THE NARRAGANSETT ELECTRIC COMPANY

DISTRIBUTION RATE PLAN
STIPULATION AND SETTLEMENT

RIPUC DOCKET NO. 3617

BEFORE THE
RHODE ISLAND PUBLIC UTILITIES COMMISSION

TESTIMONY AND EXHIBITS
OF DAVID J. EFFRON

ON BEHALF OF THE

DIVISION OF
PUBLIC UTILITIES AND CARRIERS

SEPTEMBER 15, 2004

RIPUC DOCKET NO. 3617
DISTRIBUTION RATE PLAN AND SETTLEMENT
DIRECT TESTIMONY
OF DAVID J. EFFRON
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I. STATEMENT OF QUALIFICATIONS

Q. Please state your name and business address.

A. My name is David J. Effron. My business address is 386 Main Street, Ridgefield, Connecticut.

Q. What is your present occupation?

A. I am a consultant specializing in utility regulation.

Q. Please summarize your professional experience.

A. My professional career includes over twenty years as a regulatory consultant, two years as a supervisor of capital investment analysis and controls at Gulf & Western Industries and two years at Touche Ross & Co. as a consultant and staff auditor. I am a Certified Public Accountant and I have served as an instructor in the business program at Western Connecticut State College.

Q. What experience do you have in the area of utility rate setting proceedings?

A. I have analyzed numerous electric, telephone, gas and water rate filings in different jurisdictions. Pursuant to those analyses I have prepared testimony, assisted attorneys in rate case preparation, and provided assistance during settlement negotiations with various utility companies.

I have testified in over two hundred cases before regulatory commissions in Alabama, Colorado, Connecticut, Florida, Georgia, Illinois, Indiana, Kansas,

Kentucky, Maryland, Massachusetts, Missouri, New Jersey, New York, North Dakota, Ohio, Pennsylvania, Rhode Island, South Carolina, Texas, Vermont, and Virginia.

Q. Please describe your other work experience.

A. As a supervisor of capital investment analysis at Gulf & Western Industries, I was responsible for reports and analyses concerning capital spending programs, including project analysis, formulation of capital budgets, establishment of accounting procedures, monitoring capital spending and administration of the leasing program. At Touche Ross & Co., I was an associate consultant in management services for one year and a staff auditor for one year.

Q. Have you earned any distinctions as a Certified Public Accountant?

A. Yes. I received the Gold Charles Waldo Haskins Memorial Award for the highest scores in the May 1974 certified public accounting examination in New York State.

Q. Please describe your educational background.

A. I have a Bachelor's degree in Economics (with distinction) from Dartmouth College and a Masters of Business Administration Degree from Columbia University

II. PURPOSE AND SUMMARY OF TESTIMONY

Q. On whose behalf are you testifying?

A. I am testifying on behalf of the Rhode Island Division of Public Utilities and Carriers ("the Division").

Q. What is the purpose of your testimony?

A. On June 29, 2004, the Narragansett Electric Company ("Narragansett" or "the Company") filed a Distribution Rate Plan Stipulation and Settlement ("the Settlement") in this docket. The purpose of my testimony is to summarize the benefits of the Settlement from the perspective of the Division and to address certain matters that have been raised by the Commission in its review of the Settlement. In particular, I will explain 1) how the forecasted 2005 cost of service ("COS") was used to develop the $10.2 million distribution rate reduction and the $4.6 million shared savings allowance specified in the Settlement and 2) how the Second Savings Verification (or "second proof") required by the Third Amended Stipulation and Settlement in Docket 2930 (or "Settlement in Docket 2930") was implemented by the Settlement in this docket.

III. SUMMARY OF SETTLEMENT

Q. Should the Commission approve the Settlement submitted by the parties to this Docket?

A. Yes. The Settlement is the result of extensive analysis and negotiations by the parties, and approval of the Settlement will result in substantial benefits to customers. These substantial benefits include the following:

- An immediate distribution rate reduction of $10,243,000 per year.
- Avoidance of a rate increase of $2,600,000 million per year that would otherwise take place as of January 1, 2005 with implementation of current recovery of the low-income credit. In effect, then, customers will be paying

approximately $12.8 million less annually than they would be in the absence of the Settlement.

- A rate freeze through the end of 2009.
- Reduction to the shared savings allowance to be included in the cost of service to $4,645,000 from the shared savings allowance of approximately $8 million established in the first savings proof.

