BEFORE THE

STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS

PUBLIC UTILITIES COMMISSION

RE: THE NARRAGANSETT ELECTRIC COMPANY: INVESTIGATION AS TO THE PROPRIETY OF PROPOSED TARIFF CHARGES	**))))**	**DOCKET NO. 4065**

DIRECT TESTIMONY OF

DR. DALE E. SWAN

ON BEHALF OF THE

DIVISION OF PUBLIC UTILITIES AND CARRIERS

SEPTEMBER 15, 2009

EXETER

ASSOCIATES, INC.
5565 Sterrett Place
Suite 310
Columbia, Maryland 21044

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Q. Please state your name, occupation and address.

A. My name is Dale E. Swan. I am a senior economist and principal with Exeter Associates, Inc. Our offices are located at 5565 Sterrett Place, Columbia, Maryland 21044.

Q. Dr. Swan, please summarize your professional qualifications.

A. I hold a B.S. degree in Business Administration from Ithaca College. I attended a master's program in economics at Tufts University, and I hold a Ph.D. in economics from the University of North Carolina at Chapel Hill. Prior to my consulting work, I served as Assistant and Associate Professor on the economics faculties of several colleges and universities. I also served as staff economist with the Federal Energy Administration and with the Arabian American Oil Company. For the last 30 years, I have consulted on matters primarily related to the electric utility industry, the last 26 years with Exeter. Much of my work over the last two decades has concentrated in the areas of long-term electric power supply planning and contract negotiations for large power users, and on electric utility cost allocation and rate design. For much of this period, I have directed Exeter's utility support services projects with the United

States Department of Energy (DOE). As part of this work, I have been responsible for technical supervision of Exeter's participation in DOE interventions in numerous rate cases, and for the negotiation of technical aspects of power supply and facilities contracts.

A complete copy of my resume is provided as an attachment to my testimony.

Q. Have you testified in other regulatory proceedings?

A. Yes. I have testified on a variety of topics relating to electric utilities in numerous proceedings before federal and state regulatory commissions, including the Rhode Island Public Utilities Commission ("R.I.P.U.C." or "Commission"). A complete list of the cases in which I have testified is provided as part of my resume.

I. Introduction

Q. Dr. Swan, what is the purpose of your testimony?

A. I have been asked by the Rhode Island Division of Public Utilities and Carriers ("Division") to evaluate the reasonableness of the embedded, class cost-of-service study filed by the Narragansett Electric Company ("NEC" or "Company") in this case, and to provide an alternative cost study if that is appropriate. I have also been asked to recommend to the Commission an appropriate allocation of the allowed jurisdictional revenue requirement among the customer classes based on cost of service and other general rate design considerations, such as rate gradualism or continuity. Finally, I have been asked to assess the Company's proposed rate design and recommend changes as appropriate.

Q. Do you provide schedules in support of your testimony?

A. Yes. I have attached Schedules DES-1 through DES-8 to my testimony.

Q. Were these schedules prepared by you or under your direct supervision?

A. Yes.

Q. Dr. Swan, please briefly describe your conclusions and recommendations.

A. Based on my review and evaluation of the Company's class cost of service study, its proposed spread of the requested total jurisdictional distribution revenue increase, and its proposed rate design, I have arrived at the following conclusions and recommendations:

1. The Company has classified most distribution plant and related costs above the meter as demand-related. I agree with that classification and provide reasons why a minimum system study should not be used to classify some portion of those costs as customer related.
2. The Company has inappropriately allocated line transformer costs and associated O&M on the number of customers. I have reallocated these costs on class non-concident peaks, which more accurately reflect the reasons these costs have been incurred.
3. The Company errs in allocating Uncollectible Accounts - Delivery to those classes where those bad debts originated because other customers in those classes have not caused these costs. It is more appropriate to view these costs as general costs of doing business and so I have reallocated them on Total Delivery Revenue.
4. The Company's allocation of most of Customer Service and Information expenses on the number of customers is incorrect because there is no clear relationship between the number of customers and the incurrence of these costs. Based on the descriptions of the expenses to be booked into these accounts I have reallocated these costs on energy use at meter.
5. My changes to the Company's class cost of service study result in significantly different class rates of return at current rates and so different

estimates of existing subsidies. In particular, the Residential Class rate of return rises from 58 percent of the jurisdictional average return under the Company's study to 110 percent under my revised study.

6. Company witness Mr. Gorman does not pay sufficient attention to rate continuity or gradualism in his recommended spread of the Company proposed total jurisdictional revenue increase. He fails to account for the impact of other revenue changes on the customer classes, in particular the proposed shift in transmission revenue responsibility and the SOS Administrative charges.

7. I propose an alternative spread of the Company's proposed total jurisdictional increase based on my cost of service study that mitigates the impact of the transmission revenue shift, provides a more equitable spread of the cost of the A-60 subsidy among all customer classes, and accounts for all of the revenue changes in determining how to properly account for rate continuity or gradualism concerns.

8. I also provide an illustrative recommended spread of an allowed total jurisdictional revenue increase that is likely closer to the Division's revenue requirement recommendation in direct testimony.

9. On the basis of rate continuity or gradualism, I propose to limit the increase in the A-16 customer charge to between $1.00 and $1.25 and the C-06 customer charge to $2.00.

10. I point out that, while the cost studies suggest that larger increases should be imposed on existing G-62/B-62 customers, the Commission may wish to mitigate those increases by spreading out over three to five years the

movement to rates equivalent to those paid by G-32/B-32 customers.

11. I argue that the method used by the Company to determine the SOS Administrative Cost Factors is based on a faulty allocation, which assigns the cost of bad debts to the classes where they originated, rather than socializing these costs to reflect the fact that they are general business expenses and not “caused” by any particular class. I propose that all of these costs be allocated on SOS energy deliveries, which will result in an equal SOS Administrative Cost Factor for all customers.

II. Narragansett’s Class Cost of Service Study

Q. Please describe the attributes of a class cost of service study and explain what such a study is supposed to accomplish.

A. Average, embedded, historic class cost of service studies of the type performed by NEC witness Howard S. Gorman are performed in an attempt to determine the share of total costs that is incurred to provide service to each class of customers. Such studies are referred to as average, embedded, historic cost studies because they attempt to directly assign or allocate to each customer class, actual book plant and related costs, adjusted to test year levels as authorized by the Commission. They are also referred to as “fully allocated” costs because these studies require that 100 percent of the allowed total jurisdictional costs of service be allocated among the various classes. This is done by determining the average costs of the various components of service (the total cost of the component divided by the units of service for that component), and then by allocating these component costs to each of the classes, based on each class’ service units that have caused that cost. This is a fundamental aspect of an embedded cost of service study – that is, costs should be assigned or allocated to classes on the basis of the factors that caused each of those costs to be incurred.

The costs are first functionalized into broad categories, such as production costs, transmission costs and distribution costs. These costs may be further broken down by voltage delivery level and other sub-functions may be identified. Costs are then classified as to whether they are demand-related, energy related, customer related or related to some other factor, such as labor costs or revenue. Finally, the costs are allocated among the customer classes on the basis of the most appropriate measure of demand, energy or customers, in proportion to each class' share of the various allocation measures.

Q. How has the Company classified and allocated distribution plant?

A. The Company has classified all poles, conductors, conduits and devices above the service drops, with the exception of line transformers, as demand related and has allocated this plant and the related O&M expense on Class non-coincident peak demands (NCPs) at the appropriate voltage delivery level. The cost of Line transformers are classified as demand-related, but then are allocated on a vector that was developed in a special transformer cost study, which essentially allocates these costs on the number of customers. Service drops and meters have been classified as customer-related and are essentially allocated on the number of customers, adjusted to account for the differential costs of typical installations among the customer classes.

Q. Do you find the Company's classification and allocation of these distribution plant and related costs reasonable?

A. While I believe that distribution plant is installed to meet annual energy requirements as well as to meet local neighborhood coincident demands, I can accept the Company's treatment of all costs, except line transformers, upstream of the meter and service drop as classified as demand-related and allocated on the appropriate measure of class demands. I agree that the investment in service drops and meters are essentially driven by the number of customers, weighted to account for the difference in the costs of the installations for various types of customers. Thus these components of service are appropriately allocated among classes on the basis of a weighted customer vector. I take issue, on the other hand with the way in which the Company has allocated the $160.3 million of line transformers among the classes. Although classified as demand-related, the Company essentially allocates these costs on the basis of the number of customers. I also challenge the Company's direct assignment of $4.3 million of "Uncollectible Accounts - Delivery" to the classes where the defaults originated. Finally, I take issue with the way the Company has allocated Customer Information and Services expenses. While I accept the remainder of the Company's treatment of costs for purposes of this proceeding, that does not necessarily mean that I endorse each and every functionalization, classification and allocation decision made by Mr. Gorman.

Q. Mr. Gorman testifies that a minimum system study is often used to classify a portion of upstream distribution plant as customer related, but that he was informed that such studies are not routinely performed in Rhode Island. Do you believe a minimum system study should be used to classify some portion of upstream distribution plant as customer-related?

A. No. The general rationale for arguing that some portion of these upstream distribution plant costs are customer-related is that a portion of these costs are incurred simply to "connect" customers to the system without providing any actual electric capacity or energy. The minimum system method hypothetically reconstructs the distribution system with the smallest size poles, conductors and transformers possible that are not capable of delivering actual capacity and energy. The cost of that hypothetical system is deemed to be customer-related and the remaining actual cost of the distribution system is deemed to be related to meeting customer loads.

Q. What is wrong with the minimum system approach?

A. There are two fundamental reasons why this approach is incorrect. First, these costs are not, in any meaningful way, directly related to the number of customers. Second, the minimum system methodology cannot segregate out the costs of a system that does not have any load carrying capability.

Q. Please explain why these costs are not related to the number of customers.

A. The cost of upstream distribution plant is incurred in order to meet the coincident loads of the customers that it serves and their sustained energy demands throughout the year. The size and costs of the required plant are a function of the amount of diversity of customers' loads that must be served from this plant, as well as the expected future coincident loads that may have to be served from these facilities as growth occurs on the system. There is no direct relationship between the number of customers and the size or the cost of poles, conductors or transformers. That is clearly the case for poles and conductors, but it is also true in most cases for transformers. Many transformers serve more than one customer and there is not even a unique requirement to install a transformer for a given number of customers on many systems, including the Narragansett system. (See the response to Division Data Request 18-5.) The number, sizes (and therefore costs) of transformers will depend on the diversity of the loads of the customers in the locality, the mix of customers served from the system in the area, the density of the population in that area, and probably the general configuration of the distribution system in that locality. To hypothetically carve out some portion of that cost as customer-related is simply inappropriate.

Q. Please explain why the minimum system approach cannot segregate out the costs of a system that does not have any load carrying capability?

A. The minimum system method must hypothetically construct a new upstream system that has no load carrying capability, but rather is only constructed to "connect" the customer to the system. The problem is that even the smallest size poles, conductors and transformers that can actually be purchased in the real world have significant load carrying capability. As long as the so-called minimum system has load carrying capability, one cannot allocate the remaining costs (if classified as solely demand-related) on unadjusted measures of class demands. Those demands must first be adjusted by the amount of the demand that the so-called "minimum system" can actually meet.

Q. What do you recommend to the Commission regarding the use of minimum system studies to classify a portion of upstream distribution plant as customer-related?

A. I recommend that the Commission reject the use of a minimum system study to classify some portion of upstream distribution plant as customer-related, which appears to be consistent with past Rhode Island practice.

Q. How does Mr. Gorman allocate the $160.3 million of line transformer cost?

A. Mr. Gorman allocates these costs to customer classes using an "Xmr_Cost" allocator that he develops in a separate Transformer Cost study, which is included as pages 11 through 17 of Schedule NG-HSG-2.

Q. How is the Xmr_Cost allocator developed in Mr. Gorman's study?

A. Based upon my review of Mr. Gorman's study and the Company's responses to Division Data Request 2-11, Mr. Gorman has identified the number of customers in each rate class that are served by each of a number of "standard" transformers. He has priced those transformers at the replacement cost of the equipment and then has allocated the total replacement cost of each transformer type to the several customer classes on the basis of the share of total customers taking service from each type of transformer. He then sums the total cost for each customer class across all types of transformers and uses the share of that total cost for each customer class to construct "Xmr_Cost," with which he allocates the $160.3 million transformer investment among the classes.

