BEFORE THE
RHODE ISLAND PUBLIC UTILITY COMMISSION

DOCKET NO. 4065

DIRECT TESTIMONY

OF

RICHARD S. HAHN

INVESTIGATION AS TO THE PROPRIETY OF PROPOSED TARIFF CHANGES FOR
NARRAGANSETT ELECTRIC COMPANY

ON BEHALF OF THE
RHODE ISLAND DIVISION OF PUBLIC UTILITIES AND CARRIERS

SEPTEMBER 15, 2009

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I. INTRODUCTION

Q. Please identify yourself for the record.

A. My name is Richard S. Hahn. I am a Principal Consultant for La Capra Associates, Inc. ("La Capra Associates"). My business address is La Capra Associates, One Washington Mall, Boston, MA 02108.

Q. On whose behalf are your testifying?

A. The Rhode Island Division of Public Utilities and Carriers ("Division").

Q. Could you please describe your educational background?

A. I have a both a Bachelors of Science and Masters of Science in Electrical Engineering from Northeastern University. I also have a Masters of Business Administration from Boston College.

Q. Mr. Hahn, please summarize your experience and qualifications.

A. I am a Registered Professional Engineer in Massachusetts. I have worked in the electric utility business for more than 35 years. From 1973 to 2003, I worked at NSTAR Electric & Gas (formerly Boston Edison Company). I have held many technical and managerial positions in both regulated and unregulated subsidiaries covering all aspects of utility planning, operations, regulatory activities, and finance. In 2004, I joined La Capra Associates. Since then, I have worked on projects related to power procurement, generating asset valuations, resource planning, transmission, analyzing market rules and prices, mergers, and litigation support. My resume is provided in Exhibit RSH-1.

Q. What has been your experience and expertise relative to electric delivery systems and cost recovery mechanisms?

A. At various times throughout my career, I have been involved in the planning and operation of transmission and distribution systems. I have also been involved in utility rate cases and other forums related to the recovery of utility costs. My electrical engineering degrees are from Northeastern University's Power Engineering Program, which specialized in electric utility systems.

Q. What is the purpose of your testimony in this proceeding?

A. La Capra Associates has been retained by the Division to review and comment on the petition submitted by Narragansett Electric Company ("Narragansett" or the "Company") to the Rhode Island Public Utilities Commission ("Commission") for approval of their proposed rate increase and cost recovery mechanisms. Specifically, my testimony addresses the proposed Inspection & Maintenance ("I&M") Program, the Vegetation Management Program, the Capital Plan, and the Facilities Plan, as described in the testimony of John Pettigrew, which is filed on behalf of the Company in this proceeding.

Q. Have you reviewed the Company's filing in this case?

A. Yes, I have. I have reviewed the testimonies of Mr. Pettigrew, Ms. Tierney, Mr. O'Brien, Mr. Kateregga, and Mr. Gorman. I have also reviewed relevant responses to discovery questions.

II. EXECUTIVE SUMMARY

Q. What do you recommend as a result of your review?

A. I have several recommendations, as summarized below.

- I recommend that the proposal for a separate surcharge for the I&M Program and the Vegetation Management be rejected, primarily because of their small size relative to the overall scale of the Company' operations, plus the fact that these programs appear to have been implemented a few years ago. The scope of the proposed I&M and Vegetation Management plans are well within the purview of the Company's management. If the Company believes that these plans will improve its operations, then it should implement them. Management does not need pre-approval from the Commission, nor special cost recovery mechanisms, for such activities.
- Regarding the Capital Plan and Cost Recovery mechanism, capital additions in 2008 of approximately $68 million were 45% higher than the $47 million per year level from 2005 to 2007. The Company has proposed a capital spending plan for 2009 and 2010 that is in line with 2008 levels. It appears that its electric delivery system in Rhode Island is reliable and the Company has been investing adequately in order to maintain that reliability. Since rates will be set based upon 2008 spending levels, there does not appear to be a specific need for the special capital tracking mechanism to be included in the decoupling proposal. I recommend that this separate mechanism not be approved.
- Regarding the Facilities Plan, the Commission should require the Company to include the appropriate level of savings expected as a result of the facilities consolidation in the cost of service.

III. SUMMARY OF THE COMPANY'S PROPOSAL

Q. Please briefly describe the Company's proposal in its petition.

A. The testimony of Mr. Pettigrew describes the Company's electric delivery system and its objectives to provide reliable and safe electric service for their customers and employees. He outlines a new approach where the Company will transition from a reactive, repair-oriented approach to one driven by asset management principles. Mr. Pettigrew discussed the age of the Company' assets and claims a need to replace many of them on an expedited basis. The Company will alter their organizational structures and the manner in which they develop their Annual Plan to achieve the objectives.

Mr. Pettigrew proposed several specific initiatives. The first is an enhanced inspection and maintenance program under which 20% of the Company' system will be inspected each year, and changes and / or new investments will be made depending upon the results of those inspections. Next, Mr. Pettigrew describes practices to contain costs in the core areas of Asset Management, Customer Management, Contracting Services, Work Delivery, Construction Design, and Network Operations. According to Mr. Pettigrew, implementing these improvements will require additional costs in the short run to achieve the desired efficiencies in the long run, and significant financial resources will be required for these improvements.

Mr. Pettigrew's testimony supports the Company's proposed new mechanisms for cost recovery of its I&M program, its Vegetation Management Program, and its capital funding program. Mr. Pettigrew asserts that the requested special tracking mechanisms are necessary in order for the Company to raise capital and fund necessary projects.

Q. What is the cost of the proposed I&M program?

A. According to the testimony of Mr. Pettigrew, the new I&M program is expected to cost approximately $4.7 million per year, or approximately $2.1 million per year in excess of historic levels.[1] The Company proposes to recover this amount through a separate factor or surcharge. It is my understanding that this incremental amount above historic test year levels is divided by 2010 estimated kWh sales to arrive at a $ per kWh charge that will be added to the electric bills of each of the Company's customers starting on January 1, 2010.

Q. What does the Company propose for its Vegetation Management Program?

A. Narragansett proposes to spend approximately $9 million per year in vegetation management costs, which is approximately $2 million higher than the historic test year level of $7 million.[2] It is my understanding that this incremental amount above historic test year levels is divided by 2010 estimated kWh sales to arrive at a $ per kWh charge that will also be added to the electric bills of each of the Company's customers starting on January 1, 2010.

Q. What is the Company's proposal regarding future capital investments?

A. As part of its decoupling mechanism, the Company propose to recover the incremental revenue requirements associated with capital investments made subsequent to the historic test year (2008) via a $ per kWh surcharge similar to the I&M and Vegetation Management surcharges described above. It should be noted that the decoupling

1 See Exhibit NG-RLO-2, page 24 of 39.
2 See Exhibit NG-JP-2

mechanism proposed by the Company includes other factors beside recovery of incremental capital additions, such as an inflation adjustment.

Q. Have the Company provided a forecast of the level of capital spending?

A. The testimony of Mr. Pettigrew provides a forecast of future capital spending levels. In Exhibit NG-JP-3, future levels of capital spending are provided. These capital spending levels are $60 million for 2009 and $76 million in 2010.

Q. How does this estimate of capital spending compared to recent data on capital additions reported by the Company?

A. The following table summarizes capital additions to transmission and distribution plant as reported in Narragansett Electric Company FERC Form 1 for the last three years. As noted earlier, 2008 spending is significantly above pre-2008 levels. Capital additions in 2008 are at a level that is equal to or above what the Company proposes for the future.

Year	Transmission	Distribution	Total T&D
2006	$638,517	$46,988,796	$47,627,313
2007	$8,503,766	$47,892,648	$56,396,414
2008	$31,788,587	$67,688,304	$99,476,891

Q. Please summarize the Company' proposal on facilities.

A. The parent Company, National Grid, is implementing the consolidation of facilities, offices, and operating centers as a result of the recent merger with KeySpan.

Mr. Pettigrew describes this consolidation and provides a benefit cost analysis of the consolidation as a justification for the inclusion in rates of the costs.