In addition to these substantial benefits to customers, there are also what I would describe as procedural benefits – the resolution of certain matters that in the absence of the Settlement would likely have been contentious issues requiring the dedication of significant resources, not only by the parties but also by the Commission, to resolve. These matters include the following:

- Agreement on the method of refunding $22,800,000 of shared earnings accumulated during the rate freeze period established in the Settlement in Docket 2930. This amount would have to be refunded even in the absence of the Settlement, but with the Settlement the timing and distribution of the refund have been resolved to the satisfaction of the parties.
- Completion of the Second Savings Verification required by the Settlement in Docket 2930, as explained later in this testimony
- Resolution of the regulatory accounting treatment of the costs of the voluntary early retirement offer incurred in 2003
- Resolution of rate design issues through 2009

In addition to these substantial monetary benefits and procedural benefits, the Settlement also preserves the basic framework of the Settlement in Docket 2930

and continues the other benefits of that Settlement. In my opinion, preservation of this basic framework is prudent and sensible, as the actual experience from early 2000 to date has confirmed the soundness of Commission's judgment in approving the Third Amended Stipulation and Settlement in Docket 2930.

Q. Could you please briefly review the circumstances of the Settlement in Docket 2930 and explain how actual experience has served to confirm the realization of benefits contemplated in that Settlement?

A. In Docket 2930 the Company presented a rate plan that called for virtually automatic recovery of merger related costs without any requirement that there be actual achievement of savings to offset those costs. This rate plan was unacceptable to the Division and the other parties. After intensive negotiations, the Company and the parties reached a tentative settlement on a rate plan to be presented to the Commission. The Commission scheduled several technical sessions in early 2000 to consider and analyze the proposed settlement. As a result of these technical sessions, the tentative settlement was modified and fine-tuned, based mainly on changes prompted by the Commission's review. The outcome of all these efforts was the Third Amended Stipulation and Settlement.

One of the most important underlying premises of the Third Amended Stipulation and Settlement was stated in the preamble to Section 8: "A properly structured incentive based rate plan can align the interests of the Company and its customers by establishing appropriate incentives to maximize merger related savings for the benefit of the Company and its customers." I believe that any

objective review of the experience since that settlement was approved would conclude that the intended alignment of the interests of the Company and its customers has been achieved.

The Settlement in Docket 2930 began with a $12.4 million reduction to distribution rates (plus a $0.7 million reduction to the contract termination charge), more than reversing rate increases to Narragansett and the former Blackstone Valley Electric and Newport Electric that had been put into effect less than two years before. The initial rate reduction was based on a 2000 rate year. Although Narragansett did not exceed the specified benchmark return on equity in 2000, in the succeeding years the Company was able to implement savings and achieve earnings sufficient to generate a refund to customers of $22.8 million. The achieved savings and efficiencies have been such that, even after the initial rate reduction of $12.4 million, an additional rate reduction of $1.1 million in 2004 to put the Navy on G-62 rates, the refund of $22.8 million, and full absorption of the low income discount prospectively, the Company is still in a position in this docket to implement another rate reduction of $10.2 million per year. It is clear that the framework established in Docket 2930 has provided the Company with appropriate incentives to manage the business in a way that has resulted in substantial and quantifiable benefits to customers.

Q. How does the Settlement in this docket relate to the Third Amended Stipulation and Settlement in Docket 2930?

A. The Settlement in this docket maintains the basic framework established in the Third Amended Stipulation and Settlement in Docket 2930, a framework that has been shown to be beneficial. This Settlement also builds on the Settlement in Docket 2930 based on the actual experience since that settlement was approved. Efficiencies already achieved by the Company are embedded in the distribution rates paid by customers while Narragansett must maintain those efficiencies in order to realize its own share of achieved savings. To the extent that Narragansett can enhance efficiencies, customers will share in such improvements. This Settlement expands and improves the benefits to customers while continuing to align the interests of the Company and those customers.

IV. COST OF SERVICE

Q. Did the Settlement in Docket 2930 establish a relationship between the cost of service used to establish rates and the shared savings allowance that the Company would be able to retain?

A. Yes. The Settlement in Docket 2930 provided that the Company's shared savings allowance would be established based on the difference between the COS (reflecting Commission ratemaking principles) in the chosen measurement year and the benchmark COS for that year as defined in that settlement. In other words, the Company would only be able to earn a shared savings allowance if it could reduce the COS used for ratemaking purposes below what it would be if the merger had not taken place. The parties to the Settlement in Docket 2930 deemed this to be an appropriate method to align the interests of ratepayers and investors.

