

BEFORE THE  
STATE OF NEW YORK  
PUBLIC SERVICE COMMISSION

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In the Matter of  
Central Hudson Gas & Electric Corporation  
Cases 08-E-0887 & 08-G-0888  
November 2008

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Prepared Testimony of:  
Electric Infrastructure Panel

Jerry Ancona  
Power Transmission Planner IV

Office of Electric, Gas and  
Water  
State of New York  
Department of Public Service  
300 Erie Boulevard West  
Building DG-09  
Syracuse, New York 13202

John J. Quackenbush III  
Utility Engineer 1

Karl F. Roenick  
Utility Engineer 2

Kenneth Schultz  
Utility Engineer 3

Office of Electric, Gas and  
Water  
State of New York  
Department of Public Service  
Three Empire State Plaza  
Albany, New York 12223-1350

1 Q. Please state your names, employer and business  
2 address.

3 A. Jerry Ancona, John J. Quackenbush III,  
4 Karl F. Roenick, and Kenneth Schultz. We are  
5 all employed by the New York State Department of  
6 Public Service (Department). Mr. Ancona is  
7 located at 300 Erie Boulevard West - Building  
8 DG-09, Syracuse, New York 13202. Messrs.  
9 Quackenbush, Roenick and Schultz are located at  
10 Three Empire State Plaza, Albany, New York  
11 12223-1350.

12 Q. Mr. Ancona, what is your position with the  
13 Department?

14 A. I am employed as a Power Transmission Planner IV  
15 in the Bulk Electric System Section of the  
16 Office of Electric, Gas, and Water.

17 Q. Please describe your educational background and  
18 professional experience.

19 A. I hold a Bachelor of Science Degree in  
20 Electrical Engineering from Clarkson University,  
21 and a Master of Business Administration degree  
22 from Syracuse University. Additionally, I am a  
23 licensed Professional Engineer in the State of

1 New York. I have been employed by the  
2 Department since May 2008. Prior to that, I  
3 retired from Niagara Mohawk Power Corporation in  
4 November 2007 where I was originally hired as a  
5 Distribution Engineer in the Distribution  
6 Planning Department in 1969. In 1977, I  
7 transferred to work as a Generation Planning  
8 Engineer in the System Planning Department. In  
9 1982, I was promoted to Lead Engineer in the  
10 newly formed Energy Supply and Economics  
11 Planning Department within System Planning. In  
12 1986, I was appointed Director of Transmission  
13 Planning in the System Planning Department. In  
14 1991, I transferred to System Power Control as a  
15 Senior Power Control Engineer. In 1998, I was  
16 appointed ISO Coordinator, and in 2000 I was  
17 promoted to Manager of Power Scheduling and  
18 Billing within System Power Control. In 2002, I  
19 was appointed Manager of Market Development  
20 within Transmission Regulatory Affairs.  
21 Additionally, I taught an in-house Engineering  
22 Economics course for several years; and  
23 currently serve as Adjunct Instructor at the

1           SUNY College of Environmental Science and  
2           Forestry teaching a PE review session in  
3           Engineering Economics. Overall, I have  
4           experience in electric distribution,  
5           transmission and generation planning; power  
6           system operations; reliability analyses;  
7           engineering economic evaluations; demand  
8           response programs; and wholesale electric market  
9           rule design and operations.

10   Q.    What are your responsibilities with the  
11           Department?

12   A.    My areas of responsibility include and have  
13           included review and analysis of capital projects  
14           and budgets, vertical market power mitigation,  
15           generator energy deliverability, and electric  
16           transmission and distribution loss reduction.

17   Q.    Have you previously testified before the  
18           Commission?

19   A.    No.

20   Q.    Mr. Quackenbush, what is your position with the  
21           Department?

22   A.    I am employed by the New York State Department  
23           of Public Service as a Utility Engineer 1

1           working in the Office of Electric, Gas and  
2           Water.

