Appendix B

APPENDIX B

Benefit / Cost Analysis

Niagara Mohawk Power Corporation d/b/a National Grid
ENERGY EFFICIENCY PROGRAMS
2009 - 2011 TRC BENEFIT COST TEST

Participation and Savings Goals - Electric Programs

	2009			2010			2011			2009 - 2011		
Electric Programs	Participants	Annualized MWh Savings	Lifetime MWh Savings	Participants	Annualized MWh Savings	Lifetime MWh Savings	Participants	Annualized MWh Savings	Lifetime MWh Savings	Participants	Annualized MWh Savings	Lifetime MWh Savings
Enhanced Home Sealing Incentives	360	676	13,522	660	1,239	24,790	660	1,239	24,790	1,680	3,155	63,101
Residential ENERGY STAR® Products and Recycling Program	18,100	4,757	37,880	36,300	9,539	76,003	36,300	9,539	76,003	90,700	23,835	189,886
Residential Internet Audit Program and E-Commerce Sales	50,000	3,001	18,006	50,000	3,001	18,006	50,000	3,001	18,006	150,000	9,003	54,019
Residential Building Practices and Demonstration Program	50,000	8,100	8,100	50,000	8,100	8,100	50,000	8,100	8,100	150,000	24,300	24,300
Energy*Wise* Program	1,750	2,378	39,146	3,600	4,892	80,529	3,600	4,892	80,529	8,950	12,163	200,204
Residential Pricing Pilot with Load Control	139	0	0	833	0	0	28	0	0	1,000	0	0
Energy Initiative	611	77,691	947,469	764	97,114	1,184,336	955	121,392	1,480,420	2,330	296,198	3,612,224

Participants for the Residential Internet Audit Program and E-Commerce Sales represents products. Actual participation may be lower.

Participation and Savings Goals - Gas Programs

	2009			2010			2011			2009 - 2011		
Gas Programs	Participants	Annualized MMBTu Savings	Lifetime MMBTu Savings	Participants	Annualized MMBTu Savings	Lifetime MMBTu Savings	Participants	Annualized MMBTu Savings	Lifetime MMBTu Savings	Participants	Annualized MMBTu Savings	Lifetime MMBTu Savings
Enhanced Home Sealing Incentives	125	4,140	82,800	188	6,227	124,531	188	6,227	124,531	501	16,593	331,862
Residential ENERGY STAR® Products Program	300	606	15,140	500	1,009	25,234	500	1,009	25,234	1,300	2,624	65,608
Residential Low Income Program	1,340	0	0	1,340	0	0	1,340	0	0	4,020	0	0
Residential Building Practices and Demonstration Program	51,080	73,152	76,554	50,000	69,750	69,750	50,000	69,750	69,750	151,080	212,652	216,054
Energy*Wise* Program	1,800	9,396	131,544	1,800	9,396	131,544	1,800	9,396	131,544	5,400	28,188	394,632
Commercial and Industrial Energy Efficiency Program	400	57,683	709,498	450	69,911	859,907	500	76,405	939,777	1,350	203,999	2,509,182
Commercial High-Efficiency Heating and Water Heating Program	100	7,164	143,280	300	21,492	429,840	350	25,074	501,480	750	53,730	1,074,600
Building Practices and Demonstration Program	15	19,047	259,038	15	19,046	259,029	15	19,046	259,029	44	57,139	777,095

Niagara Mohawk Power Corporation d/b/a National Grid
ENERGY EFFICIENCY PROGRAMS
2009 - 2011 TRC BENEFIT COST TEST

Summary of Benefit , Costs (2009 $s)
Total Resource Cost Test

Gas Programs	2009 TRC Benefit/ Cost	2009 Total NPV Benefits ($000)	2009 Total NPV Costs ($000)	2010 TRC Benefit/ Cost	2010 Total NPV Benefits ($000)	2010 Total NPV Costs ($000)	2011 TRC Benefit/ Cost	2011 Total NPV Benefits ($000)	2011 Total NPV Costs ($000)	2009 - 2011 TRC Benefit/ Cost	2009 - 2011 Total NPV Benefits ($000)	2009 - 2011 Total NPV Costs ($000)
Enhanced Home Sealing Incentives	0.89	$541	$ 609	1.33	$833	$ 628	1.50	$857	$ 572	1.23	$2,231	$1,808
Residential ENERGY STAR® Products Program	1.32	$107	$ 81	1.62	$184	$ 113	1.77	$189	$ 107	1.59	$480	$302
Residential Low Income Program	n/a	n/a	$ 5,000	n/a	n/a	$ 4,739	n/a	n/a	$ 4,492	n/a	n/a	$ 14,232
Residential Building Practices and Demonstration Program	1.20	$884	$ 736	1.47	$783	$ 533	1.52	$771	$ 505	1.37	$2,438	$1,774
Energy*Wise* Program	0.94	$976	$ 1,038	1.01	$991	$ 983	1.09	$1,015	$ 932	1.01	$2,982	$2,952
Commercial and Industrial Energy Efficiency Program	1.40	$5,495	$ 3,926	1.57	$6,741	$ 4,280	1.72	$7,518	$ 4,361	1.57	$19,754	$12,567
Commercial High-Efficiency Heating and Water Heating Program	2.17	$937	$ 432	2.96	$2,874	$ 970	3.16	$3,450	$ 1,092	2.91	$7,260	$2,494
Building Practices and Demonstration Program	3.11	$1,940	$ 623	3.34	$1,969	$ 589	3.61	$2,015	$ 558	3.35	$5,924	$1,770
Grand Total	**0.87**	**$10,881**	**$12,445**	**1.12**	**$14,374**	**$12,835**	**1.25**	**$15,814**	**$12,619**	**1.08**	**$41,069**	**$37,899**

Total NPV cost is the net present value of utility and participant costs
Residential Building Practices and Demonstration Program includes expected benefits and costs for the Gas Heating Equipment Tune Up.
Residential Low Income Program includes costs for the program but does not include expected benefits.

Niagara Mohawk Power Corporation d/b/a National Grid
ENERGY EFFICIENCY PROGRAMS
2009 - 2011 TRC BENEFIT COST TEST

		Total Benefits										Load Reduction (kW)			MWh Saved		MMBTU Saved	
			Capacity				Energy											
			Generation				Winter		Summer									
Year	Gas Programs	Total Benefits	Summer	Winter	Trans	MDC	Peak	Off Peak	Peak	Off Peak	Natural Gas	Summer	Winter	Lifetime	Annual	Lifetime	Annual	Lifetime
2009	Enhanced Home Sealing Incentives	$541,395	$0	$0	$0	$0	$0	$0	$0	$0	$541,395	0	0	0	0	0	4,140	82,800
	Residential ENERGY STAR® Products Program	$107,300	$83	$0	$14	$49	$5,775	$5,832	$2,735	$2,725	$90,087	0	2	1	12	311	606	15,140
	Residential Low Income Program	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0	0	0	0	0	0	0
	Residential Building Practices and Demonstration Program	$884,225	$0	$0	$0	$0	$0	$0	$0	$0	$884,225	0	0	0	0	0	73,152	76,554
	Energy*Wise* Program	$975,723	$0	$0	$0	$0	$0	$0	$0	$0	$975,723	0	0	0	0	0	9,396	131,544
	Commercial and Industrial Energy Efficiency Program	$5,495,261	$0	$0	$0	$0	$0	$0	$0	$0	$5,495,261	0	0	0	0	0	57,683	709,498
	Commercial High-Efficiency Heating and Water Heating	$936,848	$0	$0	$0	$0	$0	$0	$0	$0	$936,848	0	0	0	0	0	7,164	143,280
	Building Practices and Demonstration Program	$1,939,930	$0	$0	$0	$0	$0	$0	$0	$0	$1,939,930	0	0	0	0	0	19,047	259,038
Grand Total - 2009		**$10,880,683**	**$83**	**$0**	**$14**	**$49**	**$5,775**	**$5,832**	**$2,735**	**$2,725**	**$10,863,470**	**0**	**2**	**1**	**12**	**311**	**171,187**	**1,417,854**
2010	Enhanced Home Sealing Incentives	$832,646	$0	$0	$0	$0	$0	$0	$0	$0	$832,646	0	0	0	0	0	6,227	124,531
	Residential ENERGY STAR® Products Program	$183,551	$148	$0	$24	$85	$9,921	$10,135	$4,728	$4,749	$153,761	0	3	2	21	518	1,009	25,234
	Residential Low Income Program	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0	0	0	0	0	0	0
	Residential Building Practices and Demonstration Program	$783,009	$0	$0	$0	$0	$0	$0	$0	$0	$783,009	0	0	0	0	0	69,750	69,750
	Energy*Wise* Program	$991,296	$0	$0	$0	$0	$0	$0	$0	$0	$991,296	0	0	0	0	0	9,396	131,544
	Commercial and Industrial Energy Efficiency Program	$6,740,748	$0	$0	$0	$0	$0	$0	$0	$0	$6,740,748	0	0	0	0	0	69,911	859,907
	Commercial High-Efficiency Heating and Water Heating	$2,874,014	$0	$0	$0	$0	$0	$0	$0	$0	$2,874,014	0	0	0	0	0	21,492	429,840
	Building Practices and Demonstration Program	$1,969,102	$0	$0	$0	$0	$0	$0	$0	$0	$1,969,102	0	0	0	0	0	19,046	259,029
Grand Total - 2010		**$14,374,365**	**$148**	**$0**	**$24**	**$85**	**$9,921**	**$10,135**	**$4,728**	**$4,749**	**$14,344,576**	**0**	**3**	**2**	**21**	**518**	**196,831**	**1,899,834**
2011	Enhanced Home Sealing Incentives	$856,626	$0	$0	$0	$0	$0	$0	$0	$0	$856,626	0	0	0	0	0	6,227	124,531
	Residential ENERGY STAR® Products Program	$189,358	$157	$0	$25	$87	$10,321	$10,630	$4,939	$4,991	$158,209	0	3	2	21	518	1,009	25,234
	Residential Low Income Program	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0	0	0	0	0	0	0
	Residential Building Practices and Demonstration Program	$770,753	$0	$0	$0	$0	$0	$0	$0	$0	$770,753	0	0	0	0	0	69,750	69,750
	Energy*Wise* Program	$1,015,008	$0	$0	$0	$0	$0	$0	$0	$0	$1,015,008	0	0	0	0	0	9,396	131,544
	Commercial and Industrial Energy Efficiency Program	$7,518,293	$0	$0	$0	$0	$0	$0	$0	$0	$7,518,293	0	0	0	0	0	76,405	939,777
	Commercial High-Efficiency Heating and Water Heating	$3,449,584	$0	$0	$0	$0	$0	$0	$0	$0	$3,449,584	0	0	0	0	0	25,074	501,480
	Building Practices and Demonstration Program	$2,014,814	$0	$0	$0	$0	$0	$0	$0	$0	$2,014,814	0	0	0	0	0	19,046	259,029
Grand Total - 2011		**$15,814,437**	**$157**	**$0**	**$25**	**$87**	**$10,321**	**$10,630**	**$4,939**	**$4,991**	**$15,783,287**	**0**	**3**	**2**	**21**	**518**	**206,907**	**2,051,344**
	Enhanced Home Sealing Incentives	$2,230,667	$0	$0	$0	$0	$0	$0	$0	$0	$2,230,667	0	0	0	0	0	16,593	331,862
	Residential ENERGY STAR® Products Program	$480,209	$388	$0	$63	$221	$26,017	$26,596	$12,402	$12,465	$402,057	0	7	5	54	1,346	2,624	65,608
	Residential Low Income Program	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0	0	0	0	0	0	0
	Residential Building Practices and Demonstration Program	$2,682,243	$0	$0	$0	$0	$0	$0	$0	$0	$2,682,243	0	0	0	0	0	152,298	277,848
	Energy*Wise* Program	$2,737,772	$0	$0	$0	$0	$0	$0	$0	$0	$2,737,772	0	0	0	0	0	88,542	332,838
	Commercial and Industrial Energy Efficiency Program	$19,754,302	$0	$0	$0	$0	$0	$0	$0	$0	$19,754,302	0	0	0	0	0	203,999	2,509,182
2009 -	Commercial High-Efficiency Heating and Water Heating	$7,260,447	$0	$0	$0	$0	$0	$0	$0	$0	$7,260,447	0	0	0	0	0	53,730	1,074,600
2011	Building Practices and Demonstration Program	$5,923,845	$0	$0	$0	$0	$0	$0	$0	$0	$5,923,845	0	0	0	0	0	57,139	777,095
Grand Total - 2009 - 2011		**$41,069,484**	**$388**	**$0**	**$63**	**$221**	**$26,017**	**$26,596**	**$12,402**	**$12,465**	**$40,991,332**	**0**	**7**	**5**	**54**	**1,346**	**574,925**	**5,369,033**

Residential Building Practices and Demonstration Program includes expected benefits for the Gas Heating Equipment Tune Up.

Niagara Mohawk Power Corporation d/b/a National Grid
ENERGY EFFICIENCY PROGRAMS
2009 - 2011 TRC BENEFIT COST TEST

Year	Gas Programs	Program Planning and Administration	Program Marketing & Trade Ally	Customer Incentives or Services	Program Implementation	Evaluation & Market Research	Performance Incentive	Total Utility Cost	Particpant Cost	Total Cost
2009	Enhanced Home Sealing Incentives	$111,000	$81,509	$300,000	$30,000	$26,125	$0	$548,635	$60,000	$608,635
	Residential ENERGY STAR® Products Program	$5,000	$14,514	$30,000	$5,000	$2,726	$0	$57,240	$24,000	$81,240
	Residential Low Income Program	$0	$0	$5,000,000	$0	$0	$0	$5,000,000	$0	$5,000,000
	Residential Building Practices and Demonstration Program	$69,169	$82,406	$479,000	$30,570	$33,057	$0	$694,203	$41,800	$736,003
	Energy*Wise* Program	$48,030	$36,175	$500,000	$23,000	$30,360	$0	$637,565	$400,000	$1,037,565
	Commercial and Industrial Energy Efficiency Program	$150,000	$261,000	$1,298,700	$550,000	$112,985	$0	$2,372,685	$1,553,409	$3,926,094
	Commercial High-Efficiency Heating and Water Heating Program	$26,000	$97,000	$130,000	$10,000	$29,000	$0	$292,000	$140,000	$432,000
	Building Practices and Demonstration Program	$26,000	$20,000	$291,665	$22,000	$30,000	$0	$389,665	$233,332	$622,997
2009 Total		$435,199	$592,604	$8,029,365	$670,570	$264,254	$0	$9,991,992	$2,452,541	$12,444,533
2010	Enhanced Home Sealing Incentives	$52,000	$81,769	$300,000	$111,000	$27,238	$0	$572,008	$90,240	$662,248
	Residential ENERGY STAR® Products Program	$5,000	$15,515	$50,000	$5,000	$3,776	$0	$79,291	$40,000	$119,291
	Residential Low Income Program	$0	$0	$5,000,000	$0	$0	$0	$5,000,000	$0	$5,000,000
	Residential Building Practices and Demonstration Program	$64,000	$71,849	$425,000	$22,300	$29,157	$0	$612,307	($50,000)	$562,307
	Energy*Wise* Program	$48,030	$35,340	$500,000	$23,000	$30,319	$0	$636,689	$400,000	$1,036,689
	Commercial and Industrial Energy Efficiency Program	$150,000	$300,000	$1,461,037	$550,000	$123,052	$0	$2,584,089	$1,931,512	$4,515,601
	Commercial High-Efficiency Heating and Water Heating Program	$50,500	$122,000	$390,000	$12,500	$28,750	$0	$603,750	$420,000	$1,023,750
	Building Practices and Demonstration Program	$26,000	$30,000	$291,655	$22,000	$18,483	$0	$388,138	$233,324	$621,462
2010 Total		$395,530	$656,474	$8,417,692	$745,800	$260,775	$0	$10,476,270	$3,065,076	$13,541,346
2011	Enhanced Home Sealing Incentives	$111,000	$77,342	$300,000	$31,651	$26,000	$0	$545,992	$90,240	$636,232
	Residential ENERGY STAR® Products Program	$5,000	$15,529	$50,000	$5,000	$3,776	$0	$79,305	$40,000	$119,305
	Residential Low Income Program	$0	$0	$5,000,000	$0	$0	$0	$5,000,000	$0	$5,000,000
	Residential Building Practices and Demonstration Program	$64,000	$71,975	$425,000	$22,400	$29,169	$0	$612,544	($50,000)	$562,544
	Energy*Wise* Program	$48,030	$35,471	$500,000	$23,000	$30,325	$0	$636,826	$400,000	$1,036,826
	Commercial and Industrial Energy Efficiency Program	$150,000	$300,000	$1,623,375	$550,000	$131,169	$0	$2,754,544	$2,099,413	$4,853,957
	Commercial High-Efficiency Heating and Water Heating Program	$50,500	$100,800	$455,000	$84,500	$34,540	$0	$725,340	$490,000	$1,215,340
	Building Practices and Demonstration Program	$26,000	$30,000	$291,655	$22,000	$18,483	$0	$388,138	$233,324	$621,462
2010 Total		$454,530	$631,116	$8,645,030	$738,551	$273,461	$0	$10,742,689	$3,302,977	$14,045,666
	Enhanced Home Sealing Incentives	$274,000	$240,620	$900,000	$172,651	$79,364	$0	$1,666,635	$240,480	$1,907,115
	Residential ENERGY STAR® Products Program	$15,000	$45,558	$130,000	$15,000	$10,278	$0	$215,836	$104,000	$319,836
	Residential Low Income Program	$0	$0	$15,000,000	$0	$0	$0	$15,000,000	$0	$15,000,000
	Residential Building Practices and Demonstration Program	$197,169	$226,230	$1,329,000	$75,270	$91,383	$0	$1,919,053	($58,200)	$1,860,853
	Energy*Wise* Program	$144,090	$106,986	$1,500,000	$69,000	$91,004	$0	$1,911,080	$1,200,000	$3,111,080
	Commercial and Industrial Energy Efficiency Program	$450,000	$861,000	$4,383,112	$1,650,000	$367,206	$0	$7,711,318	$5,584,334	$13,295,652
	Commercial High-Efficiency Heating and Water Heating Program	$127,000	$319,800	$975,000	$107,000	$92,290	$0	$1,621,090	$1,050,000	$2,671,090
2009 - 2011	Building Practices and Demonstration Program	$78,000	$80,000	$874,975	$66,000	$66,966	$0	$1,165,941	$699,980	$1,865,921
2009 - 2011 Total		$1,285,259	$1,880,194	$25,092,087	$2,154,921	$798,490	$0	$31,210,951	$8,820,594	$40,031,545

Budget shows activity in program year dollars, not present valued to 2009 dollars.
Residential Building Practices and Demonstration Program includes expected costs for the Gas Heating Equipment Tune Up.

Niagara Mohawk Power Corporation d/b/a National Grid
ENERGY EFFICIENCY PROGRAMS
2009 - 2011 TRC BENEFIT COST TEST

Summary of Benefit , Costs (2009 $s)
Total Resource Cost Test

	2009			2010			2011			2009 - 2011		
Electric Programs	**TRC Benefit/ Cost**	**Total NPV Benefits ($000)**	**Total NPV Costs ($000)**	**TRC Benefit/ Cost**	**Total NPV Benefits ($000)**	**Total NPV Costs ($000)**	**TRC Benefit/ Cost**	**Total NPV Benefits ($000)**	**Total NPV Costs ($000)**	**TRC Benefit/ Cost**	**Total NPV Benefits ($000)**	**Total NPV Costs ($000)**
Enhanced Home Sealing Incentives	1.00	$811	$ 815	1.17	$1,543	$ 1,324	1.29	$1,614	$ 1,255	1.17	$3,969	$3,394
Residential ENERGY STAR® Products and Recycling Program	1.34	$3,417	$ 2,548	1.90	$7,108	$ 3,738	2.11	$7,460	$ 3,543	1.83	$17,985	$9,829
Residential Internet Audit Program and E-Commerce Sales	1.76	$1,562	$ 887	1.91	$1,604	$ 840	2.11	$1,681	$ 797	1.92	$4,846	$2,524
Residential Building Practices and Demonstration Program	1.05	$911	$ 865	1.07	$880	$ 819	1.16	$897	$ 777	1.09	$2,688	$2,461
Energy*Wise* Program	1.01	$2,839	$ 2,812	1.02	$6,068	$ 5,966	1.12	$6,352	$ 5,655	1.06	$15,259	$14,432
Residential Pricing Pilot with Load Control	n/a	n/a	$ 420	n/a	n/a	$ 1,767	n/a	n/a	$ 118	n/a	n/a	$2,305
Energy Initiative	2.97	$94,261	$ 31,745	3.25	$122,239	$ 37,613	3.59	$159,898	$ 44,565	3.30	$376,397	$113,923
Grand Total	**2.59**	**$103,802**	**$40,091**	**2.68**	**$139,441**	**$52,067**	**3.14**	**$177,901**	**$56,709**	**2.83**	**$421,144**	**$148,867**

Total NPV cost is the net present value of utility and participant costs
Residential Pricing Pilot with Load Control includes costs for the program but does not include expected benefits.

ENERGY EFFICIENCY PROGRAMS
2009 - 2011 TRC BENEFIT COST TEST

		Total Benefits										Load Reduction (kW)			MWh Saved	
			Capacity				Energy									
			Generation				Winter		Summer							
Year	Electric Programs	Total Benefits	Summer	Winter	Trans	MDC	Peak	Off Peak	Peak	Off Peak	Natural Gas	Summer	Winter	Lifetime	Annual	Lifetime
2009	Enhanced Home Sealing Incentives	$811,191	$3,965	$0	$677	$2,392	$273,334	$273,724	$129,224	$127,875	$0	3	85	51	676	13,522
	Residential ENERGY STAR® Products and Recycling Program	$3,417,122	$350,977	$0	$70,102	$247,783	$953,308	$923,922	$442,966	$428,065	$0	501	615	3,955	4,757	37,880
	Residential Internet Audit Program and E-Commerce Sales	$1,562,249	$100,110	$0	$21,878	$77,331	$474,832	$457,453	$218,738	$211,906	$0	196	738	1,176	3,001	18,006
	Residential Building Practices and Demonstration Program	$911,195	$64,021	$0	$19,577	$69,198	$279,817	$246,079	$122,301	$110,202	$0	925	925	925	8,100	8,100
	Energy*Wise* Program	$2,839,444	$210,958	$0	$36,732	$129,831	$840,349	$835,135	$396,472	$389,968	$0	154	371	2,542	2,378	39,146
	Residential Pricing Pilot with Load Control	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0	0	0	0	0
	Energy Initiative	$94,260,842	$13,055,539	$0	$2,366,309	$8,363,927	$34,461,206	$13,096,421	$16,815,872	$6,101,568	$0	12,082	0	148,705	77,691	947,469
Grand Total - 2009		**$103,802,044**	**$13,785,570**	**$0**	**$2,515,275**	**$8,890,461**	**$37,282,846**	**$15,832,734**	**$18,125,574**	**$7,369,583**	**$0**	**13,860**	**2,733**	**157,354**	**96,604**	**1,064,122**
2010	Enhanced Home Sealing Incentives	$1,543,144	$7,796	$0	$1,278	$4,516	$515,645	$523,144	$245,557	$245,208	$0	5	155	93	1,239	24,790
	Residential ENERGY STAR® Products and Recycling Program	$7,108,265	$789,989	$0	$144,399	$510,390	$1,937,931	$1,917,033	$914,487	$894,035	$0	1,001	1,233	7,912	9,539	76,003
	Residential Internet Audit Program and E-Commerce Sales	$1,603,506	$115,642	$0	$22,530	$79,635	$474,995	$469,149	$222,843	$218,711	$0	196	738	1,176	3,001	18,006
	Residential Building Practices and Demonstration Program	$879,671	$77,158	$0	$20,161	$71,260	$255,576	$234,800	$114,494	$106,222	$0	925	925	925	8,100	8,100
	Energy*Wise* Program	$6,067,746	$468,170	$0	$77,814	$275,040	$1,774,638	$1,789,163	$844,229	$838,691	$0	318	763	5,230	4,892	80,529
	Residential Pricing Pilot with Load Control	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0	0	0	0	0
	Energy Initiative	$122,238,568	$17,816,650	$0	$3,046,031	$10,766,465	$43,977,912	$16,982,524	$21,691,904	$7,957,082	$0	15,102	0	185,881	97,114	1,184,336
Grand Total - 2010		**$139,440,899**	**$19,275,406**	**$0**	**$3,312,213**	**$11,707,306**	**$48,936,697**	**$21,915,814**	**$24,033,514**	**$10,259,949**	**$0**	**17,547**	**3,814**	**201,217**	**123,886**	**1,391,764**
2011	Enhanced Home Sealing Incentives	$1,614,213	$8,305	$0	$1,316	$4,651	$536,254	$549,078	$256,622	$257,989	$0	5	155	93	1,239	24,790
	Residential ENERGY STAR® Products and Recycling Program	$7,459,546	$873,146	$0	$148,702	$525,600	$2,004,202	$2,009,650	$955,265	$942,982	$0	1,001	1,233	7,912	9,539	76,003
	Residential Internet Audit Program and E-Commerce Sales	$1,680,543	$130,761	$0	$23,202	$82,008	$490,323	$491,057	$233,003	$230,189	$0	196	738	1,176	3,001	18,006
	Residential Building Practices and Demonstration Program	$897,411	$91,021	$0	$20,761	$73,383	$246,807	$238,571	$116,146	$110,721	$0	925	925	925	8,100	8,100
	Energy*Wise* Program	$6,351,689	$501,035	$0	$80,133	$283,237	$1,844,130	$1,878,029	$882,269	$882,856	$0	318	763	5,230	4,892	80,529
	Residential Pricing Pilot with Load Control	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0	0	0	0	0
	Energy Initiative	$159,898,090	$24,058,278	$0	$3,921,004	$13,859,131	$57,007,532	$22,264,268	$28,314,979	$10,472,898	$0	18,878	0	232,352	121,392	1,480,420
Grand Total - 2011		**$177,901,492**	**$25,662,545**	**$0**	**$4,195,117**	**$14,828,010**	**$62,129,249**	**$27,430,652**	**$30,758,284**	**$12,897,635**	**$0**	**21,322**	**3,814**	**247,687**	**148,164**	**1,687,848**
	Enhanced Home Sealing Incentives	$3,968,549	$20,066	$0	$3,270	$11,559	$1,325,233	$1,345,946	$631,403	$631,072	$0	12	394	237	3,155	63,101
	Residential ENERGY STAR® Products and Recycling Program	$17,984,933	$2,014,112	$0	$363,203	$1,283,773	$4,895,441	$4,850,605	$2,312,718	$2,265,081	$0	2,504	3,081	19,779	23,835	189,886
	Residential Internet Audit Program and E-Commerce Sales	$4,846,298	$346,513	$0	$67,610	$238,974	$1,440,151	$1,417,659	$674,584	$660,806	$0	588	2,214	3,529	9,003	54,019
	Residential Building Practices and Demonstration Program	$2,688,277	$232,201	$0	$60,500	$213,841	$782,200	$719,449	$352,942	$327,145	$0	2,774	2,774	2,774	24,300	24,300
	Energy*Wise* Program	$15,258,879	$1,180,163	$0	$194,678	$688,108	$4,459,117	$4,502,328	$2,122,970	$2,111,515	$0	790	1,897	13,002	12,163	200,204
2009 -	Residential Pricing Pilot with Load Control	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0	0	0	0	0
2011	Energy Initiative	$376,397,500	$54,930,467	$0	$9,333,344	$32,989,523	$135,446,650	$52,343,212	$66,822,756	$24,531,549	$0	46,062	0	566,938	296,198	3,612,224
Grand Total - 2009 - 2011		**$421,144,435**	**$58,723,521**	**$0**	**$10,022,605**	**$35,425,777**	**$148,348,792**	**$65,179,200**	**$72,917,372**	**$30,527,168**	**$0**	**52,729**	**10,361**	**606,258**	**368,654**	**4,143,733**

Niagara Mohawk Power Corporation d/b/a National Grid
ENERGY EFFICIENCY PROGRAMS
2009 - 2011 TRC BENEFIT COST TEST

Year	Electric Programs	Program Planning and Administration	Program Marketing & Trade Ally	Customer Incentives or Services	Program Implementation	Evaluation & Market Research	Performance Incentive	Total Utility Cost	Particpant Cost	Total Cost
2009	Enhanced Home Sealing Incentives	$50,000	$100,000	$480,000	$75,000	$35,250	$26,266	$766,516	$48,320	$814,836
	Residential ENERGY STAR® Products and Recycling Program	$200,000	$700,000	$350,000	$1,000,000	$112,500	$184,818	$2,547,318	$250	$2,547,568
	Residential Internet Audit Program and E-Commerce Sales	$100,000	$200,000	$200,000	$200,000	$35,000	$116,591	$851,591	$35,000	$886,591
	Residential Building Practices and Demonstration Program	$64,000	$60,000	$425,000	$22,300	$28,565	$314,685	$914,550	($50,000)	$864,550
	Energy*Wise* Program	$100,000	$100,000	$1,500,000	$300,000	$100,000	$92,395	$2,192,395	$619,181	$2,811,576
	Residential Pricing Pilot with Load Control	$100,000	$50,000	$250,000	$0	$20,000	$0	$420,000	$0	$420,000
	Energy Initiative	$2,225,800	$281,610	$12,462,590	$520,000	$774,500	$3,018,303	$19,282,803	$12,462,590	$31,745,393
2009 Total		$2,839,800	$1,491,610	$15,667,590	$2,117,300	$1,105,815	$3,753,058	$26,975,173	$13,115,341	$40,090,514
2010	Enhanced Home Sealing Incentives	$50,000	$100,000	$900,000	$150,000	$60,000	$48,154	$1,308,154	$88,587	$1,396,741
	Residential ENERGY STAR® Products and Recycling Program	$200,000	$700,000	$700,000	$1,800,000	$170,000	$370,585	$3,940,585	$3,000	$3,943,585
	Residential Internet Audit Program and E-Commerce Sales	$100,000	$200,000	$200,000	$200,000	$35,000	$116,591	$851,591	$35,000	$886,591
	Residential Building Practices and Demonstration Program	$64,000	$60,000	$425,000	$22,300	$28,565	$314,685	$914,550	($50,000)	$864,550
	Energy*Wise* Program	$100,000	$100,000	$4,000,000	$400,000	$230,000	$190,070	$5,020,070	$1,273,743	$6,293,813
	Residential Pricing Pilot with Load Control	$50,000	$75,000	$1,500,000	$150,000	$88,750	$0	$1,863,750	$0	$1,863,750
	Energy Initiative	$2,782,250	$352,013	$15,578,238	$650,000	$968,125	$3,772,879	$24,103,504	$15,578,238	$39,681,741
2010 Total		$3,346,250	$1,587,013	$23,303,238	$3,372,300	$1,580,440	$4,812,963	$38,002,203	$16,928,568	$54,930,770
2011	Enhanced Home Sealing Incentives	$50,000	$100,000	$900,000	$150,000	$60,000	$48,154	$1,308,154	$88,587	$1,396,741
	Residential ENERGY STAR® Products and Recycling Program	$200,000	$700,000	$700,000	$1,800,000	$170,000	$370,585	$3,940,585	$3,000	$3,943,585
	Residential Internet Audit Program and E-Commerce Sales	$100,000	$200,000	$200,000	$200,000	$35,000	$116,591	$851,591	$35,000	$886,591
	Residential Building Practices and Demonstration Program	$64,000	$60,000	$425,000	$22,300	$28,565	$314,685	$914,550	($50,000)	$864,550
	Energy*Wise* Program	$100,000	$100,000	$4,000,000	$400,000	$230,000	$190,070	$5,020,070	$1,273,743	$6,293,813
	Residential Pricing Pilot with Load Control	$25,000	$0	$50,000	$50,000	$6,250	$0	$131,250	$0	$131,250
	Energy Initiative	$3,477,813	$440,016	$19,472,797	$812,500	$1,210,156	$4,716,098	$30,129,379	$19,472,797	$49,602,176
2010 Total		$4,016,813	$1,600,016	$25,747,797	$3,434,800	$1,739,971	$5,756,182	$42,295,578	$20,823,127	$63,118,705
	Enhanced Home Sealing Incentives	$150,000	$300,000	$2,280,000	$375,000	$155,250	$122,573	$3,382,823	$225,495	$3,608,318
	Residential ENERGY STAR® Products and Recycling Program	$600,000	$2,100,000	$1,750,000	$4,600,000	$452,500	$925,988	$10,428,488	$6,250	$10,434,738
	Residential Internet Audit Program and E-Commerce Sales	$300,000	$600,000	$600,000	$600,000	$105,000	$349,772	$2,554,772	$105,000	$2,659,772
	Residential Building Practices and Demonstration Program	$192,000	$180,000	$1,275,000	$66,900	$85,695	$944,055	$2,743,650	($150,000)	$2,593,650
	Energy*Wise* Program	$300,000	$300,000	$9,500,000	$1,100,000	$560,000	$472,534	$12,232,534	$3,166,667	$15,399,201
	Residential Pricing Pilot with Load Control	$175,000	$125,000	$1,800,000	$200,000	$115,000	$0	$2,415,000	$0	$2,415,000
2009 - 2011	Energy Initiative	$8,485,863	$1,073,638	$47,513,624	$1,982,500	$2,952,781	$11,507,279	$73,515,686	$47,513,624	$121,029,310
2009 - 2011 Total		$10,202,863	$4,678,638	$64,718,624	$8,924,400	$4,426,226	$14,322,202	$107,272,954	$50,867,036	$158,139,989

Budget shows activity in program year dollars, not present valued to 2009 dollars.