IV. REVIEW AND ASSESSMENT OF THE I&M PROGRAM

Q. Please comment on the Company's proposed I&M plan.

A. At a high level, increased inspection and maintenance activities can theoretically improve reliability and avoid certain outages. However, I have several concerns with what the Company has proposed here. The Company has not provided sufficient detail about the inspection plan, especially as to how it is significantly different from what is done now. It should be noted that certain distribution assets lend themselves better to inspections than others. For example, pole-mounted distribution transformers are sealed devices, and a visual inspection may not yield any meaningful information. The same applies to fused cut-outs. On the other hand, visual inspections of the poles themselves and hardware such a hangers, brackets, and insulators can help identify issues that can be corrected quickly. The Company has not provided any details about the types of inspections they plan to perform. The potential benefits have not been quantified, so it is difficult to assess its cost-effectiveness.

Another significant problem with the proposal is that the Company has not demonstrated that all of the costs of this program are truly incremental. It is inappropriate to include any existing costs in a new separate surcharge. To the extent that such a charge is allowed, it should only include truly incremental costs. Finally, it is unclear why there should be a separate surcharge for an incremental $2 million expense, even if that is the proper amount. The Company' total annual O&M costs are approximately $164 million, and distribution O&M is in excess of $51 million. In the past five years, distribution O&M has increased to over $51 million from $31 million. The proposed incremental cost of the I&M plan is very small relative to those figures, so it is difficult to justify a separate component of the Company' rates for such a low figure.

Q. Is the I&M Plan a new program for Narragansett?

A. It does not appear that it is. The Company's own filing indicates that some costs were incurred in 2008. As noted later in my testimony, Exhibit RSH-10 and RSH-11 provide excerpts from National Grid documents from a Massachusetts proceeding in Docket DPU 07-30. In these documents, it is clear that the I&M program began as far back as 2006, and perhaps earlier.

Q. What do you recommend to the Commission?

A. The scope of the proposed I&M plan is well within the purview of the Company's management. If the Company believes that this plan will improve their operations, then they should implement it. Indeed, it can be argued that the Company should have been doing this type of program all along. Management does not need pre-approval from the Commission, nor special cost recovery mechanisms, for such activities. The Company has not provided adequate justification for the proposed increased in spending on I&M activities. System reliability today is good, so the current test year level of spending seems to be producing good results. The amount that will be spent is somewhat speculative, and does not appear to be the kind of known and measurable change that is normally included as a pro forma adjustment to historic test year data. Given its small size relative to the overall scale of the Company's operations, I recommend that the proposal for a separate surcharge for this program be rejected.

V. <u>REVIEW AND ASSESSMENT OF THE VEGETATION MANAGEMENT PROGRAM</u>

Q. Please comment on the Company's proposed Vegetation Management plan.

A. I have comments on the Vegetation Management Program proposed by the Company that are essentially the same as the comments on the I&M plan. This plan also appears to have begun implementation some time ago. Its incremental costs are small relative to the Company's overall operation, and the need for a specific tracking cost recovery mechanism has not been demonstrated.

Q. What do you recommend to the Commission?

A. The scope of the proposed Vegetation Management plan is well within the purview of the Company's management. As with the I&M Plan, if the Company believes that this plan will improve their operations, then they should implement it. Indeed, it can be argued that the Company should have been and has been doing this type of program all along. Management does not need pre-approval from the Commission, nor special cost recovery mechanisms, for such activities. The Company has not provided adequate justification for the proposed increased in spending on Vegetation Management activities. System reliability today is good, so the current test year level of spending seems to be producing good results. The amount that will be spent is somewhat speculative, and does not appear to be the kind of known and measurable change that is normally included as a pro forma adjustment to historic test year data. Given its small size relative to the overall scale of the Company's operations, I recommend that the proposal for a separate surcharge for this program be rejected.

VI. REVIEW AND ASSESSMENT OF THE CAPITAL PLAN

Q. Please comment on the proposed capital plan and the mechanism for cost recovery.

A. The Company has stated that its delivery system is extremely old and in need of significant investment. However, other than providing some graphs of the vintage of some types of equipment, the Company has not provided supporting evidence to support their claim that the system is in need of huge investments. In fact, the Company's spending projections for the next two years is on the same level as recent years. In addition, there is no benchmarking information provided to help demonstrate that past investment levels have been below industry levels for comparable utilities. Utilities, particularly in the Northeast, normally have plant in service that may be considered old. Without specific evidence of problems, it is very difficult to assess the merits of the Company's claim. I should note that the depreciation study[3] submitted in this proceeding by the Company proposes to decrease the depreciation rate for distribution assets to 3.35% from 3.53%. This rate change implies that the distribution assets have now been determined to have longer remaining useful lives than those determined in the previous study, which certainly contradicts the assertion that the system is now deemed to be old and in need of accelerated replacement.

Q. Have you been able to review recent spending for capital expenditures and O&M activities by the Company?

[3] See Exhibit NG-KAK-1

A. Using publicly available data from FERC Form 1 reports, I was able to review capital spending and O&M costs from 1994 through 2008 for Narragansett Electric. Exhibit AG-RSH-2 shows capital additions to distribution plant while Exhibit AG-RSH-3 shows annual O&M spending for distribution related activities for Narragansett Electric Company. It is clear from both of these exhibits that both capital and O&M spending have increased dramatically in recent years.

Q. Is there any evidence that this increased spending is yielding any benefits?

A. Yes. On page 6 of Mr. Pettigrew's testimony, a graph of reliability statistics for SAIFI and SAIDI is provided. From 2001 to 2009, these statistics have been improving according to the information presented by the Company. In the response to Division Data Request 11-4, the Company provided the results of a 2006 benchmarking study of the reliability of its system to those of other utilities. As shown in that response, Narragansett is in the top quartile of reliability performance for the statistics for SAIDI and SAIFI. This is further evidence that the Company has been investing in its systems and providing a high level of reliability.

Q. Has the Commission reviewed the reliability performance of the Company?

A. It is my understanding that the Company files annual reports with the Division summarizing its performance relative to reliability. In the past, some of these reports have been reviewed by PowerServices, a North Carolina-based consulting firm providing engineering and management services, at the request of the Commission. In summarizing a recent assessment of Narragansett's reliability performance, Mr. Booth, President of PowerServices, wrote as follows:[4]

> *"I have been involved in the reliability assessment program with the Division in reviewing National Grid, providing reports, interfacing with National Grid, and reviewing its distribution system performance reports for nearly five years. I am convinced, to a reasonable degree of engineering certainty, that National Grid has, in fact, embraced the reliability assessment program and instituted nearly all of the action items and recommendations that came out of the initial program. It has also gone beyond the initial expectations in its program expansion, technical development, and implementation. This is not to say that the Division will not receive complaints from time-to-time from individual customers. It is reasonable for the Division to expect National Grid's reliability to be maintained and, in fact, improved (albeit somewhat marginally) throughout time as a result of this entire process and, in particular, because of the programs implemented by National Grid as outlined in each of its distribution system performance annual reports. <u>The Division can be comfortable that the reliability enhancement process is working and should sustain itself</u>."*

As further evidence of the Company's current high level of reliability, the Company sent a letter to the Division on June 30, 2009[5] regarding the performance of its distribution system. This letter indicates that the reliability statistics for SAIDI and SAIFI have continued to improve in 2009, maintaining the top quartile performance from the 2006 benchmarking study mentioned earlier. This document is informative on two other points. It states that the feeder hardening program will be replaced by the new I&M program, contrary to the Company's testimony in this proceeding that it will implement both programs. And the letter also notes that the last oil fused cutout has been replaced, ending the need for this program in future annual spending plans.

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[4] See September 15, 2008 letter To Mr. Lunch from Mr. Booth.
[5] See June 30, 2009 letter to Mr. Lynch from Mr. Teehan.

It is clear form these documents that the Company has achieved a high level of reliability and that its spending has been at appropriate levels. It is unclear that substantial increases in spending are warranted at this point in time.