3    Q.    Please state your educational background and  
4           experience.

5    A.    I attended Hudson Valley Community College and  
6           received an Associates degree in individual  
7           studies, as well as an Associate degree in  
8           Applied Science in civil engineering technology.  
9           After this, I continued my education at the SUNY  
10          Institute of Technology and graduated with a  
11          Bachelor of Science degree in civil engineering  
12          technology. From 2000 until November 2006, I  
13          was employed by Clough, Harbour, & Associates  
14          LLP as a Drafting & Design Technician. During  
15          this time, I was a member of the Wireless,  
16          Transportation, and Facility Services  
17          Departments. My work included analyzing zoning  
18          laws, the drafting and designing of cellular  
19          tower facilities, and designing various bridge  
20          and road construction projects using AutoCad and  
21          Microstation software. In February 2007, I  
22          joined the Staff of the Electric Distribution  
23          Section in the Office of Electric, Gas, and

1 Water where I have performed electric utility  
2 inspections to assess infrastructure conditions,  
3 investigated various electric utility customer  
4 reliability complaints, and reviewed utility  
5 reliability reports.

6 Q. Have you previously testified before the  
7 Commission?

8 A. No.

9 Q. Mr. Roenick, what is your position with the  
10 Department?

11 A. I am employed by the New York State Department  
12 of Public Service as a Utility Engineer 2 in the  
13 Office of Electric, Gas, and Water.

14 Q. Please describe your educational background,  
15 qualifications, and experience.

16 A. I graduated from the Polytechnic Institute of  
17 Brooklyn in 1973 with a Bachelor of Science  
18 degree in Mechanical Engineering. After a two-  
19 year tour in the US Army, I worked as a project  
20 planner for several power plant projects. In  
21 1984, I joined the Department to monitor  
22 construction of the Nine Mile Point 2 Nuclear  
23 Plant. I have worked in several areas while at

1 the Department and have spent most of my time in  
2 the electric distribution area.

3 Q. Have you previously testified before the Public  
4 Service Commission?

5 A. Yes. I have testified in a number of  
6 proceedings before the Public Service  
7 Commission, including the last Central Hudson  
8 rate proceeding, Case 05-E-0934.

9 Q. Mr. Schultz, what is your position with the  
10 Department?

11 A. I am a Utility Engineer 3 assigned to the  
12 Electric Rates and Tariff Section in the Office  
13 of Electric, Gas, and Water.

14 Q. Please describe your educational background.

15 A. I graduated from the City College of New York  
16 with a Bachelor of Engineering degree in  
17 Mechanical Engineering. I also attended  
18 Columbia University and completed selected  
19 graduate courses in the Department of Industrial  
20 and Management Engineering. In April 1970, I  
21 accepted employment with the Department of  
22 Public Service.

23 Q. What are your responsibilities with the

1 Department?

2 A. My responsibilities have involved the  
3 investigation of consumer complaints, the  
4 analysis of engineering matters in utility rate  
5 proceedings, cost of service studies, and  
6 electric rate and tariff matters. I have also  
7 participated in the implementation and  
8 administration of the Power for Jobs program.

9 Q. Have you previously testified before the  
10 Commission?

11 A. Yes, I have testified in several electric rate  
12 cases, including Central Hudson's last electric  
13 rate proceeding, Case 05-E-0934.

14 **Overview**

15 Q. What is the purpose of the Electric  
16 Infrastructure Panel testimony?

17 A. The purpose of this testimony is to review major  
18 capital projects Central Hudson Gas & Electric  
19 Corporation (Central Hudson or the Company) has  
20 included in its construction budget for the rate  
21 year ending June 30, 2010 for electric  
22 production, transmission line, substation and  
23 distribution facilities.



1           1, 2 and 3, respectively. The Rate Plan amounts  
2           include, in the electric budget, the combined  
3           gas and electric expenditures for underground  
4           residential distribution (URD) projects, but the  
5           actual amounts report only the electric  
6           expenditures.

7    Q.    Please compare the capital budgets to the  
8           amounts actually spent.

9    A.    The amounts actually spent during Rate Year 1  
10           and 2 were \$51.2 million and \$49.2 million,  
11           respectively. Rate Year 2 expenditures were  
12           about six percent less than budget.

13   Q.    What are the reasons for the decrease in Rate  
14           Year 2 expenditures compared to the budget?

15   A.    The expenditures in the New Business and  
16           Improvements budget categories were less than  
17           budget due to a slow down in the regional  
18           economy and housing market. Additionally, the  
19           decrease reflects the change in reporting the  
20           expenditures for URD projects.

21   Q.    What is the capital budget for the Rate Year in  
22           the current rate proceeding?

23   A.    The Rate Year (7/01/09-6/30/10) capital budget

1 is \$65 million, as presented by Company witness  
2 Haering.