Q. Do you find Mr. Gorman's methodology an appropriate basis for allocating transformer costs among the various customer classes?

A. No. Mr. Gorman's methodology essentially allocates line transformer costs on the number of customers, which is not a direct cause of the costs that are booked in this FERC Account No. 368. To begin, as the Company pointed out in response to Division Data Request 9-2, a portion of the costs booked to Account 368 are for distribution voltage regulators and capacitors. The Company points out in response to Division Data Request 9-1 that, "Although the voltage regulation is applied at the primary level, the intent of voltage regulation is to ensure voltage is maintained within appropriate tolerance at the point of customer connection." This expenditure is made not on the basis of the number of customers but is much more clearly related to the loads of the various customers that take service either at the primary or the secondary level. A more appropriate allocator for this component of costs in Account 368 is class NCPs at primary voltage.

Q. Is there another more serious problem associated with Mr. Gorman's allocation of these line transformer costs?

A. Yes. Mr. Gorman's allocation of these transformer costs is essentially on the basis of the number of customers in each class that use each of the "standard" transformers. This approach cannot lead to a proper allocation of these costs because it makes no allowance for the different sizes of customers in terms of their loads. It treats a residential customer on Rate A-16 with a 3 kW load the same as a G-32 customer with a minimum load of 200kW and a G-62 customer with a minimum load of 3,000 kW. Take, for example, the allocation of single phase overhead transformers with a capacity rating of 25 kVA, which appears at lines 15 through 22 of page 12 of Schedule NG-HSG-2. There are 30,076 of these transformers with an equipment replacement cost of approximately $24.5 million. (See line 4, page 17 of Schedule NG-HSG-2.) The combined residential classes (A-16 and A-60) are allocated 94 percent of these costs based on the number of customers. If account were taken of the relative size of the loads of these various classes, then the residential classes would be allocated far fewer costs. For example, simply weighting each of the customers served by this type of transformer by the average NCP per customer, would reduce the residential classes' share to approximately 78 percent. Even more egregious is the allocation of 3-phase overhead transformers with a capacity rating of 30 kVA, listed on lines 52 through 57 of page 13 of Schedule NG-HSG-2. There are 900 of these transformers with an equipment replacement cost of $1.8 million. The two residential classes are allocated 29 percent of these costs under Mr. Gorman's study. Weighting the number of customers by the average NCP per customer at primary results in a reduction of the residential share to about 5 percent. On the other hand, the G-02 class share rises from 14 percent to 46 percent and the G-32 class share rises from less than 1 percent to 32 percent by recognizing the size of loads that these transformers have to serve.

Q. Is there a straightforward and direct relationship between the number and cost of transformers and the number of customers?

A. No. According to the data provided in Mr. Gorman's Transformer Study, there are nearly 64,000 line transformers serving over 464,000 customers, for an average number of customers per transformer of 7.3. The number of customers per transformer must vary widely among the various rate classes. In response to Division Data Request 9-5, the Company states that large C&I customers on rates G-32, B-32, G-62 and B-62, who do not own their own transformers, "...are served directly from primary voltage facilities through a step-down transformer and service drop." In all likelihood each of these large customers is served by one or more large transformers. The number of small residential customers per transformer in densely populated areas, on the other hand, is likely to exceed the average of 7.3 customers per transformer by a considerable margin. In response to Division Data Request 18-5, the Company stated that there is no general rule regarding the number of customers that will be placed on a single transformer. The conditions that determine that are many and varied. In short, there is no direct relationship between the number of transformers and the number of customers, and so the costs in Account 368 should not be allocated in any way on class customer counts.

Q. How do you recommend that these line transformer costs and associated O&M expense be allocated among the customer classes?

A. I believe all of these costs should be classified as demand-related. Ordinarily I would select a demand vector at secondary to allocate these costs. But the Company's explanation of how some large C&I customers take service at primary through Company-owned line transformers requires that demands at primary be utilized. The only demand allocator available to allocate these costs are NCP demands at either primary or secondary. In my view, use of the primary NCPs will likely allocate excessive costs to the primary customers that use Company-owned transformers, whereas secondary NCPs would allocate none of these costs to these customers. Therefore I have chosen to allocate these transformer investments and the associated O&M expense on the average of the percentage NCP vectors at primary and secondary. The allocation vector sets the Propulsion class at a zero share since this class does not use Company-owned line transformation equipment. (See the response to Division 18-3.) The Company also allocated no line transformer costs to the Lighting class. When asked why, in Division Data Request 18-3, the Company responded that, “The effect of Lighting on the sizing of line transformers is very small.” However, in response to a follow-up data request (Division 21-4), the Company admitted that “customers in the Lighting Classes take service at secondary voltages and do rely on line transformers to transform energy to useable voltages.” In my view, the Company’s responses are an inadequate basis for exempting the Lighting class from its share of line transformation costs. It is my understanding that the Lighting class customers take service at secondary voltages and so benefit from the transformations undertaken by transformer equipment booked in Account 368. Thus, this class should be allocated its fair share of these costs based on its share of the average of primary and secondary NCP percentage vectors.

Q. You indicated earlier that you take issue with the way the Company has allocated “Uncollectibles Accounts - Delivery” among the customer classes. Please explain.

A. Mr. Gorman has allocated these uncollectible costs among the classes in proportion to the class origin of these uncollectibles. Essentially it amounts to a direct assignment. The bad debt that can be traced to the Residential class, for example, is assigned to the Residential class. Since most (80 percent) of the uncollectibles originate in the Residential class this means that those residential customers that have paid their bills in a timely manner are required to carry the burden of all the residential customers that failed to pay their bills. This strikes me as patently unfair to the residential customers that have paid in a timely fashion.

Q. Why is it unfair to allocate to each class the uncollectibles it is responsible for?

A. Bad debts are essentially a general cost of doing business. It is no different than general administrative costs. Nor is it any different than the loss incurred when providing a discounted rate to C&I customers for economic development purposes. The primary rule of cost allocation in an embedded class cost of service study is that costs should be allocated in the way that those costs have been caused. Mr. Smith, a residential customer, is no more the <u>cause</u> of the bad debt of Mr. Jones (another residential customer) than is the XYZ Smelting Company, which might be served under Rate G-32. Nor is the XYZ Smelting Company any more the <u>cause</u> of the bad debt associated with the failure of the ABC Cleaning Company (another G-32 customer) to pay its bills than is Mr. Smith. It is much more equitable, in my view, to recognize that bad debts are a general cost of doing business, and therefore to allocate these costs on a general allocator such as class revenue responsibility. This alternative is recognized in the 1992 NARUC Cost Allocation Manual (p. 103). In keeping with this more equitable logic, I have allocated these costs on the Company's "Total Del Rev" allocator, found at line 20, page 2 of Schedule NG-HSG-2.

Q. How has the Company allocated Customer Service and Information Expense?

A. These expenses, booked in Accounts 907 through 913, amounting to $5.4 million, are allocated to customer classes on the basis of two allocators that are developed in separate analyses provided by Mr. Gorman on pages 25 and 26 of Schedule NG-HSG-2. These two allocators are titled "Acct 908" and "Acct 910."

Q. Please describe the development of these two allocators.

A. It appears that Mr. Gorman broke down the costs in these two accounts into several "activity areas." In the case of "Acct 908," for example, the largest activities, in terms of dollars expended, include "Commercial and Industrial Custom," "Community Relations," and "IS Support Customer Assistance." He then allocates each of these dollar activity totals among the classes on the basis of other allocators. For example, "Commercial and Industrial Custom" costs are allocated on the number of C&I customers. "Retail Access Services" costs are allocated on the basis of megawatt hours at meter. However, the lion's share of these activity costs are allocated on the total number of customers. He then sums the allocated costs for the several activities for each class and calculates the share of each class total as a percentage of the total for all classes to arrive at the "Acct 908" allocator. The same process is followed in constructing the "Acct 910" allocator. The major cost components in this account are the development of information systems for customer service and information systems support for customer service – about 55 percent of the total – which are allocated on the number of bills; and the $1.0 million cost of the proposed "Economic Development Program," which is allocated on commercial and industrial energy use.

Q. Do you find Mr. Gorman's development of the "Acct 908" and "Acct 910" appropriate for the allocation of Customer Service and Information Expense?

A. No. A major portion of the costs are allocated on the total number of customers or the total number of bills in developing these allocators, and there is no evidence that these costs are directly related to the number of customers or the number of bills. Further, the $1.0 million cost of the "Economic Development Program" constitutes a significant portion of the total costs in the "Acct 910" allocator and these costs are improperly allocated only to commercial and industrial customers.

Q. Why is it improper to allocate the total costs of the proposed "Economic Development Program" to only C&I classes?

A. If the Commission decides to approve these expenditures it will do so on the basis of a policy determination. That is, presumably the Commission will have decided that the proposed program will confer benefits on the community that warrant the costs. The benefits are likely to take the form of increased general economic activity and the creation of jobs, which will redound to the benefit of the community as a whole. There is no logic in requiring that these costs only be paid by C&I customers, just as there is no logic in requiring that subsidies to low income residential customers be paid only by other residential customers. These costs should be socialized across the board, requiring that all customer classes, residential as well as commercial and industrial, pay a fair proportion of these costs.

Q. Why is it inappropriate to allocate many of these Customer Service and Information costs on either the number of customers or the number of bills?

A. The general description of Account 908 (Customer Assistance Expenses) as provided in 18 CFR Ch. I (4-1-04 Edition) is : "This account shall include the cost of labor, materials used and expenses incurred in providing instructions or assistance to customers, *the object of which is to encourage safe, efficient and economical use of the utility's service* (emphasis added)." This theme extends to the description of Account 910, which is to include miscellaneous expenses "not includable in other customer information expense accounts." The "utility service" in question is the delivery of electric energy, and so there is a presumption that the expenses booked in these accounts are more directly related to class energy use and not the number of customers or bills. Moreover, a close inspection of the activities to be included in these accounts does not indicate any close and direct relationship between the number of customers and the total costs booked in these accounts. For example, in Account 908 are to be recorded the costs of the following:

1. Supervision;
2. Processing inquiries on proper use, replacement and information on electric equipment;

3. Advice on efficient and safe use of electric equipment;
4. Demonstrations, exhibits, lectures, etc. on safe, economical use or conservation;
5. Engineering and technical advice on safe, efficient and economical use;
6. Supplies pertaining to demonstrations or other programs;
7. Loss in value on equipment used for customer assistance programs; and
8. Incidental expenses.

None of these cost elements is in any clear way directly caused by the number of customers rather than the amount of service that is provided to the various classes, which is the general purpose of these expenses as stated in the FERC Uniform System of Accounts (Code of Federal Regulations, Title 18). Account 909 (informational and instructional advertising expenses) includes costs relating to preparing materials for newspapers, periodicals, etc., preparing informational booklets, preparing window and other displays, and the use of newspapers or other media for informational purposes. None of these activities bears any direct relationship to the number of customers. The same can be said of Account 910 which is merely an account for recording expenses that don't neatly fit into Accounts 908 or 909. Moreover, the benefits of these expenditures to customers will depend on their size in terms of usage, and allocating on a simple customer or billing count does not take into account the differing amount of usage among customers.

Q. How does the NARUC Cost Allocation Manual suggest these costs be classified?

A. The NARUC Manual states that, "...except for conservation and load management, these costs are classified as customer-related." However, this pronouncement seems to be in direct contradiction with how the Manual says Sales Expenses (Accounts 911-917) should be classified. In that case, the Manual states that "These accounts include the costs of exhibitions, displays, and advertising *designed to promote utility service* (emphasis added).” (p.103) It goes on to say these costs could be classified as customer-related, but further states that “Allocation of these costs, however, should be based upon some general allocation scheme, not numbers of customers,” because they do not vary directly with the number of customers. There is little difference in the types of costs that are incurred in these two groups of accounts. Whereas Sales Expenses are intended to “promote utility service,” Customer Service and Informational Expenses are intended to “encourage safe, efficient economical use of the utility’s service.” This is an instance where I believe the stated objective of the NARUC Cost Allocation Manual should be taken to heart. That is, that the Manual should be “non-judgmental” and not advocate any one particular method. (See Preface, p. *ii*.)