Q. Have you been able to compare the spending levels for the Company with the expenditures of other utility companies?

A. Yes. Again using publicly available data from FERC Form 1 report, I examined distribution plant in service and distribution O&M costs for a sample group of utilities similar to the Company. Exhibit AG-RSH-4 contains a list of utilities that were included in this benchmarking exercise.

Using the data from FERC Form 1 reports for these utilities, I compared 2008 statistics, such as gross distribution plant per MW, per MWh, and per customer for this group of utilities.

Q. What were the results of these comparisons?

A. Exhibits AG-RSH-5, AG-RSH-6, and AG-RSH-7 compare Narragansett Electric’s gross distribution plant in service relative to its size for the value of other utilities. Narragansett Electric’s statistics indicate that its plant in service is comparable to, if not higher than, other similar utilities.

Q. These exhibits show a snapshot of gross distribution plant at the end of 2008. Has Narragansett Electric’s position relative to these other utilities changed over time?

A. Exhibit AG-RSH-8 shows the gross distribution plant per MW for the utility comparison group since 1994. Narragansett Electric's relative position appears to have improved over the same time period.

Narragansett Electric Company
Distribution Plant per MW - Relative Ranking
($000)

year	min	Narragansett	max	percentile
1994	$280	$350	$495	33%
2008	$380	$609	$790	56%

Q. How would Exhibit AG-RSH-2 change if the Company's capital spending plan was implemented?

A. Exhibit AG-RSH-9 shows the result of that comparison. The Company' capital plan calls for spending to average $68 million in 2009 and 2010. If this plan were implemented, capital spending would be comparable to the 2008 capital spending in the test year, which is already 45% higher than the capital spending level from 2005 to 2007.

Q. What do you conclude from these analyses?

A. These benchmarking comparisons indicate that the spending by the Company on their delivery systems is consistent with those of other similar utilities. This analysis at least calls into question the need for a significant ramp-up in spending as suggested by the Company. The Company's own plan calls for approximately $60 million per year in 2009 and $75 million in 2010, which is less than capital additions in 2008. Absent demonstrative proof of the need for spending levels significantly above this level, it is difficult to accept the Company's assertion that such investments are necessary, and that a special cost recovery mechanism is required.

Q. Is there other evidence that indicates that the Company's investment levels in its system have been appropriate?

A. In Massachusetts Docket D.P.U. 07-30, the issue of the reliability of the NGRID system was examined. Specifically, in response to information request AG 10-6, the Company provided several documents that describe identified reliability needs as far back as 2004. Exhibit AG-RSH-10 is an excerpt from a December 2004 internal presentation that identified the reliability issues and proposed a plan to address them. Exhibit AG-RSH-11 is another excerpt from a January 2006 internal presentation. The documents underlying these Exhibits provided information for all of National Grid's regulated affiliates, including Narragansett. These excerpts and the other accompanying documents indicate that the Company has already invested considerable funds to improve reliability and address the equipment age issue. This is consistent with the dramatic spending increases since 2004. These documents also show that spending in 2009 through 2011 does not ramp up significantly as the Company have claimed is needed in this proceeding. For example, in Exhibit AG-RSH-10, capital spending for NGRID regulated subsidiaries in New York and New England was projected to be $107 million in 2009 and $114 million in both 2010 and 2011. It would appear from these documents that the Company developed the proposed enhanced reliability program back in 2004 towards the end of the rate freeze period of the NEES merger Rate Plan[6], and that its implementation began some time ago.

Q. If current spending levels are appropriate, how does this affect the need for a special tracking mechanism as proposed by the Company?

A. If the Company 2008 test year spending is representative of the levels required in the future, then it is likely that such a special tracking mechanism for capital projects will not be needed as part of the decoupling mechanism.

Q. Have the Company demonstrated that they cannot fund necessary improvements to their delivery systems without a special mechanism?

A. No, they have not. No analyses or studies have been included as part of the Company's filing that even attempt to demonstrate or prove this assertion. The Company plans to issue $512 million in new long-term debt to replace $156 million in existing short-term debt and pay $356 million in cash dividends to their parent company.[7] Thus, it is clear that the Company can raise significant amounts of capital, if needed.

Q. What happens if the Commission does not approve the Company's request for a special rate mechanism to recovery future capital investments in this proceeding?

A. In order to fund its capital investments, the Company can rely upon depreciation, retained earnings, and other sources of internally generated funds. To the extent that these sources cannot support the Company's capital spending, the Company can issue new debt and equity, and at the appropriate time, file future rate cases. This is how most utility companies fund their construction programs. The Company is not impeded by this

[6] The Rate Plan from the NEES – EUA merger ended in 2004. A subsequent Rate Plan over the 2005 to 2009 time period.
[7] See pages 6 – 7 of the testimony of Mr. Moul.

approach, nor are they prevented from making necessary capital improvements to its system, as they have done over the past several years.

Q. What do you recommend to the Commission regarding the Company's plan for future capital additions?

A. The Commission should reject the Company's suggestion that a large increase in capital spending is driving the need for a capex tracking cost recovery mechanism. Given that the Company has not proposed an increase in capital spending over 2008 test year levels, there does not appear to be a specific need for the special capex tracking mechanism in the decoupling proposal. I recommend that this mechanism not be approved.

VII. REVIEW AND ASSESSMENT OF THE FACILITIES PLAN

Q. Please comment on the Company' Facilities Plan.

A. Exhibit NG-JP-4 contains a cost / benefit analysis of facilities consolidation. Lines 1 through 11 show a twenty-year NPV of $29 million, while lines 12 through 19 show $12 million. These NPV values appear to be net of certain on-time costs. Annual numbers are not provided, but these NPV figures would indicate significant levels of annual savings.

Q. Have these expected savings been reflected in the Cost of Service?

A. I am unable to locate a schedule or workpaper within the Cost of Service study that shows that the expected savings from the facilities consolidation as estimated in Exhibit NG-JP-4 have been reflected in the Company's proposed rates.

Q. What do you recommend regarding the Facilities Plan?

A. The Commission should require the Company to include the appropriate level of savings expected as a result of the facilities consolidation in the cost of service in this proceeding.

VIII. CONCLUSION

Q. Does that conclude your testimony?

A. At this time, yes. Should additional information become available via the discovery process, I will update this testimony as appropriate.

Exhibit RSH-1

Resume of Richard S. Hahn

La Capra Associates

Richard S. Hahn

Principal Consultant

Mr. Hahn is a senior executive in the energy industry, with diverse experience in both regulated and unregulated Company. He joined La Capra Associates in 2004. Mr. Hahn has a proven track record of analyzing energy, capacity, and ancillary services markets, valuation of energy assets, developing and reviewing integrated resource plans, creating operational excellence, managing full P&Ls, and developing start-ups. He has demonstrated expertise in electricity markets, utility planning and operations, sales and marketing, engineering, business development, and R&D. Mr. Hahn also has extensive knowledge and experience in both the energy and telecommunications industries. He has testified on numerous occasions before the Massachusetts Department of Telecommunications and Energy, and also before FERC.

SELECTED EXPERIENCE – *LA CAPRA ASSOCIATES*

- Performed an assessment of plans to procure Default Service Power Supplies for a Rhode Island utility. Provided expert testimony before the Rhode Island Public Utilities Commission.
- Served as an advisor to Vermont electric utilities regarding the evaluation of new power supply alternatives.
- Conducted a review of Massachusetts electric utilities' proposal to construct, own, and operate large scale PV solar generating units. Served as an advisor to the Massachusetts Attorney General in settlement negotiations.
- Served as a key member of a La Capra Team evaluating wind generation RFPs in Oklahoma.
- Performed an assessment of plans to procure Default Service Power Supplies for Pennsylvania utilities. Provided expert testimony before the Pennsylvania Public Utilities Commission.
- Performed an assessment of a merchant generator proposal to construct, own, and operate 800 MW of large scale PV solar generating units in Maine.
- Analyzed proposed environmental upgrades to an existing coal-fired power plant in Wisconsin, including an economic evaluation of this investment compared to alternative supply resources. Provided expert testimony before the Public Service Commission of Wisconsin.
- Performed a study of non-transmission alternatives (NTAs) to a proposed set of transmission upgrades to the bulk power supply system in Maine.
- Served as a key member of the La Capra Team advising the Connecticut Energy Advisory Board (CEAB) on a wide range of energy issues, including integrated resources plan and the need for and alternatives to new transmission projects.
- Performed a study of non-transmission alternatives (NTAs) to a proposed set of

transmission upgrades to the bulk power supply system in Vermont.

