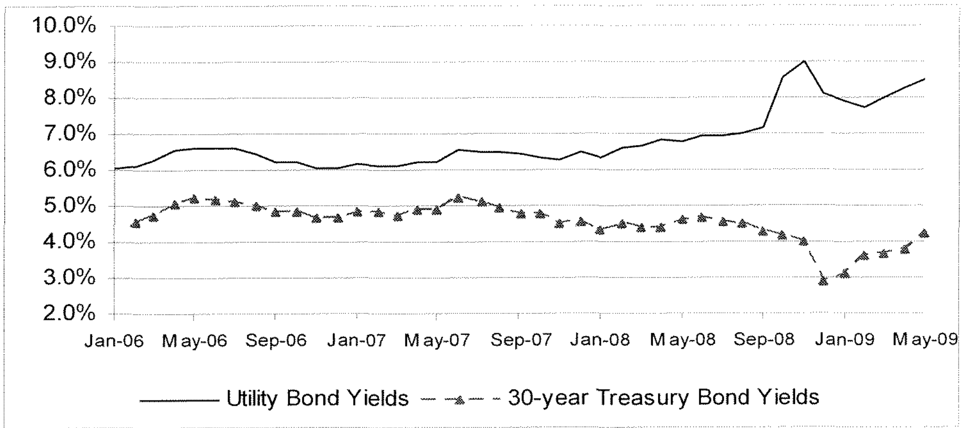
Q. Have equity risk premiums increased along with the increase in credit spreads?

A. Yes. In order to invest in common stock, investors require a substantial risk premium over and above the return on debt as compensation for the incremental risk of equity relative to debt. For this reason, the cost of equity has undergone an increase similar to the increase in the cost of debt. The relationship between the cost of debt and the cost of equity is addressed in more detail below in the sections covering the Capital Asset Pricing Model and Risk Premium Model.

Q. Do these higher risk premiums in the capital markets affect utilities in the same way as they affect other companies?

[1] Standard & Poor's Corporation, "Credit Trends: U. S. Composite Credit Spreads Daily", RatingsDirect (Dec. 2, 2008).

A. Yes, the effects on utilities have been very similar to those of other types of companies. As shown in the graph below, utilities face significantly higher costs of debt due to the higher credit spreads they now must pay relative to treasury bonds.[2]



Commenting in December 2008, S&P confirmed this trend, stating that:

> Regulated electric issuers continued to access debt markets during the fourth quarter of 2008 at rates in line with the 10-year average of about 8% for five-year notes, not the abnormally low interest rate environment of the 2000's which is a distant memory.[3]

As noted above, because an equity risk premium must be added to the higher cost of debt, the cost of equity has also increased sharply. In fact, a Managing Director with Fitch Ratings ("Fitch") observed that with debt costs at present levels, "significantly higher regulated returns will be required to attract equity capital."[4] Fitch concluded:

> The collapse in secondary market debt pricing and in equity valuations is worrisome. We see new debt now priced at around 9% or higher pushing

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[2] Monthly utility yields are from Mergents Bond Record, except May 2009 provided by Barclays Capital. The Treasury rates are from Federal Reserve, www.federalreserve.gov/releases/h15/data.htm.

[3] Standard & Poor's Corporation, "Industry Report Card: U. S. Electric Utility Credit Quality Remains Strong Amid Continuing Economic Downturn," RatingsDirect (Dec. 19, 2008).

[4] Fitch Ratings Ltd., "EEI 2008 Wrap-Up: Cost of Capital Rising", Global Power North America Special Report (Nov. 17, 2008).

up against average authorized ROEs for utilities of around 10.25% to 10.50%.[5]

Q. Are these conditions expected to continue into the foreseeable future?

A. Yes. It is clear that the events since September 2008 have undoubtedly marked a significant transition in investors' expectations and there is very little indication that the conditions confronting the economy and financial markets will be resolved quickly. As Fitch recently concluded, "higher corporate interest rates are likely to prevail through 2009 and into the foreseeable future. Moreover, the fact that market volatility may complicate the evaluation of the cost of equity provides no basis to ignore the upward shift in investors' risk perceptions and required rates of return for long-term capital."[6]

Q. Will these capital market conditions also affect utilities' access to the capital and credit markets?

A. Possibly. An October 1, 2008, Wall Street Journal report confirmed that dislocations in credit markets were impacting the utility sector:

> Disruptions in credit markets are jolting the capital-hungry utility sector, forcing companies to delay new borrowing or come up with different-often more costly-ways of raising cash.[7]

Under these conditions, companies that are not highly rated may have great difficulty in raising needed capital.

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[5] Fitch Ratings Ltd., "Investing In An Unpredictable World", Fitch Ratings' 20th Annual Global Power Breakfast" (Nov. 10, 2008).

[6] Grabelsky, Glen, "Surviving the Present, Preparing for the Future", Fitch Ratings' 20th annual Global Power Breakfast (Nov 10, 2008).

[7] Wall Street Journal "Turmoil in Credit Markets Send Jolt to Utility (Oct. 1, 2008).

IV. PSNH'S FINANCIAL CONDITION

Q. Please describe conditions in the electric utility industry.

A. Over the last decade and a half, investors have witnessed steady erosion in credit quality throughout the utility industry, both as a result of perceptions of higher risks in the industry and the weakened financial conditions of the utilities themselves. Edison Electric Institute ("EEI") has reported that at the beginning of 1992, the majority of electric utilities were rated A (67 percent rated A, 32 percent rated BBB) but by the end of 2008, most electric utilities were rated BBB (19 percent rated A, 71 percent rated BBB).[8] Most electric utilities are only one notch away from falling below investment grade.[9]

More recently, since the settlement of PSNH's previous rate case, investor concerns have been deepening. The rating agencies and investors are well-aware of the financial and regulatory pressures associated with the need to undertake significant capital investments for electric utility infrastructure. In August 2007, Moody's observed:

> [T]here are concerns arising from the sectors' sizable intrastate investment plans in the face of an environment of steadily rising operating costs.[10]

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[8] www.eei.org/whatwedo/DataAnalysis/IndusFinanAnalysis/Pages/FinancialReview.aspx; Go the Capital Markets section, page 83.