Q. How do you recommend these customer service and informational expenses be allocated among the customer classes?

A. I recommend that the sum of these costs (approximately $5.4 million) be allocated among the various customer classes on the basis of energy use at the meter. That strikes me as being consistent with the purpose for which these expenses have been made – the encouragement of safe, efficient and economical use of the utility’s service.

Q. Have you prepared a modified version of the NEC cost of service study that makes the three changes you recommend?

A. Yes. The Division requested the Company to rerun its cost of service study with the changes I recommend in the allocation of line transformers and Uncollectibles-Delivery costs. The Company reran its study according to Division request 18-01. The Company also provided its cost of service model in Excel format with all formulas intact, which allowed us to rerun the model with the changes I believe are appropriate. We first reran the model to replicate the rerun that the Company conducted for the Division to ensure we understood how to operate the model properly. That test was completed satisfactorily and so we reran the model to account for the three changes I believe are necessary. The summary results of that modified study are presented in Schedule DES-1.

Q. Do class cost responsibilities change significantly under your revision of the Company's study?

A. Yes. This can be seen most clearly by comparing the class rates of return at current rates that result from the Company's allocation of costs and my revised study. This comparison is provided in Schedule DES-2. This schedule shows, under each study, the rate of return realized for each class and also the ROR Index, which simply expresses each class' rate of return as a percentage of the jurisdictional rate of return. Of greatest significance is the increase in the Residential rate of return from 1.29 percent, or only 57.8 percent of the jurisdictional average return under the Company's study, to 2.46 percent, or 110.3 percent of the jurisdictional average under my study. In short, correcting for the three errors I have identified in the Company's study raises the Residential return to above the system average. There is also a significant increase in the return shown for the Small C&I class. The remaining classes all experience a reduction in their calculated rates of return under my study. This makes sense, since these other classes are now appropriately allocated larger shares of line transformer costs, delivery service related uncollectible costs, and customer information and assistance costs.

Q. Do you recommend that the Commission adopt your proposed class cost of service study as one of the bases for determining the spread of the allowed jurisdictional distribution revenue increase?

A. Yes.

III. Class Revenue Responsibilities

Q. Dr. Swan, would you please describe and comment on Mr. Gorman's proposed spread among the classes of the Company's requested total revenue requirement?

A. Mr. Gorman has proposed a set of class revenue responsibilities that he suggests are intended to provide some moderation in the resulting increases so as to avoid rate shock for any particular class of customers. To accomplish this, Mr. Gorman sets the distribution revenue requirement at full cost of service for all but three customer classes. He caps the Lighting and Propulsion classes at twice the jurisdictional percentage increase and has allocated all of the resulting revenue shortfall to the C&I Large Demand class. The result is that the Lighting and Propulsion classes receive an increase of 58.7 percent, the C&I Large Demand class receives an increase of 21.0 percent, and all the other classes receive increases ranging from 22 percent (Small C&I) to 32 percent (Residential), which place them at their full cost of service.

Q. Do you find that Mr. Gorman's proposed revenue spread, at the Company's proposed total revenue requirement, sufficiently recognizes concerns regarding rate continuity or gradualism?

A. No. The requested increase in distribution rates is only one of the revenue changes that would be occurring under the Company's proposal and no regard is given to the other changes in terms of the overall effect on rate continuity. Mr. Gorman does acknowledge the fact that Standard Offer Service (SOS) administrative costs are being shifted from distribution rates to SOS rates by calculating the resulting class percentage increases when including these additional revenues. However, he merely makes the calculation but does not address whether the total class revenue changes should be altered to account for these additional revenues. Moreover, and most importantly, he totally ignores the fact that the Company proposes a major shift in the recovery of transmission revenues, which has the effect of increasing residential revenue recovery by over $4.0 million while reducing the revenues of the Large C&I Demand class by over $4.0 million. To properly assess the reasonableness of the proposed class revenue spread, and whether sufficient attention has been paid to rate continuity concerns, the total revenue change for each class needs to be considered.

Q. What class total revenue increases will result from Mr. Gorman's proposed revenue spread when account is taken of the effect of the SOS Administrative costs and the shift in transmission revenue recovery?

A. This is shown in Schedule DES-3. This schedule shows for the jurisdiction and for each rate class Mr. Gorman's proposed distribution revenue, revenue from the Commodity-related Costs Tracker, and the Transmission Revenue change for each class. The sum of these three changes provides the total revenues on line 4 that will be collected from each class. Line 5 shows the total revenue at current rates for each class, and lines 6 and 7 show the net dollar increase for each class and the percentage increase. Inspection of line 7 shows that there is significantly greater variation among the total class increases than Mr. Gorman's Schedule NG-HSG-4 would suggest. Whereas the Large C&I Demand class would receive only an 11.5 percent overall increase, the Residential class would receive an overall increase of 42.2 percent, over 25 percent higher than the overall jurisdictional increase of 33.7 percent and 3.6 times higher than the increase proposed for the C&I Large Demand class. I do not believe the Company's proposed spread of the total revenues pays adequate attention to rate continuity concerns.

Q. Dr. Swan, have you developed a proposed spread of the Company's proposed jurisdictional revenue increase based on your cost of service study?

A. Yes. I should emphasize that my provision of a recommended spread of the Company's proposed total revenue increase is for ease of comparison only, and it should not be inferred that I endorse the Company's proposed total revenue requirement. Mr. Gorman has proposed to set all but three classes at their full cost of service rates based on the Company's cost of service study. He has capped two classes – Lighting and Propulsion – at twice the jurisdictional average percentage increase, and has allocated all of the resulting revenue shortfall (approximately $1.3 million) to the C&I Large Demand class. I find reasonable Mr. Gorman's approach of capping those classes that would otherwise receive very large percentage increases and spreading the shortfall to other classes. However, I believe that the shortfall should be allocated to all other classes whose increases are not capped.

Q. Have you provided a schedule that shows your proposed revenue spread at the Company's total proposed jurisdictional revenues?

A. Yes. That is provided in Schedule DES-4. The first four lines on page 1 of this schedule provide the distribution revenues at equal rates of return for each class, the distribution revenues at current rates, the distribution revenue increase to move each class to full cost of service, and the resulting percentage increase. In lines 5 through 8, I provide a first step toward a proposed revenue spread based on capping the Lighting and Propulsion classes at twice the jurisdictional percentage increase, or 58.8 percent. This results in a revenue shortfall of approximately $2.05 million, which I have allocated to all the other classes, except Lighting and Propulsion, on the basis of their Revenues at Equal Rates of Return shown in line 1. This results in the Residential class receiving a percentage increase approaching the jurisdictional average. The Small C&I class would remain well below the average increase (13.4 percent); and the General C&I class would experience a much larger increase of 38.0 percent.

Q. Dr. Swan, do you recommend the Commission adopt the spread of the Company proposed increase that appears on line 7 of page 1 of Schedule DES-4?

A. No. In determining the appropriate spread of the proposed increase, account also needs to be taken of the revenue impact of the proper allocation of the subsidy proposed by the Company for A-60 customers and the Company's proposed changes to the recovery of transmission costs. Page 2 of Schedule DES-4 addresses both of these factors. On line 1 is reproduced the Step 1 increase from line 7 of page 1 which accounts for the cap on the Lighting and Propulsion classes. Lines 2 through 5 adjust these Step 1 changes to account for the proper allocation of the A-60 subsidy proposed by the Company and endorsed by the Division.

Q. Please explain this adjustment

A. The Company is proposing to extend the existing subsidy to Low Income Rate A-60 customers, so that a 500 kWh per month A-60 customer would pay 50 percent of the amount the A-16 customer would pay. The Division supports the extension of this subsidy to Rate A-60. In response to Division 9-15, the Company indicated that the amount of the A-60 subsidy at Company proposed rates is "approximately $4,795,000." It also confirmed that the entire amount of this subsidy is being paid by Rate A-16 customers under the Company's revenue spread proposal.

Q. Do you believe it is appropriate that A-16 customers pay for the entire A-60 subsidy?

A. No. Extending a subsidy to any class for social or economic reasons is a policy decision on the part of the Commission and the costs of such policy actions should be shared proportionately by all of the utility's customers. There is no logic in making other residential customers pay for the subsidy to low income residential customers just because they are residential customers. Presumably, the regulatory authority has determined that such subsidies are in the public interest and, as such, confer benefits on all citizens, private or corporate. In a similar fashion, the costs of subsidies or rate discounts extended to commercial or industrial customers for purposes of load retention or economic development should not be imposed only on other commercial and industrial customers just because they are in the same rate class as those receiving the subsidies. The decision to extend such subsidies is made by the regulatory authority because it believes such subsidies are beneficial to the community at large, including all ratepayers, and so all ratepayers should share in recovering the costs of those subsidies. It is for this reason that I argued earlier in my testimony that the cost of the Company's Economic Development Program should be allocated to all classes on the basis of energy use at meter.

Q. How have the costs of these types of subsidy programs been allocated by Narragansett and National Grid in the past?

A. In response to Division 15-3, the Company states that the costs of National Grid energy discount programs in both upstate New York and in the Metro New York region resulted in revenue shortfalls that were allocated to all other retail customers in proportion to "each customer class' annual base rate transmission and distribution revenue..." In response to Division 9-15, the Company states that, "...in other jurisdictions in which National Grid operates, the low income discount is recovered from all retail delivery service customers..." It goes on to state that, "Today, the low income discount is recovered from all of the Company's rate classes, and the Company would not object to recovering the proposed Rate A-60 discount from all rate classes on a reasonable basis."

Q. How do you recommend that the $4.8 million A-60 subsidy be recovered?

A. I recommend that the Commission direct the Company to recover this revenue shortfall from all other classes, except from the Lighting and Propulsion classes, in proportion to the final revenue responsibility prior to this shortfall allocation. The residential class' share should be determined exclusive of the $4.8 million A-60 credit. The Lighting and Propulsion classes should be exempt because they are already capped at or are very near to the "twice-the-average" percentage increase. Line 2 on page 2 of Schedule DES-4 shows the Step 1 revenues less the $4.795 million of the A-60 subsidy. That subsidy is reallocated among the classes, except Lighting and Propulsion, on line 3 in proportion to the Step 1 revenues less the A-60 subsidy in line 2. Line 4 shows the resulting Step 2 revenues and line 5 shows the percentage changes compared to revenues at current rates on line 2 of page 1. The major changes from the adjustment is a reduction in the percentage increase for residential customers and modest increases in the percentage increases for the other affected classes.

Q. What adjustment do you propose to account for the significant shift in transmission revenues proposed by the Company?

A. As I mentioned earlier, the Company proposes to shift approximately $4.0 million in transmission revenue recovery from the C&I Large Demand class to the Residential class, which results in an unusually large relative total increase for Residential customers. I propose to mitigate the impact of this shift by 50 percent.

Q. How do you propose to implement this transmission revenue shift mitigation?

A. The Company proposes to annually allocate the costs to be recovered from the transmission adjustment factor among the classes based on each rate class' contribution to the Company's monthly peaks. That process will have the effect of shifting approximately $4 million of revenue responsibility from the C&I Large Demand class to the Residential class. To mitigate this shift impact in this case without further complicating the annual calculation of the transmission adjustment factors, I propose to reduce or increase each class' distribution revenue requirement by half of the resulting increase or decrease in transmission revenues that will result from the Company's proposed reallocation of these costs. This is accomplished in lines 6 through 9 on page 2 of Schedule DES-4. The amount of the transmission revenue changes are shown on line 6, and line 7 shows the resulting percentage increases when this revenue shift is accounted for. Line 8 shows the Distribution revenues for each class after subtracting half of the transmission revenue change for each class. As shown on line 9, this adjustment results in a reduction of the Residential Distribution Revenue increase to 25.1 percent, and an increase in the C&I Large Demand Distribution revenue change to 34.9 percent.

Q. What are the final class changes when the transmission revenue shifts and SOS Administrative charges are accounted for?