- Served as an advisor to the Delaware Public Service Commission and three other state agencies in the review of Delmarva Power & Light's integrated resource plan and the procurement of power supplies to meet SOS obligations.
- Served as an expert witness in litigation involving a contract dispute between the owner of a merchant powerplant and the purchasers of the output of the plant.
- Served as an advisor to the Maryland Attorney General's Office in the proposed merger between Constellation Energy and the FPL Group.
- Reviewed and analyzed outages for Connecticut utilities during the August 2006 heat wave. Prepared an assessment of utility filed reports and corrective actions.
- Conducted a study of required planning data and prepared forecasts of the key drivers of future power supply costs for public power systems in New England.
- Reviewed and analyzed Hawaiian Electric Company integrated resource plan and its DSM programs for the State of Hawaii. Prepared written statement of position and testified in panel discussions before the Hawaii Public Utility Commission.
- Assisted the Town of Hingham, MA in reviewing alternatives to improve wireless coverage within the Town and to leverage existing telecommunication assets of the Hingham Municipal Light Plant.
- Conducted an extensive study of distributed generation technologies, options, costs, and performance parameters for VELCO and CVPS.
- Analyzed and evaluated proposals for three substations in Connecticut. Prepared and issued RFPs to seek alternatives in accordance with state law.
- Performed an assessment of merger savings from the First Energy – GPU merger. Developed a rate mechanism to deliver the ratepayers share of those savings. Filed testimony before the PA PUC.
- Prepared long term price forecasts for energy and capacity in the ISO-NE control area for evaluating the acquisition of existing powerplants.
- Conducted an assessment of market power in PJM electricity markets as a result of the proposed merger between Exelon and PSEG. Developed a mitigation plan to alleviate potential exercise of market power. Filed testimony before the PA PUC.
- Performed a long-term locational installed capacity (LICAP) price forecast for the NYC zone of the NYISO control area for generating asset acquisition.
- Served as an Independent Evaluator of a purchase power agreement between a large mid-west utility and a very large cogeneration plant. Evaluated the implementation of amendments to the purchase power agreement, and audited compliance with very complex contract terms and operating procedures and practices.
- Performed asset valuation for energy investors targeting acquisition of major electric generating facility in New England. Prepared forecast of market prices for capacity and energy products. Presented overview of the market rules and operation of ISO-NE to investors.

- Assisted in the performance of an asset valuation of major fleet of coal-fired electric generating plants in New York. Prepared forecast of market prices for capacity and energy products. Analyzed cost and operations impacts of major environmental legislation and the effects on market prices and asset valuations.
- Conducted an analysis of the cost impact of two undersea electric cable outages within the NYISO control area for litigation support. Reviewed claims of cost impacts from loss of sales of transmission congestion contracts and replacement power costs.
- Reviewed technical studies of the operational and system impacts of major electric transmission upgrades in the state of Connecticut. Analysis including an assessment of harmonic resonance and type of cable construction to be deployed.
- Conducted a review of amendments to a purchased power agreement between an independent merchant generator and the host utility. Assessed the economic and reliability impacts and all contract terms for reasonableness.
- Assisted in the development of an energy strategy for a large Midwest manufacturing facility with on-site generation. Reviewed electric restructuring rules, electric rate availability, purchase & sale options, and operational capability to determine the least cost approach to maximizing the value of the on-site generation.
- Assisted in the review of the impact of a major transmission upgrade in Northern New England.
- Negotiated a new interconnection agreement for a large hotel in Northeastern Massachusetts.

SELECTED EXPERIENCE – *NSTAR ELECTRIC & GAS*

President & COO of NSTAR Unregulated Subsidiaries

Concurrently served as President and COO of three unregulated NSTAR subsidiaries: Advanced Energy Systems, Inc., NSTAR Steam Corporation, and NSTAR Communications, Inc.

Advanced Energy Systems, Inc.

- Responsible for all aspects of this unregulated business, a large merchant cogeneration facility in Eastern Massachusetts that sold electricity, steam, and chilled water. Duties included management, operations, finance and accounting, sales, and P&L responsibility.

NSTAR Steam Corporation

- Responsible for all aspects of this unregulated business, a district energy system in Eastern Massachusetts that sold steam for heating, cooling, and process loads. Duties included management, operations, finance and accounting, sales, and P&L responsibility.

NSTAR Communications, Inc.

- Responsible for all aspects of this unregulated business, a start-up provider of telecommunications services in Eastern Massachusetts. Duties included management, operations, finance and accounting, sales, and P&L responsibility.
- Established a joint venture with RCN to deliver a bundled package of voice, video, and data services to residential and business customers. Negotiated complex indefeasible-right-to-use and stock conversion agreements.
- Installed 2,800 miles of network in three years. Built capacity for 230,000 residential and 500 major enterprise customers.
- Testified before the Congress of the United States on increasing competition under the Telecommunications Act of 1996.

VP, Technology, Research, & Development, Boston Edison Company

- Responsible for identifying, evaluating, and deploying technological innovation at every level of the business.
- Reviewed Electric Power Research Institute (EPRI), national laboratories, vendor, and manufacturer R&D sources. Assessed state-of-the-art electro-technologies, from nuclear power plant operations to energy conservation.

VP of Marketing, Boston Edison Company

- Promoted and sold residential and commercial energy-efficiency products and customer service programs.
- Conducted market research to develop an energy-usage profile. Designed a variable time-of-use pricing structure, significantly reducing on-peak utilization for residential and commercial customers.
- Designed and marketed energy-efficiency programs.
- Established new distribution channels. Negotiated agreements with major contractors, retailers, and state and federal agencies to promote new energy-efficient electro-technologies.

Vice President, Energy Planning, Boston Edison Company

- Responsible for energy-usage forecasting, pricing, contract negotiations, and small power and cogeneration activities. Directed fuel and power purchases
- Implemented an integrated, least-cost resource planning process. Created Boston Edison's first state-approved long-range plan.
- Assessed non-traditional supply sources, developed conservation and load-management programs, and purchased from cogeneration and small power-production plants.
- Negotiated and administered over 200 transmission and purchased power contracts.

- Represented the company with external agencies. Served on the Power Planning Committee of the New England Power Pool.
- Testified before federal and state regulatory agencies.