The second proof specified in the Settlement in Docket 2930 continued this alignment of interests. The second proof would take place in the first COS rate case after the rate freeze period and would employ substantially the same method as the original savings proof. That is, the rate year COS be used to establish the Company's revenue requirement and rates and would also be the measurement year to determine the extent to which the savings from the first proof were being sustained.

Q. Did the Division see value in this method of aligning the interests of ratepayers and investors?

A. Yes. Narragansett would be able to continue to retain a share of the deemed merger savings only to the extent that it could control its COS and, therefore, its rates. If there were a substantial increase to the COS, Narragansett would lose some, or even all, of its share of merger savings. In the circumstances of Docket 2930, the Division believed that this method was superior to a framework that would attempt to specifically identify savings enabled by the merger and to allow Narragansett to retain some share of the identified savings. This is so for two reasons.

First, after the merger it would be difficult to "unscramble the omelet" and to identify exactly what savings were made possible by the merger and what savings could have been achieved in the absence of the merger. Second, and more importantly, the method established in Settlement in Docket 2930 avoided a potential situation where the Company in some future rate case would simultaneously be requesting a large distribution rate increase and also contending that the merger had resulted in cost savings, in effect claiming that the rate increase would be even

greater had it not been for the supposed merger savings. In such a situation, any theoretical merger savings would be cold comfort to the customers being asked to pay higher distribution rates. Accordingly, it was, and still is, the position of the Division that the benchmark method established in Settlement in Docket 2930 better aligned the interests of ratepayers and investors than would a method based on some attempt to isolate savings resulting from the merger.

Q. In the negotiation leading up to the Settlement in this docket, did the Division seek to preserve the framework of the Settlement in Docket 2930?

A. Yes. The Division sought to maintain the alignment of interests established in the Settlement in Docket 2930. Specifically, the Division wanted to continue to use the same COS to measure the Company's revenue requirement and to measure the savings that were deemed to be the result of the merger. The Division believed that doing so would be a natural check on any tendency to be excessively conservative in developing the COS. That is, any increase to the COS would automatically result in a reduction to the shared savings allowance, thereby creating a disincentive to overstate the COS.

The analysis performed by the Division employed a 2003 test year and a 2005 rate year. The Division believed that a COS based on a 2005 rate year was appropriate because: 1) given the timing of the negotiations, 2005 would likely be the first year of rates emanating from any new settlement; 2) the use of 2005 as the measurement year for the second proof of savings is consistent with the Settlement in

Docket 2930; and 3) the large pension credit affecting the COS in the first savings proof is substantially gone in 2005.

Q. Please explain how the Division analyzed the 2005 rate year COS for the purpose of establishing new rates while simultaneously establishing the shared savings allowance.

A. Narragansett provided the Division with a detailed COS based on a 2003 test year. That test year was rolled forward to a 2005 rate year COS, with the same type of pro forma ratemaking adjustments that would be seen in a typical rate case. These would include adjustments to rate base, operating expenses, and sales to normalize the actual test year experience and to project the results of the 2003 test year to the 2005 rate year. After analyzing the information provided by the Company and after discussions with the Company regarding the test year and rate year revenues and COS, the Division concluded that the forecasted revenue of $230,847,000 and the forecasted COS of $215,604,000, as shown on Exhibit 1, Page 1 of the Settlement, were reasonable.

The Division also performed a calculation of the forecasted 2005 Benchmark COS for 2005, using factors consistent with the forecast of the rate year revenues and COS where applicable. Based on this calculation, the Division determined that a forecasted 2005 Benchmark COS of $225,604,000, as shown on Exhibit 1, Page 2 of the Settlement, was reasonable.

With the forecasted 2005 revenue, 2005 COS, and 2005 Benchmark COS in place, the shared savings allowance is calculated to be $5,000,000 and the

distribution rate decrease is calculated to be $10,243,000 as shown on Exhibit 1, Page 1 of the Settlement. To address concerns expressed by the Commission, Narragansett agreed to reduce the shared savings allowance to $4,645,000, which is equal to the amount established in the first savings proof excluding the pension credit in the measurement year. As the shared savings allowance of $4,645,000 is less than that calculated based on the 2005 parameters but did not result in any change to the rate reduction calculated on Exhibit 1, Page 1, the Division agreed that this modification was beneficial to ratepayers.

Q. In analyzing the trade-off between the magnitude of the rate reduction and the shared savings allowance, did the Division have a preference for one vs. the other?