A. These final changes are shown on page 3 of Schedule DES-4. Lines 1 and 2 show that the resulting changes in total revenues, including the impact of the transmission shift, are much more uniform. The Residential class would experience a total revenue change of 28.6 percent, while the C&I Large Demand class would receive a total increase of 23.6 percent when its $4.4 million reduction in transmission revenues is accounted for. Lines 3 through 5 show the final changes when the SOS Administrative Charges are included. Line 3 shows the allocation among the classes of the $9.752 million of the affected costs calculated by the Company. I have allocated these costs among the classes based on an estimate of class energy delivered under commodity service, which is provided on page 4 of Schedule DES-4. This assumes an equal Standard Offer Service Administrative Cost Factor per kWh for all classes, which I shall recommend later in my testimony. Lines 4 and 5 provide the total revenue for each class, including the SOS Administrative charges, and the resulting total percentage increases compared to revenues at current rates. The results are a total increase for the Residential class just below the average increase of 33.7 percent. The Small C&I class would receive the smallest increase of 19.4 percent. The General C&I class would receive an increase of 45.2 percent, while C&I Large Demand class would get an overall increase of 30.5 percent, less than the system average.

Q. Dr. Swan, what is your recommendation to the Commission regarding the proper spread of the allowed distribution revenue requirement?

A. I recommend the Commission direct the distribution revenue increase be spread among the classes in accord with the results shown on lines 8 and 9 of page 2 of Schedule DES-4, in the event the Commission were to adopt the total revenue requirement proposed by the Company.

Q. Dr. Swan, can you provide any guidance to the Commission regarding the spread of an allowed jurisdictional revenue increase that is more in line with the Division's recommendation?

A. Yes. At the time of this writing the Division's recommendation regarding the total allowed jurisdictional revenue increase was not finalized for use in my testimony. However, I have developed an illustrative recommended spread of an allowed jurisdictional total distribution revenue increase that is likely closer to the Division's revenue requirement recommendation in direct testimony. This is provided in Schedule DES-5.

Q. Please describe your development of Schedule DES-5.

A. A jurisdictional distribution revenue increase of $35 million would result in a total distribution revenue requirement of $258.242 million, which is 89.4273 percent of what the Company is requesting. I have made the simplifying assumption that this would result in revenues at equal rates of return for each class, or what I refer to as "Adjusted Full Cost Revenues," of 89.4273 percent of revenues at equal rates of return at the Company's requested total cost of service of $288.773 million. This results in an approximation of the full cost revenues for each class, because the adjustments to the various line items in the cost of service study will not all be by the same proportion, which is what my calculation assumes. Nevertheless, I believe it provides a reasonable approximation because so much of the allocation of the costs of service is driven by one allocator -- class NCPs. These "Adjusted Full Cost Revenues" are provided on line 3 of page 1 of Schedule DES-5.

Q. How do you use these "Adjusted Full Cost Revenues" in developing an illustrative spread of the assumed $35 million increase?

A. The process is exactly the same as that presented in Schedule DES-4. On lines 4 and 5 on page 1 of Schedule DES-5 are presented the distribution revenue deficiencies and the resulting percentage increases for each class based on each class' full cost of service. Then, on lines 6 through 9 on page 1, I constrain the Lighting and Propulsion classes to an increase in distribution revenues equal to twice the jurisdictional average of 15.7 percent. The resulting revenue shortfall of $2.497 million is then allocated among all the remaining classes on the basis of each class' share of the "Adjusted Full Cost Revenue." On page 2 of Schedule DES-5, I again reallocate the estimated A-60 subsidy among all the classes based on the Constrained Step 1 Revenues less the A-60 subsidy. This adjustment is done in lines 2 through 5. I should note that I have also reduced the amount of the A-60 subsidy to the same 89.4273 percent of the Company's estimated A-60 subsidy as I used in determining the "Adjusted Full Cost Revenue." I then mitigate the impact of the shift in transmission revenues by reducing the Step 2 distribution revenues by half of the proposed transmission revenue changes. The resulting illustrative proposed distribution revenue spread appears on line 8 on page 2 and the resulting percentage changes are shown on line 9.

It is important to note that the Residential class would receive an increase in distribution revenues of 12 percent, compared to 14.2 percent based on full cost of service. The C&I Large Demand class would receive an increase of 22.3 percent compared to 13.5 percent based on full cost of service.

Q. How do these overall increases look when account is taken of the shift in transmission revenue responsibility and the SOS Administrative Charges?

A. These final overall revenue changes are shown on page 3 of Schedule DES-5. Lines 1 and 2 add back in the transmission revenue shifts, which result in the Residential class receiving an increase of 15.5 percent, and the C&I Large Demand class receiving an increase of 11.1 percent compared to the combined jurisdictional increase of 15.7 percent. When the Company proposed SOS Administrative Charges are included, the total jurisdictional increase is 20.5 percent. Residential customers would see an average overall increase of 19.4 percent, while the C&I Large Demand class would get an increase of 18 percent. The lowest overall increase would be experienced by the Small C&I class at 7.45 percent and, other than the two constrained classes, the General C&I class would receive the largest increase of 30.7 percent.

Q. To recap, what would be your recommended illustrative class revenue spread at a total jurisdictional increase of $35 million?

A. I would recommend the distribution revenue spread shown on line 8 of page 2 of Schedule DES-5. I believe this spread of an allowed $35 million distribution revenue increase would be reasonable given the required changes to the Company’s class cost of service study, a more reasonable sharing of the revenue shortfall that results from capping the Lighting and Propulsion classes, a more reasonable spread of the A-60 subsidy, and a mitigation of the impacts of the proposed shift in transmission revenue responsibility primarily from the C&I Large Demand class to the Residential class.

IV. Rate Design

Customer Charges

Q. What comments do you have regarding the general nature of the Company's proposed rate design?

A. The Company has undertaken to change the structure of its retail rates by increasing the recovery of revenue from customer and demand charges versus energy charges. This can be seen by comparing the percentage changes proposed for customer, demand and energy charges for each of the customer classes except Lighting and Propulsion that are provided in Schedule DES-6. The pattern that emerges from this schedule is that the largest percentage changes have been proposed for customer charges except for Rate G-02 and G-62, which has been combined with Rate G-32. Most important, the residential customer charge is proposed to double and the C-06 customer charge is proposed to increase by 67 percent. Further, in those rate schedules with demand charges, all of the demand charges are proposed to increase by significantly greater percentage amounts than all of the energy charges. Indeed, this relative emphasis can be seen in the process by which rates have been developed by Mr. Gorman. In just about every case, Mr. Gorman first established the desired customer charge, then the desired demand charge, and then calculated the energy charges as the residual rate required to recover the target class revenues.

Q. Why do utilities try to shift revenue recovery from energy to demand and customer charges?

A. The usual reason for shifting revenue recovery from energy to demand and customer charges is revenue stability which reduces the utility's risk. This simply reflects the fact that the revenue recovered from up-front charges that are unrelated to energy usage (customer and demand charges) will be less subject to the vagaries of economic or weather cycles. Mr. Gorman has summarized this particular rate design objective as follows: "To produce rates for customers and revenues for the Company that are reasonably stable and predictable while reflecting the nature of the costs they are designed to recover..."

Q. Is there an aspect of this proposed shift to up-front charges that is of particular concern to you regarding the rate impact on certain customer subgroups?

A. Yes. I am particularly troubled by Mr. Gorman's proposed increase in the customer charge for A-16 customers of 100 percent and of 67 percent for C-06 customers. These large increases in customer charges are out of line with the overall proposed increases that are in the 25 to 30 percent range, and they will have adverse impacts on the smallest of the customers in these two rate classes, who probably can least afford these increases during these troubled economic times.

Q. Do you have a proposal for the Commission to limit the amount of the increases for the customer charges in these two rates?

A. Yes. In the case of the A-16 Rate, I recommend that the customer charge be increased by no more than $1.00 to $3.75, which amounts to an increase of 36 percent. That is much more in line with the overall percentage increases that are being proposed by the Company. At most, I would urge the Commission to limit the increase in the A-16 customer charge to $1.25 (up to $4.00), which would amount to an increase of over 45 percent. Similarly, I recommend that the increase in the customer charge in the C-06 rate be limited to $2.00, which would amount to an increase of 33 percent. I strongly believe that limiting the customer charge increases in these two rates is appropriate on the basis of rate continuity or gradualism.

<u>The Company Proposed C&I Large Demand Class</u>

Q. Please describe your understanding of the Company's proposed C&I Large Demand class.

A. Currently larger (200 kW or greater) C&I customers take service under four different rate schedules. Customers with loads between 200 kW and 3,000 kW take service under Rate Schedule G-32. Customers of that size that meet some or all of their loads from their own generation take backup service under Rate Schedule B-32. C&I customers with loads of 3,000 kW or higher take service under Rate Schedule G-62, and backup service under Rate Schedule B-62. The Company is proposing to terminate Rate Schedules G-62 and B-62 and to shift all customers with loads of 3,000 kW or higher to Rate Schedules G-32 and B-32. The reason given for this change is that, "These classes have similar usage profiles, but somewhat different rate structures." (Gorman Direct Testimony, p. 20, lines 5-6.)

Q. What increase in distribution revenues has the Company proposed for the newly combined C&I Large Demand class?

A. At its proposed total jurisdictional revenue request, the Company is proposing an increase in delivery service revenues for the C&I Large Demand class of 21 percent, which is significantly below the jurisdictional average increase of 29.4 percent.

Q. Are the G-32/B-32 and G-62/B-62 groups of customers paying their full costs under current rates?

A. The Company's cost of service study shows that the G-32/B-32 class is paying approximately 445 percent of the average rate of return, while the G-62/B-62 class is yielding a negative rate of return of approximately -383 percent of the average. My revised cost study shows similar relative results – the G-32/B-32 class yields 315 percent of the average rate of return, and the G-62/B-62 class yields a negative return of approximately -460 percent of the jurisdictional average.

Q. What are the relative increases for current G-32/B-32 customers and current G-62/B-62 customers under the Company's proposed rates?

A. The Company provided billing comparisons for current G-32 and G-62 customers in Schedule NG-HSG-9, pages 9-16. It also provided billing comparisons for current B-32 and B-62 customers in response to Division Data Request 13-7. Page 1 of Schedule DES-7 shows the percentage delivery service revenue increases for current G-32 and B-32 customers at various sizes in terms of billing demand and various monthly hours of use. Page 2 of this same schedule shows the same percentage bill increases for current G-62 and B-62 customers. Inspection of the tables in Schedule DES-7 shows that the combined rate proposed by the Company will lead to much higher increases for G-62/B-62 customers than for G-32/B-32 customers. Indeed, current B-32 customers would receive reductions in the delivery service portion of their bills at every demand level and at every hours use level. Generally, the reductions increase as the customer's load factor increases. Current G-32 customers would receive modest increases (but well below the 21 percent increase for the class) at lower demand levels and at lower hours of use, but negative bill changes at higher demand levels and higher hours of use.

Q. How does this compare to the increases for current G-62 and B-62 customers?

A. Page 2 of Schedule DES-7 shows that while Current G-62 customers at lower load levels (below 7,500 kW) will receive reduced delivery service charges, the changes turn positive at higher load levels and increase with the hours use per month. For the very largest current G-62 customers, the delivery service charges will increase from 14 to 18 percent. The largest increases occur for the current B-62 customers. Most of these customers would receive increases in delivery charges between approximately 15 and 30 percent.

Q. Are these much higher increases for G-62 and B-62 customers appropriate?

A. There is certainly a basis in both the Company's and the Division's cost of service study for much higher increases for current G-62/B-62 customers as compared to current G-32/B-32 customers since, as mentioned earlier, current G-62/B-62 customers are yielding negative returns at current rates, whereas G-32/B-32 customers are providing a rate of return on rate base several times the jurisdictional average under current rates. On the other hand, these G-62/B-62 customers are the Company's largest C&I customers and likely some of the State's largest employers. To the extent that significant rate increases may adversely affect these customers' abilities to maintain output and employment, it may be in the best interest of the State to moderate the movement toward cost-based rates for these customers.

Q. How might the Commission moderate the increases for these largest C&I customers but still adhere to its commitment to move toward cost-based rates?

A. One way the Commission might achieve this is to phase in the movement to rates equivalent to those paid by G-32/B-32 customers. Specifically, the Commission might phase in the move toward equal rates over three to five years, which should be enough time for the economy to work itself out of the current recession. To do that, it would probably be most convenient to retain the G-62/B-62 distinction in order to treat these largest customers as their own customer class. The two groups of C&I customers could then be folded together at the end of the transition period into the C&I Large Demand class that the Company has proposed.