Appendix C

APPENDIX C

Master Worksheet With All Input Assumptions

ASTER WORKSHEET WITH ALL PROGRAM INPUT ASSUMPTIONS
ıput Assumptions Energy Efficiency Programs - Niagara Mohawk Power Corporation d/b/a National Grid
eptember 19, 2008

Electric Programs	Measure Name	Measure Life	Source of Measure Life	Incremental Cost	Source of Incremental Cost	Annual Savings Per Participant or Per Unit of Installation	Source of Annual Savings	Net to Gross Impact Factors	Source of Net to Gross
nhanced Home Sealing Incentives	BPI	20	Measure Life Report for the New England State Program Working Group, March 14, 2007 prepared by GDS Associates.	$1491	This figure represents the average cost of weatherization/insulation jobs for this program. The average rebate will be approximately $1,357, and this represents 90% of the total cost of each weatherization job. Thus the average cost of each weatherization job is approximately $1,491.	1,878	Average of projects completed in MA service territory in 2007 in the RCS Program for participants with electric heat that received air sealing and insulation.	100%	Net to gross impact factors are assumed to be 100 %.
esidential ENERGY STAR® Products ıd Recycling Program	CFLs	7	NMR, Residential Lighting Measure Life Study, June 4, 2008.	$3	Average of costs in MA service territory between '06-'07.	57	RLW Analytics, Impact Evaluation of the Massachusetts, Rhode Island, and Vermont 2003 Residential Lighting Programs".	84% In Service Rate; Net to gross factor of 139%	In service rate is from NMR, Impact Evaluation of the Massachusetts, Rhode Island, an Vermont 2003 Residential Lightin Programs, October 1, 2004. Net t gross factor is from NMR, MPER for the 2007 Massachusetts ENERGY STAR Lighting Prograr June 16, 2008.
esidential ENERGY STAR® Products ıd Recycling Program	Windows	25	Measure Life Report for the New England State Program Working Group, March 14, 2007 prepared by GDS Associates.	$1.50/ square foot assume 12.5 square feet of window (or $18.75 per window).	Quantec LLC, Residential Market Assessment for ENERGY STAR Windows in the Northeast, January 2006.	703	MMBTU Savings per window converted to kWh plus kWh cooling savings per window. The annual Mate savings per ENERGY STAR window are based on a REM/rate analysis conducted by GDS on March 12, 2004.	100%	Net to gross impact factors are assumed to be 100 %.
esidential ENERGY STAR® Products ıd Recycling Program	Energy Star Thermostats	10	Measure Life Report for the New England State Program Working Group, March 14, 2007 prepared by GDS Associates.	$92	Energy STAR cost calculator.	244	MMBTU Savings per thermostat converted to kWh to arrive at savings per thermostat. RLW Analytics-Validating the Impacts of Programmable Thermostats, dated January 2007.	100%	Net to gross impact factors are assumed to be 100 %.
esidential ENERGY STAR® Products ıd Recycling Program	Refrigerator Recycling	8	Jaco Environmental, 2008 - 2010 Refrigerator Recycling Program Scenario Analysis	$30	Jaco Environmental, 2008 - 2010 Refrigerator Recycling Program Scenario Analysis	724	Jaco Environmental, 2008 - 2010 Refrigerator Recycling Program Scenario Analysis	10% Net Free Ridership Rate	Net free ridership is a DPS staff estimate.
esidential Internet Audit Program and E ommerce Sales	CFLs	7	NMR, Residential Lighting Measure Life Study, June 4, 2008.	$3	Average of costs in MA service territory between '06-'07.	57	RLW Analytics, Impact Evaluation of the Massachusetts, Rhode Island, and Vermont 2003 Residential Lighting Programs".	84% In Service Rate; Net to gross factor of 139%	In service rate is from NMR, Impact Evaluation of the Massachusetts, Rhode Island, an Vermont 2003 Residential Lightin Programs, October 1, 2004. Net t gross factor is from NMR, MPER for the 2007 Massachusetts ENERGY STAR Lighting Prograr June 16, 2008.
esidential Building Practices and emonstration Program	Res Building Practices and Demo (includes Positive Energy)	1	Positive Energy NYS EEPS Proposal Amendment - Delivered to National Grid, 9/5/08	$10	Positive Energy NYS EEPS Proposal Amendment - Delivered to National Grid, 9/5/08	180	Positive Energy NYS EEPS Proposal Amendment - Delivered to National Grid, 9/5/08	10% Net Free Ridership Rate	Net free ridership is a DPS staff estimate.
nergy*Wise* Program	Insulation, Air Sealing, Lighting	16	Weighted average of measure life of projects completed in MA service territory 2007	$1,415	This figure represents the average cost of weatherization/insulation jobs for this program. The average rebate will be approximately $1,061, and this represents 75% of the total cost of each weatherization job. Thus the average cost of each weatherization job is approximately $1,415.	1,359	Average of projects completed in MA service territory in 2007 in the Energy*Wise* Program for participants with electric heat. Adjusted to 50% of participants receive a refrigerator.	3% free ridership; 104% realization rate	Free ridership is a National Grid staff estimate based on previous studies. Realization rate is from Summit Blue Consulting, Impact Evaluation of the 2005 Energy*Wis* Program, September 1, 2006.

ASTER WORKSHEET WITH ALL PROGRAM INPUT ASSUMPTIONS
iput Assumptions Energy Efficiency Programs - Niagara Mohawk Power Corporation d/b/a National Grid
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Electric Programs	Measure Name	Measure Life	Source of Measure Life	Incremental Cost	Source of Incremental Cost	Annual Savings Per Participant or Per Unit of Installation	Source of Annual Savings	Net to Gross Impact Factors	Source of Net to Gross
nergy Initiative	Compressed Air	13	Average of measure life of projects completed in MA service territory in 2007.	$22,671	This figure represents the average cost of projects completed in MA service territory in 2007. The average rebate will be approximately $11,336, and this represents 50% of the total cost of the project. Thus the average cost of the project is approximately $22,671.	30,485	Average savings of projects completed in MA service territory in 2007.	6% Free ridership	Free ridership is from PA Consulting, 2007 Commercial anc Industrial Programs Free-ridershi and Spillover Study, June 23, 200
nergy Initiative	Custom	12	Average of measure life of projects completed in MA service territory in 2007.	$69,337	This figure represents the average cost of projects completed in MA service territory in 2007. The average rebate will be approximately $34,668, and this represents 50% of the total cost of the project. Thus the average cost of the project is approximately $69,337.	131,771	Average savings of projects completed in MA service territory in 2007.	7% Free ridership; 76 - 117% Realization Rate by end use	Free ridership is from PA Consulting, 2007 Commercial anc Industrial Programs Free-ridershi and Spillover Study, June 23, 200 Realization rate is from RLW, Sample Design and Impact Evaluation of 2006 Custom Installations, July 20, 2008.
nergy Initiative	HVAC	10	Average of measure life of projects completed in MA service territory in 2007.	$31,301	This figure represents the average cost of projects completed in MA service territory in 2007. The average rebate will be approximately $15,651, and this represents 50% of the total cost of the project. Thus the average cost of the project is approximately $31,301.	108,801	Average savings of projects completed in MA service territory in 2007.	12% Free ridership	Free ridership is from PA Consulting, 2007 Commercial anc Industrial Programs Free-ridershi and Spillover Study, June 23, 200
nergy Initiative	LIGHT	13	Average of measure life of projects completed in MA service territory in 2007.	$32,142	This figure represents the average cost of projects completed in MA service territory in 2007. The average rebate will be approximately $16,071, and this represents 50% of the total cost of the project. Thus the average cost of the project is approximately $32,142.	133,241	Average savings of projects completed in MA service territory in 2007.	10% Free ridership; 38% - 104% Realization rate by end use.	Free ridership is from PA Consulting, 2007 Commercial anc Industrial Programs Free-ridershi and Spillover Study, June 23, 200 Realization rate is from Summit Blue, Large Commercial and Industrial Retrofit Program Impact Evaluation, June 2008.
nergy Initiative	VSD	13	Average of measure life of projects completed in MA service territory in 2007.	$52,496	This figure represents the average cost of projects completed in MA service territory in 2007. The average rebate will be approximately $26,248, and this represents 50% of the total cost of the project. Thus the average cost of the project is approximately $52,496.	145,705	Average savings of projects completed in MA service territory in 2007.	33% Free ridership	Free ridership is from PA Consulting, 2007 Commercial anc Industrial Programs Free-ridershi and Spillover Study, June 23, 200
nergy Initiative	MOTORS	15	Average of measure life of projects completed in MA service territory in 2007.	$30,083	This figure represents the average cost of projects completed in MA service territory in 2007. The average rebate will be approximately $15,042, and this represents 50% of the total cost of the project. Thus the average cost of the project is approximately $30,083.	38,401	Average savings of projects completed in MA service territory in 2007.	21 % Free ridership; 62% realization rate	Free ridership is from PA Consulting, 2007 Commercial anc Industrial Programs Free-ridershi and Spillover Study, June 23, 200 Realization rate is from Motor Ru Time and Persistence Study, 199

ASTER WORKSHEET WITH ALL PROGRAM INPUT ASSUMPTIONS
iput Assumptions Energy Efficiency Programs - Niagara Mohawk Power Corporation d/b/a National Grid
eptember 19, 2008

Gas Programs	Measure Name	Measure Life	Source of Measure Life	Incremental Cost	Source of Incremental Cost	Annual Savings Per Participant or Per Unit of Installation	Source of Annual Savings	Net to Gross Impact Factors	Source of Net to Gross
nhanced Home Sealing Incentives	BPI	20	Measure Life Report for the New England State Program Working Group, March 14, 2007 prepared by GDS Associates.	$3,200	This figure represents the incentive dollars budgeted for 10/08-5/09 divided by the total expected participation for 2009 for this program. The average rebate will be approximately $2,400, and this represents 75% of the total cost of each weatherization job. Thus the average cost of each weatherization job is approximately $3,200.	37	Based on RemRATE Analysis for small, medium and large homes in New Hampshire, and using degree days in Concord, New Hampshire. The REM/rate analysis was completed on March 12, 2004 by GDS.	10% Net Free Ridership Rate	Net free ridership is a DPS staff estimate.
esidential ENERGY STAR® Products rogram	Windows	25	Measure Life Report for the New England State Program Working Group, March 14, 2007 prepared by GDS Associates.	$1.50/ square foot assume 12.5 square feet of window (or $18.75 per window).	Quantec LLC, Residential Market Assessment for ENERGY STAR Windows in the Northeast, January 2006.	2	Quantec LLC, Residential Market Assessment for ENERGY STAR Windows in the Northeast, January 2006.	10% Net Free Ridership Rate	Net free ridership is a DPS staff estimate.
esidential Building Practices and emonstration Program	Res Building Practices and Demo (includes Positive Energy)	1	Positive Energy NYS EEPS Proposal Amendment - Delivered to National Grid, 9/5/08	$10	Positive Energy NYS EEPS Proposal Amendment - Delivered to National Grid, 9/5/08	2	Positive Energy NYS EEPS Proposal Amendment - Delivered to National Grid, 9/5/08	10% Net Free Ridership Rate	Net free ridership is a DPS staff estimate.
esidential Building Practices and emonstration Program	Tune Up	2	Quantec LLC, Ohio Home Weatherization Assistance Program Impact Evaluation, July 2006.	$150	Estimate from National Grid Energy Services	4	Quantec LLC, Ohio Home Weatherization Assistance Program Impact Evaluation, July 2006.	10% Net Free Ridership Rate	Net free ridership is a DPS staff estimate.
nergy*Wise* Program	Insulation and Air Sealing	14	Average of measure life of projects completed in RI service territory between '07-'08	$556	This figure represents the average cost of weatherization/insulation jobs for this program. The average rebate will be approximately $278, and this represents 50% of the total cost of each weatherization job. Thus the average cost of each weatherization is $556.	6	Average of projects completed in RI service territory between '07-'08	10% Net Free Ridership Rate	Net free ridership is a DPS staff estimate.
ommercial and Industrial Energy fficiency Program	Standard Comm EE Projects	12	Data from KeySpan's updated "Performance Report" report for Massachusetts programs" for Program Year 3 (this is for the period May 1, 2004 to April 30, 2005)	$5,775	Average of projects completed in NY service territory from RISE Engineering.	144	Average of projects completed in NY service territory from RISE Engineering.	10% Net Free Ridership Rate	Net free ridership is a DPS staff estimate.
ommercial and Industrial Energy fficiency Program	Economic Redevelopment Projects	12	Data from KeySpan's Annual Report for Massachusetts programs for 2005-2006 (this is for the period May 1, 2005 to April 30, 2006)	$113,496	This figure represents the incentive dollars budgeted in 2009 for the Economic Redevelopment Program divided by the total number of expected participants. The rebate offered by this program covers 50% of the project incremental cost. The projected rebate per participant is $56,748. Thus the projected incremental cost is $113,496.	1,419	Average of projects completed in NY service territory from RISE Engineering.	10% Net Free Ridership Rate	Net free ridership is a DPS staff estimate.

ASTER WORKSHEET WITH ALL PROGRAM INPUT ASSUMPTIONS
iput Assumptions Energy Efficiency Programs - Niagara Mohawk Power Corporation d/b/a National Grid
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Gas Programs	Measure Name	Measure Life	Source of Measure Life	Incremental Cost	Source of Incremental Cost	Annual Savings Per Participant or Per Unit of Installation	Source of Annual Savings	Net to Gross Impact Factors	Source of Net to Gross
ommercial High-Efficiency Heating and /ater Heating Program	Comm High Efficiency Heating	20	Energy Star Savings Calculator for Boilers. Lifetime from LBNL 2007.	$3,000	The rebate offered by this program covers 50% of the project incremental cost. The projected rebate per participant is $1,500. Thus the projected incremental cost is $3,000.	80	Average of projects completed in NY service territory from RISE Engineering.	10% Net Free Ridership Rate	Net free ridership is a DPS staff estimate.
uilding Practices and Demonstration rogram	Comm Building Practices and Demo	14	Data from KeySpan's "Cost per therm report for Massachusetts programs" for Program Year 3 (this is for the period May 1, 2004 to April 30, 2005)	$40,000	The rebate offered by this program covers 50% of the project incremental cost. The projected rebate per participant is $20,000. Thus the projected incremental cost is $40,000.	1,451	Average of projects completed in NY service territory from RISE Engineering.	10% Net Free Ridership Rate	Net free ridership is a DPS staff estimate.

Appendix D

APPENDIX D

"Niagara Mohawk Avoided Electricity and Natural Gas Costs"

APPENDIX D

Synapse
Energy Economics, Inc.

Niagara Mohawk Avoided Electricity and Natural Gas Costs

March 31, 2008

AUTHORS
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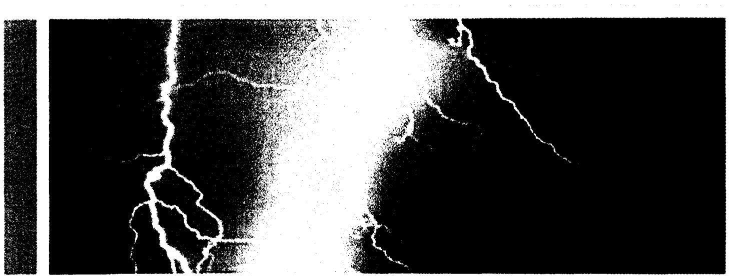

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1. Executive Summary

Background

National Grid retained Synapse Energy Economics (Synapse) and its subcontractors, Swanson Energy Group and Resource Insight, to prepare projections of retail electricity and natural gas costs that would be avoided due to reductions in retail consumption resulting from energy efficiency programs offered to customers of Niagara Mohawk (NIMO). These projections were developed in order to support energy efficiency program decision-making and regulatory filings during 2008.

This projection of retail avoided costs is an add-on to the analyses that this Synapse project team completed for the 2007 AESC Study Group. That project entailed the development of long-term projections of avoided retail electricity and natural gas costs for utilities in New England. The assumptions, methodology and results from that study are documented in *Avoided Energy Supply Costs in New England 2007 Final Report* ("AESC 2007")[1].

In this add-on project, the Synapse team developed estimates of these retail avoided costs for NIMO using essentially the same methodology as they used in the AESC 2007 project. The team drew upon materials from the AESC 2007 Study to the maximum extent possible and reasonable. It made changes to input assumptions where appropriate to reflect the market conditions in which Niagara Mohawk operates.

Due to the extremely limited time available to develop these projections, Synapse did not develop a forecast of wholesale electric energy prices in New York base upon its own simulation modeling. Instead Synapse started with the Reference Case forecast in the most recent long-term electricity and fuel price outlook[2] prepared by Global Energy Decisions (GED).[3] The Reference Case forecast is a 25-year outlook for the electric and fuel markets in the United States Northeast. It is based upon a comprehensive, independent analysis of market trends and detailed modeling of electric and fuels markets in that region. Synapse is providing the GED outlook to National Grid with this report.

Synapse chose the GED forecast as a starting point because it is a recent detailed projection of fuel and electric energy prices for the Northeast, including New York, prepared using an updated version of the same database as well as the same production simulation model as Synapse used in AESC 2007. Synapse developed a customized forecast of wholesale natural gas and electric energy prices for NIMO by adjusting the respective GED forecasts to reflect the Synapse team's outlook on certain key components.

The balance of the report is organized as follows:

Chapter 2	Projection of wholesale electric energy prices
Chapter 3	Projection of avoided retail electricity costs by costing period.
Chapter 4	Projection of avoided natural gas costs by retail end-use sector.

1 *Avoided Energy Supply Costs in New England 2007 Final Report,* August 2007 ("AESC 2007). Available at: http://www.synapse-energy.com/Downloads/SynapseReport.2007-08.AESC.Avoided-Energy-Supply-Costs-2007.07-019.pdf

2 ____, *Electricity & Fuel Price Outlook - Northeast Fall 2007,* Global Energy Decisions, Power Market Advisory Service, November 2007. Access to this intellectual property is restricted to parties that have directly licensed the report and parties that have signed a non-disclosure agreement (NDA) with Ventyx.

3 Global Energy Decisions, a Ventyx Company.

A. Levelized Avoided Costs

The detailed, year by year, avoided costs of electricity and natural gas are presented later in this report. The twenty year (2008 – 2027) levelized values for these costs, in $2007, are summarized below. The levelized values were calculated at discount rate of 2.22%.

Avoided Electricity Costs

The levelized avoided costs of electric energy and capacity applicable to load reductions by NIMO retail customers over the next twenty years are shown in Table 1.

Table 1 - NIMO 20 Year Levelized Avoided Electricity Costs ($2007)					
Period	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off Peak	Capacity
Units	$/kwh	$/kwh	$/kwh	$/kwh	$/kw-yr
Avoided Cost	0.102	0.071	0.101	0.067	104.3
CO_2 Externality	0.035	0.029	0.034	0.028	

This table also presents a projection of annual additional environmental costs associated with emissions of CO_2 related to electric energy consumption by NIMO customers. The estimates are equal to the cost of limiting CO_2 emissions to a "sustainability target" level, estimated to be a control cost of $60/ton, minus the forecast value of CO_2 allowances under the cap and trade regulations expected over the study period. We recommend that NIMO include CO_2 additional environmental costs in its analyses of DSM, unless specifically prohibited from doing so by state or local law or regulation.

Avoided Gas Costs

The levelized avoided costs of natural gas applicable to load reductions by NIMO retail customers over the next twenty years are shown in Table 2.

Table 2 - NIMO 20 Year Levelized Avoided Gas Costs ($2007/dT)							
Residential				Commercial & Industrial			ALL
Existing	New	Hot		Non			RETAIL
Heating	Heating	Water	All	Heating	Heating	All	
Dec-Feb	Nov-Mar	annual	Nov-Apr	annual	Nov-Mar	Nov-Apr	Nov-Mar
12.54	12.39	11.70	12.18	10.11	10.80	10.59	11.54

2. Electric Energy Price Forecast

Niagara Mohawk (NIMO) customers acquire their wholesale electric energy from six zones within the New York wholesale market, i.e., NY-ISO Zones A through F. Synapse developed a forecast of the wholesale electric energy prices that NIMO would avoid as a result of reductions in retail customer consumption. We accomplished this in the following three major steps:

1. Review GED Reference Case forecast of wholesale electric energy prices by zone in New York, and all underlying assumptions;
2. Adjust GED Reference Case forecast prices to reflect our outlook regarding future natural gas prices and CO_2 compliance costs; and
3. Calculate NIMO load-weighted system-wide avoided wholesale electric energy costs.

The electric workpapers with these calculations are listed in Table 3. They are provided in a workbook titled *NIMO Avoided costs electric workpapers 2008 03 27.xls*.

Table 3 – Electric workpapers Supporting Avoided Retail Electric Energy Costs

Number	Name	Content
1	NY_AB MCPs	Zonal MCPs from GED Fall 2007 Northeast Reference Case Forecast
2	NY_CDE MCPs	
3	NY_F MCPs	
4	C6-NG NY ABC	GED zonal gas price forecast
5	C7-NG NY DEFG	
6	NY_AB Implied HR	Implied heat rates derived from GED MCPs and gas prices
7	NY_CDE Implied HR	
8	NY_F Implied HR	
9	[redacted]	[redacted]
10	[redacted]	[redacted]
11	[redacted]	[redacted]
12	CO2 Price Comparison	Comparison between GED and Synapse CO2 price forecasts
13	MarginalFuelData	Marginal fuel data from Market Analytics run of Northeast in 2008
14	MarginalFuelSummary	Marginal fuel by time period and zone
15	Emissions by Fuel	Emission rates by fuel type
16	[redacted]	[redacted]
17	Load Shape Price Ratios	Ratios of NIMO Load weighted Prices by period to NY ISO Prices by period, 2007 Data
18	NY_AB MCPs Adjusted	Zonal MCPs after Synapse adjustments
19	NY_CDE MCPs Adjusted	
20	NY_F MCPs Adjusted	
21	NIMO Hourly Zonal Load Data	
22	Final MCPs	NIMO System load-weighted MCPS and Zonal MCPs by costing period
23	[redacted]	[redacted]
24	[redacted]	[redacted]
25	[redacted]	[redacted]
26	[redacted]	[redacted]

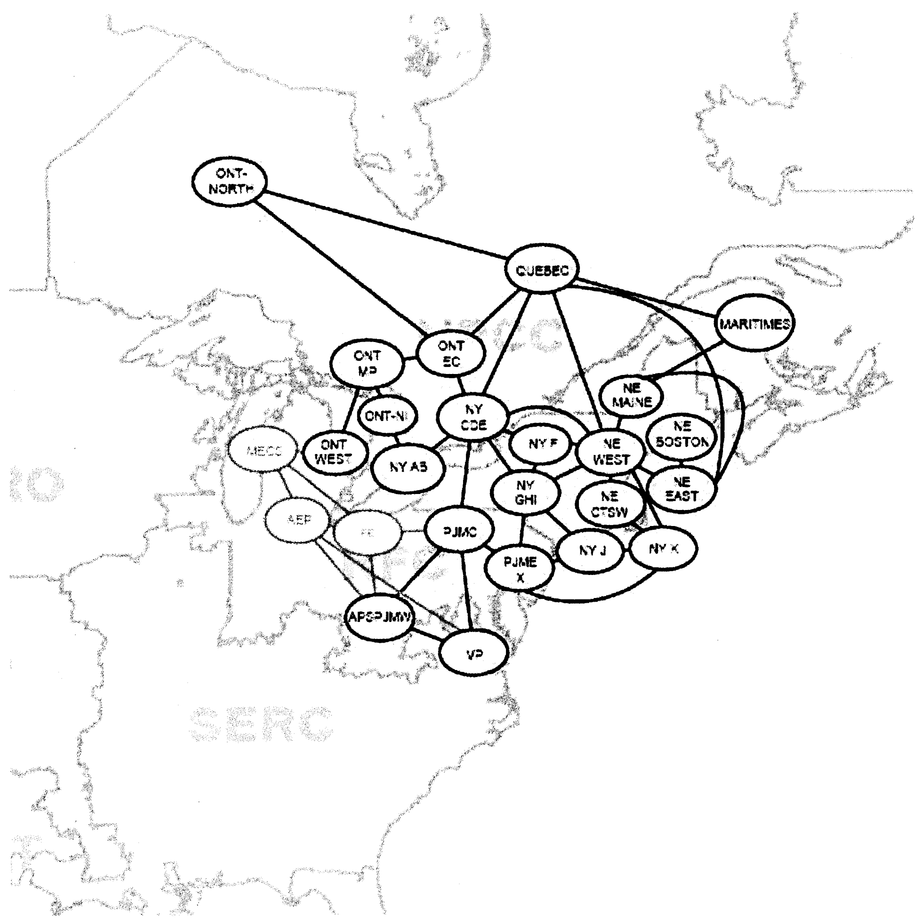
A. GED Forecast of Wholesale Electric Energy Prices

Synapse began with the Reference Case forecast of wholesale electric energy prices from GED. That forecast provides average monthly prices for peak and off-peak periods by zone in each of the wholesale electric energy markets in the Northeast. Peak period hours are 7 a.m. to 11 p.m. Monday through Friday, except for specified holidays. All other hours are off-peak.

Global Energy Decisions employs their MarketSym forecasting model to simulate the operations of those electric markets. MarketSym is a security-constrained, chronological, economic dispatch model that simulates the regional electric system on an hourly basis. The model utilizes an extensive database with detailed information for generator costs and operational constraints, transmission interfaces and constraints, customer loads, regional ancillary service requirements, and market bidding behavior.

The topology used in the Reference Forecast is shown in Figure 1.

Figure 1. Northeast Market Configuration for GED Reference Case Forecast.



Source: Global Energy Decisions

The GED forecast for New York provides average electric energy prices for peak and off-peak periods by month. These prices are provided for an aggregation of Zones A and B, i.e., "Zone AB", for an aggregation of Zones C, D, and E, i.e., "Zone CDE", and for Zone F. They are reported in electric workpapers 1, 2 and 3 respectively. The GED forecasts of wholesale gas price forecasts for the corresponding time periods and zones are presented in electric workpapers 4 and 5.

B. Adjust GED forecast of electric energy prices for Synapse outlook regarding future natural gas prices and CO_2 compliance costs.

Our second step was to adjust the GED forecast of electric energy prices to reflect our outlook regarding the future prices of natural gas and the costs of complying with future CO_2 regulation. Our review of the GED report found that we agree with most of the assumptions underlying its forecast of wholesale electric energy prices. However, our review indicates that GED has under-estimated natural gas prices at the Henry Hub in the near-term and has also under-estimated the future costs of complying with CO_2 regulation.

We adjust the GED forecast of electric energy prices by, in effect, calculating electric energy price "adders" that reflect the impacts of those differentials in forecast prices of natural gas and CO_2 respectively. For example, the adjustment for natural gas equals the differential in gas prices ($/MMBtu) multiplied by the implied heat rate for generating electricity from natural gas (MMBtu/MWh) multiplied by the percentage of time that natural gas is the marginal source of generation and thus setting the electric market price.

Analyze GED forecast to determine implied heat rates and percentage of time gas is the marginal source of generation

We began by analyzing the GED forecast to determine implied heat rates and the percentage of time gas is the marginal source of generation. We need those factors in order to

Implied heat rate is a measure of the efficiency at which a gas-fired unit produces electricity from natural gas. The implied heat rate in a zone for a given time period is the electric energy price forecast in that zone for that period in $/MWh divided by the natural gas price forecast in that zone for that period in $/MMBtu. The result is an implied heat rate, i.e. the quantity of MMBtu required to produce each MWh. We determined the implied heat rates in the GED forecast for the peak and off-peak periods in each month for Zone AB, Zone CDE and Zone F. These calculations use the GED forecasts of electric energy prices and wholesale gas prices for the corresponding zones and time periods. The results of those calculations are presented in electric workpapers 6, 7 and 8 respectively.