[9] 'AAA' and 'AA' (high credit quality) and 'A' and 'BBB' (medium credit quality) are considered investment grade. Credit ratings for bonds below these designations ('BB', 'B', 'CCC', etc.) are considered low credit quality, and are commonly referred to as non-investment grade or "junk bonds."

[10] Moody's Investor Service, "Storm Clouds Gathering on the Horizon for the American Electric Utility Sector", Special Comment, August 2007.

In October 2007, S&P noted that "onerous construction programs," along with rising operating and maintenance costs and volatile fuel costs, are a significant challenge to the utility industry.[11] Fitch recently concluded that the short- and long-term outlook for investor-owned electric utilities is negative.[12] Similarly, Moody's observed, "Material negative bias appears to be developing over the intermediate and longer term due to rapidly rising business and operating risks."[13] The headline in S&P's April 2009, Rating Roundup was "Ratings Trend Turns Negative During First Quarter Of 2009 For U.S. Electric Utilities."

It is important to recognize that these events are occurring in the midst of the worst credit crisis in many decades and at a time when the three major rating agencies have been severely criticized for not sounding an adequate alarm about the risks to which the financial markets were subject.[14] Faced with such aggressive critics, the rating agencies will likely increase the intensity of their credit reviews to ensure that they will not again be perceived as too lenient.

Q. Do these general industry concerns apply specifically to PSNH?

A. Yes. In 2007 and 2008 PSNH incurred a total of $407 million[15] for capital expenditures. Its investment requirements for the period from 2009 though 2013 are forecast to be $2.7

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[11] Standard & Poor's Corporation, "*U.S. Electric Utilities continue Their Long Shift to Stability*" RatingDirect, October 23, 2007.

[12] Fitch Ratings, Ltd., "U.S. Utilities, Power and Gas 2009 Outlook," Global Power North America Special Report (Dec. 22, 2008).

[13] Moody's Investors Service, "U. S. Electric Utility Sector," Industry Outlook January 2008.

[14] See, for example, www.riskcenter.com/story.php?id=15308, *Commentary – The History and Future of the Rating Agencies.*

[15] Northeast Utilities Combined Annual Report & Form 10K, PSNH Statement of Cash Flows; Investments in Property and Plant (millions $): 2008 - 239, 2007 – 168.

billion.[16] While providing the infrastructure necessary to meet the energy needs of customers is desirable, investors are aware that it imposes additional financial risks on the Company. As discussed below, this has contributed to the deterioration of PSNH's credit metrics.

Q. What credit ratings have been assigned to PSNH?

A. PSNH's current credit ratings are as follows:[17]

	S&P	Moody's	Finch
Corporate Credit Rating	BBB	Baa2	BBB
First Mortgage Bonds	BBB+	Baa1	BBB+
Outlook	Stable	Stable	Stable

Q. How does PSNH's relative credit standing compare with others in the utility industry?

A. The following table shows that PSNH's BBB Corporate Credit rating is below average: 85 utilities are rated higher than PSNH while only 40 are rated lower than PSNH. This indicates that PSNH's credit standing is relatively weak as compared to other utilities. Investors are, of course, hopeful that this proceeding will improve PSNH's financial condition.

[16] PSNH's 2009 - 2013 construction program (millions $) Distribution – 560, Generation – 594, Transmission – 1,497.

[17] PSNH's last credit rating change was a downgrade by S&P from BBB+ to BBB on April 14, 2004.

Rating	Number of Utilities	
AA-	1	0.53%
A+	5	2.67%
A	12	6.42%
A-	32	17.11%
BBB+	35	18.72%
BBB	63	33.69%
BBB-	28	14.97%
BB+	6	3.21%
BB	3	1.60%
BB-	3	1.60%
	187	

Source: S&P U.S. Regulated Electric Utilities, Strongest to Weakest, May 7, 2009

Q. Please explain what you mean when you state that PSNH's credit standing is relatively weak.

A. PSNH's ratings are at the lower end of the investment grade. That is one reason why PSNH has reduced flexibility to respond to challenges such as a prolonged and/or worsening credit crisis.[18] Further, the rating agencies have expressly noted in published reports that PSNH's credit metrics have weakened over the past several years. For example, S&P's April 17, 2009 Summary of Public Service Company of New Hampshire stated that PSNH's "...financial profile [is] slightly weak for the rating level." In its November 2008 Credit Opinion on PSNH, Moody's commented that PSNH's credit metrics were "under its previous averages"; that its cash metrics had generally weakened since 2006; and that, going forward, Moody's expects that "the increase level of external

[18] Reduced flexibility takes the form of fewer financing options, higher financing costs and, at particularly challenging times, difficulty in obtaining access to necessary funds

financings associated with the planned capital program will somewhat pressure credit metrics." Similarly, Fitch, in its November 2008 Credit Analysis of PSNH, commented that "Credit metrics have been trending downward."

Q. Please expound on your statement that PSNH's credit metrics have been weakening.

A. The three ratios that S&P refers to as the principal ratios[19] are:

- Funds from Operations ("FFO") Interest Coverage
- FFO to Total Debt
- Total Debt to Total Capital

The FFO/Interest and FFO/Debt ratios (known as cash flow ratios) are the most important ratios used by the credit rating agencies to evaluate a company's cash flows and the company's ability to meet its financial obligations. The table below confirms the observations of the rating agencies that PSNH's key cash flow credit metrics are declining not only in absolutely terms but also relative to the industry. In fact, the FFO to Total Debt ratio, for year-end 2008 ratio has alarmingly fallen all the way to the bottom limit of the BBB rating range.[20]

[19] While the rating agencies consider many factors in determining a rating, they generally consider their methodology proprietary. For that reason, Fitch does not publicly disclose the factors that influence its ratings, and Moody's has only recently begun to do so. S&P has historically been the most open and transparent with respect to their criteria. Because of its long-standing and high degree of transparency and availability of comparative information, the NU system companies have generally relied on the S&P methodology to establish their capital structure targets.