A. Yes. Although the shared savings allowance will continue for up to nine years after the rate freeze period in the Settlement ends (subject to the re-opener provisions), the Division preferred that the rate reduction be as large as possible, as long as the shared savings allowance wasn't clearly unreasonable.

Q. Can you explain why?

A. Please refer to Exhibit 1, Page 1 of the Settlement. The forecasted COS in 2005, as agreed upon, is $215,604,000 excluding the shared savings allowance. Suppose, hypothetically, that the Division in reality believed that this was overly optimistic, and a better estimate of the 2005 COS was actually $217,604,000. Applying the benchmark formula, this would mean that shared savings allowance was overstated

by $1,000,000. However, it would also mean that the rate reduction was overstated by $1,000,000, other things equal.

Suppose further that the actual experience in 2005 confirms the Division's unexpressed belief, and the COS is, in fact $217,604,000, again excluding the shared savings allowance. With revenue of $220,604,000, the Company would only capture $3,000,000 as its share of merger savings, but the ratepayers still have their full $10,243,000 rate reduction. Even if the COS of $215,604,000 is over-optimistic, with the Company's revenues reduced to hit that COS (plus the shared savings allowance of $5,000,000) the Company actually has to achieve that COS in order to capture the assumed shared savings allowance. If the Company fails to achieve that COS, such failure impairs the Company's shared savings allowance, not the customers' rate reduction. In short, the Company has to earn the shared savings allowance, but the rate reduction is set. Therefore, on balance the Division valued $1 of rate reduction more than $1 of shared savings allowance. However, in balancing the magnitude of the rate reduction against the amount of the shared savings allowance, the Division also had to keep in mind that it was important that the shared savings allowance in the COS not be overstated. In my opinion, the $10,243,000 distribution rate reduction and the shared savings allowance of $4,645,000 in the Settlement strike a fair balance.

V. SECOND SAVINGS VERIFICATION

Q. Does the Settlement eliminate the Second Savings Verification requirement contained in the Settlement in Docket 2930?

A. No. As explained above, the 2005 rate year was used as the Second Savings Verification. This is consistent with the requirements of the Settlement in Docket 2930 that the measurement year used in the Second Savings Verification be no less than two years after the test year used for the first savings proof and that it occur by April 30, 2007. A strict application of the formula for the Second Savings Verification would have yielded a shared savings allowance of $5,000,000 based on the 2005 rate year parameters. This is approximately $3,000,000 less than the savings established in the first savings proof. Narragansett agreed to reduce the shared savings allowance by an additional $355,000 to address concerns expressed by the Commission. With that modification, the shared savings allowance is equal to the first shared savings allowance exclusive of the pension credit. As this amount is less than the shared savings allowance using a 2005 measurement year, the Division raised no objection. In effect, the shared savings allowance agreed to by the Company is less than that established in the Second Savings Verification, but this does not change the fact that there has been a Second Savings Verification.

Q. Does this conclude your testimony?

A. Yes.

STATE OF RHODE ISLAND AND
PROVIDENCE PLANTATIONS

BEFORE THE PUBLIC UTILITIES COMMISSION

IN RE:	**NARRAGANSETT ELECTRIC COMPANY**	**:**	**DOCKET NO. 3617**
	DISTRIBUTION RATE PLAN	**:**	
	STIPULATION AND SETTLEMENT	**:**	

DIRECT TESTIMONY

OF

JOHN STUTZ

On behalf of:

The Rhode Island Division of Public Utilities and Carriers

September 15, 2004

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1. INTRODUCTION AND SUMMARY

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND POSITION.

A. My name is John K. Stutz. My business address is the Tellus Institute (Tellus), 11 Arlington Street, Boston, Massachusetts 02116-3411. I am a vice president at Tellus.

Q. HAVE YOU PREPARED A SUMMARY OF YOUR EDUCATION, EMPLOYMENT AND PROFESSIONAL QUALIFICATIONS?

A. Yes, it is provided in Exhibit JS-4.

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

A. On June 29, 2004, the Narragansett Electric Company ("Narragansett" or "the Company") filed a Distribution Rate Plan Stipulation and Settlement ("the 2004 Settlement") in this docket. My testimony addresses the Settlement from a ratemaking perspective. While I focus primarily on the features of the 2004 Settlement that affect class revenue responsibility, changes in rate design are also addressed. My testimony complements that of Mr. Effron, the other witness for the Division in this proceeding.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. The remainder of this section provides a summary of my key points and my recommendation. My detailed testimony is presented in the following two sections. The first is a general discussion of settlements in light of ratemaking principles. The second addresses the ratemaking aspects of the 2004 Settlement in particular.