3 Q. What are the projects or programs that the  
4 Company has forecast to be added to plant in  
5 service?

6 A. The Company has forecast the following major  
7 projects and amounts (\$000's): Transmission Sag  
8 Mitigation \$6,190, New Spackenkil Substation  
9 \$6,730, New 115 kV Galeville Substation \$7,760,  
10 E. Fishkill 345 Transformer \$2,142, Breaker  
11 Replacement Programs 345kV/115kV \$3,581, New  
12 Business & Improvements \$23,275, Distribution  
13 Transformers \$9,102, and Distribution Meters  
14 \$1,654.

15 Q. What are the areas your testimony will cover?

16 A. As explained in detail below, the testimony will  
17 cover these areas: Net Plant Target; Production  
18 Projects; Transmission Line Projects; Substation  
19 Projects; Distribution Infrastructure  
20 Improvement Programs; Distribution Line  
21 Clearance; and New Business, Transformers, and  
22 Meters.

23

1 Net Plant Target

2 Q. Has the Company offered any proposal to hold it  
3 accountable for its rate year electric plant in  
4 service?

5 A. No, it has not.

6 Q. Do you have a proposal to hold the Company  
7 accountable for its rate allowance for electric  
8 plant in service?

9 A. Yes. We propose a Net Plant Target for the rate  
10 year. The Net Plant Target is defined as the  
11 average forecast electric plant in service less  
12 the average depreciation reserve. If at the end  
13 of the rate year the actual net plant is less  
14 than the target, the Company would defer for the  
15 benefit of electric customers the revenue  
16 requirement impact of such shortfall below the  
17 target. The revenue requirement would be  
18 calculated by applying a carrying charge factor  
19 reflecting the authorized pre-tax rate of return  
20 to the net plant shortfall and a composite  
21 electric depreciation rate to the average  
22 electric plant in service shortfall. The amount  
23 of this adjustment would be deferred for future

1 return as a ratepayer benefit, with carrying  
2 charges calculated at the authorized pre-tax  
3 rate of return. Because we are recommending  
4 separate ratemaking treatment for the  
5 Transmission Sag Mitigation Program and the  
6 Spakenkill substation, we would exclude these  
7 projects from both the Net Plant Target and the  
8 actual net plant in the above calculation of any  
9 shortfall below the target.

10 Q. Why have you proposed to hold the Company  
11 accountable for the amount of its electric plant  
12 in service rather than to its forecast level of  
13 capital expenditures?

14 A. We are not proposing changes to the Company's  
15 capital budget. The Company is entitled to  
16 spend at a level it believes appropriate to  
17 provide safe and adequate service. Our  
18 adjustments are to the level of capital  
19 additions, because it is the level of plant in  
20 service that is used in setting rates.

21 Q. Are you recommending any reporting requirements?

22 A. Yes. We recommend that the Company make regular  
23 filings of information necessary for Staff to

1 monitor the implementation of the Company's  
2 electric capital budget. This includes annual  
3 budgets, cost breakdowns and schedules for major  
4 projects, and any variances to the annual  
5 budget, project costs and schedules for major  
6 projects. The detailed reporting requirements  
7 will be developed at a later date after  
8 discussions with the Company, but prior to the  
9 resolution of this rate case.

10 Production Projects

11 Q. Please describe the major production projects  
12 that Central Hudson has included in its capital  
13 budget.

14 A. Central Hudson plans to make improvements at its  
15 Sturgeon Pool Hydro-Electric Plant. These  
16 include capital expenditures in the rate year  
17 for installation of a 3 foot diameter 90% drain,  
18 and a rubber bladder crest gate. The drain  
19 would be installed in the Unit #1 10 foot  
20 diameter penstock, and will provide compliance  
21 for meeting a New York State Department of  
22 Environmental Conservation (NYS DEC) safety  
23 requirement to allow 90% of the pond's volume to

1           be drained in 14 days with no inflow to the pond  
2           after draining begins. Among alternatives  
3           considered, the three foot drain was deemed more  
4           practical to operate, and less likely to result  
5           in lost generation and/or surrounding property  
6           owners being inconvenienced by low pond levels.  
7           The NYS DEC Dam Safety Division agreed with this  
8           chosen project, and has accepted the completed  
9           designs. This project, with an expected in  
10          service in 2009 and a cost of \$925,000, is  
11          justified on the basis that it meets a mandated  
12          safety requirement.