[20] The Company has been told by the S&P that PSNH's will not be considered for a rating upgrade until the FFO to average debt ratio approaches 18 percent.

	2008		2007	
	PSNH	Industry	PSNH	Industry
FFO to Interest (x)	2.8	4.9	3.5	3.9
FFO to Total Debt (%)	10.09	18.00	13.52	19.70

S&P Guideline for BBB ratings	
FFO to Interest	2.0x - 3.5x
FFO to total Debt	10% - 30%

Source: Rating Trends Turn Negative During the First Quarter Of 2009 For U.S. Electric Utilities, April 14, 2009.

Q. What can be done to improve PSNH's deteriorating credit metrics?

A. As shown in the table below, PSNH's low and declining distribution return on equity has contributed to its weakening credit profile.

Actual Earned Return on Equity [a]

		Year-ending	
	Mar-09	2008	2007
Distribution [b]	5.54%	6.26%	8.70%
Total Company	8.78%	8.99%	8.41%
Rate Base:			
Distribution	739,675		
Total Company	1,218,244		
	60.7%		

a. From Form F-1 filed with the New Hampshire PUC May 19, 2009
b. In Docket No. DE 06-028, PSNH distribution was allowed a 9.67% return on equity. In the prior distribution docket a return on equity was not stated.

Because of the relative size of PSNH's distribution rate base to its total assets, its low allowed and earned ROE is a driver of the Company's earnings and credit metrics. This proceeding affords the Commission an opportunity to stop PSNH's deteriorating credit situation by not only setting a more appropriate allowed ROE but, of equal importance, by setting distribution rates at a level that will permit PSNH a realistic opportunity to earn that allowed return going forward. In addition, as discussed in the next section, it is important that PSNH's ratemaking capital structure be strengthened.

V. CAPITAL STRUCTURE

Q. What is the Company's proposed capital structure?

A. PSNH should continue to target a capital structure of 45 percent equity and 55 percent debt using the rating agency (S&P) methodology. This rating agency target is consistent with PSNH peers' actual rating agency capital structures. In Attachment GJE – 2 Capital Structure, I provide the 2007 and 2008 actual S&P capital structures for each of the peer companies.

Q. Why is it appropriate for PSNH to set a target using the rating agency methodology?

A. The principal reason is that the rating agency capital structure is highly influential in the financial markets. It exerts a strong influence over bond ratings, marketability of debt securities, and ultimately PSNH's cost of capital.

Q. How does the rating agency capital structure differ from the ratemaking capital structure?

A. The primary difference between the two capital structures is that the rating agencies include all contractual obligation that have a claim to a company's current and future cash flows, not just traditional debt (i.e., bonds). Leases are a classic example of that type of contractual obligation, sometime referred to as off-balance sheet debt. The rating agencies "impute" debt for such obligations. Consequently, the rating agency capital structures will typically have a higher percentage of debt than ratemaking capital structures. The differences between the two capital structures are discussed in more detail in Attachment GJE - 2 Capital Structure. Significantly, rating agencies now impute debt for Asset Retirement Obligations and for Unfunded Pension and Post Retirement Obligations, which can have a significant effect on rating agency capital structure.

Q. Does PSNH manage its capital structure to meet the rating agency target?

A. No. PSNH must manage to its allowed ratemaking capital structure. As explained more fully below, additional equity above the allowed level for ratemaking purposes would lower PSNH's actual earned ROE because, in effect, it would be earning a zero return on the incremental equity.

Q. How does PSNH manage to its ratemaking capital structure?

A. Although PSNH uses internal cash flow to finance a portion of its annual investment,[21] it is typical for PSNH to need additional capital over and above its internal cash flow. This "external" capital requirement is met with a combination of new debt issuances and new equity contributions from PSNH's parent, Northeast Utilities ("NU"). The relative amounts of new debt and new equity are designed to maintain the ratemaking capital structure at the allowed level. The table below shows that, as a result of PSNH's increasing capital expenditures and weak distribution earnings, NU has found it necessary to contribute increasing amounts of equity capital to PSNH to maintain the ratemaking structure.

	Year-to-Date 2009	2008	2007
NU Capital Contributions ($M)	67.3	75.6	44.2

[21] PSNH budgets 60 percent of annual earnings as a dividend to its parent, with the remainder of funds from operations utilized to meet PSNH's capital requirements.

NU's equity contributions have been instrumental in allowing PSNH to maintain its credit rating in the face of weakening cash flow credit ratios.

Q. You stated earlier that rating agencies now impute debt for Unfunded Pension and Post Retirement Obligations and Asset Retirement Obligations. How has that affected the Company's requested capital structure?

A. In the last rate case PSNH requested a ratemaking capital structure of 48.13 percent equity and 51.87 percent long-term debt in order to meet its rating agency capital structure target of 45 percent equity and 55 percent debt.[22] In order to maintain the same rating agency capital structure target, PSNH's ratemaking capital structure will now need to be set at 51.11 percent equity and 48.88 percent debt. The calculations are shown in GJE - 2 Capital Structure.

Q. Why didn't NU provide more equity to PSNH in order to attain the target rating agency capital structure?

A. As noted above, if NU had contributed equity capital to PSNH above the level allowed for ratemaking purposes in order to attain its target rating agency capital structure, PSNH would have earned a zero percent return on that incremental equity investment. As discussed above, PSNH's earned ROE is already too low. Therefore, if NU had contributed more equity to PSNH over the allowed capital structure, PSNH's earned ROE

[22] The current allowed ratemaking capital structure, which was negotiated and included in the May 2007 settlement, assumes 1.18 percent of rate base is funded with short-term debt. This is inconsistent with industry practice and the Company disagrees with the inclusion. Short-term debt is discussed in more detail in Attachment GJE -2 Capital Structure.

would have been even lower. Further, NU has a fiduciary responsibility to its equity investors and such an incremental equity investment with no return would be very difficult to justify.