Differential in Outlook regarding Natural Gas Prices

The GED forecasts of wholesale gas prices for zones in New York consists of a forecast of gas prices at the Henry Hub and a forecast of the "basis" differential to those zones[4]. Our review of the GED forecast of wholesale natural gas prices for New York indicates that its corrected forecast of basis differential is reasonable but its forecast of Henry Hub prices are too low in the near-term.

The forecasts of "basis" differentials, implicit in GED's forecasts of wholesale gas prices in the New York zones, are reasonable. We did discover an error in the basis differential underlying GED's forecast of wholesale gas prices for New York zones ABC, which we brought it to GED's attention. GED corrected the error and provided a revised gas price forecast for those zones as well as a corresponding revised electric energy price forecast for those zones in those years.

[4] Henry Hub, located in Louisiana, is in the heart of the dominant producing region of the United States. It is the most liquid trading hub with the longest history of public trading on the New York Mercantile Exchange ("NYMEX"). Market prices of gas produced and sold elsewhere in North America reflect Henry Hub prices with an adjustment for their location, which is referred to as a basis differential. Basis differential for a given time period is the difference between the wholesale price of natural gas at a particular location and the price at the Henry Hub.

GED's forecast of gas prices at the Henry Hub for the years 2008 through 2013 are less than the NYMEX futures prices for those years, as of February 27, 2008. That differential is approximately $1 per million BTU (MMBTU). It is our view that the avoided gas and electric costs should be based upon the NYMMEX prices for Henry Hub as of the time our forecast is being prepared, because those prices reflect the most recent collective view of gas buyers and sellers. A comparison of those Henry Hub prices, as well as the differential by month, is presented in gas workpaper 6 and electric workpaper 9. Our adjusted forecasts of wholesale gas prices for the New York zones are presented in electric workpapers 10 and 11.

Differential in Outlook regarding CO_2 Allowance Prices

The Reference Case forecast of electric energy prices reflects the GED forecast of CO_2 emission allowance prices in the Northeast. GED assumes that the Regional Greenhouse Gas Initiative (RGGI) will be in effect from 2009 through 2011 and that national caps on greenhouse gas (GHG) emissions will go into effect in 2012. The GED report discusses these GHG regulatory initiatives on pages 1-13 to 1-16 and presents its forecast of CO_2 allowance prices in the Northeast on pages 2-9 and 4-22.

Synapse agrees with the GED assumption that RGGI will be in effect from 2009 through 2011 and that national caps will go into effect in 2012. In addition, the CO_2 allowance prices we are assuming under RGGI[5] are very close to the GED forecasts for those years. However, we believe the GED forecast of CO_2 allowance prices from 2012 onward, under a national cap on CO2, is too low. This position is based upon our review of numerous studies of the costs of complying with the range of national regulations under consideration, as well as our review of CO_2 allowance prices being used for long-term planning in various jurisdictions.

Our review of the range of national GHG regulations under consideration in Congress, and of various studies of the costs of complying with those regulations, is presented in *Climate Change and Power: Carbon Dioxide Emissions Costs and Electricity Resource Planning* ("Synapse CO_2 price report").[6] That report, released in June 2006 and updated in March 2007, forecasts CO_2 allowance prices under a base or "mid" case as well as under low and high cases. In addition to preparing that report we have reviewed and/or provided forecasts of CO_2 allowance prices in projects involving long-term electricity planning in various jurisdictions including New England, Nova Scotia and New Mexico as well as a review of CO_2 regulation in the several countries prepared for Dow.

Based upon that direct experience, and our CO_2 price report, we believe the avoided cost of electric energy in New York should reflect our mid case forecast of CO_2 prices, rather than the low case reflected in the GED forecast. The GED and Synapse forecasts of CO_2 allowance prices, and the differentials, are presented in electric workpaper 12 and summarized below in Table 4.

[5] Drawn from IPM modeling results in *RGGI Package Scenario (Updated October 11, 2006)*. Available at http://www.rggi.org/docs/packagescenario_10_11_06.xls.

[6] Full report available at http://www.synapse-energy.com

Table 4. CO_2 Allowance Price Forecasts - GED and Synapse (2007$/short ton of CO2)

Year	GED	Synapse	Differential
2008	0.00	0.00	0.00
2009	2.11	2.21	0.10
2010	2.29	2.37	0.08
2011	2.46	2.53	0.07
2012	2.64	9.46	6.82
2013	2.94	11.56	8.62
2014	3.28	13.66	10.38
2015	3.64	15.76	12.12
2016	4.05	17.86	13.81
2017	4.50	19.96	15.46
2018	5.00	22.06	17.06
2019	5.55	24.16	18.61
2020	6.15	26.27	20.12
2021	6.82	27.32	20.50
2022	7.56	28.37	20.81
2023	8.38	29.42	21.04
2024	9.28	30.47	21.19
2025	10.28	31.52	21.24
2026	11.38	32.57	21.19
2027	12.59	33.62	21.03
2028	13.93	34.67	20.74
2029	15.40	35.72	20.32
2030	17.02	36.77	19.75
2031	18.32	36.77	18.45
2032	19.83	36.77	16.94

In order to adjust the GED forecast of energy prices for this differential in CO_2 costs we needed to identify the rate (i.e., tons per MWh) at which CO_2 would be emitted by generation of each fuel type. To do this we first estimated the percent of time generation from each fuel type would be on the margin in 2008. That analysis is presented in electric workpapers 13 and 14. We assumed that those percentages would be representative of future years. Next, we developed emission rates for generation from each fuel type based on the average heat rate for each fuel type in the on-peak and off-peak periods and the carbon content of each fuel type. Those calculations are presented in electric workpaper 15. The adjustment for the differential in CO_2 allowance prices is the marginal emission rates of CO_2 (short tons CO_2/MWh) by costing period and zone multiplied by the CO_2 allowance price differential. Those calculations are presented in electric workpaper 16.

Adjusted Forecasts of Wholesale Electric Energy Prices

We then determined the amount ($/MWH) by which the GED forecast of electric energy prices in each costing period had to be adjusted for the differential in gas price forecasts and for the differential in CO_2 allowance prices. Those calculations are presented in electric workpapers 18 to 20 respectively.

The adjustment for the differential in gas price forecasts in each costing period is essentially equal to the implied heat rate for each period multiplied by the differential in Henry Hub price forecasts in the corresponding period. The adjustment for the differential in CO_2 allowance prices is added to our gas price adjusted forecast of electric energy prices.

C. Calculate NIMO load-weighted system-wide avoided wholesale electric energy costs.

In our third step we developed NIMO load-weighted system-wide avoided wholesale electric energy costs. To do this we first calculated NIMO load-weighted electric energy prices by costing period for the six zones in order to reflect the shape of NIMO's load in each of those zones. We then calculated NIMO system-wide wholesale avoided electric energy costs from the results by zone.

NIMO load-weighted electric energy prices by costing period.

The forecast of electric energy market prices by costing period represents a simple average of hourly market prices during the period, in essence a flat load shape. In contrast, NIMO customer load varies by hour. To determine an accurate estimate of the price of electric energy that NIMO could avoid in a given period, we wish to calculate a NIMO load-weighted energy price for each period from the forecast of market prices for the period. The key input to that calculation is factor by which we must adjust our forecast of electric energy market prices by costing period, i.e. peak and off-peak, to reflect the shape of NIMO's hourly load. We refer to that factor as a "load shape price ratio".

We developed NIMO load shape price ratios for each on-peak and off-peak period. We developed these based upon a review of the historical relationship between average electric energy market prices in each period and the corresponding NIMO load-weighted average price in the corresponding period. The historical data was from 2007, NIMO MW loads in each hour of 2007 for each zone, and actual LMPs for the corresponding hours and zones from the day-ahead market. We obtained the hourly loads from NIMO and the hourly LMPS from the NY-ISO web site.

We calculated a "load shape price ratio" for each on-peak and off-peak period of each month for each of the three sets of GED energy price forecasts, i.e., Zone F, Zone aggregation CDE and Zone aggregation AB. The load shape price ratio for a given period and zone is essentially the NIMO load-weighted average hourly price for that period divided by the average hourly price for that period.

Mathematically this can be expressed as:

$$\text{load - shape price ratio zone } Z = \frac{\left[\dfrac{\sum_{\text{hrs in period}} MW_{z,hr} \times DA\ LMP_{z,hr}}{\sum_{hrs} MW_{z,hr}}\right]}{\left[\dfrac{\sum_{hrs} DA\ LMP_{z,hr}}{\text{hours in period}}\right]}$$

For the GED forecasts prices for aggregate NYISO zones, i.e. AB and CDE, we calculated the load-shape price ratio for a given period by determining the average hourly price for that period weighted by NIMO hourly load in that aggregation of zones and dividing by the hourly market price weighted by the

NY-ISO load (MW) for the full aggregated zone for that period. Thus, the price in each NIMO zone (n) is weighted by relevant NIMO load (MWN) in the numerator and the relevant NY-ISO load (MWI) in the denominator.

Mathematically, that numerator can be expressed as,

$$\text{NiMo load} - \text{wtd price for GED zone} = \frac{\sum_{\text{n, hrs}} MWN_{n,hr} \times DA\,LMP_{n,hr}}{\sum_{hrs} MWN_{n,hr}}$$

and the denominator as

$$\text{Flat GED zone price, load - weighted across NYISO zones} = \frac{\sum_{hrs} \frac{\sum_{\text{ISO zones}} MWI_{n,hr} \times \text{DA LMP}_{\text{n,hr}}}{\sum_{\text{ISO zones}} MWI_{n,hr}}}{\text{number of hours in period}}$$

The calculations of load-shape price ratios are presented in electric workpaper 17.

We developed our estimates of NIMO load-weighted prices in each period by multiplying the relevant load-shape price ratio times the corresponding forecast of market electric energy prices. Those calculations are presented in electric workpapers18 to 20 respectively.

D. Calculate NIMO system-wide wholesale avoided electric energy costs

In our final step we develop NIMO system-wide avoided electric prices by costing period. These system-wide prices are the NIMO load-weighted prices for each of the three zones (NY-AB, NY-CDE, and NY-F) weighted by the corresponding percentage of total NIMO service territory load in each of those zones.

The percentage of total NIMO service territory load in each zone is calculated in electric workpaper 21. The calculation of NIMO system-wide avoided electric prices is presented in electric workpaper 22.

3. Avoided Retail Electricity Supply Costs

This chapter provides a projection of avoided retail electricity costs and a description of the underlying assumptions. These avoided retail electricity supply costs were developed from

- our projections of NIMO system-wide load-weighted avoided electric energy costs,
- avoided capacity costs,
- adjustments for losses from the point of generation to the point of use, and
- a retail adder, reflecting the risks and costs related to power procurement.

In addition we calculated an estimate of environmental externalities based upon the costs of CO_2 not reflected in the forecast of electric energy prices.

These avoided electricity supply costs do not include various components of wholesale power costs that we consider to be largely or entirely unavoidable through energy efficiency. These components include the locational forward reserve market, real-time operating reserves, automatic generation control (also called regulation), uplift, and the reliability contracts with particular generators.

The avoided electricity supply costs also do not include a renewable energy credit (REC) component. NYSERDA is essentially purchasing a pre-determined quantity of RECs through 2013 and allocating those costs to essentially all New York ratepayers for recovery. If NIMO customers reduced their energy usage they would be allocated a lower amount of those costs, and thereby avoid them, but the costs not allocated to NIMO would just be shifted to the remaining ratepayers in New York. The state of New York would not avoid those renewable costs.

A. Capacity Prices

The NY-ISO capacity prices are set by a series of auctions:

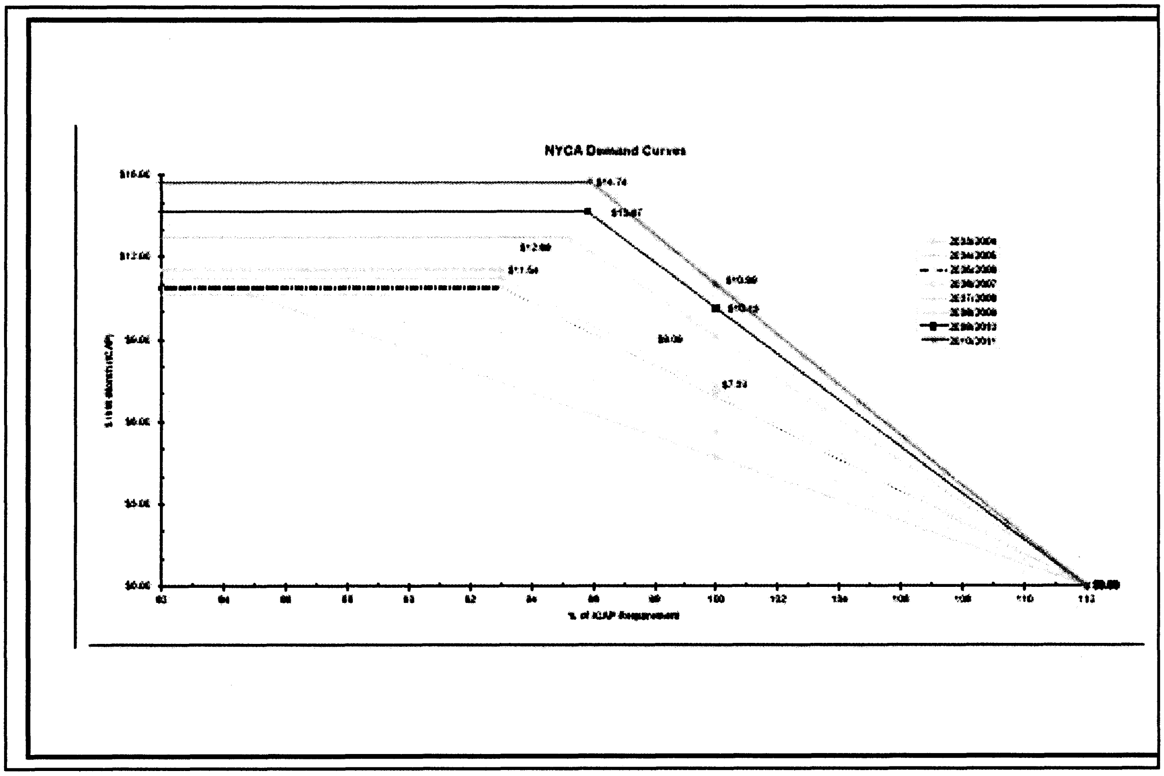
- A six-month strip acquired in April for the summer (May-October) and in October for the winter (November–April).
- Auctions for each month, from the month prior to the start of the season to the month prior to the delivery month.[7]
- A spot auction for each month, conducted in the preceding month.

The price in the spot auction is set by the demand curve, which reduces the capacity price as the reserve margin rises. Load-serving entities must provide capacity throughout the year, based on their contribution to the previous summer's peak (adjusted for migration) plus the reserve margin implied by the spot auction.

In Figure 2 we present a series of demand curves for the New York Control Area (NYCA). These curves are drawn from *Proposed NYISO Installed Capacity Demand Curves For Capability Years 2008/2009, 2009/2010 and 2010/2011*, issued by the NY ISO and dated October 5, 2007.

7 So there is only one monthly auction for May and November capacity, while there are six for October and April.

Figure 2



NIMO's service territory is entirely in the rest-of-state (ROS) capacity zone, which is the entire state other than New York City and Long Island.

In principle, knowing the current demand-curve parameters, the proposed parameters for the next three-year period (2008–2011) and forecasted loads and additions, we should be able to forecast the ROS capacity price. As the statewide reserve margin declines, the capacity price should rise until it is high enough to support new entry, and then bounce around that price as generation is added, plants are retired, load grows, etc.

This simple picture is complicated by a number of factors:

- The demand curve for ROS capacity uses total New York Control Area (NYCA) load and capacity, so addition of capacity downstate can affect prices upstate. Con Edison, NYPA and LIPA have all built and contracted for generation capacity and transmission connections that the market did not provide, and NYPA and LIPA continue to pursue capacity additions.
- A new capacity-price mitigation scheme has been accepted by FERC, which would require the pivotal in-City generators to bid at lower prices, likely resulting in more capacity clearing in New York City.

- It is not clear how much capacity LIPA will bring into NYCA, and whether that capacity will continue to depress ROS capacity prices.
- Generators outside New York (in PJM, New England, Ontario, and Quebec) can export capacity to the ROS market, while New York generators can export capacity to PJM and New England. NYISO does not appear to report the amount of imports that clear in the capacity auctions, or the amount of capacity withdrawn from the NYISO market for export.

Recent ROS capacity prices have been somewhat less than would be implied by the demand curve with only the capacity in NYCA and net firm contract imports, suggesting that NYISO has been a net purchaser of capacity. This situation appears to be changing, as capacity prices rise in the new forward markets in both PJM and ISO-NE.[8] For 2007–2008, ROS capacity prices were about $30/kW-yr, while the capacity price in neighboring portions of PJM was under $15/kW-yr and in ISO-NE the capacity price was $36.60.

The reserve margin required by NYISO depends on the quantity of capacity included in the determination of the capacity price under the demand curve. The difference between winter and summer capacity also increases the average reserve margin over the year. In 2007 the effective reserve margin, the capacity charge to load divided by the capacity payment to generation, both in $/kW-yr, is 17.2%. Under the current demand curves, the ISO's target (or "reference") annual UCAP price of $92.20/kW-yr would be reached with an effective reserve margin of about 10.8%. That reference price is based on an estimate of the cost of new entry in 2015, by which time New York is expected to need of new capacity.[9] The capacity price that would be charged to load is the reference price increased by the reserve margin, i.e., $92.20×1.108, or $102.15/kW-yr.

Our forecast of capacity prices charged to load, i.e. increased for reserves, expressed in $2007, is a linear interpolation of capacity prices in ROS, staring from the actual price in 2007 ($35.19 per kw-yr) and ending with the ROS reference price in 2015 ($102.15 per kw-yr). After 2015 we hold the price constant.

Table 5 compares actual capacity prices for PJM and ISO-NE to our projection. The actual capacity prices are UCAP capacity prices for PJM, ISO-NE and the average of those two prices in constant 2007$, with no gross up for reserve margins. Our projection appears reasonable relative to the prices in those neighboring markets.

[8] In the February 2008 ISO-NE forward capacity auction, 641 MW of New York capacity was accepted.

[9] The 2008–2011 demand curves increase the ROS reference price by about 25%.

Table 5 – Capacity Prices ($/kw-yr)				
Year beginning	PJM nominal	ISO-NE nominal	Average of PJM and ISO-NE (2007$)	Projection (2007$)
	Do not reflect reserve margin			Do reflect reserve margin
2007				$35.19
2008	$38.7	$44.3	$41.5	$43.56
2009	$67.4	$48.9	$58.1	$51.93
2010	$64.1	$50.9	$57.5	$60.30
2011				$68.67
2012				$77.04
2013				$85.41
2014				$93.78
2015				$102.15

The calculation of NIMO capacity costs is presented in electric workpapers 24 and 25.

B. Losses

There is a loss of electricity between the generating unit and the ISO's delivery points, where power is delivered from the ISO-administered pool transmission facilities (PTF) to NIMO's local transmission and distribution systems. There are also losses on the NIMO system. Therefore, a 1 kilowatt load reduction by a customer at the point of end use reduces the quantity of electricity that a generator has to produce by 1 kilowatt plus the additional quantity it would have had to generate to compensate for losses.[10]

We calculated full losses from generator to end use at peak. We add those losses to the capacity price, which is stated in dollars per kilowatt-year at the generator, to obtain an avoided capacity cost at point of end-use. We also calculate losses from the transmission system to end use by energy pricing period. We add those losses to the energy prices, which are stated in $/MWh at the ISO delivery point, to obtain avoided energy prices at point of end-use. (The energy prices forecast by GED reflect the losses between the generating unit and the ISO delivery points into the NIMO system.)

For calculating the avoided cost of capacity we use average losses from the generator to the end use. For calculating the avoided cost of energy we use marginal losses from the ISO delivery point to the end use.

Derivation of losses from generator to end use in peak hour

We assumed average losses at the peak hour of 14%, from generator to end use, based on our experience with studies of losses at other utilities. We broke this estimate between losses on the NY-ISO system and losses on the NIMO distribution system.

[10] Computations of avoided costs sometimes assume that only average, and not marginal, losses are relevant at the peak hour. The reasoning for that approach is that changes in peak load will lead to changes in transmission and distribution investment, keeping average percentage losses approximately equal. The NIMO avoided costs do not include any avoided PTF investments, so marginal losses are relevant in this situation.

From a NYISO load-forecast report[11], transmission losses at peak in the NGrid transmission district[12] are 5% of load. The statewide average transmission losses are 1.9%. Since some of the losses in the NGrid district result from power flowing to other districts, we use an average of the losses in the NGrid district and the statewide average. This is 3.5%, i.e., 50% of (5+ 1.9).

Losses between transmission and point of end use at peak would thus be 10.2% (1.14 ÷ 1.035 – 1.00).

Of that 10.2%, we assumed losses of 1% of the peak load were fixed transformer-core losses, which do not vary with load, and the remaining 9.2% were variable.

Derivation of losses from ISO Delivery Point to end use

We computed the average percentage losses for each of the four energy costing periods from the 10.2% identified above. as the sum of fixed and variable losses.

- Fixed losses, estimated as the 1% of peak load, restated as a percentage of period load by dividing by period load factor.
- Variable losses, estimated as the 9.2% rate at peak multiplied by the load factor for the relevant period[13].

The resulting average loss factors are presented in Table 6.

Table 6 Loss Factors

Period	Load Factor	Average Losses			Marginal Losses Used To Calculate Retail Avoided Costs
		Variable	Fixed	Total	
W – Off Peak	57%	5.2%	1.8%	7.0%	**10.4%**
W – On Peak	70%	6.4%	1.4%	7.9%	**12.9%**
S – Off Peak	54%	4.9%	1.9%	6.8%	**9.9%**
S – On Peak	70%	6.4%	1.4%	7.9%	**12.9%**

Across periods, these energy losses average 7.4%, which is a reasonable value. NIMO's metered losses may be lower than this, since the 7.4% includes losses on the customer side of the meter

Since losses vary with the square of load, marginal percentage energy losses in any period are about twice average variable losses.[14] The average losses reported above translate into marginal energy

[11] 2007 Weather Normalization, Load Forecasting Task Force, December 18, 2007, Arthur Maniaci, System & Resource Planning, New York ISO.

[12] NIMO is served by the NGRID transmission district, which includes parts of zones A-F. NY-ISO transmission districts and energy-pricing zones overlap

[13] Variable losses in Watts vary roughly as the square of load, since the power dissipated in the lines varies with the square of current. Thus percentage losses (loss ÷ load) varies roughly linearly with load from the equation $W= I^2R$, where W is the energy released, I is the current and R is the resistance.

[14] The derivative of the losses is $dW/dI = 2IR$, while the average losses are $I^2R \div I = IR$.

losses of 12.9% on-peak, both summer and winter, 10.4% in the winter off-peak, and 9.9% in the summer off-peak.

The results would be somewhat higher for an analysis that reflected the higher losses at high-load hours within each period, which produces a higher average percentage loss than in the average-load hour. However, since the analysis started with a generic estimate of losses at peak, the greater detail of an hourly analysis did not seem warranted.

The calculation of losses applicable to NIMO is presented in electric workpaper 26.

C. Retail Adder

Retail electricity prices are generally higher than the sum of wholesale energy and capacity prices during the time period in which the electricity is being consumed. This differential is not fully explained by the costs of ancillary service, uplift, and load shapes. The primary factor underlying the retail adder appears to be costs suppliers incur to mitigate their risk of under-recovering their costs. These risks arise from the potential for their supply costs to exceed their revenues, i.e., under contracts in which suppliers do not have a "true-up" provision or adjustment to ensure that their revenues equal their costs. The potential for supply costs to exceed revenues arises due to factors such as unexpected variations in weather, economic activity and and/or customer migration. For example, during hot summers and cold winters LSEs may need to procure additional energy at shortage prices while in mild weather they may have excess supply under contract that they need to "dump" into the wholesale market at a loss. The same pattern holds in economic boom and bust cycles. In addition, the suppliers of power for utility standard-service offers run risks related to migration of customer load from utility service to competitive supply (presumably at times of low market prices, leaving the supplier to sell surplus into a weak market at a loss) and from competitive supply to the utility service (at times of high market prices, forcing the supplier to purchase additional power in a high-cost market).

NIMO did not provide public information on the retail adders implicit in the prices bid by their suppliers. In the absence of any detailed information on the strategy that NIMO employs to acquire supply we propose a 5% retail adder be applied to wholesale electric energy costs to calculate retail avoided electric energy costs. This is a conservative estimate, as our analyses of confidential supplier bids in other projects indicate that a 10% retail adder is common.

D. CO_2 Externalities

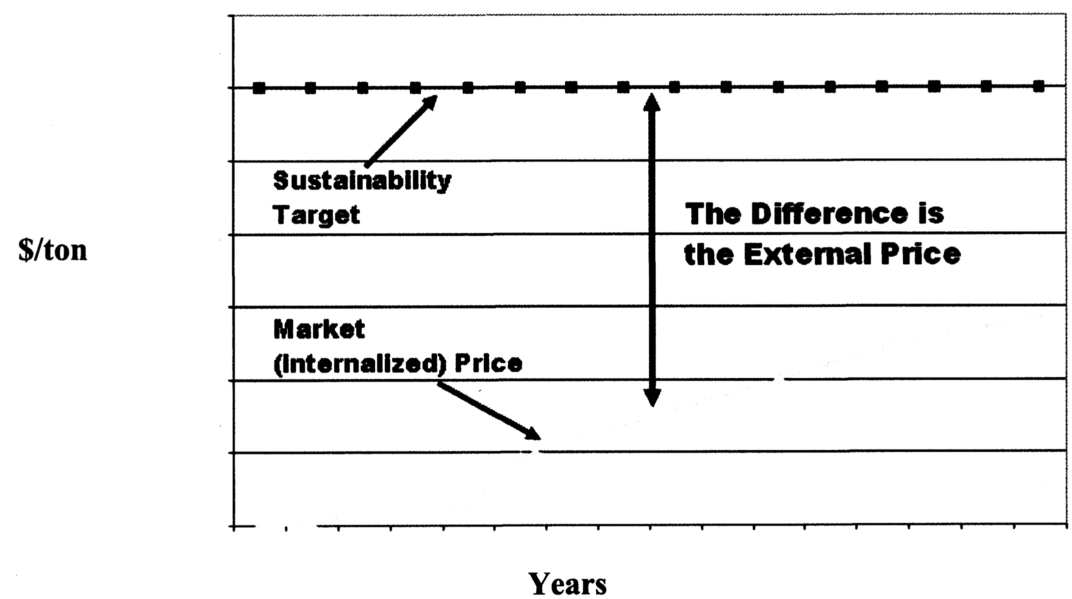
Externalities are impacts from the production of a good or service that are neither reflected in the price of that good or service nor considered in the decision to provide that good or service. There are many externalities associated with the production of electricity, including the adverse impacts of emissions of SO2, mercury, particulates, NOx and CO_2. However, the magnitude of most of those externalities has been reduced over time, as regulations limiting emission levels have forced suppliers and buyers to consider at least a portion of their adverse impacts in their production and use decisions. In other words, a portion of the costs of the adverse impact of most of these externalities has already been "internalized" in the price of electricity.

AESC 2007 identified the impacts of carbon dioxide as the dominant externality associated with marginal electricity generation in New England over the study period for two main reasons. First, policy makers are just starting to develop and implement regulations that will "internalize" the costs associated with the impacts of carbon dioxide from electricity production and other energy uses. The Regional Greenhouse Gas Initiative and anticipated future federal CO_2 regulations will internalize a portion of the "greenhouse gas externality," but AESC 2007 projects that the externality value of CO_2 will still be high even with those regulations. Second, New England avoided electric energy costs over the study period are likely to be dominated by natural gas-fired generation, which has minimal emissions of SO2, mercury, particulates and NOX, but substantial emissions of CO_2.

CO_2 allowance costs are not expected to reflect the full societal costs associated with CO_2 emissions. In this report we use a compliance cost of $60/ton of CO_2 (2007$) to reflect the full societal costs associated with those emissions. That value is drawn from an analysis of externalities we prepared for AESC 2007 which identified a target level of physical CO_2 emissions that climate scientists have identified as potentially sustainable as well as the cost of complying with that target level. The analysis from AESC 2007 is presented in Appendix A.

Figure 3 illustrates this CO_2 externality. The blue line presents the forecast of allowance prices reflected in electric energy market prices. This assumes that the United States will gradually move to reflect a portion of the impact of greenhouse gas emissions in market prices. The "externality" is the difference between the estimated total cost of achieving a sustainability target, $60/ton, and the portion reflected in market prices. This is the area between the blue line and the redline in the figure.

Figure 3. Determination of Externalities based on CO_2 Emission Costs



The calculation of the CO_2 externality applicable to NIMO is presented in electric workpaper 23.

E. Avoided Retail Electricity Costs

Retail avoided costs of electricity consist of avoided energy costs ($/kwh) and avoided capacity costs ($/kw-yr).

- Avoided retail energy costs are presented by year for four energy costing periods – Winter Peak, Winter Off-Peak, Summer Peak, and Summer Off-Peak. The avoided energy cost for a specific costing period is the avoided wholesale energy cost for that period increased by the retail adder and marginal line losses on the distribution system[15].

- Avoided retail capacity costs are presented for each year. The avoided capacity cost in each year is the avoided wholesale capacity market value for that year increased by the retail adder and line losses from generation to the point of end-use.

The detailed avoided retail electricity costs are presented in Table 7. The supporting calculations are presented in the *NIMO avoided electric costs* worksheet in *NIMO Avoided costs electric workpapers 2008 03 27.xls*.

Synapse also calculated environmental externalities based upon CO_2 emissions and allowance costs. The wholesale externality values are presented by year for the four energy costing periods. (The retail values would be wholesale value increased by marginal line losses on the distribution system).

[15] Avoided wholesale energy costs through 2032 are derived directly from the GED forecast as adjusted by Synapse. Values for 2033 through 2037 are derived from the 2032 value increased by the average rate of escalation of the prior ten years.