Q. WHAT ARE THE KEY POINTS OF YOUR TESTIMONY?

A. My key points are the following:

- Bonbright's *Criteria of a Sound Rate Structure* provide an appropriate basis for evaluation of the 2004 Settlement from a ratemaking perspective.
- In general, a broadly supported settlement developed by knowledgeable parties, such as the 2004 Settlement, is likely to satisfy Bonbright's criteria of equity, efficiency, and rate stability.
- Apportionment of the distribution rate reduction and the customer credit in the 2004 Settlement is based on factors that reflect cost causation.
- The 2004 Settlement addresses customer acceptance and fosters rate stability to an extent unlikely to be achieved through a litigated proceeding.

Q. DO YOU RECOMMEND APPROVAL OF THE 2004 SETTLEMENT?

A. Yes, I recommend it strongly.

2. RATEMAKING PRINCIPLES

Q. PLEASE EXPLAIN WHAT YOU MEAN BY RATEMAKING.

A. Ratemaking is the process by which a utility's required revenues are translated into the charges which customers pay. Ratemaking involves two steps: development of revenue requirements for individual rate classes, and the design of charges to recover those requirements.

Q. ARE SETTLEMENTS A COMMON FEATURE OF RATEMAKING?

A. Yes, they are quite common. Regulators often encourage parties to see if they can reach a settlement on all or some issues. Even without regulatory encouragement, parties often enter into settlements because that provides the best opportunity for each party to achieve the goals most important to them.

Q. WHAT GENERAL PRINCIPLES SHOULD GUIDE RATEMAKING?

A. Bonbright's *Criteria of a Sound Rate Structure*, reproduced in Exhibit JS-3, provides an appropriate general framework for ratemaking. Among his eight criteria, Bonbright identifies three as primary:

- Opportunity to earn a fair rate of return, generally referred to as "revenue sufficiency."
- Equity in the apportionment of costs.
- Efficiency in pricing.

There are many ways to address revenue sufficiency. Choices in ratemaking generally

reflect considerations of equity and efficiency.

Q. WHAT IS REQUIRED FOR EQUITY IN RATEMAKING?

A. The basic requirement for equity in ratemaking is described in Bonbright's Criterion No. 6 which calls for fairness in the apportionment of costs among ratepayers.

Q. HOW DOES ONE DETERMINE IF AN APPORTIONMENT IS FAIR?

A. To test whether an apportionment is fair, two points are generally considered:

- Are differences in apportionment based on differences in cost causation?
- If the differences in apportionment are made clear to ratepayers, are they likely to be accepted?

The second point is often referred to as "customer acceptability." Bonbright includes public acceptability among the practical attributes of a sound rate structure listed in his Criterion No. 1.

Q. WHAT IS REQUIRED FOR EFFICIENCY IN RATEMAKING?

A. The basic requirement for efficiency in ratemaking is described in Bonbright's Criterion No. 8, which calls for the development of rates that discourage wasteful use of service while promoting all justified types and amounts of use.

Q. ARE THERE OTHER IMPORTANT RATEMAKING PRINCIPLES?

A. Yes, rate stability is generally recognized as important. Rate stability is described in Bonbright's criterion No. 5. It calls for a minimum of unexpected changes seriously

adverse to existing customers.

Q. ARE SETTLEMENTS LIKELY TO MEET THE CRITERIA OF EQUITY, EFFICIENCY AND RATE STABILITY?

A. Yes. The negotiations that lead to a settlement resemble those that underlie competitive markets. Like informed buyers and sellers, knowledgeable participants in settlement negotiations drive the process toward an equitable and efficient outcome. The resulting settlement can often address rate stability more effectively than would be possible if the issues were litigated.

Q. PLEASE DISCUSS THE BASIS FOR EQUITY IN SETTLEMENTS IN A BIT MORE DETAIL.

A. The case for equity in a settlement is clear and strong as long as the settlement reflects a broad cross-section of ratepayer interests, and the parties involved are knowledgeable and have access to basic ratemaking tools such as Cost-of-Service (COSS) study results. A settlement generally does not rest directly on the results produced by ratemaking tools. However, if the participants know the results produced by those tools, they can factor them into their negotiations. In particular, if the proposed settlement is “too far” from cost responsibility as revealed by that participant’s preferred COSS results, the participant can withdraw from the settlement and oppose it, calling for litigation. Thus, when a settlement is broadly supported by knowledgeable parties, it is reasonable to assume that it has not strayed far from cost causation.