Q. How does NU obtain the equity capital that it periodically contributes to PSNH?

A. In order for NU to make equity contributions to PSNH and its other operating companies, NU periodically raises its own equity capital with common stock issuances. For example, in March 20, 2009, NU sold 18.975 million new shares of common stock to the public at a price of $20.20. After expenses NU netted $370.8 million, which it has or will invest in its operating companies.

Q. Are other utilities requesting an increase in the equity percent of their ratemaking capital structure as a result of imputed debt for Unfunded Pension and Post Retirement Obligations and Asset Retirement Obligations?

A. Yes. I asked our bankers at Citi Bank to research that precise question. John D. Clapp, Managing Director, Global Power Sector, Citi Investment Banking provided the following summary of utility equity market activity:

> … there are a number of utilities that have requested and received higher equity percentages in relation to their overall capital structure. Overall we have seen a growing number of utilities issuing equity in the capital markets over the past 6 months. These issuances have often been driven by the need to rebalance the utility's capital structure to preserve the current rating and alleviate concerns over potential downgrades typically due to a combination of: 1) declining revenues and 2) significant near-term capex requirements. In addition to showing prudence given market uncertainty, these actions also recognize that companies with stronger balance sheets/liquidity have more consistent access to all forms of capital.

> ... certain utilities are going beyond a rebalancing their cap structure and deleveraging to varying degrees. A search of the supporting testimony showed that in at least two cases (TECO and OGE, attached) utilities raised concerns about the economy, and in particular the need to reduce debt interest expenses in a time of revenue uncertainty as a major rationale behind their request for a larger equity component in the cap structure.[23]

Citi Bank also provided a list of 13 electric utilities that have or are seeking regulatory authority to increase the equity component of their ratemaking capital structure. I have provided that list in GJE - 2 Capital Structure. The average ratemaking equity percentage being requested is 51.96 percent.

Q. Do the challenging financial market conditions discussed above have any impact on the appropriate capital structure for PSNH?

A. Yes. The current environment poses significant challenges with respect to a utility's ability to raise capital on reasonable terms. For PSNH these concerns are magnified by the fact that its credit metrics are weakening. Fitch recently observed that in current credit markets, "'flight to quality is selective within the (utility) sector, favoring companies at higher rating levels."[24] Ideally, this would be a good time to strengthen PSNH's rating agency capital structure target. I have not made that recommendation, however, because the ratemaking capital structure already needs to be strengthened in this proceeding merely to maintain the current rating agency capital structure target. If the challenging financial market conditions continue, the Company will likely propose to strengthen its rating agency capital in a future proceeding.

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[23] Email from John Clapp at Citi Bank to G,J. Eckenroth dated May 22, 2009

[24] Fitch Ratings Ltd., "U.S. Utilities, Power and Gas 2009 Outlook," Global Power North America Special Report (Dec. 22, 2008).

VI. COST OF CAPITAL

a. Cost of PSNH's Long-Term Debt

Q. Please summarize your Long-Term Debt recommendation.

A. The table below shows PSNH's outstanding long-term debt, which consists of five series of pollution control revenue bonds and four series of first mortgage bonds, plus a new first mortgage bond to be issued in 2009. The table shows the total principal amount of each issue, gross financings costs and the net proceeds or cash available to fund rate base. The table also shows the total amortized issuance costs and the net cash available to fund rate base in 2009.

(million $)	At Offering Date			Total Amortized Financing Costs	Net Outstanding
	Principal	Financing Costs	Net Proceeds		
Pollution Control Revenue Bonds					
Series A	89,250	5,781	83,469	2,025	85,494
Series B	89,250	7,124	82,126	2,280	84,406
Series C	108,985	7,787	101,198	2,517	103,715
Series D	75000	4,149	70,851	3,091	73,942
Series E	44,800	3,088	41,712	2,479	44,191
	407,285	27,929	379,356	12,392	391,748
First Mortgage Bonds					
Series L	50,000	549	49,451	194	49,645
Series M	50,000	694	49,306	74	49,380
Series N	70,000	607	69,393	-166	69,227
Series O	110,000	1,465	108,535	-1,013	107,522
	280,000	3,315	276,685	-911	275,774
	687,285		656,041	11,481	667,522
New Bond	150,000	1,296	148,704	0	148,704
	837,285		804,745	11,481	816,226

The table below shows the calculation of the total annual carrying costs. The annual carrying costs are the sum of the interest payment plus the amortization of financing costs.

(million $)	Interest Rate	Principal	Annual: Interest	Annual: Amortization of Financing Costs	Annual: Total Carrying Costs
Pollution Control Revenue Bonds					
Series A	0.40%	89,250	357	413	770
Series B	4.75%	89,250	4,239	502	4,741
Series C	5.45%	108,985	5,940	427	6,367
Series D	6.00%	75000	4,500	86	4,586
Series E	6.00%	44,800	2,688	49	2,737
		407,285	17,724	1,477	19,201
First Mortgage Bonds					
Series L	5.25%	50,000	2,625	63	2,688
Series M	5.60%	50,000	2,800	23	2,823
Series N	6.15%	70,000	4,305	89	4,394
Series O	6.00%	110,000	6,600	266	6,866
		280,000	16,330	441	16,771
		687,285	34,054	1,918	35,972
New Bond	6.44%	150,000	9,660	130	9,790
		837,285	43,714	2,048	45,762

The 5.61 percent weighted cost of debt is calculated by dividing the Total Carrying Costs by the Net Outstanding.