TABLE 7

Utility — Niagara Mohawk

Constant Dollar Avoided Cost Results - $2007

Formatted for input to DSM screening models

Retail Adder	5%
Real Discount Rate	2.22%
Capacity Losses: Generation to ISO Delivery	3.5%
Peak losses: ISO to end use	10.2%

	Avoided Retail Costs, Constant Dollars					Wholesale Power Price, Constant Dollars								
	Niagara Mohawk					CO2 Related Costs NOT REFLECTED IN WHOLESALE POWER PRICES (see note below)				Wholesale Avoided Costs (i.e.before Adjustments for Losses and Retail margin)				
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr
2008	0.103	0.064	0.110	0.065	48.8	0.050	0.041	0.048	0.040	0.087	0.055	0.093	0.056	40.8
2009	0.110	0.067	0.100	0.060	58.8	0.048	0.040	0.047	0.038	0.093	0.057	0.084	0.052	49.1
2010	0.097	0.062	0.091	0.056	68.8	0.048	0.040	0.047	0.038	0.082	0.053	0.076	0.049	57.5
2011	0.091	0.061	0.089	0.057	78.9	0.048	0.039	0.046	0.038	0.077	0.053	0.075	0.049	65.9
2012	0.093	0.066	0.092	0.062	88.9	0.042	0.035	0.041	0.034	0.079	0.057	0.078	0.054	74.3
2013	0.092	0.064	0.091	0.062	98.9	0.041	0.033	0.039	0.032	0.078	0.055	0.077	0.054	82.6
2014	0.085	0.061	0.083	0.057	108.9	0.039	0.032	0.037	0.031	0.072	0.053	0.070	0.050	91.0
2015	0.096	0.066	0.096	0.061	118.9	0.037	0.030	0.036	0.029	0.081	0.057	0.081	0.053	99.4
2016	0.101	0.068	0.100	0.064	122.3	0.035	0.029	0.034	0.028	0.085	0.059	0.085	0.055	102.2
2017	0.102	0.071	0.103	0.067	122.3	0.034	0.027	0.032	0.027	0.086	0.061	0.087	0.058	102.2
2018	0.103	0.071	0.102	0.068	122.3	0.032	0.026	0.031	0.025	0.087	0.062	0.086	0.059	102.2
2019	0.103	0.073	0.103	0.069	122.3	0.030	0.025	0.029	0.024	0.087	0.063	0.087	0.060	102.2
2020	0.099	0.072	0.100	0.069	122.3	0.028	0.023	0.027	0.022	0.083	0.062	0.084	0.059	102.2
2021	0.106	0.074	0.107	0.071	122.3	0.027	0.022	0.026	0.022	0.090	0.064	0.091	0.062	102.2
2022	0.109	0.078	0.108	0.073	122.3	0.027	0.022	0.026	0.021	0.092	0.067	0.091	0.064	102.2
2023	0.111	0.080	0.110	0.075	122.3	0.026	0.021	0.025	0.020	0.094	0.069	0.093	0.065	102.2
2024	0.113	0.081	0.112	0.077	122.3	0.025	0.020	0.024	0.020	0.095	0.070	0.095	0.066	102.2
2025	0.115	0.083	0.114	0.078	122.3	0.024	0.020	0.023	0.019	0.097	0.072	0.096	0.068	102.2
2026	0.117	0.085	0.116	0.080	122.3	0.023	0.019	0.022	0.018	0.098	0.073	0.098	0.069	102.2
2027	0.118	0.086	0.118	0.081	122.3	0.022	0.018	0.021	0.018	0.100	0.074	0.100	0.070	102.2
2028	0.120	0.088	0.120	0.083	122.3	0.021	0.017	0.020	0.017	0.101	0.076	0.101	0.072	102.2
2029	0.122	0.090	0.122	0.084	122.3	0.020	0.017	0.020	0.016	0.103	0.077	0.103	0.073	102.2
2030	0.124	0.091	0.123	0.086	122.3	0.019	0.016	0.019	0.015	0.105	0.079	0.104	0.074	102.2
2031	0.125	0.092	0.124	0.087	122.3	0.019	0.016	0.019	0.015	0.106	0.079	0.105	0.075	102.2
2032	0.126	0.093	0.125	0.087	122.3	0.019	0.016	0.019	0.015	0.106	0.080	0.106	0.076	102.2
2033	0.128	0.094	0.127	0.089	122.3	0.019	0.015	0.018	0.015	0.108	0.081	0.107	0.077	102.2
2034	0.130	0.096	0.129	0.090	122.3	0.018	0.015	0.018	0.014	0.110	0.083	0.109	0.078	102.2
2035	0.132	0.098	0.131	0.092	122.3	0.018	0.014	0.017	0.014	0.111	0.084	0.111	0.080	102.2
2036	0.134	0.099	0.133	0.093	122.3	0.017	0.014	0.017	0.014	0.113	0.086	0.112	0.081	102.2
2037	0.136	0.101	0.135	0.095	122.3	0.017	0.014	0.016	0.013	0.114	0.087	0.114	0.082	102.2
Levelized														
20 years (2008-2027)	0.102	0.071	0.101	0.067	104.3	0.035	0.029	0.034	0.028					
20														

Notes:
- Peak hours are: Monday through Friday 7am - 11pm; Off-Peak Hours are: All other hours
- Summer is May through October; Winter is all other months
- Avoided Retail Costs reflect all relevant losses from generation to customer meter.
- Capacity price converted to $/kWh at zonal on-peak summer load factor.
- Capacity prices are based upon prices from Jan through April from previous power year and May to Dec from current year
- Projected costs related to CO2 represent costs that are not yet internalized. Sustainability Target = Allowance Price (internalized value) + Environmental Cost
- Costs for 2033 through 2037 are projected at the average annual rate of escalation during the prior ten years (2022 to 2032).

4. Avoided Retail Natural Gas Costs

This chapter provides a projection of wholesale natural gas prices for NIMO as well as a projection of avoided natural gas costs by retail end-use sector that would be avoided due to reductions in retail gas use by NIMO customers. The projection provides prices for 2008 through 2037 expressed in 2007 dollars per dekatherm (DT).[16] It provides prices for various shapes or types of retail load shapes. Note that in this analysis winter is defined as November through March.

The gas workpapers containing these calculations are listed in Table 8. They are provided in a workbook titled *NIMO Avoided costs gas workpapers 2008 03 27.xls*.

Table 8 – Workpapers for Avoided Retail Electric Energy Calculations

Number	Name	Content
1	HH Gas 2FO Prices'	Comparison of HH price forecasts, Develop #2 fuel price forecast
2	HH Price Chart	Chart comparing HH price forecasts
3	2 Oil Prices	No. 2 fuel oil prices from NYMEX
4	Notes re HH adjustment	
5	NYMEX HH Data-Const$	NYMEX HH prices, Feb 26 and 27, 2008 converted to constant 2007$
6	Data 2 HH Prices Monthly	HH prices Monthly, GED and NYMEX
7	DTI - HH Basis	Calculation of the Basis differential for Dominion Appalachian Index
8	Forecast Mon HH&DTI Gas Prices	Forecast of HH Natural Gas Prices for the NiMo Study
9	Data NIMO 2	Analyses of Sales and supply data from NIMO
10	LDC Fracs	Fractions (portions) of send-out by source and storage refill by month
11	Supply by Source	LDC fractions
12	DTI rates	Rates paid by for pipeline transportation and storage with Dominion Transmission Inc (DTI)
13	Dominion	Transformation of rates into LDC costs by gas source by month
14	cost by source	Example of costs of Dominion for various services in January and June
15	city gate avoided cost	Avoided Cost of Gas delivered to the LDC
16	ret margin	Retail margin for various end-use customers in NY

A. Avoided Wholesale Gas Costs

The avoided cost of gas of a local distribution company (LDC) such as NIMO is the cost of the marginal source of supply, or sources, that can be avoided in the relevant cost period. Because efficiency improvement is a long-term effect, the relevant avoided cost is the long-run cost that we estimate a local distribution company (LDC) such as NIMO can avoid. The long-run avoided cost

[16] One DT is one million BTU.

consists of the short-run variable costs and a portion, sometimes all, of the long-term fixed costs of gas supply sources.

In this analysis we compute the marginal cost (avoided cost) for each month and for the peak day. The avoided cost is the cost of delivering one DT of gas in a given month to the LDC via the three major resources: year-round, long-haul transportation; underground storage; and peaking service.

In each of the winter months (November through March) when gas is supplied by the three resources, the marginal cost is the weighted average of the cost of gas acquired from each supply source in each month. The factor used to "weight" the cost from each source is the fraction of total supply to customers, or "send-out", provided by each source. Our computation of this weighted average assumes that the LDC has optimized its mix of supply sources. Based upon that assumption we in turn assume that the LDC can avoid both the fixed and variable costs associated with each avoided supply source in response to a long-term efficiency improvement.[17]

B. Niagara Mohawk Send-out and Supply Sources

Niagara Mohawk send-out is significantly higher in the winter season than in the summer season. For example the January firm sales load can be about ten times the firm sales load in August. In addition, its send-out on winter days can vary substantially according to temperature.

In order to supply that load reliably and at reasonable rates, Niagara Mohawk relies upon a portfolio of supply resources. In general, that portfolio consists of:

- Gas delivered via long-haul pipeline transportation to meet a base portion of send-out each month of the year, as well as to refill underground storage during the summer months.
- Gas withdrawn from storage to meet incremental winter send-out[18]. The underground storage facilities used by NIMO are located in Pennsylvania, New York, and West Virginia.[19] Niagara Mohawk also use winter transportation to meet the winter sendout requirement because it can buy spot gas for delivery via the Dominion system even during the winter.
- Gas purchased from Canadian supply, and in the very last instance gas released by co-generation plants when they substitute No. 2 fuel oil, to meet peak day spikes in send-out.

The first step in calculating NIMO's avoided wholesale gas supply costs was to identify the fraction or portion of each source used to meet send-out each month. (We also identified the sources of storage refill in each of the summer months.) We analyzed data from NIMO to determine those fractions[20]. That data and our analyses are presented in gas workpapers 9 and 10. The fractions of send-out by source by month are presented in gas workpaper 11.

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[17] In a short-run marginal cost analysis only variable costs can be adjusted and thus the avoided cost is determined by the one supply source which has the highest variable cost.

[18] NIMO typically fills its underground storage during the summer months and removes gas during the winter months to serve its large winter customer load.

[19] LDCs acquire pipeline and storage services through a portfolio of contracts with natural gas transportation and storage companies that have terms, conditions and rates that are regulated by the U.S. Federal Energy Regulatory Commission (FERC).

[20] NIMO Sendout Update 01312008.

C. Components of Avoided Costs by Source

The second step in calculating NIMO's avoided wholesale gas supply costs was to forecast the future costs of gas from each marginal source. The cost of gas delivered to NIMO via long-haul pipeline transportation and from underground storage consists of the commodity cost of the gas and the various charges by Dominion for its pipeline transportation and underground storage services. The marginal source of NIMO peaking supply is gas released by the cogeneration facilities on its system, which is priced at the commodity cost of their alternate fuel, No. 2 fuel oil. This section describes our estimates of those commodity costs and Dominion service charges.

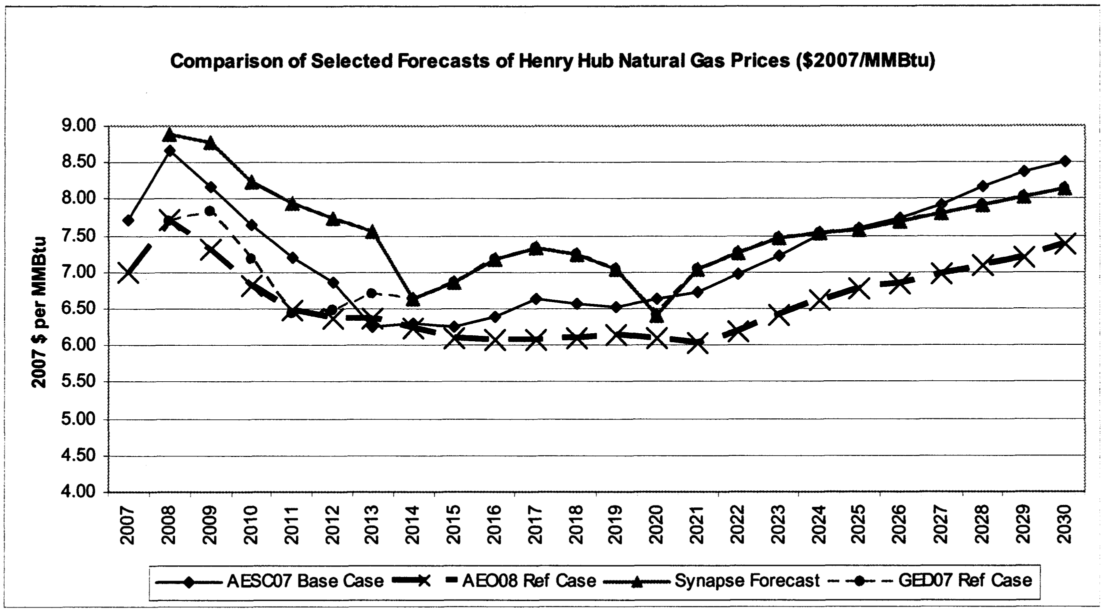
Commodity Costs

Natural Gas. Our avoided cost analysis assumes that NIMO's marginal supply is gas delivered into Dominion and priced at the "Dominion Appalachian Index" for that location or market hub. The forecast Dominion Appalachian Index is a monthly price equal to the forecast Henry Hub monthly price plus the forecast monthly basis differential to the Dominion Appalachian Index hub.

As discussed earlier, our forecast for Henry Hub prices through 2013 is based upon NYMMEX prices as of the time we prepared our forecast and the GED forecast of Henry Hub prices thereafter. Our review and analysis of the GED forecast of HH prices is presented in gas workpapers 1 through 6.

We compared our forecast for Henry Hub prices to the GED forecast as well as to forecasts we developed for AESC 2007 and the Energy Information Administration (EIA) Annual Energy Outlook 2008. That comparison is presented in Figure 4. Our forecast is higher than the others through 2013, but as noted earlier it reflects the NYMEX futures prices for those years. From 2014 onwards our forecast is comparable to the GED forecast and to the AESC 2007 forecast but higher than the AEO 2008 forecast.

Figure 4 – Comparison of Forecasts of Henry Hub prices ($2007/MMBtu)


Comparison of Selected Forecasts of Henry Hub Natural Gas Prices ($2007/MMBtu)
2007 $ per MMBtu
9.00
8.50
8.00
7.50
7.00
6.50
6.00
5.50
5.00
4.50
4.00
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
AESC07 Base Case
AEO08 Ref Case
Synapse Forecast
GED07 Ref Case

Our forecast of the annual Dominion Appalachian Index price is developed and provided in gas workpapers 7 and 8. The Dominion Appalachian Index price is our forecast of Henry Hub prices plus a forecast of basis differential to the Dominion Appalachian Index hub provided by NIMO.

No. 2 fuel oil. Our forecast of No. 2 fuel oil prices is presented in gas workpaper 1. Through 2013 it is derived from the February 27 NYMEX prices for West Texas Intermediate crude oil. From 2014 onward it is the GED forecast of No. 2 fuel oil prices.

Dominion service charges

Dominion levies three types of charges for its pipeline transportation and storage services:

- fixed demand cost of holding pipeline transportation capacity and of storage and withdrawal capacity on Dominion;
- usage (volumetric) charges for transporting gas on the pipeline and for storage injections and withdrawals; and
- the fraction (percentage) of volumes of gas received by the pipeline or storage facility that is retained by the facility for compressor fuel and losses. This "fuel and loss retention" increases the cost of gas above the Dominion Index price because the volume of gas that must be purchased for delivery into Dominion is greater than the volume that Dominion ultimately delivers to NIMO. Our analyses represent fuel and loss retention as a ratio of gas purchased (or delivered in storage) to gas delivered to NIMO.

The rates and the fuel and loss retention percentages charged by Dominion are presented in gas workpaper 12. Our analyses assume that these rates and retention percentages will persist for the forecast period, 2008 – 2032 with one exception. We have used the increase in DTI demand charges scheduled to take effect in November 2010.

D. Avoided Cost of Gas by Source

The third step in calculating NIMO's avoided wholesale gas supply costs was to develop avoided costs by supply source using the projections by cost component from the preceding section. These avoided costs were developed in gas workpaper 13. A representative set of costs by source are presented in gas workpaper 14.

Long-haul Pipeline "Cash" Costs

Gas is delivered to the LDC each month by pipelines from producing areas; in this analysis assumed to be Appalachia. By "cash cost" we mean the avoided cost of transportation arising from pipeline usage charges, which are paid for each DT of gas transported, and the demand charges allocated to that month, which pay for the reservation of pipeline capacity whether used or not.[21] The avoided commodity cost of gas purchased is the price of gas at The Dominon Appalachian Index that month multiplied by the ratio of the volume purchased to one DT of gas delivered to the LDC. Because of the retention of gas for fuel and loss in both transportation and storage, more than one dekatherm of gas must be purchased in order to deliver one dekatherm to the LDC.

[21] Rate Schedules assumed for the transportation: Dominion FTNN and FTNN-GSS for delivery of gas from underground storage.

This ratio of gas volumes purchased in the producing area to one DT of gas delivered to the LDC is established by the fuel and loss retention percentages of the various pipeline transportation and storage services used between the producing area and the LDC. For example, assume that the gas is transported by two pipelines: A and B from the producing area to the LDC. The fuel and loss percentage is 6 percent for A (Fa) and 4 percent for pipeline B (Fb). The fuel and loss amount taken by the pipeline is based on the volumes received by the pipeline (R) while the demand and usage charges are based on the volume of gas delivered by the pipeline (D). In order to compute the ratio of gas received to that delivered we use the following equations:

(1) $D = R - FR$

(2) $D = R(1\text{-}F)$

(3) $R/D = 1/(1\text{-}F)$

For pipeline A; $Ra/Da = 1/(1\text{-}.06) = 1.0638$; or $Ra = 1.0638\ Da$

For pipeline B; $Rb/Db = 1/(1\text{-}.04) = 1.0417$; or $Rb = 1.0417\ Db$

Since Db is the amount delivered to the LDC, we want to compute Ra/Db or the ratio of the amount to be purchased in the field to the amount delivered to the LDC.

Since: $Rb = Da$

$Ra = 1.0638\ Da = (1.0638)Rb = (1.0638)(1.0417)Db$

Thus: $Ra/Db = (1.0638)(1.0417) = 1.1082$

Or: 1.1082 DTs of natural gas must be purchased for each DT delivered to the LDC.

Illustrative avoided costs by gas source and pipeline route for January and June of 2009 are presented in gas workpaper 10.

Summer. Local gas distribution companies (LDCs) use a portion of their long-haul pipeline transportation in the summer to transport gas directly to the LDC from the producers for sendout. They use another portion to transport gas to fill underground storage. Consequently, a corresponding portion of the costs of demand and usage charges and the fuel and loss fraction for pipeline transportation from producers to refill storage are allocated to the avoided cost of underground storage. Even with the use of Dominion transportation capacity to fill underground storage in the summer, much of the transportation capacity is not use in the summer but has to be reserved to serve the winter firm sales load. This is typical of many LDCs and is not surprising given that January firm sales demand can be about ten times the August firm sales demand. Because marginal transportation capacity is needed for the winter, but is not used to capacity in the summer, we allocated the summer demand costs to the winter avoided cost.

We assume that there is no avoided demand cost for long-haul pipeline capacity in the summer months (April – October). We assume that there is insufficient market for Dominion FTNN released capacity in the summer that would pay for the demand charges. This means that an LDC would continue to pay the full demand charge in each summer month even if the gas requirements of customers were reduced due to energy efficiency in the summer; thus the LDC would not avoid the summer pipeline demand charges.

Winter. NIMO's use of its long-haul transportation capacity in the winter varies from about 74 percent in November to 100 percent in January. The total cost of pipeline transportation demand charges attributable to the five winter months consist of the demand charges the pipeline bills NIMO for each of those months plus the summer demand costs we have allocated to the winter season. The portion of that winter season cost allocated to each winter month is a function of the capacity used to serve load in that month. The cost of unused capacity in any month, such as November, is allocated to those months in which the capacity is used. As a result, the avoided transportation demand cost varies among the five winter months with the month of heaviest use, January, receiving the largest allocation of demand charges.

Underground Storage

Natural gas is delivered to the LDC from underground storage during the five winter months of November through March as shown in gas workpaper 11. The avoided cost of underground storage supply for one DT in January is shown in gas workpaper 14.

The avoided cost of underground storage includes the cost of buying gas on Dominion, pipeline demand charges to bring gas to the storage facility, the cost of injection, the demand cost of storage capacity, the demand and variable costs of withdrawing gas from storage, and the demand and variable costs of transporting gas to the LDC from underground storage.[22]

The cost of gas injected into storage is the cost of buying gas on Dominion, as adjusted for fuel and loss retention, plus the cost of transportation to underground storage including demand costs at 100% load factor. The cost of the gas injected into storage is less than the average cost of gas for a year, because gas is purchased for injection during the summer months when the price of gas is less than the annual average.

Since the demand charges for the withdrawal of gas from storage to the LDC are levied 12 months a year, we allocate the full year of those withdrawal demand charges to the five winter months. Then we allocate these demand charges of withdrawal and of transportation to NIMO to each of the five winter months by the use of the capacity in each month. January is the peak sendout month, as shown in gas workpaper 11. The other winter months, especially November and March experience less sendout. Thus, the demand cost of unused capacity of storage withdrawal and of transportation capacity from underground storage to the LDC in November and March is assigned to the sendout during December through February based on usage each month. Similarly the unused capacity during December and February is assigned to the cost of withdrawing and transporting gas to the LDC in January.

Peak-Day Supply

NIMO's marginal peaking supply is gas released by the cogeneration facilities on its system. For this gas NIMO pays the cost of their alternate fuel, which is No. 2 fuel oil. Thus the avoided cost of the peaking supply is the cost of No. 2 fuel oil delivered to large facilities in New York.

[22] Rate schedules used in the calculation for Dominion are: Dominion FTNN to fill storage, GSS for Storage and FTNN-GSS to deliver stored gas to NIMO. When FTNN is used to fill storage the usage and retention charges are waived; instead there is an injection charge and gas retention for injection.

E. Avoided City-Gate Gas Costs

The avoided cost of natural gas by costing period is the average of the avoided cost in each of the months that comprise the costing period. As described earlier, the avoided cost in any month is the weighted average of the avoided cost of gas delivered to the LDC from each of the three sources: long-haul pipeline, underground storage, and gas released from the cogeneration units. The weightings or fractions by source by month were presented in gas workpaper 11.

NIMO's avoided city-gate costs are presented in gas workpaper 15. Also shown is the annual Dominion Appalachian Index forecast price of natural gas. Other than for the peak-day, the commodity cost of gas is the largest component of the avoided cost.

The levelized avoided cost is the cost for which the present value at the real riskless rate of return of 2.2165 percent has the same present value as the estimated avoided costs for the periods shown at the same rate of return. The average cost is the simple average over the period 2008 through 2022.

F. Avoided Distribution System Costs

Studies of marginal distribution system costs performed by the former KeySpan LDCs in New England indicate that the incremental cost of distribution is approximately one-half of the embedded cost. For this analysis we estimated the embedded cost of distribution as the difference between the city-gate price of gas in New York State and the price charged each of the different retail customer types: residential, commercial, and industrial in New York.[23] That analysis, and our estimates of average avoided distribution costs for New York LDCs by customer segment, is presented in gas workpaper 16.

G. Avoided Retail Gas Costs

We calculated avoided retail gas costs for various types of retail end-uses. For a given costing period the avoided cost for each retail end-use is the avoided city-gate cost of gas associated with the end-use type plus the avoided LDC margin for that end-use.

The avoided city-gate cost of gas and avoided margin associated with the each retail end-use can be determined from Table 9.

[23] The city-gate gas prices and the prices charged to each retail customer type are reported by the Energy Information Administration for each state each year.

Table 9 - End-Use Type and Associated Avoided Cost Periods

End-Use Types	Period	Months
Commercial and Industrial, non-heating	Annual	Jan – Dec
Commercial and industrial, heating	5 month	Nov – Mar
Existing residential heating	3 month	Dec – Feb
New residential heating	5 month	Nov – Mar
Residential domestic hot water	Annual	Jan – Dec
All commercial and industrial	6 month	Nov – Apr
All residential	6 month	Nov – Apr
All retail end uses	5 month	Nov – Mar

The detailed avoided retail gas costs from 2008 through 2037 are presented in Table 10[24]. The supporting calculations are presented in the *retail avd gas cost* worksheet in *NIMO Avoided costs gas workpapers 2008 03 27.xls*.

[24] Avoided wholesale energy costs through 2032 are derived directly from the GED forecast as adjusted by Synapse. Values for 2033 through 2037 are derived from the 2032 value increased by the average rate of escalation of the prior ten years.

TABLE 10
AVOIDED COSTS OF GAS DELIVERED TO RETAIL CUSTOMERS
Niagara Mohawk Power Corporation
Gas Delivered via Dominion Transmission, Inc.
(2007$/Dekatherm)

Year	RESIDENTIAL				COMMERCIAL & INDUSTRIAL				ALL RETAIL
	Existing Heating Dec-Feb	New Heating Nov-Mar	Hot Water annual	All Nov-Apr	Non Heating annual	Heating Nov-Mar	All Nov-Apr		Nov-Mar
2008	13.40	13.51	13.32	13.44	11.73	11.92	11.85		12.67
2009	14.00	13.79	12.94	13.55	11.35	12.20	11.96		12.94
2010	13.33	13.14	12.40	12.93	10.81	11.55	11.34		12.29
2011	12.99	12.80	12.12	12.60	10.53	11.21	11.01		11.96
2012	12.75	12.57	11.90	12.37	10.32	10.98	10.79		11.73
2013	12.55	12.37	11.72	12.18	10.14	10.79	10.59		11.53
2014	11.59	11.43	10.74	11.22	9.15	9.84	9.63		10.58
2015	11.85	11.69	10.99	11.48	9.40	10.10	9.89		10.84
2016	12.17	12.01	11.29	11.79	9.70	10.42	10.20		11.16
2017	12.35	12.19	11.46	11.97	9.88	10.60	10.38		11.34
2018	12.25	12.08	11.36	11.87	9.78	10.49	10.28		11.24
2019	12.04	11.87	11.17	11.66	9.58	10.29	10.07		11.03
2020	11.36	11.20	10.52	11.00	8.93	9.61	9.41		10.35
2021	12.03	11.86	11.16	11.65	9.57	10.28	10.06		11.02
2022	12.28	12.12	11.40	11.90	9.81	10.53	10.31		11.27
2023	12.49	12.33	11.60	12.11	10.01	10.74	10.52		11.48
2024	12.56	12.39	11.66	12.17	10.07	10.81	10.59		11.55
2025	12.62	12.45	11.72	12.23	10.13	10.86	10.64		11.61
2026	12.74	12.57	11.82	12.34	10.24	10.98	10.76		11.72
2027	12.85	12.68	11.94	12.46	10.35	11.09	10.87		11.84
2028	12.97	12.80	12.05	12.58	10.46	11.21	10.99		11.96
2029	13.10	12.92	12.16	12.69	10.57	11.33	11.11		12.08
2030	13.22	13.04	12.28	12.81	10.69	11.46	11.23		12.20
2031	13.34	13.17	12.40	12.94	10.81	11.58	11.35		12.32
2032	13.47	13.29	12.51	13.06	10.93	11.70	11.47		12.45
2033	13.60	13.42	12.63	13.18	11.04	11.83	11.59	0.00	12.57
2034	13.72	13.54	12.75	13.30	11.16	11.95	11.72	0.00	12.70
2035	13.85	13.67	12.87	13.43	11.28	12.08	11.84	0.00	12.82
2036	13.98	13.79	12.99	13.55	11.41	12.21	11.97	0.00	12.95
2037	14.11	13.92	13.11	13.68	11.53	12.34	12.09	0.00	13.08

LEVELIZED	Years								
2008-2027	20	12.54	12.39	11.70	12.18	10.11	10.80	10.59	11.54

Real (constant $) riskless annual rate of return in %: 2.2165%

Appendix A

Pages 7-9 to 7-16 from *Avoided Energy Supply Costs In New England: 2007 Final Report*

process. The regulatory history of acid rain and of ozone depletion contributed important foundations for efforts to regulate greenhouse gas emissions (federal government role in addressing pollution, and framework for international negotiations on pollutants, respectively).

ii. Carbon Dioxide will be the Dominant Externality from Electricity Production and Use in New England Over the Study Period

Externalities associated with electricity production and uses include a wide variety of air pollutants, water pollutants, and land use impacts. The principle air pollutants that have externalities include carbon dioxide, sulfur dioxide, nitrogen oxides and ozone, particulates, and mercury.

There have been several fairly comprehensive studies that assess the full range of environmental impacts from electricity generation and use. These include:

- *Environmental Costs of Electricity*, prepared by the Pace University Center for Environmental and Legal Studies: Ottinger, R, et. al,, for NYSERDA, Oceana Publications, Inc, 1990;
- The New York State Environmental Externalities Cost Study, RCG/Hagler, Bailly, Inc. and Tellus Institute, for the Empire State Electric Energy Research Corporation (ESEERCO), multiple volumes, 1994 and 1995;
- Non-Price Benefits of BECo Demand-Side Management Programs, for the Boston Edison Settlement Board, Tellus No. 93-174A, July 1994; and
- US-EC Fuel Cycle Study, by Oak Ridge National Laboratory and Resources for the Future, for the US Department of Energy and the Commission of the European Communities, multiple volumes, 1992 to 1994.

The list of externalities from energy production and use is quite long, and includes the following:

- Air emissions (including SO_2, NO_x, particulates, mercury, lead, other toxins, and greenhouse gases) and the associated health and ecological damages;
- Fuel cycle impacts associated with "front end" activities such as mining and transportation, and waste disposal;
- Water use and pollution;
- Land use;
- Aesthetic impacts of power plants and related facilities;
- Radiological exposures related to nuclear power plant fuel supply and operation (routine and accident scenarios); and
- Other non-environmental externalities such as economic impacts (generally focused on employment), energy security, and others.

Many of these externalities have been reduced over time, as regulations limiting emission levels have forced suppliers and buyers to consider at least a portion of those costs in their production and use decisions, thereby "internalizing" a portion of those costs. For example, the Clean Air Interstate Rule, passed by Congress in March 2005, adjusts the SO_2 emissions cap downward with an ultimate effect of reducing SO_2 emissions about 73% from 2003 levels. The Clean Air Act and the Clean Air Interstate Rule require further reductions in emission levels over the study period. As a result, while there remain some "external costs" associated with the residual NO_x and SO_2 pollution, these externalities are now relatively small. In contrast, regulators are just starting to "internalize" the impacts of carbon dioxide.