13          Following completion of the drain project, the  
14          Company proposes to install an inflatable rubber  
15          bladder on the dam crest to replace wooden  
16          flashboards at Sturgeon Pool. This has  
17          previously been done at Central Hudson's  
18          Dashville Hydro Facility. The intent of this  
19          project is to improve worker safety by negating  
20          the need to manually adjust, repair and replace  
21          wooden flashboards; increase the safety level to  
22          the dam itself; improve pond control during  
23          flooding conditions, thereby reducing flooding

1 of upstream property owners; and to avoid loss  
2 of generation caused by loss of the wooden  
3 flashboards. This project is scheduled to be in  
4 service by November 2010 at a total estimated  
5 cost of \$3.601 million. The Company expects to  
6 expend \$1.53 million during the rate year.  
7 Central Hudson estimates the project may  
8 increase annual energy output of the hydro plant  
9 by thirty percent (30%), which, along with  
10 annual flashboard material savings of \$20,000,  
11 would result in net customer savings of  
12 \$1 million per year. This project is justified  
13 based upon the improvement in safety and the  
14 avoidance of significant amounts of lost  
15 generation from a renewable resource.

16 Transmission Line Projects

17 Q. Please describe the major transmission line  
18 projects that Central Hudson has included in its  
19 capital budget.

20 A. In 2006, Central Hudson performed a system-wide  
21 LiDAR, which is a Light Detection and Ranging  
22 system that can determine relative heights of  
23 transmission facilities and the adjacent

1 environment using helicopter flyovers, survey of  
2 its transmission system. With the aid of  
3 computer modeling, the results of the survey  
4 indicated that a number of the Company's  
5 transmission circuits do not meet National  
6 Electric Safety Code clearance requirements for  
7 pedestrian paths, roadways and other facilities.  
8 Clearances can change for various reasons:  
9 assumptions used in the original circuit design  
10 may no longer be consistent with current field  
11 conditions as a result of fill being added,  
12 usage under the conductor changing, or conductor  
13 creep (elongation) occurring due to aging. Re-  
14 rating conductor electrical capabilities  
15 downward to avoid clearance violations was not  
16 deemed practical and/or feasible. In less  
17 extreme instances, conductors will be re-  
18 tensioned. In more severe cases, transmission  
19 structures (poles or towers) will need to be  
20 replaced with higher structures. The  
21 Transmission Sag mitigation program is justified  
22 based upon the need to meet mandated safety  
23 requirements.

1 Q. What is the cost of the Transmission Sag  
2 Mitigation program that you described?

3 A. The Transmission Sag Mitigation program  
4 identified 810 transmission structures for  
5 replacement and 108 spans that will be addressed  
6 through re-tensioning the conductor rather than  
7 replacing the structures. Central Hudson has  
8 prioritized the circuits and plans to address  
9 the highest priority spans first. Based upon  
10 discussions with the Company, this program will  
11 impact approximately ten percent (10%) of its  
12 overall transmission system. The structure  
13 replacement is estimated to cost about  
14 \$23 million and re-tensioning the conductor is  
15 estimated to cost \$3.3 million. This program is  
16 anticipated for completion in 2012.

17 Q. What costs are included in the rate year revenue  
18 requirement for the Transmission Sag Mitigation  
19 program?

20 A. The Company has included \$6.2 million to plant  
21 in service for capital structure replacement and  
22 \$1.1 million in expense for re-tensioning the  
23 conductor. The \$6.2 million is based on

1 replacing about 213 structures at a cost of  
2 \$29,000 per structure and the \$1.1 million is  
3 based on re-tensioning about 36 spans, about  
4 one-third of the total, at a cost of \$31,000 per  
5 span.

6 Q. How were the structure and re-tensioning costs  
7 developed?

8 A. The structure costs were based on replacing a  
9 single circuit two-pole wood structure with a  
10 single circuit two-pole steel structure. The  
11 re-tensioning work estimate includes, in  
12 addition to the actual re-tensioning activity,  
13 the opening of an access road. These costs  
14 include all design, construction and material  
15 costs.

16 Q. What is your position regarding the Transmission  
17 Sag Mitigation program?

18 A. We recommend that the program be separated into  
19 two cost components: expense and capital. The  
20 expense component consists of the cost to open  
21 an access road to the span and the cost for the  
22 re-tensioning work. The capital component  
23 consists of the costs for the different types of

1 structures. Exhibit\_\_(EIP-1) summarizes, from  
2 the Company's workpapers and Staff interrogatory  
3 DPS-622, the average estimates for the expense  
4 and capital components.