Total Carrying Costs	Net Outstanding	Weighted Cost of Debt
45,762	816,226	5.607%

Q. Please discuss why PSNH must issue a new bond in 2009?

A. PSNH needs additional long-term capital to fund its construction program and for general working capital needs. In between bond issuances PSNH borrows short-term from the NU System Money Pool and its Revolving Credit Facility on a temporary basis. In the longer term, sound financial management requires using long-term financing to finance long-term assets. Therefore, it is necessary to replace the short-term financing with long-term debt when the amount reaches a level that permits PSNH to issue a bond in an economically efficient manner. PSNH's financing plan contemplates accessing the capital markets to issue long-term debt whenever short-term debt consistently exceeds the $125 to $140 million range. The Company filed an application dated February 20, 2009 with the Commission to issue long-term debt in Docket No. DE09-033. The Company's 2009 financing plan anticipated the issuance of a ten-year first mortgage bond as early as the second quarter of this year.[25] The 2009 financing plan incorporated into the 2009 budget assumed an all-in interest rate of 6.44 percent for the issuance of a new ten-year first mortgage bond.[26]

b. Return on PSNH's Common Equity

Q. What is the purpose of your ROE analysis?

A. The purpose of my analysis is to develop and support a recommendation that meets the applicable legal and economic standards, which hold that a utility and its investors should

[25] After receipt of a financing order from the Commission, the Company will move expeditiously to issue.

[26] The 6.44 percent all-in rate was based on November 2008 market data that required a 10-yer credit spread of 369 basis points over the yield on a ten-year treasury bond.

be afforded an opportunity to earn a return commensurate with returns they could expect to achieve on investments of similar risks.[27]

Q. Is there one methodology that can be used to precisely determine the proper ROE for a utility such as PSNH?

A. No. When measuring equity costs, which essentially deal with the measurement of investor expectations, no one single methodology provides a sufficiently reliable result. The Society of Utility and Regulatory Analysts supports using a multiplicity of methods and, as a member, I have complied with their recommendation. I have used the three most accepted valuation models: a Discounted Cash Flow Model ("DCF"), the Capital Asset Pricing Model ("CAPM") and a Risk Premium Model ("RPM").

Q. How did you develop your recommendation?

A. Estimating the cost of equity capital involves theoretical and empirical components. The theoretical component relies on the standard financial literature to develop cost of capital models that are consistent with what we know and observe about the way the financial markets work. Each of the accepted cost of capital models results from theoretical investigations. The empirical component includes the collection of the data to be used with the theoretical cost of capital methods. The most important empirical considerations are to use data that are (1) consistent with the theoretical models employed,(2) timely and (3) unbiased. It is also important that the calculations made with the empirical data be reliable and stable and not sensitive to minor or judgmental changes.

[27] The reference is to the *Bluefield* and *Hope* U.S. Supreme Court cases that collectively reflect the economic criteria encompassed in the "opportunity cost" principle.

<u>i. Discounted Cash Flow Method</u>

Q. Please explain the DCF Model?

A. Discounted cash flow valuation calculates the value of an asset as the present value of the expected future cash flows to be earned by the holder of the asset. Financial theory clearly establishes that the DCF is the best way to establish the value of an asset if the future cash flows can be determined accurately. There are significant challenges to overcome when applying the DCF to common stocks, however, because the cash flows on common stock are not known.

The simplest DCF model for valuing equity is the dividend discount model, which determines the value of a stock by calculating the present value of all dividends expected to be paid to holders of the stock. This approach is not very operational, as it requires an estimation of an infinite stream of dividends.

A simplified version of the DCF model was published by Professor Myron Gordon a half century ago and has been in use ever since. While Professor Gordon's model is frequently referred to as "the" DCF model, it would be more accurate to characterize it as "a form of" the DCF model that requires the acceptance of several strict assumptions. The most extreme of these assumptions is that the earnings and dividends of a company will grow at a constant rate over the company's life. The theoretical underpinnings of the DCF model are discussed in more detail in Attachment GJE – 3 <u>Discounted Cash Flow Model</u>.

The Gordon version of the DCF model sets the following formula:

$$P_0 = D_0 \times (1+g) / (K_e - g)$$ where:

P_0 = Current stock price
D_0 = Actual dividends in the last four quarters
K_e = Investors' required return or equity cost of capital
g = Estimated annual earnings growth rate

Solving the equation for K_e, the cost of equity, algebraically, the standard DCF formulation widely used in regulatory proceeding is obtained.

$$K_e = (D_0 \times (1+ g) / P_0) + g$$

This formula effectively states that the equity investors' required return can be estimated as the sum of an expected dividend yield plus an expected growth rate.

Q. The DCF model requires data that is only available for publicly-traded companies. Given that PSNH is a wholly-owned subsidiary of NU, not a publicly-traded stock, how did you proceed?

A. When dealing with a company that is not publicly traded, it is customary when using this DCF model to utilize a group of publicly-traded companies with similar financial and operational characteristics as the firm being analyzed. That group of companies is known as the proxy group. In keeping with my past practice, I developed a proxy group that institutional investors view as similar to PSNH with the assistance of Morgan Stanley (the "Institutional Investor" proxy group). In order to test the sensitivity of my results to the composition of the proxy group, I also developed alternative proxy groups. In Attachment GJE – 3 Discounted Cash Flow Model, I discuss my various proxy groups.

Q. The DCF model requires a stock price, dividend and a dividend yield. How did you develop those inputs?

A. The dividend yield is simply the annual dividend divided by a stock price. For the dividend, I used the sum of the actual last four quarterly dividends paid by each of the 57 companies in my data base. For the stock price, I averaged the high and low stock price in each month and then calculated an average price for period for each of the companies in the data base. Because of the steady decline in stock prices since September 2008, I calculated the dividend yield using six, three and one-month average stock prices. The calculation of dividends, average stock prices and yield is discussed in more detail in Attachment GJE - 3 Discounted Cash Flow Model.

Q. The DCF model requires a long-term growth rate. How did you develop it?

A. The most challenging part of the DCF methodology is estimating the growth rate. In their 2008 MBA text, Michaels C. Ehrhardt and Eugene F. Brigham's include a section entitled "Evaluating the Methods for Estimating Growth." The authors conclude that "studies have shown that analysts' forecast usually represent the best source of growth rate data for the DCF cost of capital estimations." [28] That conclusion is consistent with my view and my past practice. Therefore, I used the consensus or average of publicly available growth rates. In particular, I utilized the growth rates, published by Value Line, Yahoo Finance, Zacks Investment Services, SNL, and Institutional Brokers Estimate System ("I/B/E/S"). My growth rate is the simple average of those five growth rates. In Attachment GJE - 3 Discounted Cash Flow Model, I discuss the use of analyst growth rates in more detail and present each of the growth rates that I utilized.