It is expected that the "carbon externality" will be the dominant externality associated with marginal electricity generation in New England. This is the case for two main reasons. First, as noted above, regulations to address the greenhouse gas emissions responsible for global climate change are lagging, particularly in the United States. The damages from criteria air pollutants are relatively bounded, and to a great extent "internalized," as a result of existing regulations. In contrast, global climate change is a problem on an unprecedented scale with far-reaching and potentially catastrophic implications. Second, New England avoided electric energy costs over the study period are likely to be dominated by natural gas-fired generation, which has minimal SO_2, mercury, and particulate emissions and relatively low NO_x emissions. Hence, spending extensive time reviewing the latest literature on externality values for these emissions would not be a good use of time and budget. Based on knowledge of the electric system, and review of model runs, it is believed that the dominant environmental externality in New England over the study period will be the un-internalized cost of carbon dioxide emissions. RGGI and any federal CO_2 regulations will only internalize a portion of the "greenhouse gas externality," particularly in the near term.

The California PUC has directed electric companies to include a value for carbon dioxide in their avoided cost determination and long-term resource procurement. The CA PUC found:

> "In terms of specific pollutants, of significant concern to regulators and the public today is the environmental damage caused by carbon dioxide (CO_2) emissions—an inescapable byproduct of fossil fuel burning and by far the major contributor to greenhouse gases. Unlike other significant pollutants from power production, CO_2 is currently an unpriced externality in the energy market.... CO_2 is not consistently regulated at either the Federal or State levels and is not embedded in energy prices....[115]

For the above reasons, values were developed for the one major emission associated with avoided electricity costs for which the near-term internalized cost most significantly understates the value supported by current science.

[115] R.04-04-003, Appendix B, p. 5.

iii. General Approaches to Monetizing Environmental Externalities

There are various methods available for monetizing environmental externalities such as air pollution from power plants. These include various "damage costing" approaches that seek to value the damages associated with a particular externality, and various "control cost" approaches that seek to quantify the marginal cost of controlling a particular pollutant (thus internalizing a portion or all of the externality).

The "damage costing" methods generally rely on travel costs, hedonic pricing, and contingent valuation in the absence of market prices. These are forms of "implied" valuation, asking complex and hypothetical survey questions, or extrapolating from observed behavior. For example, data on how much people will spend on travel, subsistence, and equipment, can be used to measure the value of those fish, or more accurately the value of *not* killing fish via air pollution. Human lives are sometimes valued based upon wage differentials for jobs that expose workers to different risks of mortality. In other words, comparing two jobs, one with higher hourly pay rate and higher risk than the other can serve as a measure of the compensation that someone is "willing to accept" in order to be exposed to the risk.

There are myriad problems with these approaches, two of which will be discussed here. First, the damage costing approaches are, in the case of global climate change, simply subject to too many problematic assumptions. We do not subscribe to the view that a reasonable economic estimate of the "damages" around the world can be developed and used as a figure for the externalities associated with carbon dioxide emissions. In other words, estimating damage is a moving target – it depends upon what concentrations we ultimately reach (or what concentrations we reach and reduce from). This is exacerbated by the fact that we do not fully understand climate change, and cannot project with certainty the levels at which certain impacts will occur. A further complicating factor is that different emissions concentrations create different damages for different regions and different groups of people. Thus, such exercises, while interesting, are fraught with difficulties including: (a) identifying the categories of changes to ecosystems and societies around the planet; (b) estimating magnitudes of impacts; (c) valuing those impacts in economic terms; (d) aggregating those values across countries with different currency exchange rates and different cultures; (e) addressing the non-linear and catastrophic aspects of the climate change damage; and (f) dealing with the paradoxes and conundrums involved in applying financial discount rates to effects stretching over centuries. Second, the fact that the "regulators' revealed preferences" approach is unavailable, as regulators have not established relevant reference points, complicates the task of determining a carbon externality cost.

The "control cost" methods generally look at the *marginal* cost of control. That is, the cost of control valuations look at the last (or most expensive) unit of emissions reduction required to comply with regulations. The cost of control approach can be based upon a "regulators' revealed preference" concept. That is, if "air regulators" are requiring a particular technology with a cost per ton of $X to be installed at power plants, then this can be taken as an indication that the value of those reductions is perceived to be at or above the cost of the controls. The cost of control approach can also be based upon a "sustainability target" concept. With the sustainability target, we start with a level of damage or risk that is considered to be acceptable, and then estimate the marginal cost of achieving that target.

The "sustainability target" approach relies on the assumption that the nations of the world will not tolerate unlimited damages. It also relies partly on an expectation that policy leaders will realize that it is cheaper to reduce emissions now and achieve a sustainability target than it is not to address climate change. It is worth noting that a cost estimate based on a sustainability target will be a bit lower than a damage cost estimate because the "sustainability target" is going to be a calculus of what climate change the planet is already committed to, and what additional change we are willing to live with (again complicated by the fact that different regions will see different impacts, and have different ideas about what is dangerous and what is sustainable). While we do not use a damage cost estimate, it is informative to consider damages to get a sense of the scale of the problem. In October 2006 a major report to Prime Minister Tony Blair stated that "the benefits of strong and early action far outweigh the economic costs of not acting." Based on its review of results from formal economic models, the Stern Review on the Economics of Climate Change estimated that in the absence of efforts to curb climate change, the overall costs and risks of climate change will be equivalent to losing at least 5% of global GDP each year, now and forever, and could be as much as 20% of GDP or more. In contrast, the Stern Review states that the costs of action – the cost of implementing actions to curb climate change – can be limited around 1% of global GDP each year.[116]

iv. Estimation of CO_2 Environmental Costs

Based upon our review of the merits of those various approaches, we selected an approach that estimates the cost of controlling, or stabilizing, global carbon emissions at a "sustainable level" or sustainability target. To develop that estimate, the most recent science regarding the level of emissions that would be sustainable was reviewed, as well as the literature on costs of controlling emissions at that level.

The conceptual and practical challenges for estimating a carbon externality price include the following:

- The damages are very widely distributed in time (over many decades or even centuries) and space (across the globe);
- The "physical damages" include some impacts that are very difficult to quantify and value, such as flooding large land areas; changes to local climates; species range migration; increased risk of flood and drought; changes in the amount, intensity, frequency, and type of precipitation; changes in the type, frequency, and intensity of extreme weather events (such as hurricanes, heat waves, and heavy precipitation);

[116] Stern, Sir Nicholas; *Stern Review of the Economics of Climate Change*; Cambridge University Press, 2007.

- This list of "physical damages" includes some that are extremely difficult, perhaps impossible, to reasonably express in monetary terms;
- The scientific understanding of the climate change process and climate change impacts is evolving rapidly;
- There may well be reasons (not considered here) that the environmental cost value could have a shape that starts lower and increases faster, or vice versa, having to do with periods in which rates of change are most problematic;
- The scale of the impact on the world economies associated with the impacts of climate change and/or associated with the transformations of economies to reduce greenhouse gas emissions are so large that using terms and concepts such as "marginal" can be problematic; and
- The impacts of climate change are non-linear and non-continuous, including "feedback cycles" that can most reasonably be thought of in terms of thresholds beyond which there are "run away damages" such as irreversible melting of the Greenland ice sheet and the West Antarctic ice sheet, and collapse of the Atlantic thermohaline circulation – a global ocean current system that circulates warm surface waters.

Given the daunting challenge of valuing climate damages in economic terms, AESC 2007 takes a practical approach consistent with the concepts of "sustainability" and "avoidance of undue risk." Specifically, the carbon externality can be valued by looking at the marginal costs associated with controlling total carbon emissions at, or below, the levels that avoid the major climate change risks according to current expectations.

Nonetheless, because the environmental costs of energy production and use are so significant, and because the climate change impacts associated with power plant carbon dioxide emissions are urgently important, it is worthwhile to attempt to estimate the externality price and to put it in dollar terms that can be incorporated into electric system planning.

(a) What is the Correct Level of CO_2 Emissions?

In order to determine what is currently deemed a reasonable sustainability target, current science and policy was reviewed. In 1992, over 160 nations (including the United States) agreed to "to achieve stabilization of atmospheric concentrations of greenhouse gases at levels that would prevent dangerous anthropogenic (human-induced) interference with the climate system…." (United Nations Framework Convention on Climate Change or UNFCCC).[117] Achieving this commitment requires determining the maximum temperature increase above which impacts are anticipated to be dangerous, the atmospheric emissions concentration that is likely to lead to that temperature increase, and the emissions pathway that is likely to limit atmospheric concentrations and temperature increase to the desired levels.

[117] There are currently over 180 signatories.

The definition of what level of temperature change constitutes a dangerous climate change will ultimately be established by politicians, as it requires value judgments about what impacts are tolerable regionally and globally.[118] We expect that such a definition and decision will be based upon what climate science tells us about expected impacts and mitigation opportunities.

While uncertainty and research continue, a growing number of studies identify a global average temperature increase of 2°C above pre-industrial levels as the temperature above which dangerous climate impacts are likely to occur.[119] Temperature increases greater than 2°C above pre-industrial levels are associated with multiple impacts including sea level rise of many meters, drought, increasing hurricane intensity, stress on and possible destruction of unique ecosystems (such as coral reefs, the Arctic, alpine regions), and increasing risk of extreme events.[120] The European Union has adopted a long-term policy goal of limiting global average temperature increase to 2°C above pre-industrial levels.[121]

Because of multiple uncertainties, it is difficult to define with certainty what future emissions pathway is likely to avoid exceeding that temperature increase. We reviewed several sources to determine reasonable assumptions about what level of concentrations are deemed likely to achieve the sustainability target, and what emission reductions are necessary to reach those emissions levels. The Intergovernmental Panel on Climate Change's most recent Assessment Report indicates that concentrations of 445-490 ppm CO_2 equivalent correspond to 2° – 2.4°C increases above pre-industrial levels.[122] A comprehensive assessment of the economics of climate change, The Stern Review, proposes a long-term goal to stabilize greenhouse gases at between the equivalent of 450 and 550 ppm CO_2.[123] Recent research indicates that achieving the 2°C goal likely requires stabilizing atmospheric concentrations of carbon dioxide and other heat-trapping gases near 400 ppm carbon dioxide equivalent.[124]

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[118] For multiple discussions of the issues surrounding dangerous climate change, _see_ Schnellnhuber, Cramer, Nakicenovic, Wigley and Yohe, editors; *Avoiding Dangerous Climate Change*; Cambridge University Press, 2006. This book contains the research presented at The International Symposium on Stabilisation of Greenhouse Gas Concentrations, Avoiding Dangerous Climate Change, which took place in the U.K. in 2005.

[119] Mastrandrea, M. and Schneider, S.; *Probabilistic Assessment of "Dangerous" Climate Change and Emissions Scenarios: Stakeholder Metrics and Overshoot Pathways;* Chapter 27 in *Avoiding Dangerous Climate Change*; Cambridge University Press, 2006.

[120] Schnellnhuber, 2006.

[121] The European Union first adopted this goal in 1996 in "Communication of the Community Strategy on Climate Change." Council conclusions. European Council. Brussels, Council of the EU. The EU has since reiterated its long-term commitment in 2004 and 2005 (_see_, _e.g._ Council of the European Union, Presidency conclusions, March 22-23.)

[122] IPCC AR4, WGIII Summary for Policy Makers, 2007. Table SPM5.

[123] Stern, Sir Nicholas; *Stern Review of the Economics of Climate Change*; Cambridge University Press, 2007.

[124] Meinshausen, M.; *What Does a 2°C Target Mean for Greenhouse Gases? A Brief Analysis Based on Multi-Gas Emission Pathways and Several Climate Sensitivity Uncertainty Estimates;* Chapter 28 in *Avoiding Dangerous Climate Change*; Cambridge University Press, 2006.

The Intergovernmental Panel on Climate Change (IPCC) indicates that reaching concentrations of 450-490ppm CO_2-eq requires reduction in global CO_2 emissions in 2050 of 85-50% below 2000 emissions levels.[125] The Stern Review indicates that global emissions would have to be 70% below current levels by 2050 for stabilization at 450ppm CO_2-eq.[126] To accomplish such stabilization, the United States and other industrialized countries would have to reduce greenhouse gas emissions on the order of 80 – 90% below 1990 levels, and developing countries would have to achieve reductions from their baseline trajectory as soon as possible.[127] In the United States, several states have adopted state greenhouse gas reduction targets of 50% or more reduction from a baseline of 1990 levels or then-current levels by 2050 (California, Connecticut, Illinois, Maine, New Hampshire, New Jersey, Oregon, and Vermont). In 2001, the New England states joined with the Eastern Canadian Premiers in also adopting a long-term policy goal of reductions on the order of 75-80% of then-current emission levels.[128]

The sobering news is that a long term stabilization goal of even 400 ppm might not be sufficient: "while very rapid reductions can greatly reduce the level of risk, it nevertheless remains the case that, even with the strictest measures we model, the risk of exceeding the 2°C threshold is in the order of 10 to 25 per cent."[129] Similarly, the 2°C threshold may not be sufficient to avoid severe impacts.[130]

(b) What is the Cost of Stabilizing CO_2 Emissions at this Sustainable Level?

There have been several efforts to estimate the costs of achieving a variety of atmospheric concentration targets. The most comprehensive effort is the work of the Intergovernmental Panel on Climate Change. The IPCC was established by the World Meteorological Organization and UNEP in 1988 to provide scientific, technical and methodological support and analysis on climate change. IPCC has issued three assessment reports on the science of climate change, climate change impacts, and on mitigation and adaptation strategies (1990, 1995, 2001), and is currently issuing its fourth assessment report. In its fourth Assessment Report, the IPCC indicates that reductions on the order of 34 gigatonnes (Gt) would be necessary to achieve an 80% reduction below current.[131] That report estimates that up to 31 Gt in reductions are available for \$100/te of

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[125] IPCC AR4, WGIII Summary for Policy Makers, 2007. Table SPM5.

[126] Stern Review, Long Executive Summary, 2007. Page xi.

[127] den Elzen, M., Meinshausen, M; *Multi-Gas Emission Pathways for Meeting the EU 2°C Climate Target;* Chapter 31 in *Avoiding Dangerous Climate Change*; Cambridge University Press, 2006. Page 306.

[128] New England Governors/Eastern Canadian Premiers, *Climate Change Action Plan 2001*, August 2001. NEG/ECP reiterated this commitment in June 2007 through Resolution 31-1, which states, in part, that the long term reduction goals should be met by 2050.

[129] Bauer and Mastrandrea; *High Stakes: Designing emissions pathways to reduce the risk of dangerous climate change;* Institute for Public Policy Research, U.K.; November 2006.

[130] See recent research by James Hansen, Goddard Space Flight Institute – NASA's top climate scientist.

[131] 2000 emissions levels were 43Gt CO_2-eq. IPCC AR4, WGIII, Summary for Policy Makers, 2007. Page 11.

CO_2 or less (Working Group III Summary for Policy Makers). Other studies on the costs of achieving stabilization targets include the following:

- A Vattenfalls study of abatement potential estimates that about 30 Gt reduction would be necessary for stabilization at 450 ppm, and about 27Gt are available for around \$50/tCO_2 – so cost would go above \$50/t;[132]
- McKinsey & Company have developed an abatement cost curve that indicates that stabilization at 450 ppm would have a marginal abatement cost of about \$50/t, stabilization at 400 ppm would have a marginal abatement cost of over \$60/tCO_2; and
- The Stern Review itself talks primarily about macro-economic costs; however an underlying meta-analysis of modeling literature concludes that "even stringent stabilization targets can be met without materially affecting world GDP growth, at low carbon tax rates or permit prices, at least by 2030 (in \$US(2000), less than \$15/tCO_2 for 550ppmv and \$50/tCO_2 for 450ppmv for CO_2)."[133]

The IPCC Working Group III Summary for Policy Makers states on page 29 (references omitted): "An effective carbon-price signal could realize significant mitigation potential in all sectors.

- Modeling studies show carbon prices rising to 20 to 80 US\$/tCO_2-eq by 2030 and 30 to 155 US\$/tCO_2-eq by 2050 are consistent with stabilization at around 550 ppm CO_2-eq by 2100. For the same stabilization level, studies since the Third Assessment Report that take into account induced technological change lower these price ranges to 5 to 65 US\$/tCO_2eq in 2030 and 15 to 130 US\$/tCO_2-eq in 2050.
- Most top-down, as well as some 2050 bottom-up assessments, suggest that real or implicit carbon prices of 20 to 50 US\$/tCO_2-eq, sustained or increased over decades, could lead to a power generation sector with low-greenhouse gas emissions by 2050 and make many mitigation options in the end-use sectors economically attractive."

Based on a review of these different sources, we believe that it is reasonable to anticipate a marginal cost of control of \$60/tCO_2-eq for achieving a stabilization target that is likely to avoid temperature increases higher than 2°C above pre-industrial levels. Of course, selection of this value requires multiple assumptions.

[132] *Vattenfalls Global Climate Impact Abatement Map*, accessed May 30, 2007.

[133] Barker, Terry et. al.; *A report prepared for the HM Treasury Stern Review on "The economics of climate change" The Costs of Greenhouse Gas Mitigation with Induced Technological Change: A Meta-Analysis of Estimates in the Literature*; 4 CMR, University of Cambridge. July 2006.

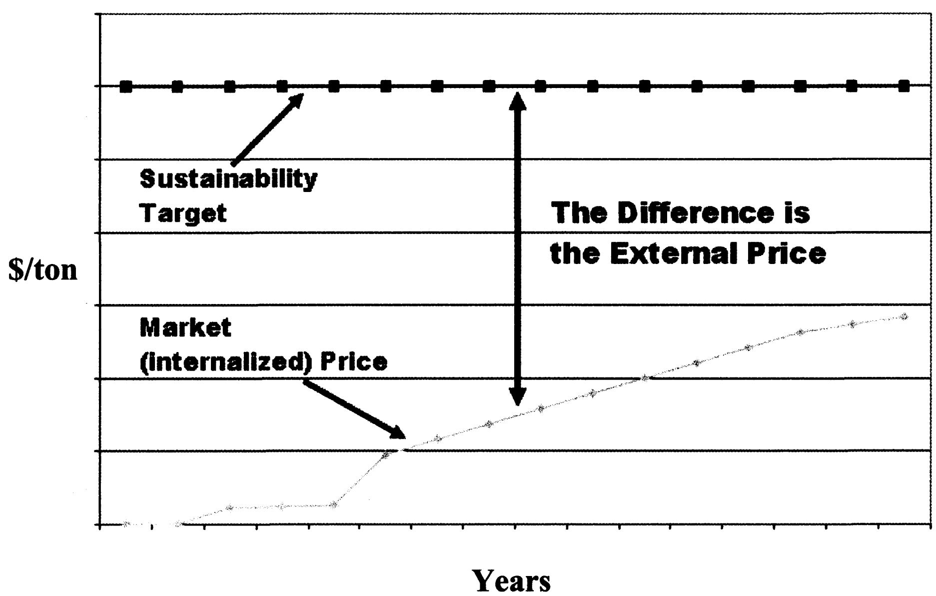
v. Estimating CO_2 Environmental Costs for New England

Our estimates of the "external" or additional cost associated with emissions of carbon dioxide in New England are based upon the sustainability target and the forecast of carbon emission regulation in New England over the study period. The externality value for carbon dioxide in each year was calculated as the estimated annual sustainability target value of $60/ton minus the annual allowance values internalized in the projected electric energy market prices.

The annual allowance values internalized in the projected electric energy market prices are described in Chapter 5. These values are based upon a Synapse forecast of the carbon trading price associated with anticipated carbon regulations. That carbon price was included in the dispatch model runs (in the generators' bids) and hence is embedded within the AESC 2007 avoided electricity costs. The additional value in each year is the difference between the estimate of marginal cost to achieve a sustainability target ($60/ton CO_2) and the value of the carbon trading price embedded in the projection of wholesale electric energy prices.

Exhibit 7-13 illustrates how the additional CO_2 cost was determined. The line for the allowance price is based on the forecast of carbon allowance costs, illustrating the notion that the United States will gradually move to incorporate the climate externality into policy. The "externality" is simply the difference between the estimate of the cost of achieving a sustainability target and the anticipated allowance cost; that is, the area above the blue line (and below $60/ton) in the graph.

Exhibit 7-13. Determination of the Additional Cost of CO_2 Emissions



The carbon dioxide externality price forecast is presented above as a single simple price. This is for ease of application and because doing something more complex such as varying the shape over time or developing a distribution to represent uncertainty would go beyond the scope of this project and would stretch the available information upon which the externality price is based. We fully acknowledge the many complexities involved in estimating a carbon price, both conceptual and practical. Some of these are listed in the Estimation of CO_2 Environmental Costs section (iv) above

With regard to environmental costs, AESC 2007 focuses on the externality value of carbon dioxide for the purpose of screening DSM programs for two main reasons. First, the environmental costs of carbon dioxide emissions are substantially greater than the costs of the other environmental impacts of electricity generation. Second, carbon dioxide is expected to be the dominant environmental impact of the marginal sources of generation in New England over the study period. Thus, the cost associated with carbon dioxide emissions dominates other values to an extent that justifies focusing exclusively on carbon dioxide.

The additional value for carbon dioxide in each year is an estimated annual sustainability target value of $60/ton minus the annual projected allowance values internalized in our model. Synapse reviewed science and policy to assess current emerging consensus on what is an appropriate sustainability target. The sustainability target value is an estimate of the cost of stabilizing carbon dioxide emissions at levels that seem likely, based on current science, to avoid more than a 2°C increase in the global average temperature. The annual allowance values are drawn from our forecast of carbon allowance prices associated with anticipated carbon regulations over the study period. The following exhibit presents the recommended values.

Exhibit 7-14. Recommended Externality Values

Year	Sustainability Target ($/ton)	Allowance Price (internalized value $/ton)	Additional Environmental Cost (Sustainability Target - Allowance Price $/ton)
2007	60	0.00	60.00
2008	60	0.00	60.00
2009	60	2.21	57.79
2010	60	2.37	57.63
2011	60	2.53	57.47
2012	60	9.46	50.54
2013	60	11.56	48.44
2014	60	13.66	46.34
2015	60	15.76	44.24
2016	60	17.86	42.14
2017	60	19.96	40.04
2018	60	22.06	37.94
2019	60	24.16	35.84
2020	60	26.27	33.73
2021	60	27.32	32.68
2022	60	28.37	31.63

The values in the right hand column of the table are, in one sense, externalities. They may be borne by citizens in the form of damages from climate change. There is also a significant chance that the "additional" CO2 costs will be borne to some degree by electricity consumers in the form of compliance costs in electricity rates if emission regulations require greater reductions more rapidly than we have assumed.

vi. Applying CO_2 Costs in Evaluations of DSM Programs

The externality values from Exhibit 7-14 are provided in the avoided electricity cost workbooks presented in Appendix E. They are expressed as $/kWh based upon our analysis of the CO_2 emissions of the marginal generating units in each year of the study period.

At a minimum program administrators should calculate the costs and benefits of DSM programs without, and then with, these values in order to assess their incremental impact on the cost-effectiveness of programs. However, we recommend the program administrators include these values in their analyses of DSM, unless specifically prohibited from doing so by state or local law or regulation. The next section explains why a DSM program could result in CO_2 emission reductions even under a cap and trade regulatory framework.

vii. Impact of DSM on Carbon Emissions Under a Cap and Trade Regulatory Framework

The Regional Greenhouse Gas Initiative is a cap and trade greenhouse gas program for power plants in the northeastern United States. Discussions to develop the program began in 2003, states signed a memorandum of understanding identifying the main elements of the program in December 2005, and in August 2006 they adopted a model rule for implementing the program. Currently nine states have decided to participate: Connecticut, Delaware, Maine, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, and Vermont. Maryland passed a law in April 2006 requiring participation in RGGI. Pennsylvania, the District of Columbia, the Eastern Canadian Provinces, and New Brunswick are official "observers" in the RGGI process. Individual states are now engaged in regulatory proceedings to adopt regulations consistent with the agreement.

As currently designed, the program will:

- Stabilize CO_2 emissions from power plants at current levels for the period 2009-2015, followed by a 10% reduction below current levels by 2019;
- Allocate a minimum of 25% of allowances for consumer benefit and strategic energy purposes. Allowances allocated for consumer benefit will be auctioned and the proceeds of the auction used for consumer benefit and strategic energy purposes; and
- Include certain offset provisions that increase flexibility to moderate price impacts and development of complimentary energy policies to improve energy efficiency, decrease the use of higher polluting electricity generation and maintain economic growth.

With carbon dioxide emissions regulated under a cap and trade system, as is assumed in this market price analysis, it is conceivable that a load reduction from a DSM program will not lead to a reduction in the amount of total system carbon dioxide emissions. The annual total system emissions for the affected facilities in the relevant region are, after all, capped. In the analysis that was documented in this report, the relevant cap and trade regulation is the Regional Greenhouse Gas Initiative (RGGI) for the period 2009 to 2012 and the assumed national cap and trade system thereafter. However, there are a number of reasons why a DSM program could result in CO_2 emission reductions, specifically:

- Reduction in load that reduces the cost (marginal or total cost) of achieving an emissions cap can result in a tightening of the cap. This is a complex interaction between the energy system and political and economic systems, and is difficult or impossible to model, but the dynamic may reasonably be assumed to exist;
- Specific provisions in RGGI provide for a tightening or loosening of the cap (via adjustments to the offset provisions that are triggered at different price levels). It is unknown at this point whether and to what extent such "automatic" adjustments might be built into the US carbon regulatory system;
- It is also possible that DSM efforts will be accompanied by specific retirements or allocations of allowances that would cause them to have an impact on the overall system level of emissions (effectively tightening the cap); and
- to the extent that the cap and trade system "leaks" because of its geographic boundaries, one would expect the benefits of a carbon emissions reduction resulting from a DSM program to similarly "leak." That is, a load reduction in New York could cause reductions in generation (and emissions) at power plants in New York, Pennsylvania, and elsewhere. Because New York is in the RGGI cap and trade system, the emissions reductions realized at New York generating units may pop up as a result of increased sales of allowances from NY to other RGGI states. But because Pennsylvania is not in the RGGI system, the emissions reductions at Pennsylvania generating units would be true reductions attributable to the DSM program.

Appendix E

APPENDIX E

Executive Summaries of Illustrative Evaluation Studies

PA Consulting Group

National Grid

2007 Commercial and Industrial Programs Free-ridership and Spillover Study

Final Executive Summary

June 23, 2008

PA

National Grid

2007 Commercial and Industrial Programs Free-ridership and Spillover Study

Final Executive Summary

June 23, 2008

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PA

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1. EXECUTIVE SUMMARY: NATIONAL GRID

This Executive Summary summarizes the findings of the program year 2007 Commercial and Industrial Programs Free-ridership and Spillover Study for National Grid customers. The purpose of this study was to assess program free-ridership, participant spillover, and nonparticipant spillover for the following programs offered by National Grid:

- Energy Initiative
- Design 2000*plus*
- Small Business Services

The 2007 Free-ridership and Spillover Studies ran concurrently for National Grid, Cape Light Compact, United Illuminating, and Unitil.

1.1 STUDY OBJECTIVES

The primary objective of the program year 2007 Commercial and Industrial Programs Free-ridership and Spillover Study was to assist National Grid in quantifying the net impacts of their commercial and industrial energy efficiency programs by estimating the extent of:

- Program free-ridership
- Participant "like" spillover
- Nonparticipant "like" spillover

This executive summary provides the free-ridership, participant spillover and nonparticipant spillover estimates for 2007. First, a summary of the study methodology is provided.

1.2 STUDY METHODOLOGY

The methodology used for this year's study follows the standardized methods developed in 2003 for a group of Massachusetts energy efficiency program administrators[1].

To accomplish the above objective, telephone surveys were conducted with samples of 2007 program participants in each of the programs and with design professionals and equipment vendors involved in these 2007 installations. The program participant sample consisted of unique electric utility *accounts*, not unique customer names. The same customer name, or business identity, can have multiple accounts in multiple locations, but program technical support and incentives are provided on behalf of an individual account. Thus, for the purposes of this study, a customer or participant is defined as a unique account.

The majority of these telephone interviews were completed with program participants between March 5 and May 9, 2008. All sampled participating customers were mailed a letter on National Grid letterhead in advance of the telephone call. This letter explained the purpose

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[1] Pamela Rathbun, Carol Sabo, and Bryan Zent, *Standardization Methods for Free-ridership and Spillover Evaluation—Task 5 Final Report (Revised),* prepared for National Grid, NSTAR Electric, Northeast Utilities, Unitil, and Cape Light Compact, June 16, 2003.

of the call, informed customers that someone would be calling them in the next couple of weeks to ask them some questions about their experience with the programs, and thanked them for their cooperation in advance. This advance letter and repeated call attempts resulted in a high response rate of 76 percent, which increases the level of confidence in the survey results. The duration of interviews with program participants averaged ten minutes.

In addition to the customer surveys, surveys were conducted with:

- Design professionals and vendors identified by customers as being the most knowledgeable about the decisions to install the equipment through National Grid's Design 2000*plus* or Energy Initiative programs. These surveys were used for estimating free-ridership for those installations where the design professional/equipment vendor was more influential in the decision than the customer.
- Design professionals and equipment vendors who had recommended, sold and/or installed equipment through National Grid's Design 2000*plus* or Energy Initiative programs, as well as Unitil and United Illuminating's Medium and Large Commercial design professionals and vendors. These surveys were used for estimating the extent of nonparticipant "like" spillover for the Sponsor's programs.

The number of survey completions for some measure categories is low because the number of installations within these measure categories for program year 2007 was small. Thus, although a high percentage of the 2007 program participants completed surveys, some caution should be used when interpreting the results.

1.3 TOTAL PARTICIPANT FREE-RIDERSHIP ESTIMATES

A program's ***free-ridership rate*** is the percentage of program participants deemed to be free riders. A ***free rider*** refers to a customer who received an incentive through an energy efficiency program who would have installed the same or a smaller quantity of the same high efficiency measure on their own within one year if the program had not been offered. For free riders, the program is assumed to have had no influence or only a slight influence on their equipment purchase decision. Consequently, none or only some of the energy savings of equipment purchased by this group of customers should be credited to the energy efficiency program. Free riders account for costs, but not benefits, to the program, driving benefit-cost ratios down.

For programs that offer monetary incentives for multiple measure categories (e.g., motors, lighting, HVAC), it is important to estimate free-ridership by specific measure category. Category-specific estimates produce feedback on the program at the level at which it actually operates and allow for cost-effectiveness testing by measure category.

In addition, for commercial and industrial incentive programs, free-ridership has often been found to be highly variable among measure categories, making it essential to produce measure category-specific estimates. The ability to provide reliable estimates by measure category is dependent on the number of installations within that measure category—the fewer installations, the less reliable the estimation.