Q. WHAT ABOUT EFFICIENCY?

A. As long as there are parties, such as Narragansett, the Division of Public Utilities, the large commercial and industrial customers, and the Attorney General's Office, for whom efficient prices are important, it is reasonable to assume that a broadly supported settlement will foster efficiency.

Q. FINALLY, WHAT ABOUT RATE STABILITY?

A. The requirements for rate stability are clearly met by a settlement. In fact, a settlement avoids the need for an adversarial proceeding which could lead to unexpected changes adverse to at least some existing customers.

Q. WHAT CONCLUSIONS DO YOU DRAW FROM THE PRECEDING DISCUSSION?

A. The preceding discussion shows that, in general, a broadly supported ratemaking settlement developed by knowledgeable parties is likely to satisfy Bonbright's criteria of equity, efficiency, and rate stability.

Q. IS THE 2004 SETTLEMENT BROADLY SUPPORTED AND WAS IT DEVELOPED BY KNOWLEDGEABLE PARTIES?

A. Yes.

3. THE 2004 SETTLEMENT

Q. WHAT IS THE PURPOSE OF THIS PORTION OF YOUR TESTIMONY?

A. In the preceding section I discussed ratemaking settlements generally in light of Bonbright's criteria. Here I will examine the major ratemaking aspects of the 2004 Settlement in light of those same criteria.

Q. WHAT ASPECTS OF THE 2004 SETTLEMENT HAVE A MAJOR EFFECT ON CLASS REVENUE REQUIREMENTS?

A. Apportionment of the $10.243 distribution rate reduction, the associated rate freeze through 2009 and apportionment of the $22.769 customer credit have the major effect on distribution revenue requirements.

Q. DO THESE ASPECTS OF THE 2004 SETTLEMENT MEET BONBRIGHT'S CRITERIA?

A. Yes, they do. For apportionment of class revenue responsibility the key criteria are equity and rate stability. The apportionment of the rate reduction and the customer credit in the 2004 Settlement addresses the two points related to equity:

- **Cost Causation.** The apportionment is based on usage, which the Commission accepted as related to cost causation in its recent Pascoag Utility District decision in Docket 3546, and on current revenues which reflect the Commission's past decisions concerning appropriate revenue responsibility.

- **Acceptance.** The 2004 Settlement enjoys very broad support, indicating "customer acceptability."

The requirements for rate stability are also met. Acceptance of the 2004 Settlement avoids the need for cost-of-service studies and an adversarial proceeding which could lead to "unexpected changes adverse to existing customers." In fact, the 2004 Settlement avoids "unexpected changes" altogether. As the data in Settlement Exhibits 3 and 4 show, impacts on all rate classes are clearly specified. Further, as Settlement Exhibits 3 and 4 also show, all customers share in the distribution rate reduction and all but the Navy—which voluntarily gave up its claims—share in the customer credit. Support by all parties including the Navy shows that "adverse changes" have also been avoided.

Q. IS THE RATE FREEZE AN IMPORTANT FEATURE OF THE 2004 SETTLEMENT?

A. Yes. To see why, it is useful to have a look back at the history of distribution rate changes in Rhode Island. Historically, Narragansett, Blackstone Valley Electric (BVE) and Newport Electric have had a pattern of frequent and substantial distribution revenue increases. This pattern is shown in Exhibit JS-1. In the period 1980 to 1999, 14 of the 20 years saw changes in distribution revenues for at least one of the three utilities. In the 20-year period there were a total of 21 changes in distribution revenues. In all but one case, the change was an increase. Distribution rate increases generally result in changes that customers see as "adverse." Regardless of the justification, customers receiving increases are likely to feel that they have been treated inequitably. As a result of the settlement approved in Docket No. 2930, and its attendant change in regulatory framework, there has

been only one distribution rate change in the last 5 years, and that was a substantial decrease. The apportionment of additional decreases and the rate freeze proposed in the 2004 Settlement will provide decreases for all classes and 5 more years of rate stability.

To summarize the data in JS-1, the total of the distribution rate changes from electric utility rate filings for the period 1980 through 1999 was an **increase** of $94.2 million in rates. For the period 2000-2009, under the approved and proposed settlements stemming from the mergers, there is a total of $46.1 in rate **decreases / refunds**, not including any possible further refunds from earnings sharing for 2005-2009.