Q. Would this phase-in result in a revenue shortfall and, if so, how should that shortfall be allocated among the customer classes?

A. The phase-in would result in a revenue shortfall for the Company during the phase-in period. Since there are only two current B-62 customers and approximately eleven G-62 customers, I doubt the magnitude of these shortfalls would be particularly large. In any event, I would recommend that the amount of the shortfall be allocated among all the other customer classes, including the G-32/B-32 class but excepting the Lighting and Propulsion classes which are already capped. I would allocate that shortfall in proportion to each class' distribution revenue requirement, without the G-62/B-62 phase-in subsidy, determined at the close of this case.

Standard Offer Service Administrative Costs

Q. The Company has proposed to recover the portion of uncollectibles associated with commodity purchases on a reconciling basis through the Standard Offer Service rates. How should this portion of uncollectibles costs be allocated among the classes?

A. Division witness Mr. Bruce Oliver is addressing the Company's proposal to split off the recovery of the commodity-related uncollectibles costs and other administrative costs. Regardless whether those costs are recovered through Standard Offer rates or as part of the Delivery Services charges, those uncollectibles costs should be allocated in a similar manner to the delivery portion of uncollectibles expense.

Q. How has the Company proposed to recover these costs?

A. Mr. O'Brien has developed Standard Offer Service Administrative Cost Factors in his Schedule NG-RLO-6 for the two proposed groups of customers – the Small Customer Group, consisting of the residential, small commercial and lighting classes; and the Large Customer Group, consisting of Rate Classes G-02, B-32, G-32, B-62, G-62 and Propulsion. These differential cost factors would be added to the cost per kWh of SOS power, which is currently $0.092/kWh.

Q. What do these SOS cost factors consist of?

A. Most (81%) of these costs consist of "Bad Debt Expense." The remaining 19 percent is made up of various administrative costs incurred to procure SOS power and to administer the program.

Q. How does Mr. O'Brien allocate these costs to the two groups?

A. Bad Debt Expense is essentially allocated to the classes where the bad debt originates. That is, $6.6 million of the bad debt originates among the Small Customer Group rate classes, and so that amount is assigned to the Small Customer Group. The remainder of the costs, with the exception of Cash Working Capital, is divided evenly between the two groups. Cash Working Capital requirements are allocated among the classes on the basis of Commodity Revenue taken from the Company's 2008 FERC Form 1 report.

Q. Do you agree with Mr. O'Brien's allocation of Bad Debt Expense?

A. No. As I explained earlier in connection with Distribution Uncollectibles Expense, these expenses are essentially a cost of doing business. The bad debt associated with one residential customer is not "caused" by the other residential customers who do pay their bills on time, no more than the failure of a large commercial customer to pay its bills is "caused" by the other large commercial customers who do pay their bills on time. As a general cost of doing business, these expenses should be socialized with a general allocation factor. This could be either total commodity revenue or SOS related kWh deliveries. I proposed to use SOS related kWh deliveries to allocate these costs.

Q. Have you developed a Schedule that shows how the Standard Offer Service Administrative Cost Factors would change if the Bad Debt Expense component is allocated between the two groups on the basis of SOS energy deliveries?

A. Yes. This adjustment is provided on page 1 of Schedule DES-8. With Bad Debt Expense allocated on SOS energy deliveries, but all other cost components allocated in the same way the Company has allocated them, the Small Customer Group Cost Factor would fall from the Company's $0.00215 to $0.00155, and the Large Customer Group Cost Factor would rise from the Company's $0.00078 to $0.00160.

Q. Can you explain why the cost factor is higher for the Large Customer Group than for the Small Customer Group?

A. The relationship is not intuitively obvious. I would note, however, that it makes little sense to allocate the other administrative costs (except Cash Working Capital) equally between the two groups. Doing so will increase the cost per kWh for the Large Customer Group because it is responsible for a smaller share of SOS delivered energy. It seems to me that these administrative costs are incurred to facilitate the purchase of SOS energy, and so these costs should be more appropriately allocated on SOS delivered energy, just as the Bad Debt Expense should be. On page 2 of Schedule DES-8, I provide the calculation of the adjusted SOS Administrative cost factors when allocating all the costs, except Cash Working Capital, on SOS delivered energy. Cash Working Capital remains allocated on Commodity Revenue following the Company's approach. With that change the differential between the Small Customer Group and the Large Customer Group falls. The kWh factors are $0.00155 for small customers and $0.00159 for large customers.

Q. Do Cash Working Capital requirements have to be allocated on commodity revenue rather than on SOS energy deliveries?

A. No. I think allocating that component of costs on SOS energy deliveries makes as much sense as allocating it on commodity revenue. When that is done, both groups would pay the same SOS Administrative Cost Factor – $0.00157/kWh. In fact, I recommend that the Commission adopt a uniform SOS Administrative Cost Factor for all customer groups.

Q. Will your proposal for a uniform SOS Administrative Cost Factor be affected by the revised customer groupings that are being considered in Docket No. 4041?

A. No. The SOS Adjustment Cost Factor would be applied to the SOS charges applicable to any revised customer groups. My recommendation, if adopted, would apply a uniform SOS Adjustment Cost Factor to all customers, and so will be unaffected by any change in customer groupings that may emerge in Docket No. 4041.

Q. Does this complete your direct testimony?

A. Yes.

DALE E. SWAN

Dr. Swan is a senior economist and principal at Exeter Associates, Inc. His areas of expertise include energy supply planning, electric industry restructuring, utility cost allocation and rate structure design, utility contract negotiation, antitrust policy, and public utility regulation.

Dr. Swan has presented expert testimony in utility rate cases before the Federal Energy Regulatory Commission and before numerous state regulatory commissions. He has testified on marginal and embedded costing, rate structure design, long-term demand forecasting, short-term sales forecasts, the treatment of off-system sales, electric industry restructuring, and antitrust considerations. He has directed major projects for the U.S. Department of Energy, the U.S. Air Force, and the Rhode Island Public Utilities Commission on such issues as alternative power supply options and innovative rate structure experiments and implementation, and he has prepared and presented seminars and workshops on such issues as marginal costing, rate design, and interruptible rates for, among others, the National Regulatory Research Institute, the U.S. Department of Energy, and for state commission staffs in Maryland, Minnesota, and New Hampshire.

Dr. Swan has assisted federal agencies in the negotiation of electric power supply contracts and in the financial and locational assessment of transmission and generation projects. He has also prepared reports to several federal and state agencies on costing methods, rate design, the demand for electric power, PURPA requirements, bulk power supply planning, stranded cost recovery, standby rates, value-of-service pricing, the use of special contracts, and other issues. He has also acted as an Advisor to the Maine Public Utilities Commission in the restructuring proceedings for the three investor-owned Maine electric companies.

<u>Education</u>:

B.S. (Business Administration) - Ithaca College, 1962.

M.A. Program in Economics - Tufts University, 1962-63.

Ph.D. (Economics) - University of North Carolina at Chapel Hill, 1972.

<u>Previous Employment</u>:

1976-1980	-	Senior Economist, J.W. Wilson & Associates, Inc.
1974-1976	-	Associate Professor of Economics, Jacksonville State University
1974	-	Economist, Office of Energy Systems, Federal Energy Administration
1973	-	Staff Economist, Economics Department, Arabian-American Oil Company

1968-1973	-	Assistant and Associate Professor of Economics, Hampden-Sydney College
1969-1973	-	Visiting Assistant Professor of Economics, Randolph-Macon Womans College
1967-1968	-	Assistant Professor of Economics, Southern Methodist University
1966-1967	-	Visiting Assistant Professor of Economics, North Carolina Central University
1963-1964	-	Market Research Analyst, The Carter's Ink Company

<u>Previous Professional Work</u>:

At J.W. Wilson & Associates, Inc., Dr. Swan had primary responsibility for the development and direction of several of the firm's largest projects relating to the electric utility industry and costing and rate design issues in particular. Dr. Swan also had major responsibilities in the areas of cogeneration, antitrust, PURPA requirements, and technical assistance to state regulatory authorities under DOE grant programs.

At the Federal Energy Administration, Dr. Swan participated in the development of a National Energy Accounting System, similar to and compatible with the National Income and Product Accounts and the U.S. Input/Output Accounts. During his tenure at Jacksonville State University, Dr. Swan continued with this work as a consultant to the FEA.

While with ARAMCO, Dr. Swan prepared financial analyses of capital investment alternatives, developed cost trend estimates for price negotiations, and initiated the preparation of revised price trend factors to be used for budgeting purposes.

At Carter's Ink Company, Dr. Swan was responsible for conducting new product and new market research for the Director of Marketing, including consumer attitudinal studies on new product and packaging designs.

Dr. Swan has taught both graduate and undergraduate courses during his academic career. Among the courses he has taught are Microeconomic Theory, Industrial Organization, Economic History, International Trade, Economic Development, and Principles of Economics.

Selected Publications, Papers, and Reports:

"The Northern California DOE Laboratory Electric Power Purchasing Consortium: A History," (Exeter Associates, Inc., for the U.S. Department of Energy, Federal Energy Management Program, September 2009.)

"Electric Power Options Study Follow-up Report for Brookhaven National Laboratory," (Exeter Associates, Inc. for the U.S. Department of Energy, Federal Energy Management Program, June 2008.)

"Updated Phase 1 Electric Power Options Study for Brookhaven National Laboratory," (Exeter Associates, Inc. for the U.S. Department of Energy, Federal Energy Management Program, April 2007.)

"Fermi National Accelerator Laboratory Phase 1 Electric Supply Options Study," (Exeter Associates, Inc., for the U.S. Department of Energy, Federal Energy Management Program, December 2004.)

"Phase 1 Electric Power Options Study for Brookhaven National Laboratory," (Exeter Associates, Inc. for the U.S. Department of Energy, Federal Energy Management Program, June 2004).

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Expert Testimony

Presented by Dale E. Swan

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2. Before the Public Utilities Commission of the State of South Dakota, Docket No. 3362, on marginal costs and electric rate structure design.

3. Before the Public Utilities Commission of the State of South Dakota, Docket Nos. F-3240 and F-3241, on electric rate structure design.

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6. Before the Public Utilities Commission of the State of South Dakota, Docket No. F-3116, on test year sales forecasts.

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15. Before the Public Utilities Commission of the State of Idaho, Case No. U-1006-185, on class revenue requirements and rate design.

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18. Before the Public Utilities Commission of the State of Maryland, Case No. 7695, on proper electric class cost-of-service methodologies.

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23. Before the Public Utilities Commission of the State of Idaho, Case No. U-1500-157 (May 1985), on the public interest aspects of declaring one utility as the sole supplier of the Idaho National Engineering Laboratory.

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26. Before the Public Utilities Commission of the State of Maine, Docket No. 86-242 (August 1987), on by-pass and incentive rate discounts for large industrial customers.

27. Before the Illinois Commerce Commission, Docket No. 87-0427, (February and April 1988), on marginal-cost-based class revenues, Ramsey pricing considerations, and industrial rate design.

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30. Before the Public Utilities Commission of the State of Maine, Docket 89-68 (January 1990), on measurement and use of marginal costs for determining class revenues.

31. Before the Federal Energy Regulatory Commission, Docket No. EC90-10-000, et al. (May 1990), with Matthew I. Kahal, on the potential effects of the Northeast Utilities acquisition of Public Service New Hampshire on market concentration and competition in the New England bulk power market.

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33. Before the Public Service Commission of Nevada, Docket Nos. 91-5032 and 91-5055 (September 1991), on the estimation of marginal costs, class revenue responsibilities and rate design for large power users.

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35. Before the Public Utilities Commission of the State of Maine, Docket No. 92-095 (February 1993), Affidavit regarding the efficacy of rate discounts in attracting new business.

36. Before the Public Utilities Commission of the State of Maine, Docket No. 92-315 (June 1993), on revamping of the rate structure to meet competition for sales.

37. Before the Public Utilities Commission of the State of Maine, Docket No. 92-345 (August 1993), with Marvin H. Kahn, on price cap mechanisms as an alternative form of regulation.

38. Before the Public Service Commission of Nevada, Docket No. 92-9055 (October 1993), on franchise rights to serve a large DOE customer.