It is also important to measure the *extent* of free-ridership for each customer. Pure free riders (100%) would have installed exactly the same quantity and type of equipment within one year in the absence of the program. Partial free riders (1-99%) are those customers who would have installed some equipment within one year on their own, but a smaller quantity and/or a lesser efficiency. Thus, the program had some impact on their decision. Non-free riders (0%) are those who would not have installed any high efficiency qualifying equipment within one year in the absence of the program services. The total free-ridership estimates in this report include pure, partial, and non-free riders.

This year's approach to estimating free riders follows the approach outlined in the *Standardization Methods...* report, which consists of a sequential question technique to identify free riders. This sequential approach asks program participants about the actions they would have taken if the program had not been offered. This approach is considered an accurate method of estimating the actual level of free-ridership among program participants because it addresses the program's impact upon project timing, measure quantity, and efficiency levels while explicitly recognizing that the cost of energy-efficient equipment can be a barrier to installation in the absence of utility-sponsored energy efficiency programs. This method is also recommended because it walks survey respondents through their decision process with the objective of helping them recall the program's impact upon all aspects of project decision-making.

One issue with the method is how to handle responses of "don't know." The "don't know" responses to the initial free-ridership question are assigned a free-ridership value of zero percent. For these cases, we then check their responses to the consistency questions and their response to open-ended question and adjust the free-ridership rate as appropriate. Note that program total free-ridership (pure and partial) rates illustrated in the following tables are weighted by measure category kWh savings as well as the disproportionate probability of being sampled. When reviewing the measure category free-ridership rates it is important to consider the number of survey completions that the estimate is based upon.

Energy Initiative Participant Free-ridership Rates. Table 1-1 summarizes the total free-ridership results overall and by measure category for 2007 Energy Initiative installations. The overall Energy Initiative program free-ridership for the 2007 program year was 10.5 percent, which is higher than the 8.9 percent rate found for 2005 installations, and higher than the 6.7 percent rate found in 2004. The HVAC installations' free-ridership rates dropped significantly in 2007, which reflects changes in program requirements related to HVAC efficiency levels.

The rate was highest for VSD measures (33.1 percent), which changed significantly from previous years. A close review of the data shows that the relatively small population, and high savers with high free-ridership rates, drove the rate up for this measure category.

Table 1-1
National Grid Energy Initiative Program Total Participant Free-ridership Rates
All 2007 Installations

Measure Description	Total Participant Free-ridership Rate					
	# Accounts (Survey/Pop)	2007	2007 90% Error Margin	2005	2004	2002
Custom: Process, HVAC, Drivepower, Lighting, O&M	50/118	7.4%	±4.6%	8.4%	5.5%	10.9%
Motors	6/6	21.0%	±0.0%	32.4%	15.2%	9.1%
HVAC	23/29	12.5%	±5.5%	40.9%	0.3%	43.8%
VSD	12/18	33.1%	±12.9%	2.0%	0.1%	0.5%
Lighting: T8, Other Fluorescent, CFL, Controls, HID, LED Exit Signs	93/397	10.2%	±4.5%	5.9%	7.5%	14.5%
Compressed Air	15/19	5.7%	±4.5%	36.8%	26.4%	17.1%
Overall Energy Initiative Program	**178/558**	**10.5%**	**±3.1%**	**8.9%**	**6.7%**	**15.3%**

Overall survey and population participant counts do not equal the sum of measure category survey and population participant counts; the same participant may be represented in multiple measure categories.

Design 2000*plus* Participant Free-ridership Rates. Table 1-2 summarizes Design 2000*plus* free-ridership results overall and by measure category for 2007 installations. The overall Design 2000*plus* program free-ridership rate for 2007 was 19.0 percent, which is lower than the 21.7 percent rate found for 2005 installations and slightly higher than the 18.1 percent rate found for 2004 installations. As with the Energy Initiative program, HVAC measures' free-ridership rates dropped significantly between 2005 and 2007. VSD and compressed air measures had the highest free-ridership rates.

Table 1-2
National Grid Design 2000*plus* Program Total Participant Free-ridership Rates
All 2007 Installations

Measure Description	Total Participant Free-ridership Rate					
	# Accounts (Survey/Pop)	2007	2007 90% Error Margin	2005	2004	2002
Custom: Process, HVAC, Drivepower, Lighting	42/84	14.6%	±6.3%	10.1%	2.4%	16.6%
Motor: New	37/88	28.8%	±9.3%	15.1%	15.5%	40.1%
Motor: Failed/Stock	22/32	11.2%	±6.2%	23.5%	21.8%	23.2%
HVAC (Unitary): Packaged A/C and Water Source Heat Pump	55/124	14.8%	±5.9%	56.4%	5.3%	40.0%
HVAC (Non-unitary): Programmable Thermostat, Energy Management System, Chiller, Control	36/69	8.3%	±5.2%	49.1%	64.0%	39.5%
VSD	10/16	58.7%	±15.7%	8.6%	43.5%	19.3%
Lighting: T8, Other Fluorescent, CFL, Controls, HID, LED Exit Signs	51/123	27.9%	±7.9%	28.2%	50.6%	36.3%
Compressed Air	55/113	33.8%	±7.5%	32.7%	17.6%	20.6%
Overall Design 2000*plus* Program	**241/516**	**19.0%**	**±3.0%**	**21.7%**	**18.1%**	**27.2%**

Overall survey and population participant counts do not equal the sum of measure category survey and population participant counts; the same participant may be represented in multiple measure categories.

Custom measures include six Comprehensive Program participants. The Comprehensive Program free-ridership rate was zero percent for 2007 installations.

Small Business Services Participant Free-ridership Rates. Table 1-3 summarizes the results overall and by measure category for 2007 Small Business Services installations. The total free-ridership rate for 2007 was 5.5 percent, which is slightly higher than past years.

Table 1-3
National Grid Small Business Services Program Total Participant Free-ridership Rates
All 2007 Installations

Measure Description	**Total Participant Free-ridership Rate**					
	# Accounts (Survey/Pop)	**2007**	**2007 90% Error Margin**	**2005**	**2004**	**2002**
Lighting: Fluorescent with ELIG/3'4'8' Lamp & EEMAG, Standard Ballast, Exit Sign, Compact Fluorescent, HID	243/1,329	5.8%	±2.2%	2.3%	1.0%	1.0%
Non-lighting: Water Heater Wrap, Programmable Thermostat, Economizer	64/155	3.6%	±2.9%	2.0%	1.3%	1.0%
Overall Small Business Services Program	**284/1,441**	**5.5%**	**±2.0%**	**2.2%**	**1.0%**	**1.0%**

Overall survey and population participant counts do not equal the sum of measure category survey and population participant counts; the same participant may be represented in multiple measure categories.

State-level Participant Free-ridership Rates. Table 1-4 shows Massachusetts has a total 2007 free-ridership rate of 12.7 percent, New Hampshire 21.1 percent, and Rhode Island 10.0 percent.

Table 1-4
National Grid State-level Total Participant Free-ridership Rates
All 2007 Installations

Program	Total Participant Free-ridership Rates								
	Massachusetts			New Hampshire			Rhode Island		
	# Accounts Surveyed	2007 Total Free-ridership	90% Error Margin	# Accounts Surveyed	2007 Total Free-ridership	90% Error Margin	# Accounts Surveyed	2007 Total Free-ridership	90% Error Margin
Energy Initiative	128	11.3%	±3.8%	8	24.2%	±11.1%	42	7.9%	±5.9%
Design *2000plus*	154	18.6%	±3.8%	8	51.1%	±15.2%	79	18.1%	±5.1%
Small Business Services	127	6.9%	±3.4%	45	0.5%	±0.8%	112	4.3%	±2.8%
ALL	**392**	**12.7%**	**±2.4%**	**60**	**21.1%**	**±3.4%**	**228**	**10.0%**	**±2.8%**

Overall survey and population participant counts do not equal the sum of program survey and population participant counts; the same participant may be represented in multiple programs.

1.4 PARTICIPANT "LIKE" SPILLOVER ESTIMATES

Spillover refers to additional energy-efficient equipment installed by a customer due to program influences but without any financial or technical assistance from the program. ***Participant "like" spillover*** refers to the situation where a customer installed equipment through the program in the past year and then installed additional equipment of the same type due to program influences. In contrast to free-ridership, spillover adds benefits to the program at no additional cost, increasing the program benefits and benefit-cost ratio.

Survey free-ridership questions were followed by questions designed to measure "like" spillover. These questions asked about recent purchases (since program participation in 2007) of any additional energy-efficient equipment of the same type as installed through the program that were made *without* any technical or financial assistance from the utility. A "like" spillover estimate was computed based on how much more of the same energy-efficient equipment the participant installed outside the program and did so because of their positive experience with the program.

One of the issues with attempting to quantify spillover savings is how to value the savings of measures installed outside the program since we are relying on customer self-reports of the quantity and efficiency of any measures installed. We used a conservative approach and reported only those measures installed outside the program that were of exactly the same type and efficiency as the ones installed through the program. Our conservative approach allowed customers to be more certain about whether the equipment they installed outside the program was the same type as the program equipment. This, in turn, makes it possible for us to use the estimated program savings for that measure to calculate the customer's "like" spillover savings.

Note that the "like" spillover rates illustrated in the following tables are weighted by measure category kWh savings and the disproportionate probability of being sampled. When reviewing the measure category "'like' spillover," it is important to consider the number of survey completions that the estimate is based upon. The number of survey completions for some measure categories is low because very few customers in the sample installed the measure. Thus, although a high percentage of the 2007 program participants completed surveys, some caution should be used when interpreting the results.

Energy Initiative Participant "Like" Spillover Rates. Table 1-5 presents the "like" spillover rates for year 2007 Energy Initiative participants, overall and by measure category. The estimate of "like" spillover savings attributable to the overall Energy Initiative program for the purchase of like equipment outside of the program is 3.3%, which is slightly higher than previous years' spillover rates.

Table 1-5
National Grid Energy Initiative Program Participant "Like" Spillover Rates
All Year 2007 Installations

Measure Description	Total Participant "Like" Spillover Rate					
	# Accounts (Survey/Pop)	2007	2007 90% Error Margin	2005	2004	2002
Custom: Process, HVAC, Drivepower, Lighting, O&M	50/118	8.5%	±4.9%	1.9%	0.7%	1.4%
Motors	6/6	13.9%	±0.0%	1.7%	0.0%	2.5%
HVAC	23/29	5.2%	±3.5%	0.3%	27.0%	7.9%
VSD	12/18	0.0%	±0.0%	0.2%	16.2%	12.0%
Lighting: T8, Other Fluorescent, CFL, Controls, HID, LED Exit Signs	93/397	1.8%	±2.0%	1.4%	0.4%	2.1%
Compressed Air	15/19	0.0%	±0.0%	0.0%	0.0%	0.0%
Overall Energy Initiative Program	**178/558**	**3.3%**	**±1.8%**	**1.4%**	**2.7%**	**2.7%**

Overall survey and population participant counts do not equal the sum of measure category survey and population participant counts; the same participant may be represented in multiple measure categories.

Design 2000*plus* Participant "Like" Spillover Rates. Table 1-6 presents the "like" spillover rates for year 2007 Design 2000*plus* installations overall and by measure category. The overall Design 2000*plus* program spillover rate for the 2007 program year was 5.9 percent, which is lower than 8.8 percent rate found for 2005 installations but higher than 2004 and 2002 rates.

Table 1-6
National Grid Design 2000*plus* Program Participant "Like" Spillover Rates
All Year 2007 Installations

Measure Description	Total Participant "Like" Spillover Rate					
	# Accounts (Survey/Pop)	2007	2007 90% Error Margin	2005	2004	2002
Custom: Process, HVAC, Drivepower, Lighting	42/84	3.7%	±3.4%	11.3%	1.8%	1.0%
Motor: New	37/88	9.2%	±5.9%	5.3%	2.4%	8.4%
Motor: Failed/Stock	22/32	4.5%	±4.0%	10.4%	3.4%	21.4%
HVAC (Unitary): Packaged A/C and Water Source Heat Pump	55/124	5.9%	±3.9%	6.6%	2.5%	2.3%
HVAC (Non-unitary): Programmable Thermostat, Energy Management System, Chiller, Control	36/69	15.2%	±6.8%	0.2%	1.4%	4.1%
VSD	10/16	0.0%	±0.0%	0.0%	NA	3.9%
Lighting: T8, Other Fluorescent, CFL, Controls, HID, LED Exit Signs	51/123	13.4%	±6.0%	8.4%	0.3%	1.1%
Compressed Air	55/113	0.0%	±0.0%	0.2%	1.0%	0.2%
Overall Design 2000*plus* Program	**241/516**	**5.9%**	**±1.8%**	**8.8%**	**1.4%**	**2.0%**

Overall survey and population participant counts do not equal the sum of measure category survey and population participant counts; the same participant may be represented in multiple measure categories.

Custom measures include six Comprehensive Program participants. The Comprehensive Program spillover rate was zero percent for 2007 installations.

Small Business Services Participant "Like" Spillover Rates. Table 1-7 summarizes the "like" spillover rates for year 2007 Small Business installations overall and by measure category. The overall Small Business Services program spillover rate was 2.0 percent, which is comparable with previous years' rates.

Table 1-7
National Grid Small Business Services Program Participant "Like" Spillover Rates
All Year 2007 Installations

Measure Description	**Total Participant "Like" Spillover Rate**					
	# Accounts (Survey/Pop)	**2007**	**2007 90% Error Margin**	**2005**	**2004**	**2002**
Lighting: Fluorescent with ELIG/3'4'8' Lamp & EEMAG, Standard Ballast, Exit Sign, Compact Fluorescent, HID	243/1,329	2.2%	±1.4%	2.0%	0.5%	2.0%
Non-lighting: Water Heater Wrap, Programmable Thermostat, Economizer	64/155	0.7%	±1.3%	1.0%	0.3%	0.6%
Overall Small Business Services Program	**284/1,441**	**2.0%**	**±1.2%**	**1.9%**	**0.4%**	**1.9%**

Overall survey and population participant counts do not equal the sum of measure category survey and population participant counts; the same participant may be represented in multiple measure categories.

State-level Participant "Like" Spillover Rates. Table 1-8 shows the "like" spillover rate for Massachusetts is 3.5 percent, New Hampshire is 2.1 percent, and Rhode Island is 4.6 percent. The surveyed number represents the number of accounts surveyed within each state.

Table 1-8
National Grid State-level Program Participant "Like" Spillover Rates by Account
All Year 2007 Installations

Program	Total Participant "Like" Spillover Rates								
	Massachusetts			New Hampshire			Rhode Island		
	# Accounts Surveyed	2007 Spillover	90% Error Margin	# Accounts Surveyed	2007 Spillover	90% Error Margin	# Accounts Surveyed	2007 Spillover	90% Error Margin
Energy Initiative	128	4.3%	±2.4%	8	0.0%	—	42	0.4%	±1.4%
Design *2000plus*	154	2.2%	±1.5%	8	0.0%	—	78	14.2%	±4.6%
Small Business Services	127	2.5%	±2.1%	45	3.9%	±2.1%	112	1.1%	±1.5%
ALL	**392**	**3.5%**	**±1.3%**	**60**	**2.1%**	**±1.4%**	**228**	**4.6%**	**±2.0%**

Overall survey and population participant counts do not equal the sum of program survey and population participant counts; the same participant may be represented in multiple programs.

1.5 NONPARTICIPANT SPILLOVER ESTIMATES

Nonparticipant spillover refers to energy efficient measures installed by program nonparticipants due to the program's influence. The program can have an influence on design professionals and vendors as well as an influence on product availability, product acceptance, customer expectations, and other market effects, all of which may induce nonparticipants to buy high efficiency products. Total nonparticipant spillover would also include responses from nonparticipating designers and vendors.

The methodology for the 2007 study estimated only a portion of nonparticipant like-measure spillover based on responses from design professionals and vendors participating in National Grid, United Illuminating, and Unitil's Medium and Large Commercial programs[2]. Cape Light Compact vendors were not included in this study due to insufficient data; however, two of the three vendors that *were* indicated within Cape Light Compacts' vendor data overlapped with National Grid's vendor sample and were surveyed.

The data for the analysis could have been collected from nonparticipants directly or from the design professionals and vendors who recommended, sold, and/or installed qualifying high

[2] Nonparticipant spillover for small business programs was not estimated because of the small number of vendors involved in delivering the program.

efficiency equipment. We chose to survey the design professionals and vendors primarily because they could typically provide much more accurate information about the efficiency level of installed equipment than could the nonparticipants. Experience has shown that customers cannot provide enough data about the new equipment they have installed to allow for accurate estimates of the energy savings achieved from the equipment. While they usually can report what type of equipment was installed, they typically cannot provide sufficient information about the quantity, size, efficiency, and/or operation of that equipment to allow us to determine whether the equipment is "program-eligible." On the other hand, design professionals and equipment vendors who have worked with the program are typically more knowledgeable about equipment and are familiar with what is and is not "program-eligible."

Another argument in favor of using design professionals and equipment vendors to estimate nonparticipant spillover was that we could use data in the program tracking system database to attach kWh savings estimates to nonparticipant spillover. In the program tracking system database, measure-specific program kWh savings are associated with each design professional and vendor who participated in the program in 2007.

To determine nonparticipant spillover, design professionals and equipment vendors were asked (by measure category they installed in the program) what percent of their sales were program-eligible and what percent of these sales did not receive an incentive through the programs. They were then asked about the program's impact on their decision to recommend/install this efficient equipment outside the program. Using the survey responses and measure savings data from the program tracking system, the participating vendor nonparticipant like spillover savings could be estimated for each design professional/vendor and the results extrapolated to the total program savings.

This method of estimating nonparticipant spillover is a *conservative* estimate for two reasons. First, not all design professionals and equipment vendors who are familiar with the programs specified and/or installed equipment through the program in 2007. Thus, we miss any nonparticipant spillover that was associated with these other design professionals/vendors (although it is less likely these design professionals/vendors had nonparticipant spillover if they were not involved with the program in 2007).

Second, this method only allows us to extrapolate nonparticipant spillover for those same measure categories that a particular design professional/vendor was associated with for the 2007 programs. Thus, if a vendor installed program-eligible equipment in other measure categories in the year 2007 outside the program, but none through the program, we did not capture nonparticipant spillover savings with that particular type of equipment. In essence, we measured only "like" nonparticipant spillover; that is, spillover for measures like those installed through the program in 2007.

The nonparticipant spillover results for the Medium and Large Commercial and Industrial programs are based on surveys with 106 design professionals and vendors out of a population of 237 National Grid, United Illuminating, and Unitil vendors. Because of the significant overlap in sponsors' territories, as well as vendors across sponsors, we report the results in aggregate rather than by sponsor. The analysis indicates that the combined nonparticipant spillover from the medium and large commercial and industrial programs amounted to 2,603,307 kWh in the 2007 program year, which is approximately 2.6 percent% of the total savings produced by these programs combined (Table 1-9).

Table 1-9
Nonparticipant "Like" Spillover Results for Program Year 2007
National Grid, Unitil, and United Illuminating Vendors

A	B	C	D	E	F	G	H	I
Survey Categories	**Vendor Population kWh Savings[3]**	**Number of Firms Surveyed with kWh Savings/ Number of Firms in Program with kWh Savings**	**Surveyed kWh Savings[4]**	**Surveyed Savings Coverage Rate (D/B)**	**Nonparticipant Spillover from Surveyed Firms (kWh)[5]**	**Estimated Spillover Percent (F/D)**	**90% CI**	**Nonparticipant Spillover Extrapolated to Population (kWh) (B*G)**
Motors	102,873	6/16	38,077	37.0%	0	0.0%	0.0%	0
HVAC	10,877,314	27/60	2,175,565	20.0%	79,149	3.6%	0.7% to 3.5%	395,726
VSD[6]	2,393,842	11/28	802,202	33.5%	115,569	14.4%	4.8% to 25.3%	344,868
Lighting	56,560,136	60/151	20,074,391	35.3%	603,572	3.0%	1.0% to 4.6%	1,700,580
Compressed Air	4,671,464	10/22	1,743,112	37.3%	60,498	3.5%	1.3% to 6.3%	162,132
Refrigeration	4,758,046	2/6	1,197,312	25.2%	0	0.0%	0.0%	0
Other[7]	19,474,884	10/33	4,998,940	25.7%	0	0.0%	0.0%	0
Total	**98,838,559**	**106/254**	**31,029,599**	**31.4%**	**858,788**	**2.6%**	**1.0% to 3.7%**	**2,603,307**

[3] The vendor population kWh savings represents the total savings for all measures for Medium and Large C&I programs for actual vendors. Spillover is measured for each vendor associated with the program.

[4] The total surveyed kWh savings represents the total savings for all surveyed design professionals and surveyed vendors in the program tracking system database whose names suggested they were actual vendors, not participants.

[5] Net of "like" spillover for the customers associated with the surveyed design professionals/vendors, as identified from the participating customer survey.

[6] One VSD response suggested spillover but could not respond to the percentage question (VNP3). We imputed the percentage with the values from other VSD vendors that could respond to this question. Only one case was considered in the imputation, with a value of 50 percent.

[7] "Other" is a residual category consisting of measures remaining from "Custom" after equipment was reassigned to existing categories such as "Motors," "HVAC," or "Lighting," as well as process equipment, process cooling equipment, and comprehensive chillers.

LARGE COMMERCIAL AND INDUSTRIAL RETROFIT PROGRAM

IMPACT EVALUATION

2007

Submitted To:

National Grid

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FINAL REPORT

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1 EXECUTIVE SUMMARY

National Grid offers an energy efficiency retrofit program to their Large Commercial and Industrial customers. This is called the Energy Initiative (EI) program. A large share of the electric energy savings from the EI program comes from prescriptive lighting measures.

The purpose of this study is to estimate a realization rate for the prescriptive lighting measures from participants in the 2007 EI program. The realization rate compares estimated savings from the tracking system to actual billing data to verify the gross energy savings that were achieved.

The statistical model that was developed to estimate the savings from the lighting measures installed through EI was framed within the Statistically Adjusted Engineering (SAE) approach. Under this approach, the engineering estimate of savings is included as an explanatory variable in a regression equation with the billed electricity consumption as the dependent variable. The estimated coefficient on the engineering estimate of savings may be interpreted as the realization rate. That is, the coefficient indicates the percentage of the engineering estimate of energy savings that is realized on average according to the analysis of billing records.

The final model result was a realization rate of 1.04 with a t-value of 8.72. This result is statistically significant at the 90% confidence level and the precision of the estimate is plus or minus 19% at that confidence level.

Table 1-1 presents the results of this statistical modeling effort for the EI program. The final model result was a realization rate of 1.04 with a t-value of 8.72. This result is statistically significant at the 90% confidence level and the precision of the estimate is plus or minus 19% at that confidence level.

Table 1-1. Summary of Lighting Savings Realization Rate for EI Program[1]

Realization Rate	T-value[2]	Statistically Significant at the 90% Confidence Level?	Precision at the 90% Confidence Level	Lower Bound of Realization Rate at 90% Confidence Level	Upper Bound of Realization Rate at 90% Confidence Level
1.04	8.72	Yes	± 19%	0.85	1.24

The realization rate from this study should be applied to gross energy savings estimates from engineering calculations or deemed savings to create verified gross energy savings estimates. Additional estimates of free-ridership and/or spillover effects would need to come from other studies and be applied to the verified gross energy savings to estimate net energy savings. The development of net energy savings estimates is beyond the scope of this study.

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[1] All results shown in this table are calculated using realization rates and T-values with six decimal points. After the calculations, the results are rounded to two decimal points for reporting purposes.

[2] The T-value is equal to the estimated realization rate divided by its standard error. It can be used directly to test the hypothesis that the realization rate is equal to zero. A T-value of 1.645 indicates there is 90% confidence that the realization rate is statistically significant and is not zero. Higher T-values indicate higher confidence levels.

Sample Design and Impact Evaluation Analysis of the 2007 Custom Program

July 20, 2008

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Sample Design and Impact Evaluation Analysis of the 2007 Custom Program

Introduction

This report provides estimates of the realization rates and statistical precision for the Custom measures installed in the year-2007 Energy Initiative and Design 2000*plus* programs.

Purpose of this Study

This study has the following purposes:

1. To document the sample designs used to select the projects that were used to calculate the new realization rates for Process and HVAC measures. The samples were drawn from various program years, 2005 and 2006 for Process, and 2005 for HVAC,
2. To provide a statistical analysis of the engineering studies of 2005 and 2006 Process installations carried out for the evaluation of the Process category of Custom measures installed in year 2007 in the Energy Initiative and Design 2000*plus* programs,
3. To provide a statistical analysis of the engineering studies of 2005 Custom HVAC installations carried out for the evaluation of the HVAC category of Custom measures installed in year 2007 in the Energy Initiative and Design 2000*plus* programs,
4. Provide revised statistical analysis of the 2002 Comprehensive Design Approach (CDA) to match revised methodology implemented for the 2007 analysis,
5. To assess the error ratios, i.e., the measures of variability, to be used in developing the sample designs for future studies, and
6. To draw together the results from the new Process and HVAC studies, revised CDA study, and the previously reported Lighting[1] and study to:

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[1] 2006 Lighting study methodology is consistent with the current methodology therefore no revisions to the Lighting study results are required

- Provide unbiased estimates of the collective realization rate of all projects in the program population,
- Summarize the overall savings, and
- Determine the statistical precision for all Custom measures installed in year 2007 in the Energy Initiative and Design 2000*plus* programs.

Scope

The scope of the analysis includes installations in the three New England states that National Grid offered electric efficiency measures in 2007: Massachusetts, Rhode Island and New Hampshire.

Methodology

For the last ten years or more, National Grid has used the model-assisted stratified ratio estimation methodology described in [1] and [2]. The key parameter of interest is the population realization rate, i.e., the ratio of the evaluated savings for all population projects divided by the tracking estimates of savings for all population projects. Of course, the population realization rate is unknown, but it can be estimated by evaluating the savings in a sample of projects. The sample realization rate is the ratio between the weighted sum of the evaluated savings for the sample projects divided by the weighted sum of the tracking estimates of savings for the same projects. The sample realization rate is equivalent to the usual stratified ratio estimator of the population realization rate. The total tracking savings in the population is multiplied by the sample realization rate to estimate the total evaluated savings in the population.

Sample Design

The sample designs guide the selection of the projects to be studied. This year's report differs from prior year's reports in that only the most recent Process and HVAC sample designs will be presented. The samples have been drawn from various program years, 2005 and 2006 for Process, and 2005 for HVAC.

Each of the sample designs was developed using the model-based methodology [1]. A statistical model was used to describe the relationship between the evaluated savings and tracking savings for all projects in the target population. The parameters of this model were combined with the information in the tracking system to develop an efficient sample design with the expected statistical precision that is desired. The key parameters of the model are the realization rate (defined above), the error ratio, and gamma. The error ratio is a measure of the project-to-project variation in the relationship between the evaluated savings and the tracking estimate of savings. The error ratio was used to choose the sample size and to estimate the expected statistical precision. Gamma describes how the residual standard deviation varies with the tracking estimate and was primarily used to stratify the population.

These parameters have been estimated as part of the analysis of many prior evaluation studies. Reference [3] provides an overview of the results found in earlier Custom studies carried out from 1994 through 1999. In these and other studies, we have found that the realization rate and error ratio vary from measure category to category and from one measure of savings to another. We have also found that the estimated value of gamma tends to vary randomly around 0.8. Therefore we currently use a simplified methodology to estimate the error ratio from sample data that assumes that the true value of gamma is 0.8.

We have also learned that it can be advantageous in recruiting and fieldwork to reduce the sampling fraction for the large projects. In particular, we have learned that reducing the set gamma moderately reduces the expected statistical precision very little but often yields more effective recruiting and field work. Therefore, it has become our standard practice to construct the sample designs with a set gamma of 0.5.

The sample designs used in the present studies reflect the values of tracking savings observed in the program-year population from which the measures were drawn, combined with the realization rates and error ratios found in the prior studies. This information was used to choose the new sample sizes and to estimate the statistical precision to be expected from the new studies.

Analysis

When sample data are used to estimate the characteristics of a particular population, the accuracy of the results depends on the weights applied to each case in the sample. The case weight is defined to be the ratio between the number of projects in each stratum of the population divided by the number of projects in the corresponding stratum in the sample. As long as the sample projects are randomly selected from each stratum, the sample realization rate is a virtually unbiased estimator of the population realization rate.[2]

In prior analyses, samples were post stratified to the current year population which weighted sites based on the distribution of sites within strata for the current year. In the 2007 analysis, for the first time, the population that the sample was drawn from and the current year population were significantly different. The current year population did not contain any sites in the largest stratum of the original sample design. During the review of prior year data as well as future tracking data that is being compiled, it became clear that this variation in savings wasn't due to some fundamental shift in the magnitude of savings at sites, but was simply a result of what sites enrolled in the program within a given year. Using the current year post-stratification technique from prior analyses, all sites in the largest stratum would be given a case weight of 0, meaning that they represented no sites within the current population. Model-based stratification selects proportionately more sites within the largest savings stratum because sites with large savings have the largest amount of uncertainty associated with them. If populations vary year to year such that sample designed stratum cut points are not plausible for future year analysis populations, then it becomes desirable to extrapolate the sample back to the population from which it was originally drawn and then apply the realization rate to the current year population. Extrapolating back to the population from which it was drawn

[2] Technically the ratio estimator is biased but in practice the bias is negligible with a properly stratified sample design.

allows use of all sites in the analysis. For the Process category where two years of samples were analyzed together, a simple average of measured savings of the two years was used to come up with an overall estimate of savings, an example of which is given after the Process PY2006 results section.

The Sample

The results presented in the main sections of this report are based on the new definitions of peak periods used in both this year's and last year's reports for Custom Process. For Custom Lighting the results are presented for this new definition as well as a definition being proposed for the ISO New England Forward Capacity Market (FCM). The results for the old definition of peak for Custom Process and the FCM definition are provided in a separate section after the main results[3]. Table 1 summarizes the number of sample projects used to develop the Program Year ("PY") 2007 savings estimates. The Custom HVAC study sites were all installed in program year 2005 while the Process sites were a combination of program year 2005 and 2006 install years. Detailed methodologies of sample selection for both categories are listed below.

Table 1: Sample Sizes

Category	*New Study*	*Install Year*	*Sample Size*
HVAC	Yes	PY2005	15
Lighting	No	PY2006	10
Process	Yes	PY2006	15
Process	No	PY2005	15
CDA	No	PY2002	3
Total			68

[3] From the sample data files, the following variables were assigned to the other and new peak definitions:

***HVACPY05**: labeled as 'New', considered 'New Peak'; labeled as 'Old', included in 'Other Peak' section*

***ProcessPY06**: labeled as 'New', considered 'New Peak'; labeled as 'FCM', included in 'Other Peak' section*

***ProcessPY05**: labeled as 'New', considered 'New Peak'; labeled as 'Old', included in 'Other Peak' section*

Sample Designs

This section summarizes the sample designs used to select the Process and HVAC projects analyzed in this report. The Process sample design for PY2005 was documented in [4], while PY2006 for Process and the PY2005 HVAC sample design are documented in this report. Those reports as well as [1] provide more details about the methodology used to develop the sample designs described in the present report.