[28] M.C. Ehrhardt, E. F. Brigham, Corporate Finance, A Focused Approached, South-Western Cengage Leaning, 2008, page 302.

Q. On which of your proxy groups have you based your recommendation?

A. In keeping with my past practice, I base my recommendation on the Institutional Investor proxy group. However, as shown in Attachment GJE - 3 <u>Discounted Cash Flow Model</u>, using other proxy groups would tend to increase my ROE calculations.

The details for each company in the Institutional Investor proxy group are presented below. The range of ROEs is from 11.96 percent to 12.32 percent, depending on the time-period for calculating the stock price.

		Institutional Investor - PSNH Proxy Based on Average Stock Prices of: 6 month ROE Adj Yield plus Growth Rate	3 months ROE Adj Yield plus Growth Rate	1 month ROE Adj Yield plus Growth Rate
1	ALLETE	10.35%	10.91%	10.74%
2	Alliant Energy Corporation	11.75%	12.33%	12.28%
3	Amer. Elec. Power	10.11%	10.71%	10.75%
4	Avista Corp.	10.78%	11.35%	10.99%
5	CH Energy Group	7.88%	8.05%	8.08%
6	Cleco Corp.	16.70%	16.75%	16.88%
7	Consol. Edison	8.86%	9.05%	9.18%
8	DPL Inc.	13.24%	13.17%	13.18%
9	DTE Energy Company	11.31%	11.95%	11.43%
10	Empire Dist. Elec.	16.00%	16.66%	16.10%
11	IDACORP, Inc.	9.80%	10.32%	10.29%
12	Northeast Utilities	12.28%	12.54%	12.55%
13	Northwestern Corporation	16.13%	16.35%	16.18%
14	NSTAR	11.63%	11.89%	11.78%
15	PG&E Corp.	11.39%	11.39%	11.51%
16	Pinnacle West Capital	12.00%	12.70%	12.48%
17	Portland General	12.37%	12.56%	12.30%
18	Progress Energy	12.48%	12.85%	12.78%
19	Southern Co.	10.83%	11.33%	11.48%
20	TECO Holding Corp.	15.11%	15.39%	14.88%
21	UIL Holding Company	11.58%	12.44%	12.25%
22	Westar Energy	10.85%	11.25%	11.12%
23	Wisconsin Energy	11.87%	11.99%	12.06%
24	Xcel Energy Inc.	11.77%	11.82%	11.85%
	average	11.96%	12.32%	12.21%

Some of my misgivings with the DCF model are illustrated by the table above. For example, the range of investor returns for a group of companies with similar financial and operational companies is too large: CH Energy Group 7.9 percent to Cleco Corp 16.8 percent. Further, several low ROEs clearly do not make economic sense, as investors are not being compensated for accepting the incremental risk of equity risk over debt with a higher return. Conversely, several of the high numbers are too generous; investors would quickly eliminate such outliers through arbitrage.[29]

Q. How did you correct for this shortcoming of the DCF model?

A. Consistent with my past practice, I apply an Acceptance Criterion to the ROE for each company in the Institutional Investor proxy group. My Acceptance Criterion requires that the company's calculated ROE must fall within a range of reasonableness. After applying the Acceptance Criterion, the range of ROEs is reduced from 11.96 percent to 12.32 percent to 11.45 to 11.86 percent. My Acceptance Criterion and its impact on the proxy group are discussed in GJE - 3 Discounted Cash Flow Model.[30]

Acceptance Criterion
Return on Equity Institutional Investor Proxy Group
Based on Average Stock Prices of:

	Six Month Price		Three Month Price		One Month Price	
	ROE	Accept	ROE	Accept	ROE	Accept
Per-acceptence average	11.96%		12.32%		12.21%	
Post-acceptence average		11.66%		11.86%		11.45%
ROE over Long-Term Debt		3.40%		3.57%		3.39%

[29] Arbitrage is the simultaneous purchase and sale of an asset in order to profit from a difference in the price. It is a trade that profits by exploiting price or return differences of identical or similar financial instruments.

[30] For the cost of debt, I used the average monthly cost of a Baa bond yield as published by the Federal Reserve in publication H.15.

Q. Would you make any additional adjustment to the average DCF ROE?

A. Yes. I would adjust for flotation costs. On March 20, 2009, NU sold new common equity. The price paid by investors was $20.20 per share but NU received only $19.54 per share. The $.6622 per share (or 3.28 percent) difference was the cost to issue the new shares of common stock. In order for NU to earn the ROE required by investors based on NU's $20.20 share price, NU must earn a higher return on the $19.54 per share to that NU actually receives. The flotation cost adjustment is discussed in more detail, along with the supporting calculations, in Attachment GJE - 3 Discounted Cash Flow Model. A 20 basis point issuance cost adjustment to the ROEs is required to earn the investors' required return on the net proceeds available to the company.

Q. Please summarize your DCF analysis.

A. Using my proxy group and Acceptance Criterion, and adjusting for flotation costs, my DCF analysis supports an ROE in the 11.65 percent to 12.06 percent range.

ii. Capital Asset Pricing Models ("CAPM" and "ECAPM")

Q. Please describe the CAPM.

A. The CAPM is a widely-referenced method for estimating the cost of equity both among academicians and professional practitioners. As with other risk premium-based models, the CAPM recognizes that risk-averse investors demand higher returns for assuming additional risk and that higher-risk securities are therefore priced to yield higher expected returns than lower-risk securities. The CAPM goes one step further by providing a formal risk-return relationship that quantifies the risk premium required for bearing incremental risk in the context of a highly diversified portfolio. The CAPM is mathematically expressed as:

$$K_e = R_f + \text{Beta}\,(R_m - R_f)$$

where:

K_e = investors required return or equity cost of capital
R_f = risk free rate of return
Beta = measure of risk
R_m = market rate of return
$R_m - R_f$ = market risk premium

As discussed below, the CAPM has been demonstrated to have a key bias and the Empirical CAPM ("ECAPM") was developed to correct that bias.