Q. ARE THERE BENEFITS TO A DISTRIBUTION RATE FREEZE BEYOND THOSE JUST DISCUSSED?

A. Yes. Deciding how much of a distribution rate increase should be granted and how the increases should be apportioned among rate classes is a difficult, time and resource intensive activity. Avoiding it will allow the Commission and the Division Staff to focus more of their attention on other important issues, such as future arrangements for generation supply. Freezing distribution rates will also allow ratepayers to focus on electric supply costs. In particular, it will provide a stable background against which the many ratepayers on Standard Offer Service can "see" and respond to the increases in this rate which are anticipated through 2009.

Q. ARE THERE SPECIFIC FEATURES OF THE 2004 SETTLEMENT THAT ADDRESS EFFICIENCY?

A. Yes, there are three such features:

- Reduced rates for backup and supplemental service, particularly the redesigned B-32 and B-62 rates, encourage the use of cogeneration and other distributed generation, fostering efficiency in electricity supply.
- Historically, Rhode Island has had very low monthly customer charges compared to the rest of the region. This is shown in Exhibit JS-2. The 2004 Settlement makes very modest changes in these charges, preserving the efficiency benefits of usage sensitive rates which Rhode Island currently enjoys.
- The redesign of Rate A-60 provides for an inclining block structure for kWh charges which encourages efficient use of the discounted service provided on this rate.

Q. IS RELIANCE ON COSS RESULTS AND LITIGATION LIKELY TO PRODUCE A BETTER RESULT THAN THE 2004 SETTLEMENT?

A. No. Consideration of COSS results would allow the Commission to determine how costs should be allocated. However, any gains in equity due to Commission reliance on COSS results as a guide to the apportionment of decreases would likely be outweighed by the losses in customer acceptance due to the rejection of a settlement with widespread support, and the loss of rate stability related benefits associated with a rate freeze.

I see no reason why litigation would produce a more efficient distribution rate design than that provided in the 2004 Settlement. And, with the 5-year rate freeze, the distribution rates provided in the 2004 Settlement will be in place long enough for customers to “hear” the price signals the distribution rates send. The same cannot be said

for the distribution rates that litigation might produce.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

Exhibit JS-1

ELECTRIC UTILITY DISTRIBUTION RATE INCREASES AND DECREASES: 1980-2009

Year Implemented	Amount Granted ($ Million) Narragansett $	BVE $	Newport $	Total $
1980				
1981	9.4		2.1	11.5
1982	6.2	3.2		9.4
1983		1.6		1.6
1984	(1.5)			(1.5)
1985			1.4	1.4
1986		2.4		2.4
1987			.6	.6
1988				
1989	5.8	3.6		9.4
1990	13.0			13.0
1991				
1992		3.0	3.7	6.7
1993				
1994				
1995	14.6			14.6
1996				
1997[1]	10.5	2.8	1.4	14.7
1998[1]	7.5	2.0	.9	10.4
1999				
1980-1999				**94.2**
2000	(13.1)[2]			(13.1)
2001				
2002				
2003				
2004				
2005	(10.2)[3] (22.8)[4]			(33.0)
2006				
2007				
2008				
2009				
2000-2009				**(46.1)**

[1] For 1997 and 1998 these rate increases were required by the 1996 Utility Restructuring Act.

[2] Rate reduction per Docket 2930 Merger Rate Settlement.
[3] Rate reduction per Docket 3617 proposed settlement.
[4] Customers' share of shared earnings per Docket 2930 Settlement.

Exhibit JS-2

New England Electric Utilities
Residential Customer Charge Comparison
May 2004

Company	State	Customer Charge
Connecticut Light & Power	CT	$8.69
The United Illuminating Company	CT	$8.30
Western Mass. Electric Company	MA	$8.53
NSTAR - Cambridge Electric	MA	$6.87
NSTAR - Boston Edison	MA	$6.43
Massachusetts Electric Company	MA	$5.81
NSTAR - Commonwealth Electric	MA	$3.73
Fitchburg Gas & Electric Light Company	MA	$3.02
New Hampshire Electric Co-op	NH	$20.00
Public Service of New Hampshire	NH	$7.07
Unitil	NH	$7.00
Granite State Electric Company	NH	$4.72
Narragansett Electric Company (proposed)	RI	$2.75

CRITERIA OF A SOUND RATE STRUCTURE

1. The related, "practical" attributes of simplicity, understandability, public acceptability, and feasibility of application.

2. Freedom from controversies as to proper interpretation.

3. Effectiveness in yielding total revenue requirements under the fair-return standard.

4. Revenue stability from year to year.

5. Stability of the rates themselves, with minimum of unexpected changes seriously adverse to existing customers. (Compare "The best tax is an old tax.")