39. Before the Illinois Commerce Commission, Docket No. 94-0065 (June 1994), on the estimation of marginal costs, class revenue responsibilities, and industrial rate design.

40. Before the Public Service Commission of Nevada, Docket No. 93-11045 (June 1994) on the estimation of marginal costs, environmental externality adders, competition for loads, and class revenue responsibilities.

41. Before the Idaho Public Utilities Commission, Case No. IPC-E-94-5 (November 1994), on embedded class cost allocation and class revenue responsibilities.

42. Before the Public Utilities Commission of the State of Maine, Docket No. 92-315 (II) (March 1995), on the estimation of marginal distribution demand and customer costs.

43. Before the Public Utilities Commission of the State of Maine, Docket No. 95-052 (RD) (October 1995 and January 1996), with Daphne Pscharopoulos, on the estimation of marginal costs as the basis for class revenues and rate design.

44. Before the Public Service Commission of Nevada, Docket No. 96-7020 (November 1996), on the estimation of marginal costs, class revenue responsibilities, and the reasonableness of fixed, up-front facilities charges.

45. Before the Public Service Commission of Montana, Docket No. 97.7.90 (November 1997 and March 1998), on aspects of Montana Power Company's proposed restructuring plan.

46. Before the Illinois Commerce Commission, Docket No. 99-0117 (April 1999), on the design of distribution delivery rates for Commonwealth Edison Company.

47. Before the Public Utilities Commission of Nevada, Docket Nos. 99-4005 and 99-4006, (November 1999), on the design of an electric distribution service tariff for Nevada Power Company.

48. Before the Public Utilities Commission of Nevada, Docket No. 99-7035 (January and February 2000), on Nevada Power proposed revision to its base rates and deferred energy adjustment rates, including the recovery and allocation of deferred capacity costs and the appropriate calculation of annualized fuel and purchased power costs.

49. Before the Illinois Commerce Commission, Docket No. 01-0423 (August, October 2001), on the proper design of distribution delivery rates for Commonwealth Edison Company.

50. Before the Public Utilities Commission of the State of Maine, Docket No. 2001-239 (November 2001), on appropriate procedures governing the provision of rate discounts to retain or attract customers.

51. Before the Public Utilities Commission of Nevada, Docket Nos. 01-10001, 01-10002 and 01-11029 (February 2002), on Nevada Power Company's proposed class cost allocations and revisions to its base rates.

52. Before the Illinois Commerce Commission, Docket No. 02-0479 (August 2002), on the appropriateness of the Company's petition to have bundled Rate 6L service to customers with loads of 3 MW or more declared a competitive service, thereby eliminating Rate 6L as a service of last resort for these customers.

53. Before the Illinois Commerce Commission, Docket Nos. 02-0656, 02-0671, and 02-0672 (CONS.) (December 2002), on proposed changes to Commonwealth Edison Company's retail access options.

54. Before the Public Utilities Commission of Nevada, Docket Nos. 03-10001 and 03-10002 (January 2004), on Nevada Power Company's proposed class revenue allocation and the imposition of new Customer Specific Facilities Charges on certain large customers.

55. Before the Illinois Commerce Commission, Docket No. 05-0159 (June 2005), on the need for Commonwealth Edison Company to offer a fixed-price POLR service to large customers.

56. Before the Illinois Commerce Commission, Docket No. 05-0597 (February 2006), on the allocation of costs and the design of rates for retail delivery service.

57. Before the Illinois Commerce Commission, Docket No. 07-0566 (February 2008), on embedded class cost of service and the design of rates for retail delivery service.

58. Before the Indiana Utility Regulatory Commission, Cause No. 43306 (September 2008), on embedded class cost of service and the design of rates for retail customers.

59. Before the Indiana Utility Regulatory Commission, Cause No. 43526 (May 2009), on embedded class cost of service, revenue spread and rate design.

BEFORE THE

STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS

PUBLIC UTILITIES COMMISSION

RE: THE NARRAGANSETT ELECTRIC COMPANY: INVESTIGATION AS TO THE PROPRIETY OF PROPOSED TARIFF CHARGES	**))))**	**DOCKET NO. 4065**

SCHEDULES ACCOMPANYING THE

DIRECT TESTIMONY OF

DR. DALE E. SWAN

ON BEHALF OF THE

DIVISION OF PUBLIC UTILITIES AND CARRIERS

SEPTEMBER 15, 2009

EXETER

ASSOCIATES, INC.
5565 Sterrett Place
Suite 310
Columbia, Maryland 21044

NARRAGANSETT ELECTRIC COMPANY

Division Class Cost of Service Study ($000s)
TOTAL DISTRIBUTION REVENUE REQUIREMENT CLASS ALLOCATION

	Account Description	Account No.	Total Dollars	Residential	Small C&I	General C&I	200 kW Demand	3000 kW Demand	Lighting	Propulsion
				A16 / A60	C6	G2 / E40	B32 / G32	B62 / G62	S10 / S14	X1
1	**A. PRODUCTION PLANT**									
2	**Production Plant**									
3	Production Plant		3,127	1,261	229	569	806	223	28	10
4		350-359	3,127	1,261	229	569	806	223	28	10
5										
6	**B. DISTRIBUTION PLANT**									
7	Land and Land Rights	360	9,586	4,315	825	1,669	2,025	598	87	68
8	Structures and Improvements	361	7,196	3,239	619	1,253	1,520	449	65	51
9	Station Equipment	362	171,209	77,067	14,728	29,811	36,159	10,685	1,551	1,208
10	Poles, Towers and Fixtures	364	185,255	95,670	18,283	36,847	24,478	7,234	1,926	818
12	Overhead Conductors and Devices	365	265,515	130,998	25,034	50,522	42,383	12,525	2,637	1,416
12	Underground Conduit	366	62,534	29,588	5,654	11,426	11,491	3,396	596	384
13	Underground Conductors & Devices	367	135,960	63,429	12,121	24,506	26,056	7,700	1,277	871
14	Line Transformers	368	160,301	86,674	16,552	33,331	16,987	5,019	1,738	0
15	Services	369	72,382	62,666	8,094	1,537	85	1	0	0
16	Meters	370	49,671	33,809	8,204	5,814	1,834	9	0	0
17	Installations on Cust. Prem./ARO	371/374	165	112	27	19	6	0	0	0
18	Street Lighting & Signal Systems	373	52,924	0	0	0	0	0	52,924	0
19	Subtotal - DISTRIBUTION PLANT	360-373	1,172,698	587,565	110,142	196,735	163,023	47,616	62,801	4,815
20										
21	**C. GENERAL PLANT**									
22	Land and Land Rights	389	952	517	91	134	116	32	59	3
23	Structures and Improvements	390	23,532	12,772	2,258	3,322	2,867	782	1,455	77
24	Office Furniture and Equipment	391	859	466	82	121	105	29	53	3
25	Passenger Cars - Transp Equipment	392	646	351	62	91	79	21	40	2
26	Stores Equipment	393	454	246	44	64	55	15	28	1
27	Tools, Shop & Garage Equipment	394	2,678	1,453	257	378	326	89	166	9
28	Laboratory Equipment	395	1,905	1,034	183	269	232	63	118	6
29	Communications Equipment	396	25,774	13,988	2,473	3,639	3,140	857	1,593	84
30	Miscellaneous Equipment	397/399.1	123	67	12	17	15	4	8	0
31	Subtotal - GENERAL PLANT	389-399	56,923	30,894	5,462	8,036	6,935	1,892	3,519	185
32										
33	**TOTAL UTILITY PLANT**		1,232,748	619,720	115,833	205,340	170,765	49,731	66,348	5,011
34										
35	**II. DEPRECIATION RESERVE**									
36	Production	108.3	(3,120)	(1,258)	(229)	(568)	(804)	(223)	(28)	(10)
37	Distribution	108.5	(488,824)	(244,766)	(45,882)	(81,949)	(68,133)	(19,901)	(26,175)	(2,019)
38	General	108.6	(24,583)	(13,342)	(2,359)	(3,470)	(2,995)	(817)	(1,520)	(80)
39	TOTAL DEPREC. RESERVE	108	(516,527)	(259,365)	(48,470)	(85,987)	(71,932)	(20,940)	(27,723)	(2,110)

NARRAGANSETT ELECTRIC COMPANY

Division Class Cost of Service Study ($000s)
TOTAL DISTRIBUTION REVENUE REQUIREMENT CLASS ALLOCATION

	Account Description	Account No.	Total Dollars	Residential	Small C&I	General C&I	200 kW Demand	3000 kW Demand	Lighting	Propulsion
				A16 / A60	C6	G2 / E40	B32 / G32	B62 / G62	S10 / S14	X1
40										
41	**III. OTHER RATE BASE ITEMS**									
42	Property Held for Future Use	131	204	103	19	34	28	8	11	1
43	Contributions in Aid of Construction	255	(103)	(52)	(10)	(17)	(14)	(4)	(5)	(0)
44	Materials and Supplies	255	6,378	3,205	604	1,065	885	257	336	26
45	Loss on Reacquired Debt	255	4,592	2,307	435	767	637	185	242	19
45	Cash Working Capital		17,789	9,503	1,668	2,622	2,369	647	920	60
46	Accumulated Deferred FIT	154	(113,088)	(56,851)	(10,626)	(18,837)	(15,665)	(4,562)	(6,087)	(460)
47	Customer Deposits	182	(3,283)	(24)	(1,563)	(1,565)	(131)	0	(0)	0
48	Injuries and Damages Reserve		(4,762)	(2,394)	(447)	(793)	(660)	(192)	(256)	(19)
49	Total - OTHER RATE BASE ITEMS	131-283	(92,273)	(44,203)	(9,920)	(16,724)	(12,551)	(3,661)	(4,840)	(374)
50										
51	**TOTAL RATE BASE**		623,948	316,152	57,443	102,628	86,281	25,129	33,785	2,528
52										
53	**I. OPERATING AND MAINTENANCE EXPENSES**									
54	**A. DISTRIBUTION EXPENSE**									
55	Purchased Power- Borderline	555	38	15	3	7	10	3	0	0
56	Operation Supervision & Engineering	580	1,481	698	140	244	218	61	113	6
57	Load Dispatching	581	2,372	956	174	432	612	169	22	8
58	Station Expenses	582	3,174	1,429	273	553	670	198	29	22
59	Overhead Line Expenses	583	5,315	2,673	511	1,030	788	233	54	26
60	Underground Line Expenses	584	1,849	863	165	333	354	105	17	12
61	Street Light and Signal Systems	585	530	0	0	0	0	0	530	0
62	Meter Expenses	586	2,842	1,934	469	333	105	1	0	0
63	Customer Installation Expenses	587	1,569	810	155	312	207	61	16	7
64	Misc. Distribution Expenses	588	12,495	5,889	1,180	2,063	1,839	518	956	51
65	Rents	589	109	55	10	18	15	4	6	0
66	Maint Supervision & Engineering	590	42	20	4	7	6	2	3	0
67	Maint of Structures	591	25	11	2	4	5	2	0	0
68	Maintenance of Station Equipment	592	3,332	1,500	287	580	704	208	30	24
69	Maintenance of Overhead Lines	593	18,701	9,404	1,797	3,625	2,774	820	189	93
70	Maintenance of Underground Lines	594	1,095	511	98	197	210	62	10	7
71	Maintenance of Line Transformers	595	263	142	27	55	28	8	3	0
72	Maintenance of Street Lights	596	1,652	0	0	0	0	0	1,652	0
73	Maintenance of Meters	597	318	216	53	37	12	0	0	0
74	Total - OPER. AND MAINT. EXP.	500-599	57,202	27,126	5,347	9,830	8,558	2,455	3,631	256
75										

NARRAGANSETT ELECTRIC COMPANY

Division Class Cost of Service Study ($000s)
TOTAL DISTRIBUTION REVENUE REQUIREMENT CLASS ALLOCATION