Q. How did you choose a risk free rate of return?

A. The ideal estimate for the risk-free rate should have a term to maturity equal to the security being analyzed and the maturity of the assets being financed. Because common stock has a perpetual life, cash flows to equity investors last indefinitely, regardless of an individual investor's holding period. Moreover, most utility assets have very long-term useful lives. Therefore, the best available proxy for the risk-free rate in the CAPM is the return on the longest term Treasury bond that is traded. At present, the longest possible term on a government bond is the yield on 30-year Treasury bonds.[31] Therefore, I have used the yield on 30-year Treasury bonds in implementing the CAPM. In Attachment GJE - 4 CAPM, I have provided detail on the 30-year Treasury bond yield. The yield has been slowly but steadily rising;[32] the average yield in December 2008 was 2.87 percent and in May 2009 the average yield was 4.23 percent. I have used an extremely conservative 4 percent as the risk-free rate.

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[31] While the return on Treasury Bills is sometimes used as the risk-free rate, Treasury Bills are not an ideal choice. Investors in common stocks (which do not expire or mature) have an investment horizon far in excess of Treasury Bills. An appropriate risk-free rate for valuing common stocks must have a long term to maturity.

[32] See Yahoo Finance ^TYX 30-yr Treasury bond

Q. Please explain Beta.

A. The beta coefficient is the measure of risk used in the CAPM. Under the CAPM view, total risk (the variability of returns) of an investment consists of two parts: systematic risk and unsystematic risk. Systematic risk is unavoidable since it affects all assets in the economy to some degree. In contrast, unsystematic risk is due to the unique circumstances of a specific asset. The impact of unsystematic risk can be greatly reduced through diversification.[33] The CAPM theorizes that since unsystematic risk can be largely avoided through diversification; it is not rewarded with a risk premium. Conversely, since systematic risk cannot be avoided, it is rewarded with a risk premium.

The beta coefficient measures the average change in a security's (stock) return relative to the market.[34] By the design of the CAPM model, the overall market always has a beta of 1.0. A beta of greater than one indicates that a company is more risky than the market as a whole; a beta of less than one means that the company is less risky than the market. There is a well-known tendency of beta to gradually migrate toward the average beta of 1.0 over time, also known as regression toward the mean.[35] Therefore, in estimating betas, it is necessary to adjust for this tendency. I have utilized the betas published by

[33] Diversification is the (calculated) spreading of investments over a number of different asset classes, sectors, countries. This provides a cushion, since different asset classes, sectors, or countries seldom move in the same direction.

[34] Absolute estimates of beta vary when different computational methods are used. The return data, the time period used, its duration, the choice of a market index and whether annual, monthly or weekly return figures are used will influence the final result.

[35] See www.wikipedia.org/wiki/Regression_toward_the_mean

Value Line, which have been adjusted for this movement of betas toward 1.0.[36] I have used a conservative beta of .70. A more detailed discussion of beta is provided in Attachment GJE – 4 CAPM.

Q. How did you determine the Market Risk Premium?

A. The market risk premium ("MRP") is the compensation in excess of the return on a risk-free asset that investors require for the additional market risk they bear. The MRP is of critical importance in the CAPM given the direct relationship between it and the expected ROE. The MRP is forward-looking, however, and not directly observable. I have traditionally estimated the MRP using historical returns. However, historical equity risk premiums are not indicative of equity investors' required returns to induce them to buy or hold stocks at this time. As discussed above under Current Market Conditions, with the risk premiums for corporate bonds at historic highs, the equity risk premium must also be higher than normal in order to compensate investors for the higher risk of investing in equity rather than debt.

To capture the current high level of uncertainty in investor future expectations, with the assistance of Barclays Capital, I developed a DCF of the S&P 500 to calculate the expected return on the market.

In Attachment GJE – 4 CAPM, I discuss and present the calculation of the S&P 500 expected return in more detail. Combining a forward S&P 500 dividend yield of 3.75 percent with an expected long-term S&P 500 growth rate of 9.74 percent results in a

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[36] Per www.valueline.com, "[t]he 'Beta coefficient' is derived from a regression analysis of the relationship between weekly percentage changes in the price of a stock and weekly percentage changes in the NYSE Index over a period of five years. The Betas are adjusted for their long-term tendency to converge toward 1.00."

13.49 percent long-term expected S&P 500 market return. The market return less the 4.00 percent 30-year treasury yield provides a market risk premium of 9.49 percent.

Q. What is the result of your CAPM before correcting for the biases to which you referred above?

A. Based on the inputs discussed above the Traditional CAPM formula results in a ROE of 10.64 percent.

ROE	=	Risk Free Rate	+	(Beta	x	MRP)
				0.70	x	9.49%
10.64%	=	4.00%	+	6.64%		

Q. **Please describe the biases in the CAPM to which you referred.**

A. A consistent finding of empirical studies of the CAPM show that there is a discrepancy between the risk-return tradeoff predicted by the CAPM and the risk-return tradeoff actually observed. Specifically, these empirical findings show that low beta stocks have higher rates of return than predicted by the model. This finding has given rise to the "Empirical CAPM" or ECAPM, which is designed to correct this bias. The ECAPM corrects the ROE to 10.79 percent as follows.

ECAPM	=	(30 yr Treasury	+	Alpha)	+	[Beta	x	(Risk Premium	-	Alpha)]
10.79%		4.00%	+	0.50%		0.70	x	9.49%	-	0.50%

I discuss the need for and computation of the ECAPM adjustment in more detail in Attachment GJE – 4 CAPM.