EMPLOYMENT HISTORY

La Capra Associates, Inc.	Boston, MA
Managing Consultant	*2004 – present*
Advanced Energy Systems, Inc.	Boston, MA
President & COO	*2001-2003*
NSTAR Steam Corporation	Cambridge, MA
President & COO	*2001-2003*
NSTAR Communications, Inc.	
President & COO	*1995-2003*
Boston Edison Company	Boston, MA
VP, Technology, Research, & Development	*1993-1995*
VP, Marketing, Boston Edison Company	*1991-1993*
Vice President, Energy Planning, Boston Edison Company	*1987-1991*
Manager, Supply & Demand Planning	*1984-1987*
Manager, Fuel Regulation & Performance	*1982-1984*
Assistant to Senior Vice President, Fossil Power Plants	*1981-1982*
Division Head, Information Resources	*1978-1981*
Senior Engineer, Information Resource Division	*1977-1978*
Assistant to VP, Steam Operations	*1976-1977*
Electrical Engineer, Research & Planning Department	*1973-1976*

EDUCATION

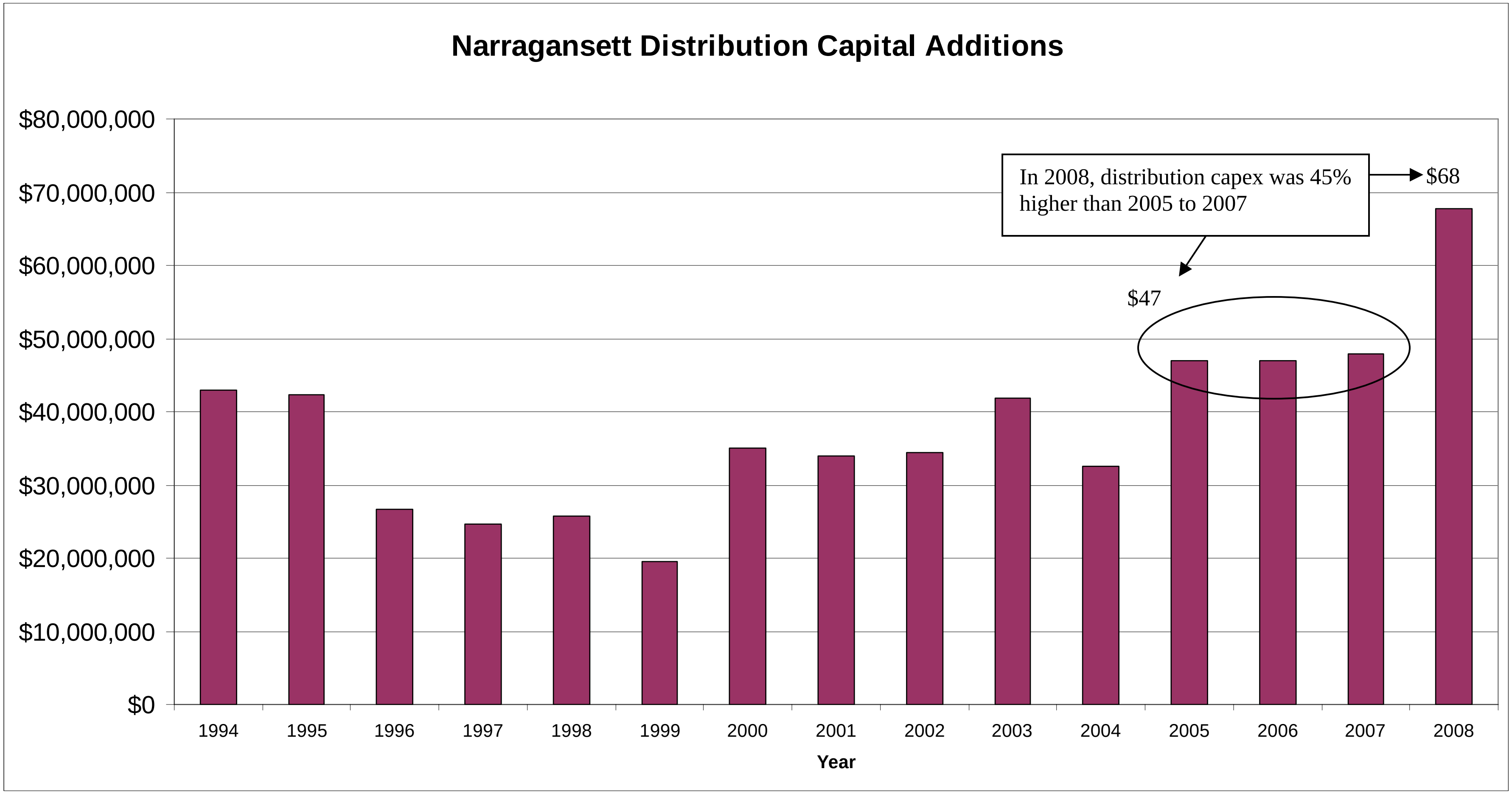
Boston College	Boston, MA
Masters in Business Administration	*1982*
Northeastern University	Boston, MA
Masters in Science, Electrical Engineering	*1974*
Northeastern University	Boston, MA
Bachelors in Science, Electrical Engineering	*1973*

PROFESSIONAL AFFILLIATIONS

Director, NSTAR Communications, Inc.	*1997-2003*
Director, Advanced Energy Systems, Inc.	*2001-2003*
Director, Neuco, Inc.	*2001-2003*
Director, United Telecom Council	*1999-2003*

Head, Business Development Division, United Telecom Council	*2000-2003*
Elected Commissioner – Reading Municipal Light Board	*2005-present*
Registered Professional Electrical Engineer in Massachusetts	

Exhibit RSH-2



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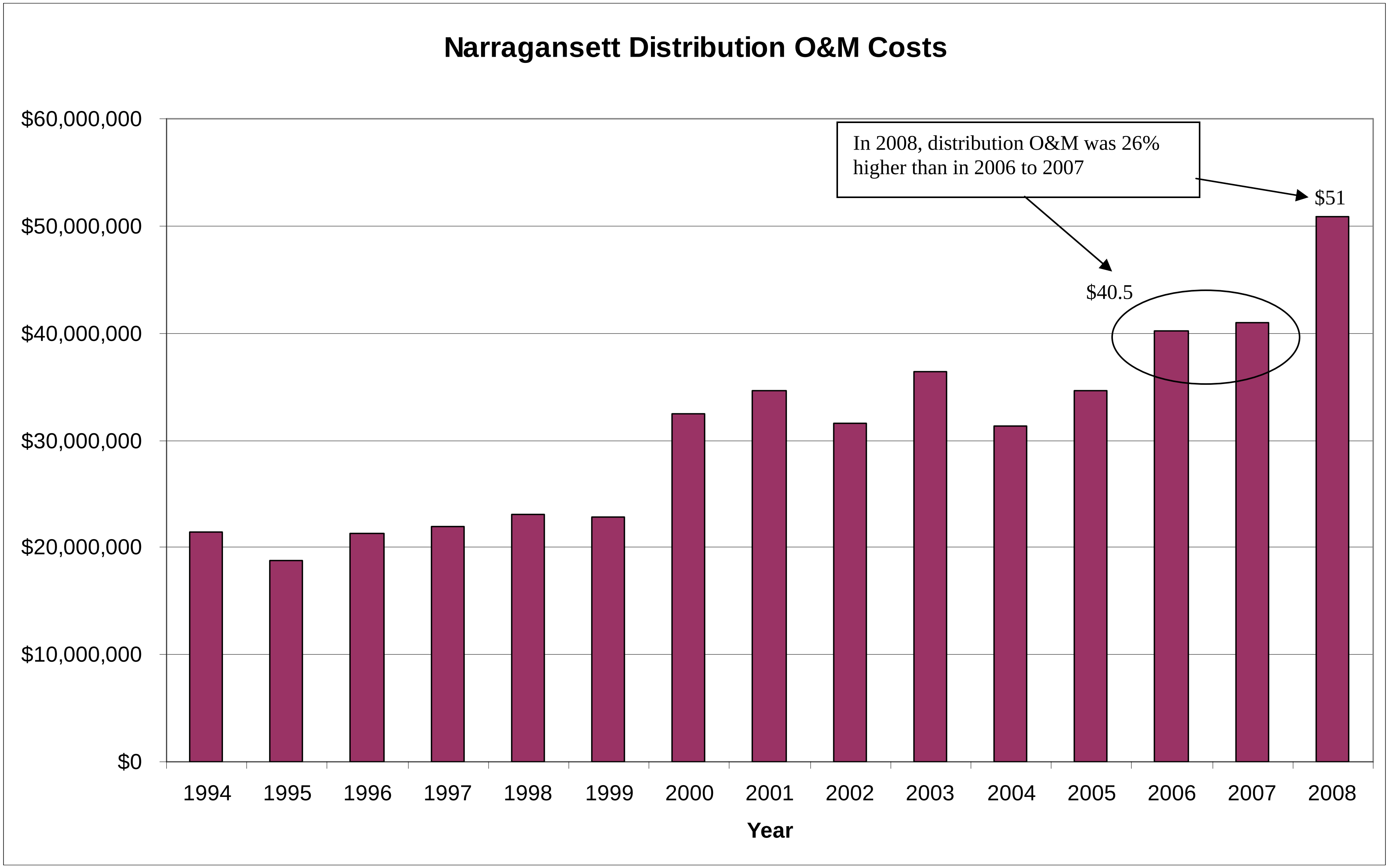