6. Fairness of the specific rates in the appointment of total costs of service among the different customers.

7. Avoidance of "undue discrimination" in rate relationships.

8. Efficiency of the rate classes and rate blocks in discouraging wasteful use of service while promoting all justified types and amounts of use:

   (a) in the control of the total amounts of service supplied by the company;

   (b) in the control of the relative uses of alternative types of service (on-peak versus off-peak electricity, Pullman travel versus coach travel, single-party telephone service versus service from a multi-party line, etc.).

Source: James Bonbright, *Principles of Public Utility Rates*, Columbia University Press, 1961, page 291.

BACKGROUND AND QUALIFICATIONS

Education and Employment

Dr. Stutz received a B.S. from the State University of New York at Stonybrook in 1965 and a Ph.D. from Princeton University in 1969. Both degrees are in mathematics. After completing his Ph.D., he taught and did research at the Massachusetts Institute of Technology, the State University of New York at Albany where he received tenure, and Fordham University where he held the position of associate professor of mathematics and was co-director of the program in mathematics and economics. He left Fordham to help found Tellus where he has been employed since 1976. Tellus is a non-profit institute. It provides research and consulting services to clients in the public and private sectors in the areas of energy, environmental policy, solid waste management, water resource planning, and sustainable development.

Professional Qualifications

Dr. Stutz has extensive experience in the utility industry, particularly as an expert witness. Since 1977 he has appeared before the Federal Energy Regulatory Commission (FERC) as well as Public Utility Commissions in 39 states, the District of Columbia, and three provinces in Canada. In total, he has appeared in 181 proceedings as shown in the attached table. While most of Dr. Stutz's appearances have been in electric utility proceedings, he has also testified on gas and telecommunications matters. Much of Dr. Stutz's testimony has addressed ratemaking issues. Since 1979, he has appeared as a witness on ratemaking in 123 proceedings. His testimony has addressed a variety of topics, including marginal costs, embedded cost-of-service studies (COSS), service quality standards, and numerous aspects of rate design.

Since the early 1980s Dr. Stutz has testified regularly on behalf of the Staff of the Rhode Island Division of Public Utilities and Carriers on electric ratemaking matters. He participated in the development of the settlement approved in Docket No. 2930 as well as the 2004 Settlement now before the Commission. Since the mid 1990s Dr. Stutz has also appeared regularly on behalf of the Staff of the Nova Scotia Utility and Review Board. In addition, he is currently working for the New Jersey Division of the Ratepayer Advocate, and the Colorado Office of Consumer Counsel.

Dr. Stutz's articles and comments on utility-related subjects have appeared in the *Public Utilities Fortnightly*, *The Electricity Journal*, and elsewhere. His paper with Thomas Austin is cited, in the second edition of Bonbright's *Principles of Public Utility Rates*, as a source of information on electric ratemaking in general and COSS in particular. He was the lead author of *Aligning Rate Design Policies with Integrated Resource Planning*, a report commissioned and published by the National Association of Regulatory Utility Commissioners (NARUC). As NARUC's preface states, Tellus was selected to prepare this report largely because of Dr. Stutz's expertise. In 2004 Dr. Stutz was an invited speaker on electricity markets at the annual CAMPUT conference and at the Delaware PSC Conference on Standard Offer Supply.

Dr. Stutz's Testimony Before Regulatory Commissions

STATE	APPEARANCES		STATE	APPEARANCES	
	Ratemaking	Planning		Ratemaking	Planning
Alabama	1		Minnesota	2	
Arizona	5		Mississippi	1	
Arkansas	1		Nevada	4	3
Canada	9		New Jersey	7	
Colorado	5	4	New York		5
Connecticut	3	3	New Mexico	6	
Delaware	2		New Hampshire	2	
District of Columbia	1		North Carolina	3	
FERC		3	Ohio	5	1
Florida	1	3	Oregon	1	
Georgia		1	Pennsylvania	2	4
Hawaii		1	Rhode Island	21	3
Illinois	1	3	South Carolina	1	
Iowa	1		Tennessee	1	
Kansas	1		Texas	7	1
Kentucky	1		Utah	2	
Louisiana	2		Vermont	3	1
Maine	11	5	Virginia	1	
Maryland	2		Washington		1
Massachusetts	1	4	West Virginia	3	
Michigan	2	12	Wisconsin	1	
				Total Ratemaking	Total Planning
				123	58