	Account Description	Account No.	Total Dollars	Residential	Small C&I	General C&I	200 kW Demand	3000 kW Demand	Lighting	Propulsion
				A16 / A60	C6	G2 / E40	B32 / G32	B62 / G62	S10 / S14	X1
76	**B. CUSTOMER ACCOUNTS AND SERVICE**									
77	Supervision	901	1,197	1,026	107	39	21	0	4	0
78	Meter Reading Expenses	902	1,626	1,107	269	190	60	0	0	0
79	Customer Records & Collection Expense	903	11,449	9,813	1,019	373	205	0	39	0
80	Uncollectible Accounts- Delivery	904	4,301	2,258	464	633	664	101	176	4
81	Uncollectible Accounts- Commodity	904Com	0	0	0	0	0	0	0	0
82	Misc Customer Accounts Expenses	905	1,074	950	103	19	2	0	0	0
83	Subtotal - Customer Accounts Exp.	901-905	19,647	15,154	1,961	1,254	953	102	219	4
84										
85	Supervision	907	88	35	6	16	23	6	1	0
86	Customer Assistance Exp Electric	908-909	1,860	737	134	333	496	137	17	6
85	Customer Assistance Expenses	910	3,460	1,372	249	619	922	255	31	12
86	Subtotal - Customer Service & Info.	907-913	5,408	2,144	390	968	1,441	399	48	18
87										
88	Total - CUST. ACCT. & SERV. EXP.	901-919	25,055	17,298	2,351	2,222	2,393	501	267	22
89										
90	**C. ADMINISTRATIVE AND GENERAL**									
91	GENERAL EXPENSES									
92	A&G-Salaries	920	9,223	5,006	885	1,302	1,124	307	570	30
93	A&G-Office Supplies	921	9,498	5,155	911	1,341	1,157	316	587	31
94	A&G-Outside Services Employed	923	1,902	1,032	182	269	232	63	118	6
95	Property Insurance	924	1,037	521	97	173	144	42	56	4
96	Injuries & Damages Insurance	925	6,804	3,420	639	1,133	943	274	366	28
97	Employee Pensions & Benefits	926	22,946	12,454	2,202	3,239	2,796	763	1,418	75
98	Regulatory Comm Expenses	928	5,083	2,576	468	836	703	205	275	21
99	A&G-Misc Expenses	930200	3,870	1,560	284	704	998	276	35	13
100	A&G-Research & Development	930210	125	63	12	21	17	5	7	1
101	A&G-Rents	931	4,590	2,491	440	648	559	153	284	15
101	A&G Maint-General Plant-Elec	935	252	137	24	36	31	8	16	1
102	TOTAL A&G EXPENSES	920-932	65,330	34,415	6,145	9,701	8,703	2,411	3,732	223
103										
104	TOTAL OPERATING EXPENSES		147,587	78,839	13,843	21,753	19,654	5,367	7,630	502
105										
106	**II. DEPRECIATION EXPENSE**									
107	Depreciation Expense	403	41,466	20,846	3,896	6,907	5,744	1,673	2,232	169
108	TOTAL DEPREC. EXPENSE	403	41,466	20,846	3,896	6,907	5,744	1,673	2,232	169
109										

NARRAGANSETT ELECTRIC COMPANY

Division Class Cost of Service Study ($000s)
TOTAL DISTRIBUTION REVENUE REQUIREMENT CLASS ALLOCATION

	Account Description	Account No.	Total Dollars	Residential	Small C&I	General C&I	200 kW Demand	3000 kW Demand	Lighting	Propulsion
				A16 / A60	C6	G2 / E40	B32 / G32	B62 / G62	S10 / S14	X1
110	**III. TAXES and OTHER**									
111	**A. GENERAL TAXES**									
112	Municipal taxes	408	20,085	10,097	1,887	3,346	2,782	810	1,081	82
113	Payroll taxes	408	3,700	2,008	355	522	451	123	229	12
114	Other taxes	408	275	138	26	46	38	11	15	1
115	Subtotal - General Taxes		24,060	12,243	2,268	3,914	3,271	944	1,325	95
116										
117	**B. FEDERAL / STATE INCOME TAXES**									
118	Amort. ITC		(488)	(245)	(46)	(81)	(68)	(20)	(26)	(2)
119	Federal Income Tax Expense		(3,198)	(1,620)	(294)	(526)	(442)	(129)	(173)	(13)
120	Subtotal - Federal / State Income Taxes	409-411	(3,686)	(1,866)	(340)	(607)	(510)	(148)	(199)	(15)
121										
122	TOTAL TAXES	408-411	20,374	10,378	1,928	3,306	2,761	796	1,125	80
123										
124	**C. OTHER**									
125	Merger / Synergy Benefits		(850)	(431)	(78)	(140)	(118)	(34)	(46)	(3)
126	Amortization of Loss on Reacq Debt		686	345	64	114	95	28	37	3
127	Interest on Customer deposits		75	1	36	36	3	0	0	0
128	Subtotal- Other		(89)	(85)	22	10	(20)	(7)	(9)	(1)
129										
130	TOTAL EXPENSES		209,338	109,977	19,689	31,977	28,140	7,829	10,978	750
131										
132	**IV. OPERATING REVENUES at Current Rates**									
133	Distribution charge revenue	440	215,420	113,105	23,237	31,707	33,256	5,080	8,834	201
134	Forfeited discounts	450-451	2,230	1,752	170	174	134	0	1	0
135	Rent from Utility property	451Misc	2,644	1,365	261	526	349	103	27	12
136	Other revenue	454	2,948	1,548	318	434	455	70	121	3
137	Total Operating Revenues		223,242	117,770	23,985	32,841	34,194	5,253	8,983	215
138										
139	TOTAL EXPENSES		209,338	109,977	19,689	31,977	28,140	7,829	10,978	750
140										
141	**V. NET INCOME at Current Rates**		13,904	7,793	4,296	865	6,055	(2,576)	(1,995)	(534)
142										

NARRAGANSETT ELECTRIC COMPANY

Division Class Cost of Service Study ($000s)
TOTAL DISTRIBUTION REVENUE REQUIREMENT CLASS ALLOCATION

	Account Description	Account No.	Total Dollars	Residential	Small C&I	General C&I	200 kW Demand	3000 kW Demand	Lighting	Propulsion
				A16 / A60	C6	G2 / E40	B32 / G32	B62 / G62	S10 / S14	X1
143	**SUMMARY REPORT**									
144	OPERATING REVENUES									
145	Utility Revenues	440-446	215,420	113,105	23,237	31,707	33,256	5,080	8,834	201
146	Other Operating Revenues	450-456	7,822	4,665	749	1,134	938	173	149	14
147	Total Operating Revenues		223,242	117,770	23,985	32,841	34,194	5,253	8,983	215
148										
149	OPERATING EXPENSES									
150	Distribution	580-599	57,202	27,126	5,347	9,830	8,558	2,455	3,631	256
151	Customer Acctg & Service	901-919	25,055	17,298	2,351	2,222	2,393	501	267	22
152	Admin & General	920-932	65,330	34,415	6,145	9,701	8,703	2,411	3,732	223
153	Total Operating Expenses		147,587	78,839	13,843	21,753	19,654	5,367	7,630	502
154										
155	Depreciation Expense	403	41,466	20,846	3,896	6,907	5,744	1,673	2,232	169
156	Taxes Other Than Income Tax / Other	408	23,971	12,158	2,290	3,924	3,252	938	1,315	94
157	INCOME BEFORE INCOME TAXES		10,218	5,927	3,956	257	5,545	(2,724)	(2,194)	(549)
158	Income Taxes	409-411	(3,686)	(1,866)	(340)	(607)	(510)	(148)	(199)	(15)
159	NET INCOME		13,904	7,793	4,296	865	6,055	(2,576)	(1,995)	(534)
160										
161	RATE BASE		623,948	316,152	57,443	102,628	86,281	25,129	33,785	2,528
162	Return on Rate Base		2.23%	2.46%	7.48%	0.84%	7.02%	(10.25%)	(5.90%)	(21.13%)
163										
164	**REVENUE REQUIREMENTS**									
165	Target Rate of Return		8.980%	8.980%	8.980%	8.980%	8.980%	8.980%	8.980%	8.980%
166	Rate Base		623,948	316,152	57,443	102,628	86,281	25,129	33,785	2,528
167										
168	Operating expenses		147,587	78,839	13,843	21,753	19,654	5,367	7,630	502
169	Additional uncollectibles expense		719	565	55	56	43	0	0	0
170	Depreciation expense		41,466	20,846	3,896	6,907	5,744	1,673	2,232	169
171	General taxes / Other		23,971	12,158	2,290	3,924	3,252	938	1,315	94
172	Subtotal- Operating Costs to recover		213,743	112,407	20,084	32,640	28,693	7,977	11,178	764
173										
174			56,031	28,390	5,158	9,216	7,748	2,257	3,034	227
175										
176	Income taxes to recover		18,999	9,627	1,749	3,125	2,627	765	1,029	77
177										
178	**TOTAL REVENUE REQUIREMEN**		288,773	150,424	26,991	44,981	39,068	10,999	15,240	1,068
179										
180	Revenue at Current rates		223,242	117,770	23,985	32,841	34,194	5,253	8,983	215
181	**Revenue Excess (Deficiency)**		(65,531)	(32,655)	(3,006)	(12,140)	(4,873)	(5,746)	(6,257)	(853)

NARRAGANSETT ELECTRIC COMPANY

Comparison of Class Relative Rates of Return
Under the Company's and the Division's COSS

	Company COSS		Division COSS	
Class	ROR	ROR Index	ROR	ROR Index
Residential	1.29%	57.8%	2.46	110.3%
Small C&I	4.41	197.8	7.48	335.4
General C&I	3.24	145.3	0.84	37.7
200 kW Demand	9.92	444.8	7.02	314.8
3000 kW Demand	(8.55)	(383.4)	(10.25)	(459.6)
Lighting	(5.12)	(229.6)	(5.90)	(264.6)
Propulsion	(20.25)	(908.1)	(21.13)	(947.5)
Total	2.23%	100.0%	2.23%	100.0%

NARRAGANSETT ELECTRIC COMPANY

Total Company Proposed
Class Revenue Increases
($1,000s)

		Total	Residential	Small C&I	General C&I	C&I Large Demand	Lighting	Propulsion
1.	Company-proposed distribution revenues[1]	288,772	155,718	29,277	41,448	47,730	14,257	342
2.	Commodity-related Cost Tracker[2]	9,752	7,558	696	816	680	2	-0-
3.	Change in Transmission Costs[3]	4	4,140	221	245	(4,430)	(171)	(1)
4.	Total Revenues	298,528	167,416	30,194	42,090	43,980	14,088	341
5.	Current Distribution Revenues	223,242	117,770	23,985	32,841	39,447	8,983	215
6.	Net Increase - $	75,286	49,646	6,209	9,249	4,533	5,105	126
7.	Net Increase - %	33.7%	42.2%	25.9%	28.2%	11.5%	56.8%	58.6%

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1 Schedule NG-HSG-4, p. 2, line 52.