5 Q. How do you propose to handle the expense  
6 component?

7 A. We recommend that the re-tensioning cost per  
8 span, as shown in the exhibit, be applied to the  
9 actual number of spans completed in the rate  
10 year. The Company should be allowed the cost so  
11 calculated, or the actual re-tensioning cost,  
12 whichever is less. For spans requiring access  
13 roads, we recommend that the cost per road, as  
14 shown in the exhibit, be applied to the actual  
15 number of access roads. The Company should be  
16 allowed the cost so calculated, or the actual  
17 access road cost, whichever is less.

18 Q. How do you propose to handle the capital  
19 component?

20 A. The actual structure replacements may reflect a  
21 mix of structures different than the two-pole  
22 structure used for the cost estimate.

23 Therefore, the cost for each of the different

1 types of structures, as shown in the exhibit,  
2 would be applied to the mix of structures  
3 completed. We recommend deferral treatment for  
4 the difference in the revenue requirement  
5 between the \$6.2 million rate year addition and  
6 the costs so calculated, or the actual costs,  
7 whichever is less.

8 Q. How would you determine the revenue requirement  
9 for the capital component?

10 A. The revenue requirement would be determined by  
11 applying a carrying charge factor reflecting the  
12 authorized pre-tax rate of return to the  
13 difference in average rate year net plant, plus  
14 the change in depreciation expense. The revenue  
15 requirement would be deferred, with carrying  
16 charges calculated at the authorized pre-tax  
17 rate of return.

18 Q. Please continue with your description of the  
19 transmission line projects.

20 A. Additionally, Central Hudson plans to rebuild  
21 11.5 miles of the "WM" 69 kV line with 795 ACSR  
22 in Orange County. The projected in service date  
23 is 2012. This project is to replace aging

1 infrastructure (1930's vintage poles), address  
2 right of way issues and increase capability to  
3 avoid contingency load shedding due to  
4 anticipated load growth. Among the alternatives  
5 considered, the proposed 795 ACSR rebuild of the  
6 entire line appears to be the least costly  
7 option that addresses the identified issues.  
8 Central Hudson estimates the total cost of this  
9 project to be \$13.4 million, with capital  
10 expenditures of \$3.1 million in the rate year.  
11 However, this project will not have plant added  
12 in the rate year, and in fact, expenditures may  
13 need to be postponed due to permitting issues.

14 Substation Projects

- 15 Q. Please describe the major substation projects  
16 that Central Hudson has included in its capital  
17 budget.
- 18 A. Central Hudson has a continuing plan to replace  
19 circuit breakers. The Company has prioritized  
20 circuit breaker replacements based upon a number  
21 of factors including: an evaluation of breaker  
22 duties being exceeded; age and relative  
23 condition based upon failure reports and testing

1 results; obsolescence in terms of outdated  
2 technology and/or unavailability of replacement  
3 parts; and other factors such as coordination  
4 with other substation projects. In 2009, plans  
5 call for two 345 kV, and one 115 kV breaker  
6 replacement, while plans for 2010 call for two  
7 345 kV and three 115 kV breaker replacements.  
8 Capital expenditures in the rate year for 345 kV  
9 and 115 kV breaker replacements are expected to  
10 be \$5.2 million and the plant added in the rate  
11 year for the 345 kV and 115 kV Breaker  
12 Replacement Programs 345kV/115kV is expected to  
13 be \$3.6 million. This program is justified on  
14 the basis that it will ensure reliability,  
15 safety, and operations with highest priorities  
16 met first.

17 Q. What is the Company's position regarding the  
18 Spakenkill substation project?

19 A. The Company forecasts that the Spakenkill  
20 substation will be placed in service in  
21 December 2009 at a cost of \$6.73 million.

22 Q. What is your position regarding the Spakenkill  
23 substation?

1 A. We believe that the Spakenkill substation will  
2 not likely go in service during the rate year.  
3 It is currently projected to be in service no  
4 earlier than June 2010, which is the last month  
5 of the rate year. Because the approval process  
6 with the Town of Poughkeepsie is moving much  
7 slower than planned, as shown in the response to  
8 Staff interrogatory DPS-440, Exhibit\_\_(EIP-2),  
9 we recommend that the Spakenkill substation be  
10 removed from the rate year plant in service. We  
11 estimate that the removal of the substation will  
12 decrease average net plant in service by  
13 \$3.58 million and decrease depreciation expense  
14 by \$109,000. These amounts, which reflect  
15 Staff's proposed depreciation rates, are  
16 included in Staff Accounting Panel  
17 Exhibit\_\_(AP-1).