Table 2 summarizes the PY2005 Process sample design. The PY2005 Process tracking data were stratified by gross annual MWh savings into five strata as shown in the table. For example, stratum one consisted of all projects with tracking annual savings of 45 MWh or less. There were 44 projects in stratum one in the PY2005 population, with a total tracking annual savings of 1,045 MWh. Three projects were randomly selected from these 44 projects.

Table 2: PY2005 Process Sample Design

Stratum	Max Annual MWh	Projects in PY2005 Population	Total Annual MWh	Projects in Sample
1	45	44	1,045	3
2	80	27	1,760	3
3	155	20	2,208	3
4	272	14	3,257	3
5	2,732	7	7,399	3

Table 3 summarizes the PY2006 Process sample design. The PY2006 Process tracking data were stratified by gross annual MWh savings into five strata as shown in the table. For example, stratum one consisted of all projects with tracking annual savings of 64 MWh or less. There were 82 projects in stratum one in the PY2006 population, with a total tracking annual savings of 2,515 MWh. Three projects were randomly selected from these 82 projects.

Table 3: PY2006 Process Sample Design

Stratum	Max Annual MWh	Projects In PY2006 Population	Total Annual MWh	Projects In Sample
1	64	82	2,515	3
2	147	31	3,077	3
3	293	15	3,469	3
4	829	9	4,186	3
5	1,271	5	5,434	3

Taking the PY2005 and PY2006 samples together, a total of 30 Process sample projects were available for analysis.

Table 4 shows the assumptions that we used in the PY06 Process sample design. During the sample design process, it was assumed that the PY06 sample would be combined with the PY05 sample[4]. The table shows the number of projects and total savings from the PY05 tracking data, which differs from the data displayed for Process in the preceding section on PY06. The table also shows the realization rates and error ratios found in the PY06 evaluation of Process which analyzed projects from PY04 and PY05. These are the key parameters needed to plan new studies.

Table 4: PY06 Process Sample Design Assumptions

PY2006 Sample Design	*PROCESS*
Number of Projects	142
Planned Sample	15
Expected MWh	15,954
Expected Relative Precision	10.6%
Expected Error Bound	1,687
Gross Annual MWh	18,682
Realization Rate	0.85
Error Ratio	0.70

Table 5 summarizes the PY2005 HVAC sample design. The PY2005 HVAC tracking data were stratified by gross annual MWh savings into five strata as shown in the table. For example, stratum one consisted of all projects with tracking annual savings of 53

[4] During the planning stages it was assumed that there would be 15 sample sites in each of the two years, resulting in a total of 30 sample sites. The final sample for PY05 was 15 sites and for PY06 it was 15 sites.

MWh or less. There were 33 projects in stratum one in the PY2005 HVAC population, with a total tracking annual savings of 828 MWh. Three projects were randomly selected from these 33 projects.

Table 5: PY2005 HVAC Sample Design

Stratum	Max Annual MWh	Projects In PY2005 Population	Total Annual MWh	Projects In Sample
1	53	33	828	3
2	122	16	1,558	3
3	197	12	1,958	3
4	526	9	2,862	3
5	2,457	5	5,596	3

Table 6 shows the assumptions that we used in the sample design. The table shows the number of projects and total savings from the PY05 tracking data, as discussed in the preceding section. The table also shows the realization rates and error ratios found in recent evaluations of HVAC.

Table 6: HVAC Sample Design Assumptions

PY2005 Sample Design	*HVAC*
Number of Projects	75
Planned Sample	15
Expected MWh	12,507
Expected Relative Precision	18.2%
Expected Error Bound	2,281
Gross Annual MWh	12,802
Realization Rate	0.977
Error Ratio	0.480

Case Weights

As previously mentioned, the methodology for this year has been changed, and each of the samples were extrapolated back to the population from the year in which they were drawn. The stratum cut points that were used for the analysis were the same cut points created in the sample design. Weights were recalculated during the analysis to account for any changes to the sample due to replacing sample points with backup sites. The PY2005 and PY2006 samples were analyzed separately and extrapolated back to their respective population and ultimately the results were combined to come up with an overall realization rate and relative precision for each program. Documentation of the methodology for combining multiple year results can be found in the Appendix.

In the case of Process, we used the stratum boundaries from the original sample design for each year. The final case weights for the Process PY05 and PY06 categories are shown in the final column of Table 7 and Table 8.

Table 7: Process PY2005 Case Weights

Category	Stratum	Maximum Annual MWh	Projects in PY2005 Population	Total Annual MWh	Sample	Case Weight
Process	1	45	44	1,045	3	14.7
Process	2	80	27	1,760	3	9.0
Process	3	155	20	2,208	3	6.7
Process	4	272	14	3,257	3	4.7
Process	5	2,732	7	7,399	3	2.3

Table 8: Process PY2006 Case Weights

Category	Stratum	Max Annual MWh	Projects in PY2006 Population	Total Annual MWh	Project In Sample	Case Weight
Process	1	64	82	2,515	3	27.3
Process	2	147	31	3,077	3	10.3
Process	3	293	15	3,469	3	5.0
Process	4	829	9	4,186	3	3.0
Process	5	1,271	5	5,434	3	1.7

HVAC also used the stratum boundaries from the original sample design. The final case weights for HVAC are shown in the final column in Table 9.

Table 9: HVAC PY2005 Case Weights

Category	Stratum	Max Annual MWh	Projects in PY2005 Population	Total Annual MWh	Project In Sample	Case Weight
HVAC	1	53	33	828	3	11.0
HVAC	2	122	16	1,558	3	5.3
HVAC	3	197	12	1,958	3	4.0
HVAC	4	526	9	2,862	3	3.0
HVAC	5	2,457	5	5,596	3	1.7

Process PY2005 Results

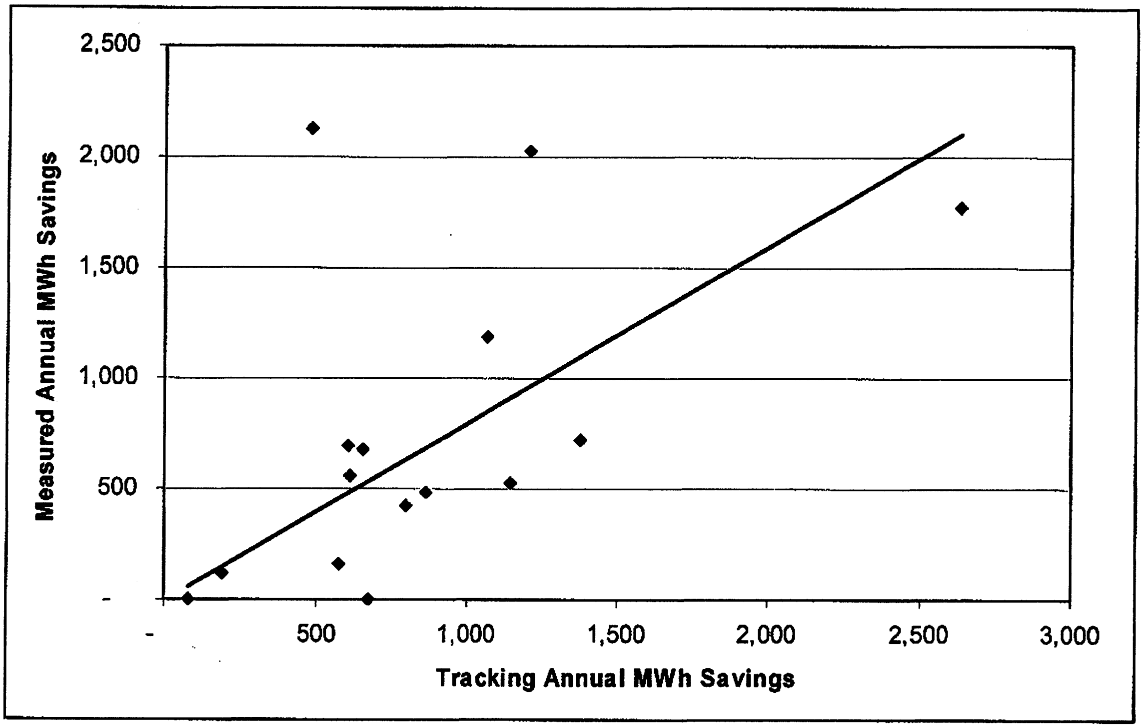
This section summarizes the primary results found from the analysis of the Process sample. Table 10 summarizes the results of the stratified ratio analysis of the Process sample. The table shows the results for each of the four measures of savings. In the case of Annual MWh savings, the realization rate for Process measures was found to be 88.2%. The relative precision was found to be ± 25.9% at the 80% level of confidence. The error ratio was found to be 0.83. Table 10 also shows the results for the on-peak savings, measured in MWh. The on-peak MWh savings is the percent on-peak times the annual MWh savings. Our analysis gave a realization rate of 110% for the on-peak MWh savings, meaning that the measured on-peak savings was about 110% of the tracking on-peak savings. Considering all projects taken together and using the percent on-peak found in the tracking system, 41% of the savings were on peak. The evaluation results indicate that 51% of all savings were on peak. The ratio between these two results is the realization rate for the percent on-peak savings, 124%.

Table 10: Summary of PY2005 Process Results

Statistic	Annual MWh	On-Peak MWh	Summer kW	Winter kW	Percent On-Peak
Total Tracking Savings	15,669	6,455	2,109	2,153	41.2%
Realization Rate	88.2%	109.7%	100.8%	85.9%	124.3%
Relative precision	25.9%	28.4%	26.5%	28.4%	
Total Measured Savings	13,828	7,080	2,125	1,848	51.2%
Error bound for Measured Savings	3,577	2,013	563	524	
Error ratio	0.83	0.90	0.91	0.90	

Figure 1 shows the sample data underlying the realization rate for the annual savings in the Process category. The figure has been obtained by multiplying both the tracking and measured savings of each sample project by the case weight associated with the project and then creating a scatter plot of the results. We have also plotted the line through the origin with slope equal to the realization rate estimated from the sample projects. If each of the sample projects had the same realization rate, then all of the points would lie along this line.

Figure 1: Custom Process PY2005 Measured vs. Tracking Weighted Annual Savings



Process PY2006 Results

This section summarizes the primary results found from the analysis of the Process sample. Table 11 summarizes the results of the stratified ratio analysis of the Process sample. The table shows the results for each of the four measures of savings. In the case of Annual MWh savings, the realization rate for Process measures was found to be 87%. The relative precision was found to be ± 21.9% at the 80% level of confidence. The error ratio was found to be 0.66. Table 11 also shows the results for the on-peak savings, measured in MWh. The on-peak MWh savings is the percent on-peak times the annual MWh savings. Our analysis gave a realization rate of 126% for the on-peak MWh savings, meaning that the measured on-peak savings was about 126% of the tracking on-peak savings. Considering all projects taken together and using the percent on-peak found in the tracking system, 41% of the savings were on peak. The evaluation results indicate that 60% of all savings were on peak. The ratio between these two results is the realization rate for the percent on-peak savings, 145%.

Table 11: Summary of PY2006Process Results

Statistic	Annual MWh	On-Peak MWh	Summer kW	Winter kW	Percent On-Peak
Total Tracking Savings	18,682	7,674	2,242	2,306	41.1%
Realization Rate	87.1%	126.2%	119.2%	91.4%	144.8%
Relative precision	21.9%	21.6%	32.4%	40.0%	
Total Measured Savings	16,276	9,683	2,673	2,108	59.5%
Error bound for Measured Savings	3,563	2,090	865	842	
Error ratio	0.66	0.65	0.97	1.17	

Figure 2 shows the sample data underlying the realization rate for the annual savings in the Process category. The figure has been obtained by multiplying both the tracking and measured savings of each sample project by the case weight associated with the project and then creating a scatter plot of the results. We have also plotted the line through the origin with slope equal to the realization rate estimated from the sample projects. If each of the sample projects had the same realization rate, then all of the points would lie along this line.

Figure 2: Custom Process PY2006 Measured vs. Tracking Weighted Annual Savings

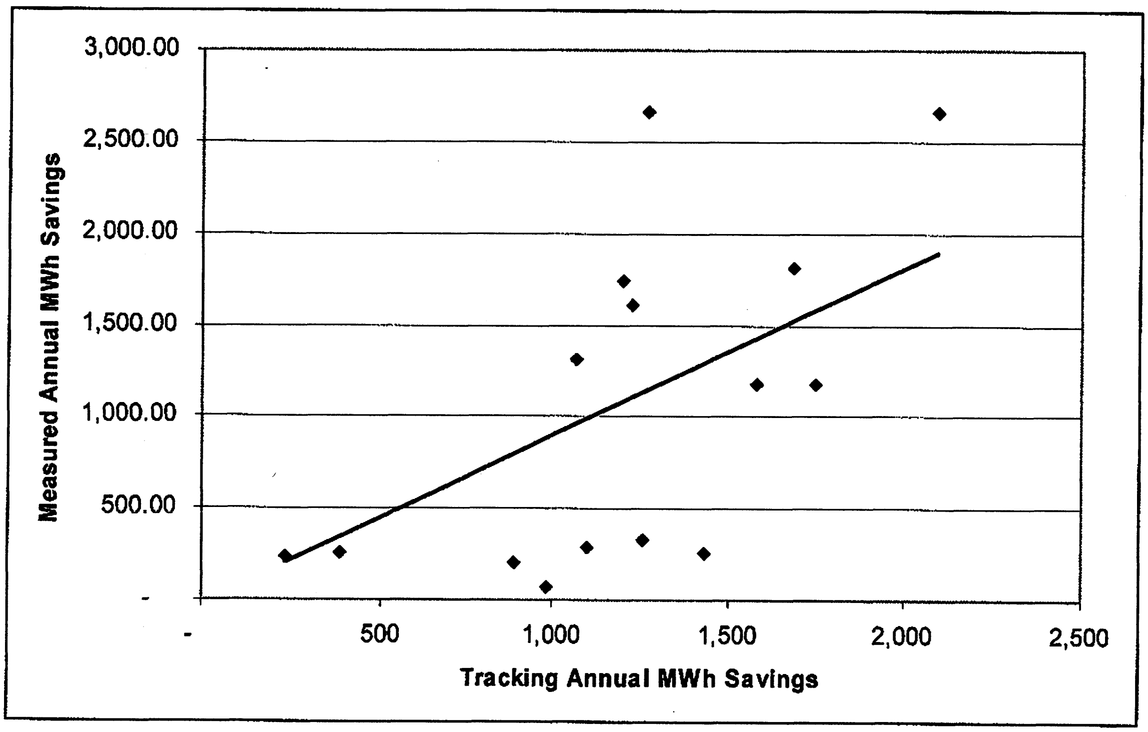


Table 12 shows the realization rates for the Process category for PY2005 and PY2006. The overall realization rate was calculated as the simple average of the realization rate from each program year.

Table 12: Averaged Process Realization Rate

	Annual kWh	On-Peak kWh	Summer kW	Winter kW	Percent On-Peak
Process05 RR	88.2%	109.7%	100.8%	85.9%	124.3%
Process06 RR	87.1%	126.2%	119.2%	91.4%	144.8%
Combined	87.7%	117.9%	110.0%	88.7%	134.6%

HVAC Results

This section summarizes the primary results found from the analysis of the HVAC sample. Table 13 summarizes the results of the stratified ratio analysis of the HVAC sample. The table shows the results for each of the four measures of savings. In the case of Annual MWh savings, the realization rate for HVAC measures was found to be 75.7%. The relative precision was found to be ± 17.7% at the 80% level of confidence. The error ratio was found to be 0.48.

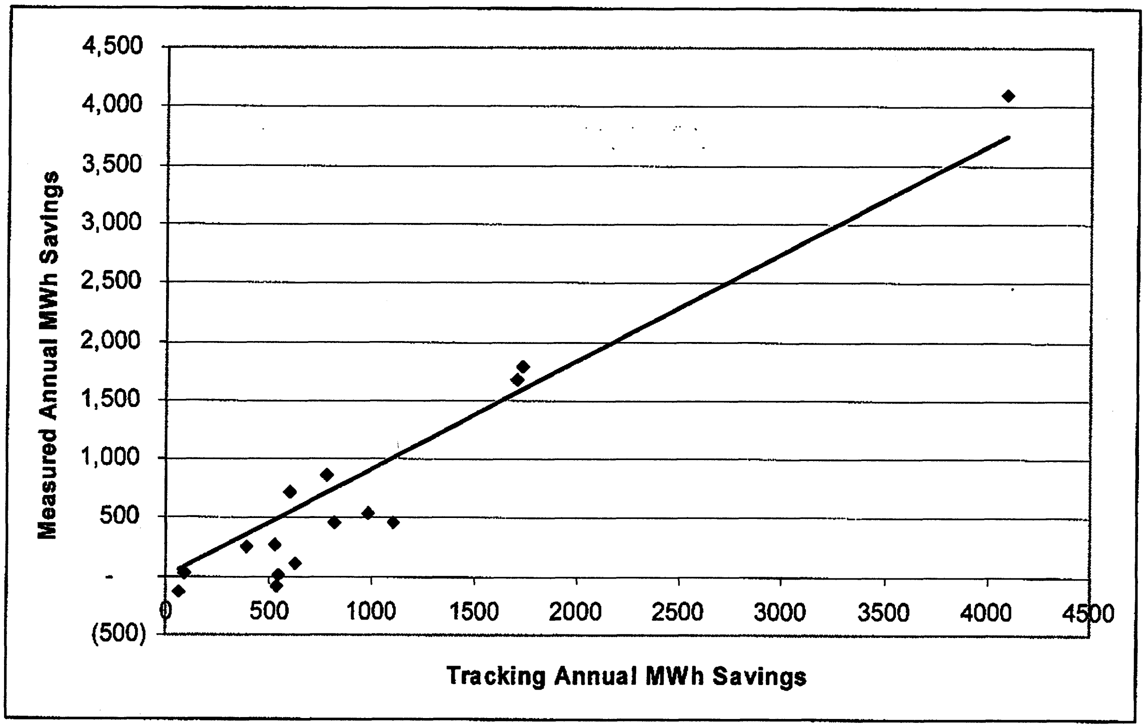
Table 13 also shows the results for the on-peak savings, measured in MWh. The on-peak MWh savings is the percent on-peak times the annual MWh savings. Our analysis gave a realization rate of 115.6% for the on-peak MWh savings, meaning that the measured on-peak savings was about 116% of the tracking on-peak savings. Considering all projects taken together and using the percent on-peak found in the tracking system, 35% of the savings were on peak. The evaluation results indicate that 54% of all savings were on peak. The ratio between these two results is the realization rate for the percent on-peak savings, 153%.

Table 13: Summary of HVAC Results

Statistic	Annual MWh	On-Peak MWh	Summer kW	Winter kW	Percent On-Peak
Total Tracking Savings	12,802	4,488	1,889	1,311	35.1%
Realization Rate	75.7%	115.6%	70.0%	106.1%	152.7%
Relative precision	17.7%	33.7%	36.3%	25.5%	
Total Measured Savings	9,687	5,186	1,323	1,392	53.5%
Error bound for Measured Savings	1,716	1,747	481	355	
Error ratio	0.48	0.78	1.22	0.81	

Figure 3 shows the sample data underlying the realization rate for the annual savings in the HVAC category. The figure has been obtained by multiplying both the tracking and measured savings of each sample project by the case weight associated with the project and then creating a scatter plot of the results. We have also plotted the line through the origin with slope equal to the realization rate estimated from the sample projects. If each of the sample projects had the same realization rate, then all of the points would lie along this line.

Figure 3: Custom HVAC Measured vs. Tracking Weighted Annual Savings



Application to the 2007 Population

Table 13 summarizes the PY2007 tracking information used in the analysis. The table shows the gross first-year annual and on-peak energy savings in MWh, and the gross summer and winter demand savings in kW. The Process category had more projects, 138, and more savings, while HVAC had 56 projects and less savings.

Table 14: Tracking Statistics

	Annual MWh	On-Peak MWh	Summer kW	Winter kW	Percent On-Peak
HVAC	7,899	3,644	2,060	416	46.1%
Lighting	3,854	2,188	665	758	56.8%
Process	21,578	9,806	2,923	2,959	45.4%
CDA	5,904	2,566	1,755	476	43.5%
Total	39,235	18,205	7,403	4,608	46.4%

Combined Results

This section combines the new results for the Process and HVAC categories with the results from previous Lighting study and recalculated results of the CDA study in order to obtain results for all Custom Program measure categories taken together.

Table 15 summarizes the estimated realization rates obtained from the statistical analysis. The first four rows of the table show the estimated realization rates for the four measure categories. The final row shows the overall realization rate for the four measure categories taken together. Considering Annual MWh savings as an example, we estimated the realization rate to be 76% for HVAC and 88% for Process. Combining the new results from these two categories with the previous results for Lighting and CDA, we estimated an overall realization rate of 91% for the annual savings of all 2007 projects in the four categories. This indicates that the annual savings would be found to be about 9% smaller than the gross savings from the tracking system if all 2007 projects were to be evaluated.

Table 15: Realization Rates

Category	Annual MWh	On-Peak MWh	Summer kW	Winter kW	Percent On-Peak
HVAC	75.7%	115.6%	70.0%	106.1%	152.7%
Lighting	117.2%	126.8%	109.7%	113.6%	108.1%
Process	87.7%	117.9%	110.0%	88.7%	105.9%
CDA	104.2%	87.2%	103.4%	105.5%	83.6%
Total	90.7%	114.2%	97.3%	96.1%	126.0%

The first four columns of Table 15 show the realization rates for each type of savings: Annual MWh, On-peak MWh, Summer kW, and Winter kW. These results are the ratio between the case-weighted sum of the evaluated savings divided by the case-weighted sum of the tracking savings, summed across all projects in the sample. If the realization rate is greater than one, the total evaluated savings estimated in the population is greater than the total tracking savings for the corresponding category. This occurred, for example, with the annual energy savings for Lighting measures, where the realization rate was about 118%.

The last column of Table 15 shows the realization rates for the percent on-peak energy savings. This is the realization rate for the estimate of the percent on-peak energy savings found in the tracking system for each measure category. The same results for on-peak energy savings can be obtained in either of two ways:

1. Multiply the annual kWh savings found in the tracking system by the percent on-peak found in the tracking system, and multiply the results by the on-peak energy realization rate, or
2. Multiply the percent on-peak found in the tracking system by the percent on-peak realization rate to get an adjusted percent on-peak. Then multiply the annual savings found in the tracking system by the annual energy realization rate, and multiply this adjusted annual energy savings by the adjusted percent on-peak.

Table 16 reports the relative precision obtained for each measure of impact for each category and over all measures taken together. The results are calculated at the 80% level of confidence. The overall relative precision for annual savings was ±9.7% at the 80% level of confidence. The overall relative precision for the on-peak energy impacts and the summer and winter demand impacts was in the range ±10.3% to ± 15.0% at the 80% level of confidence.

Table 16: Relative Precision at 80% Level of Confidence

Category	Annual MWh	On-Peak MWh	Summer kW	Winter kW
HVAC	17.7%	33.7%	36.3%	25.5%
Lighting	12.2%	15.3%	20.5%	33.7%
Process	17.0%	17.6%	21.3%	24.8%
CDA	12.0%	22.4%	9.1%	9.6%
Total	9.7%	12.3%	10.3%	15.0%

Usually, the relative precision is better for the total impact than for individual categories. This is because the error of estimation is independent from one category to another. Therefore when the results are pooled across categories, underestimates in some categories will tend to be offset by overestimates in other categories.

Table 17 shows the estimated measured savings for PY2007. The savings estimates for the 2007 population were calculated by multiplying the realization for each program category by the 2007 tracking estimates of savings.

Table 17: 2007 Estimated Measured Savings

Category	Annual MWh	On-Peak MWh	Summer kW	Winter kW	Percent On-Peak
HVAC	5,977	4,211	1,443	441	70.5%
Lighting	4,518	2,774	730	860	61.4%
Process	18,921	11,564	3,216	2,623	61.1%
CDA	6,153	2,237	1,815	502	36.4%
Total	35,569	20,787	7,203	4,427	58.4%

Table 18 show the error bounds associated with the total measured savings. These results are equal to the square root of the sum of the squared error bounds of all categories. For example, for the total Annual MWh savings of all categories, the error bound is 3,449 MWh and the 80% confidence interval for the total Annual MWh savings is 35,569 ± 3,449 MWh. The overall error bound is calculated by taking the square root of the sum of the squared error bounds. The overall relative precision shown in Table 16 can be obtained from these results. For example, the relative precision for the total Annual MWh savings is 3,449 / 35,569 = 9.7%.

Table 18: Error Bounds at 80% Level of Confidence

Category	*Annual MWh*	*On-Peak MWh*	*Summer kW*	*Winter kW*
HVAC	1,716	1,747	480.6	355.2
Lighting	548	428	142	215
Process	2,553	1,471	511.8	489.9
CDA	1,462	1,091	192	166
Total	3,449	2,567	742	663

The information developed in the present study can be used to help plan future studies of the Custom program. Some important insights can be drawn from Table 18. The measure categories with the largest error bounds, e.g., Process in the case of Annual MWh savings, contribute the greatest uncertainty to the overall program impact. This suggests that added attention should be given to these categories.

To quantify the expected statistical precision of a new study and to choose new sample sizes, it is necessary to estimate the variability in the population. For stratified ratio estimation the appropriate measure of variability is a population parameter called the error ratio. In the context of impact evaluation, the error ratio is a measure of the variability between the evaluated savings and the tracking estimate of savings adjusted for the realization rate of the category. The error ratio is a statistical measure of the variability in the entire population, but it is reflected in the sample scatter plot shown in Figure 1 for Process. If the error ratio is close to zero then the points are expected to lie close to the line. It the error ratio is larger, then the points are expected to be more widely scattered around the line.

The error ratio can be regarded as a measure of the quality of the tracking estimates for the population of individual projects. Error ratios less than 0.5 are desirable. An error ratio of 0.5 would indicate that for the majority of projects the evaluated savings are within ± 50% of the savings recorded in the tracking system after adjustment for the realization rate. When the error ratio is greater than one, it indicates that the measured savings are poorly related to the tracking estimates of savings. In such instances, it may be productive to seek improvements in the procedures for determining the tracking savings.

Although the true error ratios are always unknown, the error ratios can be estimated from the sample data. Error ratios were estimated for the Process category based on the PY05 and PY06 sample data, for the HVAC category based on the PY05 data, and for the CDA category based on the PY02 sample data. The Lighting error ratios are from the PY06 report [4]. Table 19 shows the results.

Table 19: Estimated Error Ratios

Category	*Annual MWh*	*On-Peak MWh*	*Summer kW*	*Winter kW*
HVAC	0.48	0.78	1.22	0.81
Lighting	0.31	0.41	0.58	0.83
Process05	0.83	0.90	0.91	0.90
Process06	0.66	0.65	0.97	1.17
CDA	0.16	0.30	0.12	0.13

The estimates of Process savings are not as accurate as estimates of savings for Custom Lighting and CDA projects. Process has more sampled sites due to the higher error ratio and the large amount of savings associated with this measure category.

For Lighting, the error ratios are generally 0.5 or smaller for energy. This indicates that in the Lighting category, the tracking estimates of energy savings provide fairly accurate estimates of the evaluated energy savings for the majority of Custom projects after adjustment for the realization rates. The Lighting error ratios for demand savings are higher.

Process Comparison with Prior Studies

This section compares the new Process results with the results from the preceding study.[5] Table 20 summarizes the results for the realization rates. The realization rates are a measure of the bias of the tracking estimates. For example, a realization rate less than 100% indicates that the tracking estimates tend to overstate savings across the projects in the category. Ideally, the realization rate should be close to 100%.

The realization rates found in the present Process study are similar to those found in most of the prior studies of this category with the exception of last year. These results continue to reverse the low values found in the PY2002-03 study.

Table 20: Custom Process New and Prior Realization Rates

Study	*Installed Year*	*Sample Projects*	*Annual MWh*	*On-Peak MWh*	*Summer kW*	*Winter kW*
New	PY2005-06	30	87.7%	117.9%	110.0%	88.7%
Prior	PY2004-05	34	108.5%	140.9%	109.7%	100.7%
Prior	PY2003-04	39	85.4%	80.6%	85.8%	72.1%
Prior	PY2002-03	40	68.1%	60.2%	68.1%	62.4%
Prior	PY2001-02	41	85.0%	85.2%	86.0%	75.9%
Prior	PY2000-01	41	87.8%	85.3%	81.2%	75.0%

Table 21 compares the error ratios found in the current and prior Process studies. With the new methodology of extrapolating each year of Process findings to the population from which it was drawn, an overall error ratio cannot be calculated. An error ratio for each analysis has been listed below. The error ratio for PY2006 falls in line with the PY2004-05 results with the exception of winter kW which experienced a substantial increase.

[5] These results are listed for illustration purposes only. The 2007 analysis is the first year implementing a new methodology so results are not directly comparable to prior year analyses. In this years analysis the sample data for each program year were expanded back to the population year from which they were drawn. In previous years analysis the sample data for each program year was expanded to the population of the current year to be evaluated.

Table 21: Custom Process New and Prior Error Ratios

Study	*Installed Year*	*Sample Projects*	*Annual MWh*	*On-Peak MWh*	*Summer kW*	*Winter kW*
New	PY2006	15	0.66	0.65	0.97	1.17
New	PY2005	15	0.83	0.90	0.91	0.90
Prior	PY2004-05	34	0.69	0.72	0.83	0.84
Prior	PY2003-04	39	0.70	0.85	1.16	1.26
Prior	PY2002-03	40	0.66	0.72	0.83	1.15
Prior	PY2001-02	41	0.62	0.75	0.63	0.90
Prior	PY2000-01	41	0.54	0.74	0.71	1.27

HVAC Comparison with Prior Studies

This section compares the new HVAC results with the results from the preceding HVAC study.[6] Table 22 summarizes the results for the realization rates. The realization rates are a measure of the bias of the tracking estimates. For example, a realization rate less than 100% indicates that the tracking estimates tend to overstate savings across the projects in the category. Ideally, the realization rate should be close to 100%.

The realization rates found in the present HVAC study are lower than those found in the prior studies, with the exception of On-peak MWh. Originally plans were made to combine PY2005 and PY2006 HVAC in the same way that Process is combined. The PY2006 HVAC sites were not completed in time to be included in this analysis.

[6] These results are listed for illustration purposes only. The 2007 analysis is the first year implementing a new methodology so results are not directly comparable to prior year analyses. In this years analysis the sample data for each program year were expanded back to the population year from which they were drawn.