2 Schedule NG-HSG-4, p. 2, line 38.

3 Schedule NG-HSG-7, p. 1, line 14 minus line 5.

4 Schedule NG-HSG-4, p. 1, line 4.

NARRAGANSETT ELECTRIC COMPANY

Division Proposed Class Revenue Increases at Company-Proposed Total Jurisdictional Revenues

Line		Total	Residential	Small C&I	General C&I	C&I Large Demand	Lighting	Propulsion
1	Revenue at Equal ROR [1]	288,773	150,424	26,991	44,981	50,067	15,240	1,068
2	Revenue at Current Rates [2]	223,242	117,770	23,985	32,841	39,447	8,983	215
3	Revenue Deficiency [3]	65,531	32,654	3,006	12,140	10,620	6,257	853
4	Percentage Increase	29.4%	27.7%	12.5%	37.0%	26.9%	69.7%	396.7%
5	Constrained Increase at 58.8%	63,479	32,655	3,006	12,140	10,270	5,282	126
6	Allocation of Shortfall [4]	2,052	1,133	203	339	377	-	-
7	Step 1 Revenue Increase - $ [5]	65,531	33,788	3,209	12,479	10,647	5,282	126
8	Step 1 Revenue Increase - %	29.4%	28.7%	13.4%	38.0%	27.0%	58.8%	58.6%

[1] Schedule DES-1, p. 5, line 178
[2] Schedule DES-1, p. 5, line 180
[3] Line 1 MINUS Line 2
[4] Allocated on Line 1
[5] Line 5 PLUS Line 6

NARRAGANSETT ELECTRIC COMPANY

Division Proposed Class Revenue Increases
at Company-Proposed Total Jurisdictional Revenues

Line		Total	Residential	Small C&I	General C&I	C&I Large Demand	Lighting	Propulsion
1	Step 1 Constrained Increase [1]	65,531	33,788	3,209	12,479	10,647	5,282	126
	Step 1 Revenues less A-60							
2	Subsidy of $4,795 [2]	283,978	146,763	27,194	45,320	50,094	14,265	341
3	Reallocation of A-60 Subsidy [3]	4,795	2,612	484	807	892	-	-
4	Step 2 Revenues	288,773	149,375	27,678	46,126	50,986	14,265	341
5	Percentage Step 2 Increase	29.4%	26.8%	15.4%	40.5%	29.3%	58.8%	58.6%
6	Adjustment for Trans Charges [4]	4	4140	221	245	(4430)	(171)	(1)
7	Percentage Increase net of							
	Transmission Charges [5]	29.4%	30.4%	16.3%	41.2%	18.0%	56.9%	58.1%
8	Step 2 Dist'n Revenues Less							
	Half of Transmission Charges [6]	288,771	147,305	27,568	46,004	53,201	14,351	342
9	% Change	29.4%	25.1%	14.9%	40.1%	34.9%	59.8%	58.8%

[1] Page 1, line 7

[2] Page 1, line 2 PLUS Page 2, Line 1, LESS A-60 Subsidy

[3] Allocated on Line 2

[4] Schedule DES-3, p. 1, line 3

[5] (Line 4 PLUS Line 6) DIVIDED By (Page 1, Line 2)

[6] Line 4 LESS half of Line 6

NARRAGANSETT ELECTRIC COMPANY

Division Proposed Class Revenue Increases
at Company-Proposed Total Jurisdictional Revenues

Line		Total	Residential	Small C&I	General C&I	C&I Large Demand	Lighting	Propulsion
1	Revenue with Transmission Charges [1]	288,775	151,445	27,789	46,249	48,771	14,180	341
2	% Change	29.4%	28.6%	15.9%	40.8%	23.6%	57.8%	58.4%
3	SOS Administrative Charges [2]	9,752	4,636	844	1,428	2,714	104	26
4	Total Revenue with SOS Admin Charges [3]	298,527	156,081	28,633	47,677	51,485	14,284	367
5	Final % Change with All Revenue Adjustments	33.72%	32.53%	19.38%	45.18%	30.52%	59.01%	70.47%

[1] Line 8 PLUS Line 6

[2] From Schedule NG-RLO-6, p. 1, line 1, allocated per column 4 on p. 4 this schedule

[3] Line 10 PLUS Line 12

NARRAGANSETT ELECTRIC COMPANY

Development of Commodity Service
Energy by Class

	mWh @ Meter[1] (1)	% Under Commodity Service[2] (2)	Energy Under Commodity Service	
			mWh (4)	%
Residential	3,037,613	97.13%	2,950,434	47.54%
Small C&I	552,429	97.13	536,574	8.65
General C&I	1,371,694	66.25	908,747	14.64
C&I Large Demand	2,606,916	66.25	1,727,082	27.83
Lighting	68,382	97.13	66,419	1.07
Propulsion	25,939	66.25	17,185	0.28
Total	7,662,973	80.99%	6,206,441	100.01%

[1]Schedule NG-HSG-3, p. 5, line 1.

[2]Schedule NG-RLO-6, p. 1, Section 2, line 2.

NARRAGANSETT ELECTRIC COMPANY
Illustrative Division Proposed Class Revenue Increases
at a Total Jurisdictional Revenue Increase of $35 Million

Line	Total	Residential	Small C&I	General C&I	C&I Large Demand	Lighting	Propulsion
1 Present Dist'n Rate Revenue [1]	223,242	117,770	23,985	32,841	39,447	8,983	215
2 Company's Proposed Full Cost Rate Revenues[2]	288,773	150,424	26,991	44,981	50,067	15,240	1,068
3 Adjusted Full Cost Revenues [3]	258,242	134,520	24,138	40,226	44,774	13,629	955
4 Adjusted Revenue Deficiency [4]	35,001	16,750	153	7,385	5,327	4,646	740
5 Percentage Increase	15.7%	14.2%	0.6%	22.5%	13.5%	51.7%	244.2%
6 Constrained Increase at 31.4%	32,504	16,750	153	7,385	5,327	2,821	68
7 Allocation of Shortfall [5]	2,497	1,379	247	412	459	-	-
8 Step 1 Revenue Increase - $ [6]	35,001	18,129	400	7,797	5,786	2,821	68
9 Step 1 Revenue Increase - %	15.7%	15.4%	1.7%	23.7%	14.7%	31.4%	31.6%

[1] Schedule DES-4, p. 1, line 2
[2] Schedule DES-4, p. 1, line 1
[3] 89.4273% of Line 2
[4] Line 3 MINUS Line 1
[5] Allocated on Line 3
[6] Line 6 PLUS Line 7

NARRAGANSETT ELECTRIC COMPANY
Illustrative Division Proposed Class Revenue Increases
at a Total Jurisdictional Revenue Increase of $35 Million

Line		Total	Residential	Small C&I	General C&I	C&I Large Demand	Lighting	Propulsion
1	Step 1 Constrained Increase [1]	35,001	18,129	400	7,797	5,786	2,821	68
2	Step 1 Revenues less A-60 Subsidy of $4,288 [2]	253,955	131,611	24,385	40,638	45,233	11,804	283
3	Reallocation of A-60 Subsidy [3]	4,288	2,333	432	720	802	-	-
4	Step 2 Revenues	258,243	133,944	24,817	41,358	46,035	11,804	283
5	Percentage Step 2 Increase	15.7%	13.7%	3.5%	25.9%	16.7%	31.4%	31.6%
6	Adjustment for Trans Charges [4]	4	4140	221	245	(4430)	(171)	(1)
7	Percentage Increase net of Transmission Charges [5]	15.7%	17.2%	4.4%	26.7%	5.5%	29.5%	31.2%
8	Step 2 Dist'n Revenues Less Half of Transmission Charges [6]	258,241	131,874	24,707	41,236	48,250	11,890	284
9	% Change	15.7%	12.0%	3.0%	25.6%	22.3%	32.4%	31.9%

[1] Page 1, Line 8

[2] Page 1, Line 1 PLUS Page 2, Line 1, LESS A-60 Subsidy

[3] Allocated on Line 2

[4] Schedule DES-03, p. 1, Line 3

[5] (Line 4 PLUS Line 6) DIVIDED By (Page 1, Line 1)

[6] Line 4 LESS half of Line 6

NARRAGANSETT ELECTRIC COMPANY
Illustrative Division Proposed Class Revenue Increases
at a Total Jurisdictional Revenue Increase of $35 Million

Line	Total	Residential	Small C&I	General C&I	C&I Large Demand	Lighting	Propulsion
1 Revenue with Transmission Charges [1]	258,245	136,014	24,928	41,481	43,820	11,719	283
2 % Change	15.7%	15.5%	3.9%	26.3%	11.1%	30.5%	31.4%
3 SOS Administrative Charges [2]	9,752	4,636	844	1,428	2,714	104	26
4 Total Revenue with SOS Admin Charges [3]	267,997	140,650	25,772	42,909	46,534	11,823	309
5 Final % Change with All Revenue Adjustments	20.05%	19.43%	7.45%	30.66%	17.97%	31.61%	43.49%

[1] Page 2, Line 8 PLUS Page 2, Line 6

[2] From Schedule NG-RLO-6, p. 1, line 1, allocated per Schedule DES-4, p. 4

[3] Line 1 PLUS Line 3

NARRAGANSETT ELECTRIC COMPANY

Company Proposed Percentage Changes
in Customer, Demand and Energy Charges
by Customer Class

	Rate Schedule					
	A-16	A-68	C-06	G-02	G-32	G-62
	%	%	%	%	%	%
Customer charge	+100	NA	+67	+21	+315	-94
Distribution demand charge	NA	NA	NA	+40	+26	+13
Distribution energy charge	+24	*	+15	+18	-6	**
Transmission demand charge	NA	NA	NA	+40	+26	+13
Transmission energy charge	+9	+16	+3	-32	-42	-42

*   Varies from -13% to +594%, depending on the energy block.
** From zero to $0.00840.
NA = Not applicable

Source: Schedule NG-HSG-9

NARRAGANSETT ELECTRIC COMPANY

Percentage Changes in Average Monthly Delivery
Service Costs for Current G-32 and B-32 Customers
at the Company's Proposed Rates

Rate G-32 Bill Comparisons

kW	Hours Use 200 (%)	300 (%)	400 (%)	500 (%)
200	18.5	10.5	5.3	1.6
750	9.9	3.3	-0.9	-3.8
1,000	9.1	2.6	-1.5	-4.3
1,500	8.2	1.8	-2.1	-4.8
2,500	7.5	1.3	-2.6	-5.3

Source: Schedule NG-HSG-9

Rate B-32 Bill Comparisons

kW		Hours Use			
Supplemental	Backup	200 (%)	300 (%)	400 (%)	500 (%)
200	200	-9.3	-11.4	-12.7	-13.7
750	750	-4.3	-7.5	-9.6	-11.1
1,000	1,000	-3.9	-7.2	-9.3	-10.8
1,500	1,500	-3.4	-6.8	-9.0	-10.6
2,500	2,500	-3.0	-6.5	-8.8	-10.4

Source: Response to Division Data Request 13-7.

NARRAGANSETT ELECTRIC COMPANY

Percentage Changes in Average Monthly Delivery
Service Costs for Current G-62 and B-62 Customers
at the Company's Proposed Rates

Rate G-62 Bill Comparisons

	Hours Use			
kW	200 (%)	300 (%)	400 (%)	500 (%)
3,000	-28.0	-22.0	-17.5	-13.6
5,000	-13.0	-8.0	-4.2	-1.1
7,500	-3.0	1.3	4.3	6.6
10,000	3.5	6.8	9.2	11.0
20,000	14.6	16.2	17.4	18.3

Source: Schedule NG-HSG-9

Rate B-62 Bill Comparisons

kW		Hours Use			
Supplemental	Backup	200 (%)	300 (%)	400 (%)	500 (%)
3,000	3,000	-0.4	3.4	6.1	8.2
5,000	5,000	14.0	15.7	16.9	17.9
7,500	7,500	23.0	23.1	23.2	23.3
10,000	10,000	28.0	27.1	26.6	26.3
20,000	20,000	36.0	33.7	32.1	30.9

Source: Response to Division Data Request 13-7

NARRAGANSETT ELECTRIC COMPANY

Recalculation of Standard Offer Service
Administrative Cost Factors
Bad Debt Expense Allocated on SOS Energy Deliveries

	Total	Small Customer Group	Large Customer Group
Total Standard Offer Service Administrative Costs per NG-RLO-6, page 2.	$ 9,751,787	$7,661,160	$2,090,627
Less Bad Debt Expense per NG-RLO-6, page 2	(7,861,885)	(6,655,432)	(1,206,453)
Plus Bad Debt Expense allocated on Total SOS kWh Deliveries	7,861,885	4,504,860	3,357,025
Total Adjusted Standard Offer Service Administrative Costs	$ 9,751,787	$5,510,588	$4,241,199
Estimated Standard Offer Service-Related kWh Deliveries from NG-RLO-6, page 1	6,209,599,876	3,558,657,016	2,650,942,859
Adjusted Standard Offer Administrative Cost Factors per kWh	$0.00157	$0.00155	$0.00160

NARRAGANSETT ELECTRIC COMPANY

Recalculation of Standard Offer Service Administrative Cost Factors
All Costs But Cash Working Capital Allocated on SOS Energy Deliveries

	Total	Small Customer Group	Large Customer Group
Total Standard Offer Service Administrative Costs	$ 9,751,787		
Less Cash Working Capital	1,688,117		
Costs to be allocated on SOS energy	8,063,670	$4,620,483	$3,443,187
Allocation of Cash Working Capital on Commodity Revenue	1,688,117	904,836	783,281
Total Adjusted Standard Offer Service Administrative Costs	9,751,787	5,525,319	4,226,468
Estimated Standard Offer Service Related kWh Deliveries	6,209,599,876	3,558,657,016	2,650,942,859
Adjusted Standard Offer Administrative Cost Factors per kWh	$0.00157	$0.00155	$0.00159