18 Q. What is your position if the permitting process  
19 is completed and the Spakenkill substation goes  
20 in service before the end of the rate year?

21 A. We propose that the Company be allowed to defer  
22 the carrying charges on the \$6.73 million amount  
23 at the authorized pre-tax rate of return from

1 the date the substation goes in service.

2 Q. What is your position if the Spakenkill  
3 substation goes in service before the end of the  
4 rate year at a cost different from the  
5 \$6.73 million?

6 A. If the cost is less than \$6.73 million, we  
7 propose the deferral be based on the actual cost  
8 of the substation. If the cost is greater than  
9 \$6.73 million, we propose the deferral be based  
10 on the \$6.73 million amount to hold the Company  
11 accountable for its electric plant in service  
12 forecast.

13 Distribution Infrastructure Improvement Programs

14 Q. What is the Company's historic level and rate  
15 year level of expenditures for budget category  
16 15, Distribution Improvements?

17 A. The amount of capital dollars actually spent was  
18 \$11.1, \$12.1 and \$11.5 million for 2006, 2007  
19 and 12 months ending June 2008, respectively.  
20 The proposed rate year level is \$17.5 million.

21 Q. What are the programs included in the rate year  
22 expenditures?

23 A. The expenditures include the distribution

1 projects which are needed for daily operations  
2 and multi-year distribution improvement  
3 programs. The expenditures for these programs  
4 are spread over a five-year period through 2013.

5 Q. Is there a concern with utility infrastructure  
6 in general?

7 A. Yes. In fact, as an outgrowth of the ongoing  
8 process to develop a comprehensive New York  
9 State Energy Plan, Staff has received condition  
10 assessments of electric transmission and  
11 distribution infrastructure from all the New  
12 York regulated utilities.

13 Q. Does the Company testimony address distribution  
14 infrastructure improvement?

15 A. Yes. Company witness Haering has identified  
16 several significant new or expanded distribution  
17 infrastructure programs in his testimony. These  
18 programs are part of what appears to be a  
19 general shift in Company spending from growth-  
20 related projects, as load growth has slowed.

21 Q. What are the primary reasons cited by the  
22 Company?

23 A. The reasons cited for the additional programs

1 are related to equipment age and/or reliability.

2 Q. Are these programs of high magnitude regarding  
3 cost?

4 A. Yes. They are estimated by the Company to cost  
5 \$22.3 million (in 2008 dollars) through 2013.

6 Q. How are these program costs broken down?

7 A. The Company's response to Staff interrogatory  
8 DPS-483, see Exhibit\_\_(EIP-3), provides a  
9 breakdown of the \$22.3 million. In  
10 Exhibit\_\_(EIP-4), we summarized the Company's  
11 response to Staff interrogatories DPS-483 and  
12 DPS-611 to show that the Company plans to spend  
13 about \$6.6 million on these projects in the rate  
14 year.

15 Q. What are your conclusions after reviewing these  
16 programs?

17 A. We support these programs. Based on our review  
18 of the Company's workpapers, responses to  
19 information requests and presentations, we  
20 conclude that these programs are worthwhile to  
21 help shore up the Company's infrastructure and  
22 reliability. We also recommend that the Company  
23 include with its reporting requirements a

1 narrative discussion of its progress with these  
2 ongoing distribution improvement programs. Any  
3 slippage in the progress of these programs will  
4 be captured in our proposed Net Plant Target.

5 Q. Please go into detail and comment on the  
6 proposed programs.

7 A. 14.4kV Cable Rejuvenation Program

8 2009-2013 estimate: \$6,500,000

9 Rate year estimate: \$1,295,000

10 14.4kV Underground Infrastructure

11 2009-2013 estimate: \$2,070,000

12 Rate year estimate: \$1,046,000

13 Both of the above programs combine to rebuild  
14 the 14.kV feeds into the Poughkeepsie secondary  
15 network. The Company states that some of these  
16 paper and lead cables are over 60 years old and  
17 are causing reliability problems. The  
18 Underground Infrastructure program involves  
19 replacing crumbling underground manholes and  
20 duct banks so that the cables may be replaced.  
21 The cable replacement is being planned to  
22 replace the least reliable cables first.