Exhibit RSH-4

List of Utilities in Benchmarking Exercise

Atlantic City Electric

Connecticut Light and Power

Duquesne Light Company

Jersey Central Power and Light

Mass Electric

Metropolitan Edison

NStar

PECO Energy

Pennsylvania Electric Company

Pennsylvania Power and Light

Public Service Electric and Gas

Public Service New Hampshire

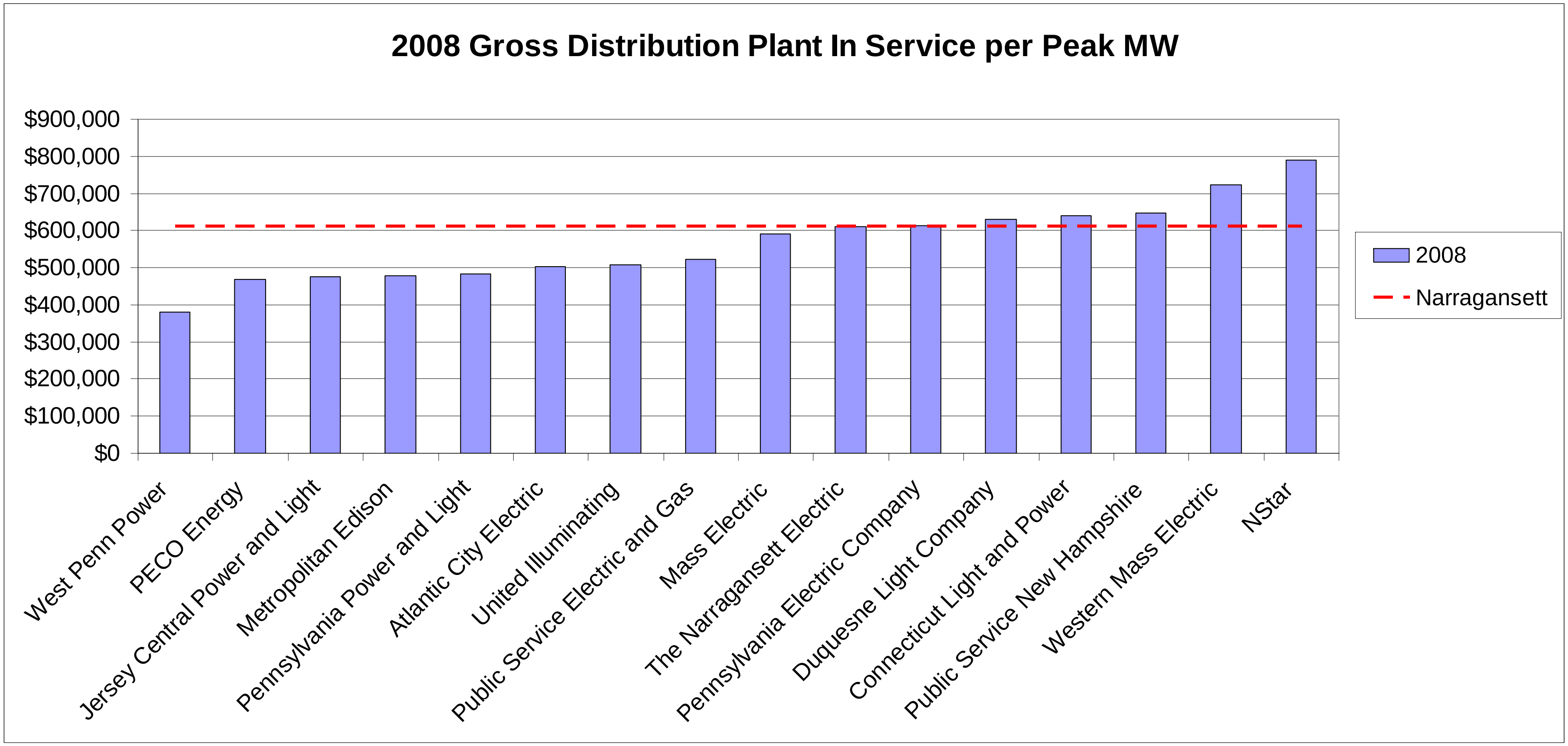
The Narragansett Electric

United Illuminating

West Penn Power

Western Mass Electric

Exhibit RSH-5



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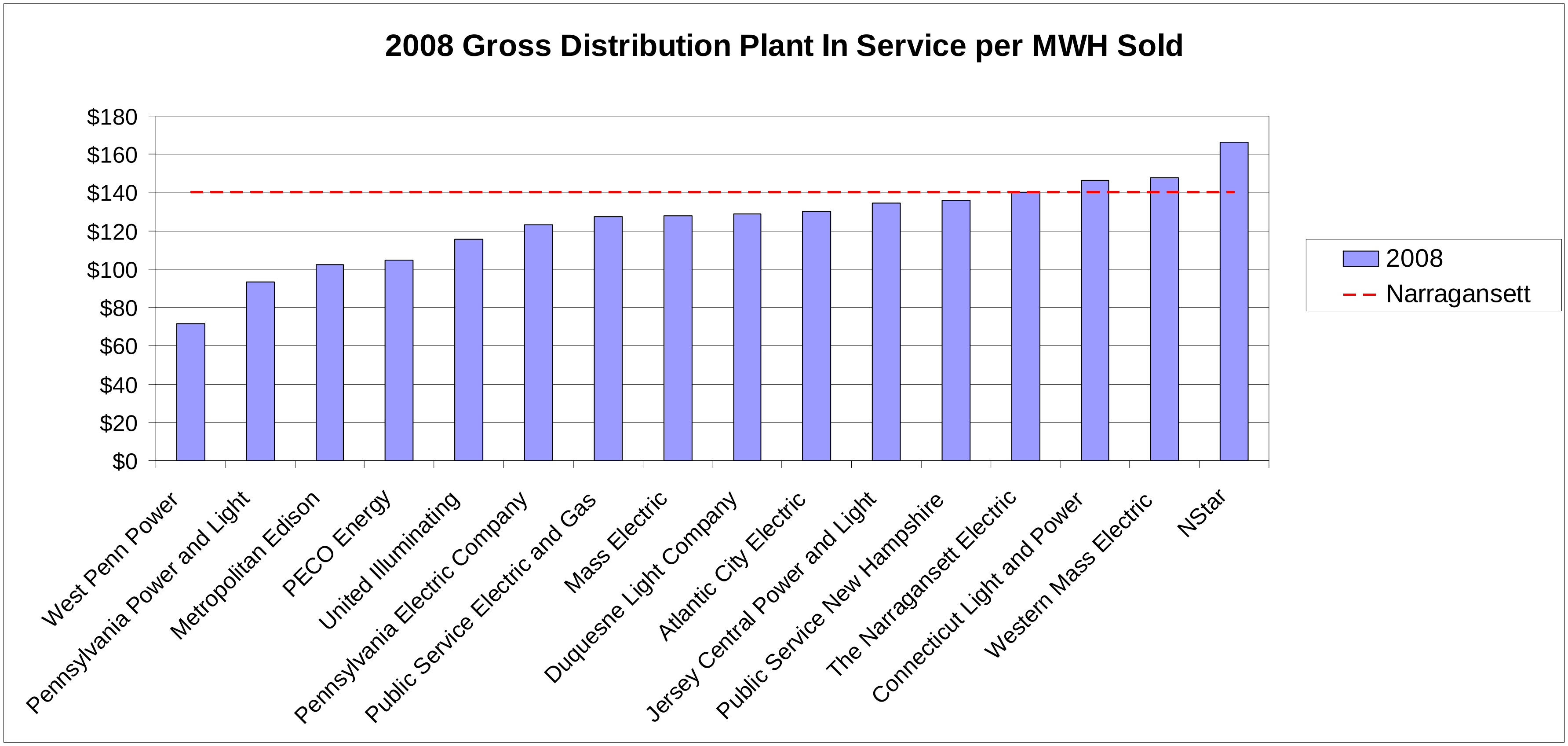