Q. What other adjustments should be made to the CAPM/ ECAPM?

A. One of the discoveries of modern finance is that of a relationship between company size and return. The relationship cuts across the entire spectrum of size but is most evident among smaller companies, including electric utilities. The CAPM does not account for size differentials across companies and therefore understates the cost of equity for small companies. If PSNH were a stand-alone publicly trade company, investors would be expected to earn at least an additional 74 basis points, which would increase the ECAPM recommendation to 11.53 percent. I discuss the size premium in more detail in Attachment GJE – 4 <u>CAPM</u>.

Q. Are you proposing an adjustment for issuance cost to the CAPM as you did to your DCF model?

A. Yes. In GJE - 4 <u>CAPM</u>, I provide a numerical example of the need for an issuance cost adjustment. My example is based on March 2009 sale of NU common stock. Investors paid $20.20 for each share of NU stock. If an investor purchased the stock with an expectation of earning annually 11 percent, then they expected to receive on average annually $2.22 (20.20 x .11). However, after paying issuance expenses, NU received only $19.54 per share to invest. Consequently, NU must earn approximately 11.37 percent on the invested equity to meet the investor's $2.22 expected returns. The incremental 37 basis points should be added to the size-adjusted ECAPM of 11.53 percent to arrive at an 11.89 ROE.[37]

[37] The calculation of issuance costs using the CAPM method differs from the calculation using the DCF method.

		Adjustments	Cumulative
Traditional CAPM	10.64%		
Empirical		0.15%	10.79%
Size		0.74%	11.53%
Issuance costs		0.37%	11.90%

iii Risk Premium Model ("RPM")

Q. Please discuss the development of an ROE using the Traditional RPM.

A. The traditional RPM is based on the fact that the return on debt is far easier to measure than the required return on equity. The RPM takes the return on debt and adds an equity risk premium that is estimated from past market returns.[38] The RPM is conceptually similar to CAPM, but was in wide use even before the CAPM was developed. Risk premium analysis is commonly used by analysts, investors and expert witnesses and is widespread in investment community reports.

The equity risk premium measures the additional risk required by investors for investing in equities rather than less risky assets, such as bonds. The RPM equation is as follows:

$K_e = D + R_p$

where:

K_e = investor's required return or equity cost of capital

D = the cost (interest rate) of a company's debt

R_p = the investor's risk premium over a debt instrument

Q. How is the equity risk premium estimated?

A. The equity risk premium is measured by the difference between equity returns and debt returns over the very long term. Use of long-term data is essential. In the short term, equity returns are strongly influenced by positive and negative surprises that result in

[38] Some have argued that historical returns are affected by investors' adjustments to relative taxation rates, and therefore not reflective of future expectations without tax adjustments. The core determinate of expected return is not taxability, but rather risk. Investors will examine the risk-return trade-off offered by various securities first and as a secondary matter the taxability issue.

unexpected outcomes. Therefore, actual equity returns may differ substantially from the returns required by equity investors. Over the long term, however, such surprises will tend to average out so that investors' required return and expected returns will converge. This will not be true for shorter time periods that do not provide an adequate sample size. Accordingly, I have used data from 1945 to 2008.

Q. How did you measure the cost of debt?

A. In the CAPM portion of my testimony, I explained why the appropriate cost of debt to use when calculating an equity risk premium is the longest-term debt security that is traded. For that reason, I have used the Moody's long-term bond yields for public utility bonds published in the Mergent Bond Record as the debt security from which to calculate the equity risk premium. Moody's long-term corporate bond yields have been published daily since 1929 in Mergent Bond Record. Mergent states in an explanatory footnote that "(t) he bonds have maturities as close as possible to 30 years; they are dropped from the list if their remaining life falls below 20 years." [39]

Q. How did you measure actual equity returns?

A. I used two data sources: the Moody's Electric Utility Index and the S&P Electric Utility Index.

Q. What were the results of your analysis?

A. The results indicate a risk premium of 3.95 percent using the Moody's Electric Utility Index and 4.39 percent using the S&P Electric Utility Index. The average of these two estimates is an equity premium of 4.17 percent. As shown in the table below, the

[39] Mergent Bond Record May 2009 page 10

estimated current interest rate that PSNH would be required to pay on a newly issued 30-year bond is 8.28 percent. Adding a 4.17 percent risk premium to the 8.28 percent cost of debt results in a cost of equity for PSNH of 12.45 percent. The detailed calculations are presented and discussed in Attachment GJE - 5 RPM.

	PSNH Cost of Debt	Equity Premium	Cost of Equity
Treasury yield	4.00%		
BBB+ Credit Spread	4.28%		
	8.28%	4.17%	12.45%

VII. CONCLUSION

Q. Please summarize your testimony.

A. These are difficult economic times, both for businesses and their customers. The recommendations in this testimony are designed to preserve PSNH's access to needed funding on reasonable terms without unduly burdening customers at a time when PSNH's credit metrics have been weakening to a degree that has provoked published comments by the major rating agencies.

In attempting to find the appropriate balance, it is essential to keep in mind the clear evidence that, at this time of economic stress, investors are extraordinarily risk averse. This has resulted in historically high risk premiums on both debt and equity. These high risk premiums have raised the cost of capital for all companies, including electric utilities.

I have utilized three well-established methods to estimate the appropriate allowed ROE for PSNH. As shown in the table below, each of these methods supports an ROE of 11.65 percent or higher.

Results of ROE Calculations

DCF	11.65%	to	12.06%
CAPM			11.90%
RPM			12.45%

In deference to the economic challenges that many PSNH's customers are facing, and in light of recent regulatory decisions around the country, I am recommending only a 10.5 percent allowed ROE. With a 10.5 percent ROE and my recommended capital structure, PSNH's appropriate WACC is 8.11 percent.

Ratemaking Capital Struture
and the Weighted Cost of Capital

		Cost	
	Ratio	Embedded	Weighted
Long-Term Debt	48.88%	5.61%	2.74%
Common Equity	51.12%	10.50%	5.37%
			8.11%

Q. Does that conclude your testimony?

A. Yes.