23

1           Cutout Replacement Program

2           2009-2013 estimate:   \$4,000,000

3           Rate year estimate:   \$1,236,000

4           Porcelain cutouts have been problematic for the  
5           Company. The Company has been replacing them  
6           with polymer models. Since 2002, the Company  
7           has replaced about 5,000 to date. The program  
8           has been phased, targeting those whose failure  
9           would affect the most customers first. The  
10          Company has completed replacing all cutouts  
11          whose failure would affect more than 1,500  
12          customers and is completing the current program,  
13          scheduled to finish in 2009, which targets all  
14          cutouts whose failure would cause an outage to  
15          more than 1,000 customers. The proposed program  
16          would take the level down to those whose failure  
17          could affect 500 or more customers and will  
18          require the replacement of 8,036 more cutouts.  
19          At the end of the program, a total of 15,644  
20          cutouts out of a total of 47,446 cutouts should  
21          be replaced.

22          Distribution Pole Replacement Program

23          2009-2013 estimate:   \$3,725,000

1 Rate year estimate: \$1,243,000

2 A higher level of scrutiny during distribution  
3 line patrols, brought on by Staff requirements,  
4 has led to an increase in the number of poles  
5 that require replacement. The Company estimates  
6 they will have to replace an additional 202  
7 poles per year over and above the existing  
8 annual level of about 200 poles. Because of a  
9 backlog that has accumulated and to levelize  
10 spending, the Company proposes to replace 322  
11 poles in the Rate Year and every year thereafter  
12 for five years. While Staff is supportive of  
13 this program, it is one to especially watch for  
14 slippage.

15 Distribution Automation - ALT Program

16 2009-2013 estimate: \$2,000,000

17 Rate year estimate: \$618,000

18 The Company states that the use of Automatic  
19 Load Transfer (ALT) switches, which transfer  
20 interrupted pockets of load to alternate primary  
21 feeds, has had a major effect on improving  
22 reliability. It estimates that the 51 ALT's,  
23 applied to 40,000 customers out of the Company's

1 300,000 customers, installed on the system have  
2 caused an overall reduction of customer  
3 interruptions by ten percent. The ALT's 'talk'  
4 to the Company's outage management system (OMS)  
5 as well, for additional value-added benefits.  
6 The program in the filed rate case shows that  
7 the Company plans to install ALT's in 37 new  
8 locations in a reliability-prioritized manner  
9 that should benefit an additional 10,000  
10 customers.

11 Recloser Replacement Program

12 2009-2013 estimate: \$2,275,000

13 Rate year estimate: \$703,000

14 The Company reports that it has many old  
15 reclosers that are high maintenance and obsolete  
16 with regard to replacement parts. The new  
17 digital units are virtually maintenance free and  
18 also communicate with OMS in a similar fashion  
19 as the ALT's. The Company plans to replace 13  
20 sets of reclosers per year.

21 10X Reliability Program

22 2009-2013 estimate: \$1,125,000

23 Rate year estimate: \$258,000

1 This program focuses on improving the  
2 reliability of customers who have been  
3 interrupted more than ten times in a year. The  
4 Company estimates that 5,000 customers scattered  
5 across the system could potentially be targeted  
6 by this program.

7 CEMesh

8 2009-2013 estimate: \$150,000

9 Rate year estimate: \$116,000

10 CEMesh is a former Research and Development  
11 project whose function is to provide information  
12 on the operating parameters of the Poughkeepsie  
13 secondary network. Because of the favorable  
14 experience the Company has had with the system,  
15 it is planning to install the system in its  
16 other networks.

17 Secondary Network Upgrade Program

18 2009-2013 estimate: \$450,000

19 Rate year estimate: \$103,000

20 In a similar way that two programs mentioned  
21 earlier address the 14.4kV feeds into the  
22 Poughkeepsie network, this program will identify  
23 failed cables and reinforce identified

1 weaknesses in the secondary network.

2 Distribution Line Clearance Program

3 Q. Do you have any comments regarding the Company's  
4 line clearance program?

5 A. Yes. According to Company witness DuBois, the  
6 Company has revamped its distribution line  
7 clearance program after a consultant review.