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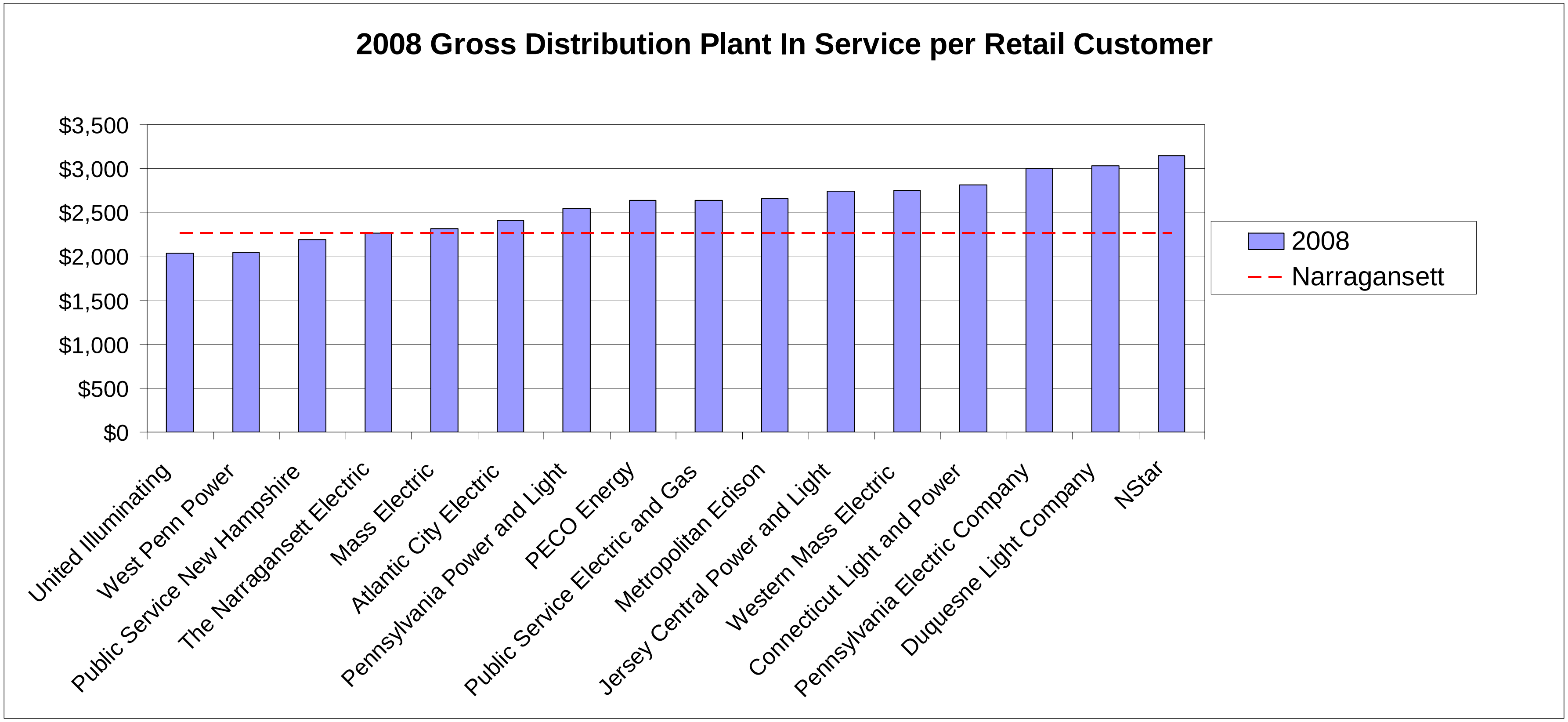

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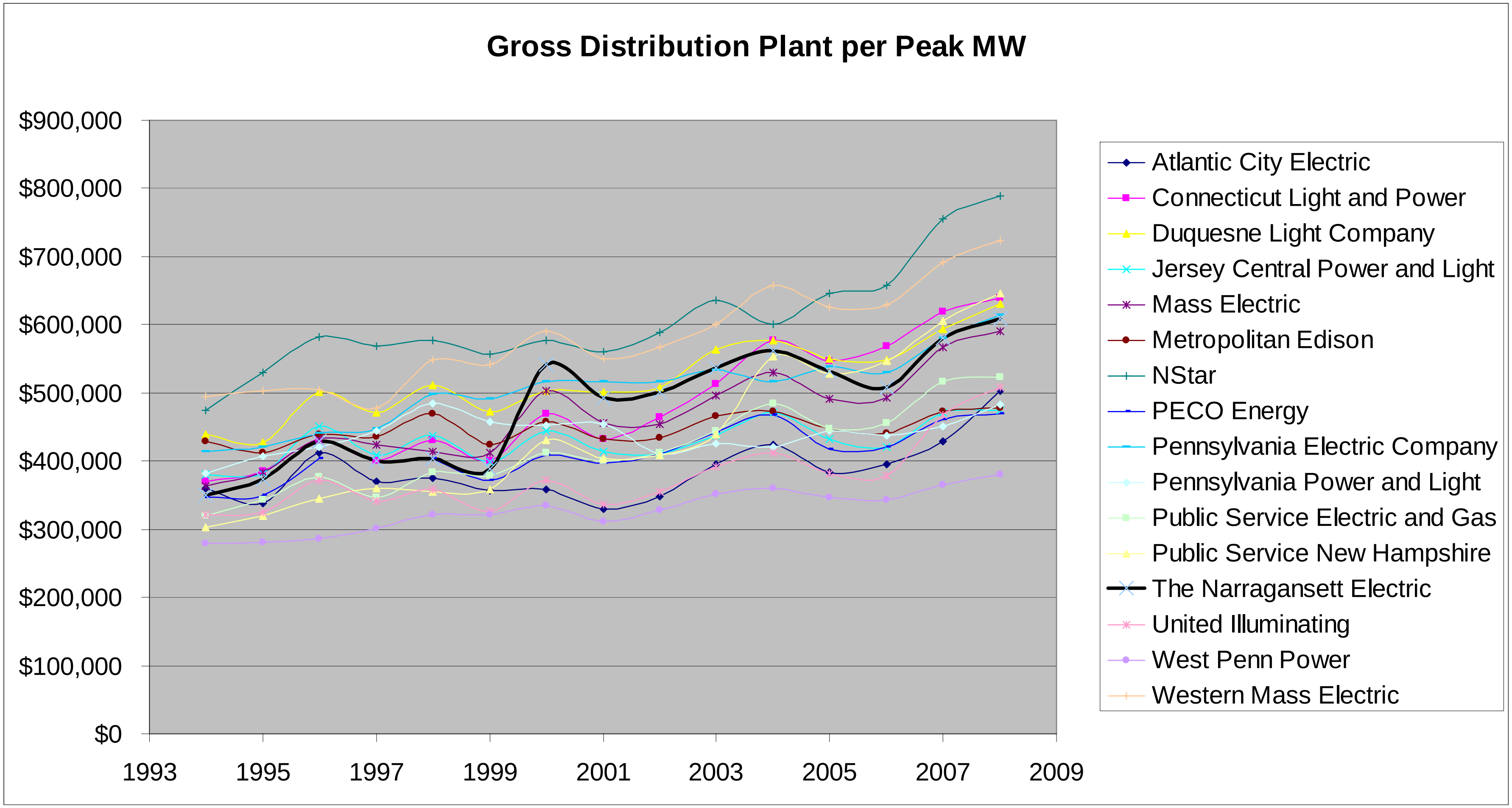