8 Q. What are the highlights of the revised program?

9 A. It has its origins in an aggressive 3-phase main  
10 line clearance program, termed by the Company as  
11 the "Enhanced Line Clearance Program" begun in  
12 2003 using funds from the sale of its generating  
13 assets. Key features of the program include  
14 increased clearances, removal of danger trees  
15 and complete ground to sky clearance so that  
16 there are no tree limbs overhanging the wires.  
17 The consultant and the Company maintain that  
18 overhanging branches are much more of a factor  
19 in outages than branches growing into the lines.

20 Q. Please continue.

21 A. In the current Rate Plan, the Company requested,  
22 and Staff supported, additional funding for  
23 300 miles of Enhanced Line Clearance (ELC)

1           during the course of the Rate Plan. The  
2           achievement of 100 miles per year of enhanced  
3           trimming was built into the Rate Plan's  
4           Reliability Performance Mechanism (RPM).

5   Q.   Is the Company making any new proposals for the  
6           rate year in regards to this program?

7   A.   Yes. Based on the consultant's recommendation  
8           that Enhanced Trimming be done on an additional  
9           760 miles of three-phase lines, witness DuBois  
10          proposes that approximately \$1.8 million be  
11          expended in the rate year to increase the amount  
12          of miles in its Enhanced Line Clearance Program  
13          to 150 miles. Witness DuBois also proposes that  
14          the ELC program continue to be on a three-year  
15          cycle.

16   Q.   Are there any other related programs?

17   A.   Yes. In early 2007, the Company started to use  
18          a revised version of the above plan to create a  
19          program called the "Modified Enhanced Line  
20          Clearance Program". This new program is now the  
21          standard program for line clearance, and is used  
22          for all lines not being maintained under the ELC  
23          program.

1 Q. What are the features of the Modified Enhanced  
2 Line Clearance Program?

3 A. The Modified Enhanced Line Clearance Program is  
4 a less aggressive version of the ELC program,  
5 but still, as Witness DuBois notes, emphasizes  
6 removal of most overhanging branches and has  
7 increased side clearances. Because of reasons  
8 noted previously concerning overhanging limbs  
9 vs. growth, and the Company's stated desire to  
10 maintain cost given that the new program is 25  
11 percent more costly, the trimming cycle has been  
12 increased from three years to four years. That  
13 is, it will take four years to trim all the  
14 lines in the program before the cycle starts  
15 over again.

16 Q. Do you support these new changes?

17 A. With some caveats, yes. Staff has reviewed the  
18 consultant's report and has discussed details  
19 with both the consultant and the Company. The  
20 program's general emphasis on elimination of  
21 overhanging branches makes intuitive sense.  
22 While growth into lines is claimed not to be a  
23 major factor, the lengthening of the cycle for

1 most of the system from three years to four  
2 years might have some unforeseen effects.  
3 Additionally, Staff has recently expressed  
4 concern about the continuing high level of the  
5 Company's tree-caused outages compared with  
6 other companies in its 2007 Electric Reliability  
7 Performance Report. As a result, Staff  
8 requested a Company self-assessment of its line  
9 clearance program.

10 Q. Do you have any other concerns?

11 A. Yes. We are concerned that funds could be  
12 diverted for other Company uses and the three-  
13 year cycle for Enhanced and four-year cycle for  
14 Modified Enhanced trimming could be compromised.

15 Q. Do you have recommendations that will alleviate  
16 your concerns?

17 A. Yes. While we accept the Company's projections,  
18 we recommend that the clearance of 150 circuit  
19 miles per year under the Enhanced Line Clearing  
20 program become a part of the Company's  
21 Reliability Performance Mechanism. We also  
22 propose that if actual expenditures for the  
23 Modified Enhanced Line Clearing program are less

1           than the rate case allowance, the shortfall be  
2           deferred as a ratepayer credit.

3                       New Business, Transformers, and Meters

4   Q.    Please explain your review of the forecast for  
5           New Business, Distribution Transformers and  
6           Distribution Meters.

7   A.    The Company developed the expenditures for these  
8           budget categories from an analysis of the trend  
9           in actual historic expenditures and system  
10          energy requirements.

11   Q.    What is your conclusion after reviewing these  
12          budget categories?

13   A.    We accept the Company's forecast. For the rate  
14          year, the level of expenditures is estimated at  
15          \$20.2 million. The rate year reflects increased  
16          equipment prices and more stringent energy  
17          efficiency standards required by the U.S.  
18          Department of Energy's Standards for Transformer  
19          Efficiency, which go in effect beginning 2010.

20   Q.    Does this conclude your direct testimony?

21   A.    Yes, it does.