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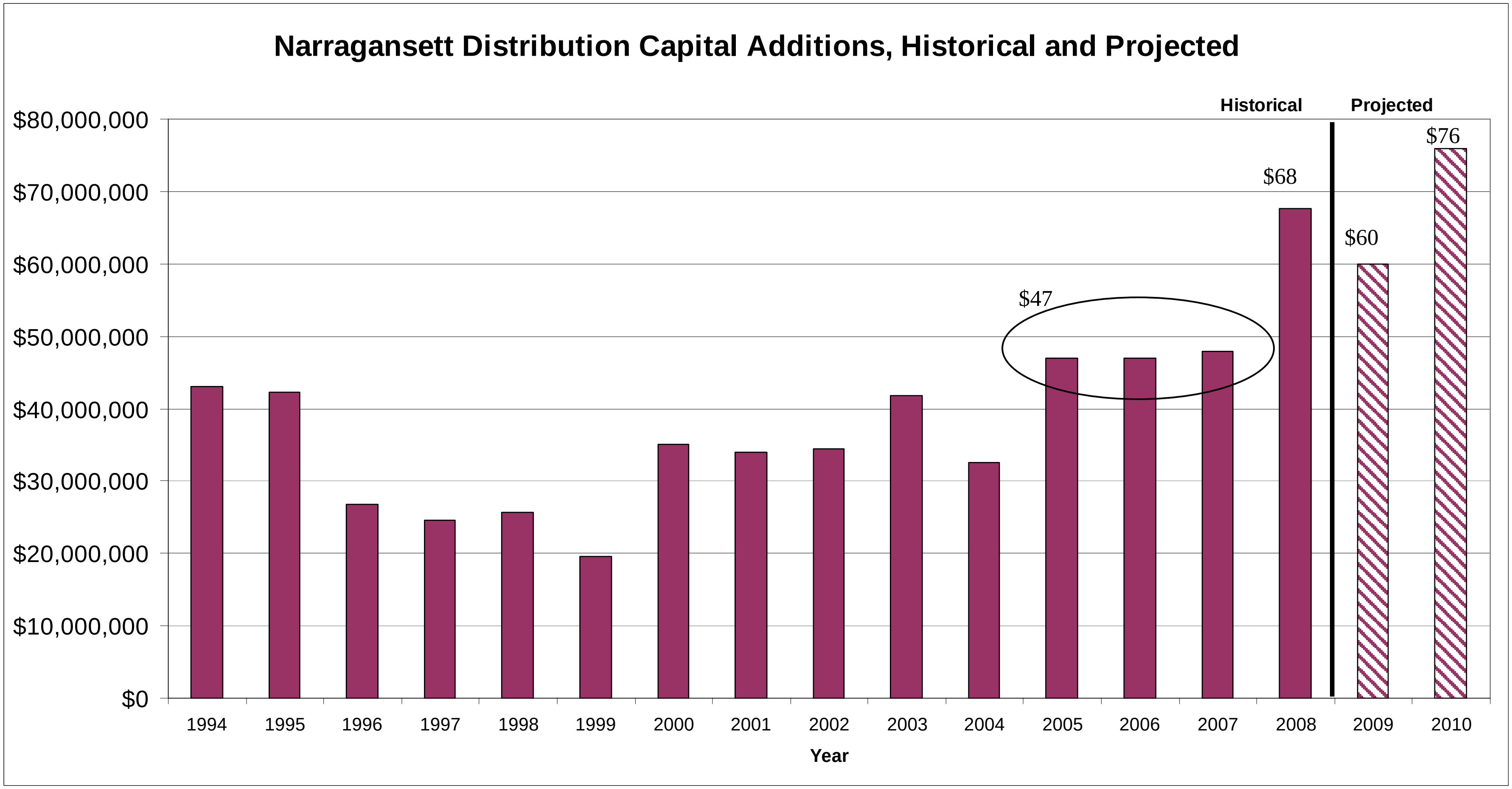

Exhibit RSH-10

Excerpt from National Grid December 14, 2004 Presentation per DPU 07-30, AG1-6 attachment 2

National Grid
D.P.U. 07-30
AG 10-6 - Attachment 2
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Costs and Benefits

NEW ENGLAND DISTRIBUTION RELIABILITY ENHANCEMENT PROGRAM

(in millions)	FY 2006 Capital	FY 2006 O&M	FY 2007 Capital	FY 2007 O&M	FY 2008 Capital	FY 2008 O&M	FY 2009 Capital	FY 2009 O&M	FY 2010 Capital	FY 2010 O&M	CAPEX TOTAL	OPEX TOTAL
Costs												
Increased Capex	$ 24.6	$ 3.4	$ 24.6	$ 3.4	$ 24.6	$ 3.4	$ 24.6	$ 3.4	$ 24.6	$ 3.4	$ 123.0	$ 17.0
5 Yr Hardening Program												
Vegetation Management		$ 4.6		$ 4.6		$ 4.6		$ 4.6		$ 4.6	$ -	$ 23.2
Feeder Hardening												
Survey - Inventory & Assess		$ 6.0	$ -	$ 11.0	$ -	$ 3.0	$ -	$ -	$ -	$ -	$ -	$ 20.0
Repairs	$ 2.3	$ 20.0	$ 2.3	$ 20.0	$ 2.3	$ 20.0	$ 2.3	$ 20.0	$ 2.3	$ 20.0	$ 11.5	$ 100.0
Total Costs - Hardening Program	$ 2.3	$ 30.6	$ 2.3	$ 35.6	$ 2.3	$ 27.6	$ 2.3	$ 24.6	$ 2.3	$ 24.6	$ 11.5	$ 143.2
Inspection & Maintenance Program	$ 1.0	$ 1.7	$ 1.0	$ 1.7	$ 1.0	$ 1.7	$ 1.0	$ 1.7	$ 1.0	$ 1.7	$ 5.1	$ 8.7
Total Costs	$ 27.9	$ 35.8	$ 27.9	$ 40.8	$ 27.9	$ 32.8	$ 27.9	$ 29.8	$ 27.9	$ 29.8	$ 139.6	$ 168.9
Costs Included in Business Plan	$ 24.6		$ 24.6		$ 24.6		$ 24.6		$ 24.6		$ 123.0	$ -
Costs Not Included in Business Plan	$ 3.3	$ 35.8	$ 3.3	$ 40.8	$ 3.3	$ 32.8	$ 3.3	$ 29.8	$ 3.3	$ 29.8	$ 16.6	$ 168.9
Benefits												
Avoided Penalties		?		?		?		?		?		?
Avoided Trouble Labor		$ 0.2		$ 0.5		$ 0.8		$ 1.1		$ 1.4		$ 4.0
Survey												
Hard		1.9		2.1		1.6		1.1		1.1		$ 7.8
Soft		1.2		1.2		1.2		1.2		1.2		$ 6.0
Total Benefits		$ 3.3		$ 3.8		$ 3.6		$ 3.4		$ 3.7		$ 17.8

National Grid

Exhibit AG-RSH-11

Excerpt from National Grid January 18, 2006 Presentation per DPU 07-30, AG 10-6 attachment 6

NY NE Distribution
REP Opex and Capex Summaries

	FY 2007 Business Plan	FY 2008 Business Plan	FY 2009 Business Plan	FY 2010 Business Plan	FY 2011 Business Plan	5-year Program Total
Inspection & Maintenance*						
Opex	21	26	16	16	16	95
Capex	2	2	2	2	2	8
Vegetation Management						
Opex	11	11	11	10	10	53
Capex	0	0	0	0	0	0
Feeder Hardening Program						
Opex	10	15	21	22	23	91
Capex	9	15	20	22	22	88
Infrastructure Enhancement						
Opex	5	8	9	9	9	39
Capex	54	70	85	90	90	390
TOTAL RELIABILITY PROGRAMS						
Opex	46	60	57	57	58	278
Capex	65	86	107	114	114	486

*** $5.7M per year ($28.5M over 5 years) reflect costs of mandatory inspection programs for which we anticipate full recovery**

nationalgrid