Table 22: Custom HVAC New and Prior Realization Rates

Category	*Study*	*Installed Year*	*Sample Projects*	*Annual MWh*	*On-peak MWh*	*Summer kW*	*Winter kW*
HVAC	New	PY2005	15	75.7%	115.6%	70%	106.1%
HVAC	Prior	PY2003	10	97.7%	83.1%	106.4%	124.7%
HVAC	Prior	PY2001	10	94.9%	105.0%	72.7%	68.1%
HVAC	Prior	PY1999	15	94.0%	86.2%	85.0%	141.6%

Table 23 compares the error ratios found in the current and prior HVAC studies. In the HVAC category, the error ratios for Annual MWh are similar to past years with the exception of PY2003 in which there was an outlier that substantially impacted the error ratio.

Table 23: Custom HVAC New and Prior Error Ratios

Category	*Study*	*Installed Year*	*Sample Projects*	*Annual MWh*	*On-peak MWh*	*Summer kW*	*Winter kW*
HVAC	New	PY2005	15	0.48	0.78	1.22	0.81
HVAC	Prior	PY2003	10	1.12	0.99	0.82	1.14
HVAC	Prior	PY2001	10	0.48	0.46	0.90	0.87
HVAC	Prior	PY1999	15	0.40	0.54	0.72	0.66

Other Peak Definitions

This section presents the results for the Process and HVAC peak summer and winter kW using 'Other Peak' definitions. From the sample data files, the following variables were assigned to the other and new peak definitions:

HVAC:

labeled as 'New', considered 'New Peak';

labeled as 'Old, included in 'Other Peak' section

Process PY05:

labeled as 'New', considered 'New Peak';

labeled as 'Old, included in 'Other Peak' section

Process PY06:

labeled as 'New', considered 'New Peak';

labeled as 'FCM, included in 'Other Peak' section

Table 24 through Table 27 present the realization rates, relative precision, measured savings, and the error bounds for the summer and winter kW estimates. Realization rates, relative precisions, and measured savings of the "other" definitions are calculated using methodology that is consistent with those explained in the previous section.

Table 24: Realization Rates

Category	Other Summer kW	Other Winter kW
HVAC	52.2%	101.1%
Process	105.9%	92.2%

Table 25: Relative Precision

Category	Other Summer kW	Other Winter kW
HVAC	45.0%	26.5%
Process	21.2%	23.4%

Table 26: PY2007 Estimated Measured Savings

Category	Other Summer kW	Other Winter kW
HVAC	1,076	420
Process	3,095	2,730

Table 27: Error Bounds

Category	Other Summer kW	Other Winter kW
HVAC	444	351
Process	488	483

Conclusions and Recommendations

The following conclusions and recommendations are offered:

- A new methodology of extrapolating samples back to the population from which they were drawn has been adapted for all categories.
- Realization rates have been estimated for the Process category by combining a new sample of PY2006 projects with a prior sample of PY2005 projects as done in the PY04-05 analysis. However, following the revised methodology, the sample for each year of Process was extrapolated back to the population from which it was drawn and then combined together to come up with an overall realization rate. These results are believed to provide the best available estimates of the realization rates of this measure category.
- CDA results were recalculated to conform with revised methodology
- The Company should continue to strive to improve the accuracy of the tracking estimates of savings, especially in the Process and HVAC categories.

Using the Results in the Savings Calculations

The realization rates developed in this study will be applied to calculate post-evaluation energy and demand savings for the 2007 program year.

References

[1] *The California Evaluation Framework*, prepared for Southern California Edison Company and the California Public Utility Commission, by the TecMarket Works Framework Team, June 2005, Chapters 12-13.

[2] *Model Assisted Survey Sampling,* C. E. Sarndal, B. Swensson, and J. Wretman, Springer, 1992.

[3] *Meta-Analysis of the Custom Evaluation Studies: 1994-1999,* Prepared for National Grid by RLW Analytics, February 12, 2001.

[4] *Sample Design and Impact Evaluation Analysis of the 2006 Custom Program,* Final Report, Prepared for National Grid by RLW Analytics, July 20, 2007.

Appendix

Combining Process Results Methodology

The following explains the methodology used to combine the results of two independent studies of a program in two program years, in this case, the combining of two years of studies for the Custom Process category.

Let R_1 and R_2 be the true realization rates of the program in the two program years. We want to estimate the average realization rate $w_1 R_1 + w_2 R_2$. As a matter of policy, we have agreed that $w_1 = w_2 = .5$ but the following method is applicable for any given weights. Let $\hat{R}_1$ and $\hat{R}_2$ be statistically independent, unbiased estimators of the true realization rates of the program in the two program years and let eb_1 and eb_2 be the error bounds of the two estimators, calculated at the chosen level of confidence using the same z coefficient for both years. Typically, $\hat{R}_1$, $\hat{R}_2$, eb_1 and eb_2 will be calculated using stratified ratio analysis of two statistically independent samples, one drawn from each year.

Then an unbiased estimator of the average realization rate is $w_1 \hat{R}_1 + w_2 \hat{R}_2$. The error bound of this estimator is $\sqrt{(w_1\, eb_1)^2 + (w_2\, eb_2)^2}$. The *rp* is
$\sqrt{(w_1\, eb_1)^2 + (w_2\, eb_2)^2} \Big/ \left(w_1 \hat{R}_1 + w_2 \hat{R}_2\right)$.

When each individual study is analyzed, our standard practice is to estimate the error ratio measuring the variability between measured savings and tracking savings. Let these error ratios be denoted er_1 and er_2. These error ratios are of interest because they can be used to choose future sample sizes or to estimate the expected relative precision for a future study with a given sample size. Let rp_1 and rp_2 be the expected relative precisions of two future studies to be combined as described above. Then the expected *rp* of the average realization rate would be $\sqrt{(w_1 R_1\, rp_1)^2 + (w_2 R_2\, rp_2)^2} \Big/ \left(w_1 \hat{R}_1 + w_2 \hat{R}_2\right)$. If we assume that $w_1 = w_2 = .5$ and $R_1 = R_2$ then the expected *rp* of the average realization rate is $0.5\sqrt{(rp_1)^2 + (rp_2)^2}$. If rp_1 and rp_2 are equal and their common value is denoted *rp* then the combined relative precision is $rp/\sqrt{2}$. If you let rp_c denote the desired value of the combined relative precision, you can choose the sample sizes for each individual study so that the expected relative precision of each individual study is equal to $\sqrt{2}\,rp_c$.

MULTIPLE SMALL BUSINESS SERVICES PROGRAMS

IMPACT EVALUATION

2007

Submitted To:

Cape Light Compact

National Grid

NSTAR

Unitil

Western Massachusetts Electric Company

SUMMIT BLUE
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FINAL REPORT

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TABLE OF CONTENTS

1 EXECUTIVE SUMMARY

The five sponsoring organizations of this study, the Cape Light Compact, National Grid, NSTAR, Unitil (Fitchburg Gas and Electric Light Company d/b/a Unitil), and Western Massachusetts Electric Company (WMECO), have offered Small Business Services (SBS) programs throughout Massachusetts to small business energy consumers for several years. A large share of the electric energy savings from the SBS program comes from prescriptive lighting measures.

Impact evaluations have been conducted in previous years to obtain estimates of realization rates for the gross energy savings resulting from the prescriptive lighting measures that are part of the SBS program. These realization rates reflect a comparison of estimated savings from the program tracking systems to actual customer billing data to verify the gross energy savings that were achieved. The purpose of this study is to estimate similar realization rates for 2007 program participants for each individual participating sponsor.

The statistical model that was developed to estimate the savings from the lighting measures installed through SBS was framed within the Statistically Adjusted Engineering (SAE) approach. Under this approach, the engineering estimate of savings is included as an explanatory variable in a regression equation with the billed electricity consumption as the dependent variable. The estimated coefficient on the engineering estimate of savings may be interpreted as the realization rate. That is, the coefficient indicates the percentage of the engineering estimate of energy savings that is realized on average according to the analysis of billing records.

Table 1-1 presents the results of this statistical modeling effort for each sponsor.

Table 1-1. Summary of Lighting Savings Realization Rates by Sponsor[1]

	Realization Rate	T-value[2]	Statistically Significant at the 90% Confidence Level?
Cape Light Compact	1.04	8.58	Yes
National Grid	1.00	22.38	Yes
NSTAR	0.89	23.37	Yes
Unitil	1.02	12.39	Yes
Western Massachusetts Electric			

The realization rates varied from a low of 0.89 to a high of 1.04 with most of them near the value of one. This indicates there is a good correspondence between initial estimates of gross energy savings and

[1] This table will be completed after data is received from WMECO.

[2] The T-value is equal to the estimated realization rate divided by its standard error. It can be used directly to test the hypothesis that the realization rate is equal to zero. A T-value of 1.645 indicates there is 90% confidence that the realization rate is statistically significant and is not zero. Higher T-values indicate higher confidence levels.

verified gross energy savings for prescriptive lighting measures in the SBS program. All of the realization rates are statistically significant at the 90% confidence level.

Table 1-2 shows the precision rates that were achieved for each sponsor. The estimates for National Grid and NSTAR have a precision rate of plus or minus 7%. Sponsors with smaller numbers of customers had precision levels in the 10% to 20% range at the 90% confidence level. This wider precision range reflects the lower certainty of the coefficient estimates given similar variability and fewer observations.

Table 1-2. Confidence Intervals and Precision Levels for Realization Rates[3]

Sponsor	Expected Value of Realization Rate	Precision at the 90% Confidence Level	Lower Bound of Realization Rate at 90% Confidence Level	Upper Bound of Realization Rate at 90% Confidence Level
Cape Light Compact	1.04	± 19%	0.84	1.25
National Grid	1.00	± 7%	0.92	1.07
NSTAR	0.89	± 7%	0.82	0.95
Unitil	1.02	± 13%	0.88	1.16
WMECO		±		

The realization rates from this study should be applied to gross energy savings estimates from engineering calculations or deemed savings to create verified gross energy savings estimates. Additional estimates of free-ridership and/or spillover effects would need to come from other studies and be applied to the verified gross energy savings to estimate net energy savings. The development of net energy savings estimates is beyond the scope of this study.

[3] All results shown in this table are calculated using realization rates and T-values with six decimal points. After the calculations, the results are rounded to two decimal points for reporting purposes. This rounding method was used for all similar tables in this report.

Appendix F

APPENDIX F

Other Screening Metrics

National Grid - Residential
Total Suite of Electric Energy Efficiency Programs

	cents per kWh
2009 Forecasted Price (Full Service Customers):	16.21
2009 Forecasted SBC Charge	0.16
2009 Forecasted RPS Charge	0.09
2009 Forecasted Price Excl. SBC & RPS:	15.96

	Projected 2009	Projected 2010	Projected 2011	Projected 2012	Projected 2013	Projected 2014	Projected 2015
Projected Delivery Price Without Environmental Programs:[1]	7.67	7.84	8.00	8.17	8.34	8.52	8.69
Projected Commodity Price Without Environmental Programs:[2]	8.28	9.73	10.20	10.73	11.33	12.01	12.80
Projected Avg. Price without Environmental Programs (cents per kWh):	15.96	17.57	18.20	18.90	19.67	20.53	21.49

Impacts of Environmental Programs (cents per kWh)

	2009	2010	2011	2012	2013	2014	2015
Projected SBC Cost:	0.16	0.16	0.08	0.00	0.00	0.00	0.00
Projected SBC Reallocation Cost:	0.00	0.00	0.08	0.17	0.17	0.17	0.17
Projected RPS Cost:	0.09	0.11	0.13	0.15	0.18	0.18	0.18
Projected EEPS Cost:	0.19	0.19	0.19	0.00	0.00	0.00	0.00
Proposed EE Program Cost	0.097	0.139	0.157	0.158	0.159	0.160	0.160
Projected RGGI Cost:	0.05	0.05	0.06	0.07	0.08	0.09	0.10
Projected Lost Delivery Revenue Cost:	0.07	0.25	0.46	0.64	0.79	0.94	1.08
Projected Delivery Price with Environmental Programs:	8.27	8.68	9.11	9.28	9.64	9.96	10.29
Projected Commodity Price with Environmental Programs:	8.33	9.62	10.02	10.47	11.00	11.61	12.32
Projected Avg. Price with Environmental Programs:	16.61	18.31	19.13	19.75	20.63	21.57	22.61
Proposed EE Program Cost -	$ 26,975,173	$ 38,002,204	$ 42,295,579	$ 42,295,579	$ 42,295,579	$ 42,295,579	$ 42,295,579
Lost Delivery Revenue associated with EE Program	$ 7,414,191	$ 9,707,729	$ 11,853,986	$ 12,102,920	$ 12,357,081	$ 12,616,580	$ 12,881,528
Total Costs associated with EE Program	$ 34,389,364	$ 47,709,933	$ 54,149,565	$ 54,398,499	$ 54,652,660	$ 54,912,159	$ 55,177,107
Total Projected Increase to bill (cents per kWh)	0.124	0.174	0.201	0.204	0.206	0.208	0.209
Levelized Increase to bill (cents per kWh)	0.189	0.189	0.189	0.189	0.189	0.189	0.189
Electric Rate Impact							
Increase in Delivery Rate	1.617%	2.226%	2.510%	2.494%	2.466%	2.438%	2.406%
Levelized Increase in Delivery Rate	2.311%	2.311%	2.311%	2.311%	2.311%	2.311%	2.311%
Increase in Overall Rate	0.778%	0.993%	1.103%	1.078%	1.046%	1.011%	0.973%
Levelized Increase in Overall Rate	0.999%	0.999%	0.999%	0.999%	0.999%	0.999%	0.999%
Electric Rate Impact per mWh saved							
Levelized Rate Impact per mWh saved - Delivery Rate	1.68%	1.68%	1.68%	1.68%	1.68%	1.68%	1.68%
Levelized Rate Impact per mWh saved - Overall Rate	0.73%	0.73%	0.73%	0.73%	0.73%	0.73%	0.73%
Electric Rate Impact per mW saved							
Levelized Rate Impact per mW saved - Delivery Rate	0.12%	0.12%	0.12%	0.12%	0.12%	0.12%	0.12%
Levelized Rate Impact per mW saved - Overall Rate	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%

(1) Delivery costs were inflated at the long-term inflation estimate of 2.1%.
(2) Commodity costs were inflated based on company-specific energy price MAPS runs and an avoided cost forecast for capacity.

National Grid - Residential
Enhanced Home Sealing Incentives

	cents per kWh
2009 Forecasted Price (Full Service Customers):	16.21
2009 Forecasted SBC Charge	0.16
2009 Forecasted RPS Charge	0.09
2009 Forecasted Price Excl. SBC & RPS:	15.96

	Projected 2009	Projected 2010	Projected 2011	Projected 2012	Projected 2013	Projected 2014	Projected 2015
Projected Delivery Price Without Environmental Programs:(1)	7.67	7.84	8.00	8.17	8.34	8.52	8.69
Projected Commodity Price Without Environmental Programs:(2)	8.28	9.73	10.20	10.73	11.33	12.01	12.80
Projected Avg. Price without Environmental Programs (cents per kWh):	15.96	17.57	18.20	18.90	19.67	20.53	21.49

Impacts of Environmental Programs (cents per kWh)

	2009	2010	2011	2012	2013	2014	2015
Projected SBC Cost:	0.16	0.16	0.08	0.00	0.00	0.00	0.00
Projected SBC Reallocation Cost:	0.00	0.00	0.08	0.17	0.17	0.17	0.17
Projected RPS Cost:	0.09	0.11	0.13	0.15	0.18	0.18	0.18
Projected EEPS Cost:	0.19	0.19	0.19	0.00	0.00	0.00	0.00
Proposed EE Program Cost	0.097	0.139	0.157	0.158	0.159	0.160	0.160
Projected RGGI Cost:	0.05	0.05	0.06	0.07	0.08	0.09	0.10
Projected Lost Delivery Revenue Cost:	0.07	0.25	0.46	0.64	0.79	0.94	1.08
Projected Delivery Price with Environmental Programs:	8.27	8.68	9.11	9.28	9.64	9.96	10.29
Projected Commodity Price with Environmental Programs:	8.33	9.62	10.02	10.47	11.00	11.61	12.32
Projected Avg. Price with Environmental Programs:	16.61	18.31	19.13	19.75	20.63	21.57	22.61
Proposed EE Program Cost -	$ 766,516	$ 1,308,154	$ 1,308,154	$ 1,308,154	$ 1,308,154	$ 1,308,154	$ 1,308,154
Lost Delivery Revenue associated with EE Program	$ 51,882	$ 97,089	$ 99,128	$ 101,210	$ 103,335	$ 105,505	$ 107,721
Total Costs associated with EE Program	$ 818,398	$ 1,405,243	$ 1,407,282	$ 1,409,364	$ 1,411,489	$ 1,413,659	$ 1,415,875
Total Projected Increase to bill (cents per kWh)	0.003	0.005	0.005	0.005	0.005	0.005	0.005
Levelized Increase to bill (cents per kWh)	0.005	0.005	0.005	0.005	0.005	0.005	0.005
Electric Rate Impact							
Increase in Delivery Rate	0.038%	0.066%	0.065%	0.065%	0.064%	0.063%	0.062%
Levelized Increase in Delivery Rate	0.060%	0.060%	0.060%	0.060%	0.060%	0.060%	0.060%
Increase in Overall Rate	0.019%	0.029%	0.029%	0.028%	0.027%	0.026%	0.025%
Levelized Increase in Overall Rate	0.026%	0.026%	0.026%	0.026%	0.026%	0.026%	0.026%
Electric Rate Impact per mWh saved							
Levelized Rate Impact per mWh saved - Delivery Rate	5.21%	5.21%	5.21%	5.21%	5.21%	5.21%	5.21%
Levelized Rate Impact per mWh saved - Overall Rate	2.25%	2.25%	2.25%	2.25%	2.25%	2.25%	2.25%
Electric Rate Impact per mW saved							
Levelized Rate Impact per mW saved - Delivery Rate	12.80%	12.80%	12.80%	12.80%	12.80%	12.80%	12.80%
Levelized Rate Impact per mW saved - Overall Rate	5.54%	5.54%	5.54%	5.54%	5.54%	5.54%	5.54%

(1) Delivery costs were inflated at the long-term inflation estimate of 2.1%.
(2) Commodity costs were inflated based on company-specific energy price MAPS runs and an avoided cost forecast for capacity.

National Grid - Residential
Residential ENERGY STAR Products and Recycling Program

	cents per kWh
2009 Forecasted Price (Full Service Customers):	16.21
2009 Forecasted SBC Charge	0.16
2009 Forecasted RPS Charge	0.09
2009 Forecasted Price Excl. SBC & RPS:	15.96

	Projected 2009	Projected 2010	Projected 2011	Projected 2012	Projected 2013	Projected 2014	Projected 2015
Projected Delivery Price Without Environmental Programs:[1]	7.67	7.84	8.00	8.17	8.34	8.52	8.69
Projected Commodity Price Without Environmental Programs:[2]	8.28	9.73	10.20	10.73	11.33	12.01	12.80
Projected Avg. Price without Environmental Programs (cents per kWh):	15.96	17.57	18.20	18.90	19.67	20.53	21.49

Impacts of Environmental Programs (cents per kWh)

	2009	2010	2011	2012	2013	2014	2015
Projected SBC Cost:	0.16	0.16	0.08	0.00	0.00	0.00	0.00
Projected SBC Reallocation Cost:	0.00	0.00	0.08	0.17	0.17	0.17	0.17
Projected RPS Cost:	0.09	0.11	0.13	0.15	0.18	0.18	0.18
Projected EEPS Cost:	0.19	0.19	0.19	0.00	0.00	0.00	0.00
Proposed EE Program Cost	0.097	0.139	0.157	0.158	0.159	0.160	0.160
Projected RGGI Cost:	0.05	0.05	0.06	0.07	0.08	0.09	0.10
Projected Lost Delivery Revenue Cost:	0.07	0.25	0.46	0.64	0.79	0.94	1.08
Projected Delivery Price with Environmental Programs:	8.27	8.68	9.11	9.28	9.64	9.96	10.29
Projected Commodity Price with Environmental Programs:	8.33	9.62	10.02	10.47	11.00	11.61	12.32
Projected Avg. Price with Environmental Programs:	16.61	18.31	19.13	19.75	20.63	21.57	22.61

	2009	2010	2011	2012	2013	2014	2015
Proposed EE Program Cost -	$ 2,547,318	$ 3,940,585	$ 3,940,585	$ 3,940,585	$ 3,940,585	$ 3,940,585	$ 3,940,585
Lost Delivery Revenue associated with EE Program	$ 365,095	$ 747,484	$ 763,181	$ 779,208	$ 795,571	$ 812,278	$ 829,336
Total Costs associated with EE Program	$ 2,912,413	$ 4,688,069	$ 4,703,766	$ 4,719,793	$ 4,736,156	$ 4,752,863	$ 4,769,921
Total Projected Increase to bill (cents per kWh)	0.011	0.017	0.017	0.018	0.018	0.018	0.018
Levelized Increase to bill (cents per kWh)	0.017	0.017	0.017	0.017	0.017	0.017	0.017
Electric Rate Impact							
Increase in Delivery Rate	0.137%	0.219%	0.218%	0.216%	0.214%	0.211%	0.208%
Levelized Increase in Delivery Rate	0.203%	0.203%	0.203%	0.203%	0.203%	0.203%	0.203%
Increase in Overall Rate	0.066%	0.098%	0.096%	0.094%	0.091%	0.088%	0.084%
Levelized Increase in Overall Rate	0.088%	0.088%	0.088%	0.088%	0.088%	0.088%	0.088%
Electric Rate Impact per mWh saved							
Levelized Rate Impact per mWh saved - Delivery Rate	2.30%	2.30%	2.30%	2.30%	2.30%	2.30%	2.30%
Levelized Rate Impact per mWh saved - Overall Rate	0.99%	0.99%	0.99%	0.99%	0.99%	0.99%	0.99%
Electric Rate Impact per mW saved							
Levelized Rate Impact per mW saved - Delivery Rate	0.22%	0.22%	0.22%	0.22%	0.22%	0.22%	0.22%
Levelized Rate Impact per mW saved - Overall Rate	0.09%	0.09%	0.09%	0.09%	0.09%	0.09%	0.09%

(1) Delivery costs were inflated at the long-term inflation estimate of 2.1%.
(2) Commodity costs were inflated based on company-specific energy price MAPS runs and an avoided cost forecast for capacity.

National Grid - Residential

Residential Internet Audit Program and E-Commerce Sales

	cents per kWh
2009 Forecasted Price (Full Service Customers):	16.21
2009 Forecasted SBC Charge	0.16
2009 Forecasted RPS Charge	0.09
2009 Forecasted Price Excl. SBC & RPS:	15.96

	Projected 2009	Projected 2010	Projected 2011	Projected 2012	Projected 2013	Projected 2014	Projected 2015
Projected Delivery Price Without Environmental Programs:[1]	7.67	7.84	8.00	8.17	8.34	8.52	8.69
Projected Commodity Price Without Environmental Programs:[2]	8.28	9.73	10.20	10.73	11.33	12.01	12.80
Projected Avg. Price without Environmental Programs (cents per kWh):	15.96	17.57	18.20	18.90	19.67	20.53	21.49

Impacts of Environmental Programs (cents per kWh)

	2009	2010	2011	2012	2013	2014	2015
Projected SBC Cost:	0.16	0.16	0.08	0.00	0.00	0.00	0.00
Projected SBC Reallocation Cost:	0.00	0.00	0.08	0.17	0.17	0.17	0.17
Projected RPS Cost:	0.09	0.11	0.13	0.15	0.18	0.18	0.18
Projected EEPS Cost:	0.19	0.19	0.19	0.00	0.00	0.00	0.00
Proposed EE Program Cost	0.097	0.139	0.157	0.158	0.159	0.160	0.160
Projected RGGI Cost:	0.05	0.05	0.06	0.07	0.08	0.09	0.10
Projected Lost Delivery Revenue Cost:	0.07	0.25	0.46	0.64	0.79	0.94	1.08
Projected Delivery Price with Environmental Programs:	8.27	8.68	9.11	9.28	9.64	9.96	10.29
Projected Commodity Price with Environmental Programs:	8.33	9.62	10.02	10.47	11.00	11.61	12.32
Projected Avg. Price with Environmental Programs:	16.61	18.31	19.13	19.75	20.63	21.57	22.61
Proposed EE Program Cost -	$ 851,591	$ 851,591	$ 851,591	$ 851,591	$ 851,591	$ 851,591	$ 851,591
Lost Delivery Revenue associated with EE Program	$ 230,324	$ 235,161	$ 240,099	$ 245,141	$ 250,289	$ 255,545	$ 260,912
Total Costs associated with EE Program	$ 1,081,915	$ 1,086,752	$ 1,091,690	$ 1,096,732	$ 1,101,880	$ 1,107,136	$ 1,112,503
Total Projected Increase to bill (cents per kWh)	0.004	0.004	0.004	0.004	0.004	0.004	0.004
Levelized Increase to bill (cents per kWh)	0.004	0.004	0.004	0.004	0.004	0.004	0.004
Electric Rate Impact							
Increase in Delivery Rate	0.051%	0.051%	0.051%	0.050%	0.050%	0.049%	0.049%
Levelized Increase in Delivery Rate	0.050%	0.050%	0.050%	0.050%	0.050%	0.050%	0.050%
Increase in Overall Rate	0.024%	0.023%	0.022%	0.022%	0.021%	0.020%	0.020%
Levelized Increase in Overall Rate	0.022%	0.022%	0.022%	0.022%	0.022%	0.022%	0.022%
Electric Rate Impact per mWh saved							
Levelized Rate Impact per mWh saved - Delivery Rate	1.66%	1.66%	1.66%	1.66%	1.66%	1.66%	1.66%
Levelized Rate Impact per mWh saved - Overall Rate	0.72%	0.72%	0.72%	0.72%	0.72%	0.72%	0.72%
Electric Rate Impact per mW saved							
Levelized Rate Impact per mW saved - Delivery Rate	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%
Levelized Rate Impact per mW saved - Overall Rate	0.11%	0.11%	0.11%	0.11%	0.11%	0.11%	0.11%

(1) Delivery costs were inflated at the long-term inflation estimate of 2.1%.

(2) Commodity costs were inflated based on company-specific energy price MAPS runs and an avoided cost forecast for capacity.

National Grid - Residential
Residential Building Practices and Demonstration Program

	cents per kWh
2009 Forecasted Price (Full Service Customers):	16.21
2009 Forecasted SBC Charge	0.16
2009 Forecasted RPS Charge	0.09
2009 Forecasted Price Excl. SBC & RPS:	15.96

	Projected 2009	Projected 2010	Projected 2011	Projected 2012	Projected 2013	Projected 2014	Projected 2015
Projected Delivery Price Without Environmental Programs:(1)	7.67	7.84	8.00	8.17	8.34	8.52	8.69
Projected Commodity Price Without Environmental Programs:(2)	8.28	9.73	10.20	10.73	11.33	12.01	12.80
Projected Avg. Price without Environmental Programs (cents per kWh):	15.96	17.57	18.20	18.90	19.67	20.53	21.49

Impacts of Environmental Programs (cents per kWh)

	2009	2010	2011	2012	2013	2014	2015
Projected SBC Cost:	0.16	0.16	0.08	0.00	0.00	0.00	0.00
Projected SBC Reallocation Cost:	0.00	0.00	0.08	0.17	0.17	0.17	0.17
Projected RPS Cost:	0.09	0.11	0.13	0.15	0.18	0.18	0.18
Projected EEPS Cost:	0.19	0.19	0.19	0.00	0.00	0.00	0.00
Proposed EE Program Cost	0.097	0.139	0.157	0.158	0.159	0.160	0.160
Projected RGGI Cost:	0.05	0.05	0.06	0.07	0.08	0.09	0.10
Projected Lost Delivery Revenue Cost:	0.07	0.25	0.46	0.64	0.79	0.94	1.08
Projected Delivery Price with Environmental Programs:	8.27	8.68	9.11	9.28	9.64	9.96	10.29
Projected Commodity Price with Environmental Programs:	8.33	9.62	10.02	10.47	11.00	11.61	12.32
Projected Avg. Price with Environmental Programs:	16.61	18.31	19.13	19.75	20.63	21.57	22.61

	2009	2010	2011	2012	2013	2014	2015
Proposed EE Program Cost -	$ 914,550	$ 914,550	$ 914,550	$ 914,550	$ 914,550	$ 914,550	$ 914,550
Lost Delivery Revenue associated with EE Program	$ 621,668	$ 634,723	$ 648,052	$ 661,661	$ 675,556	$ 689,742	$ 704,227
Total Costs associated with EE Program	$ 1,536,218	$ 1,549,273	$ 1,562,602	$ 1,576,211	$ 1,590,106	$ 1,604,292	$ 1,618,777
Total Projected Increase to bill (cents per kWh)	0.006	0.006	0.006	0.006	0.006	0.006	0.006
Levelized Increase to bill (cents per kWh)	0.006	0.006	0.006	0.006	0.006	0.006	0.006
Electric Rate Impact							
Increase in Delivery Rate	0.072%	0.072%	0.072%	0.072%	0.072%	0.071%	0.071%
Levelized Increase in Delivery Rate	0.072%	0.072%	0.072%	0.072%	0.072%	0.072%	0.072%
Increase in Overall Rate	0.035%	0.032%	0.032%	0.031%	0.030%	0.030%	0.029%
Levelized Increase in Overall Rate	0.031%	0.031%	0.031%	0.031%	0.031%	0.031%	0.031%
Electric Rate Impact per mWh saved							
Levelized Rate Impact per mWh saved - Delivery Rate	0.89%	0.89%	0.89%	0.89%	0.89%	0.89%	0.89%
Levelized Rate Impact per mWh saved - Overall Rate	0.38%	0.38%	0.38%	0.38%	0.38%	0.38%	0.38%
Electric Rate Impact per mW saved							
Levelized Rate Impact per mW saved - Delivery Rate	0.08%	0.08%	0.08%	0.08%	0.08%	0.08%	0.08%
Levelized Rate Impact per mW saved - Overall Rate	0.03%	0.03%	0.03%	0.03%	0.03%	0.03%	0.03%

(1) Delivery costs were inflated at the long-term inflation estimate of 2.1%.
(2) Commodity costs were inflated based on company-specific energy price MAPS runs and an avoided cost forecast for capacity.

National Grid - Residential
Energy*Wise* Program

	cents per kWh
2009 Forecasted Price (Full Service Customers):	16.21
2009 Forecasted SBC Charge	0.16
2009 Forecasted RPS Charge	0.09
2009 Forecasted Price Excl. SBC & RPS:	15.96

	Projected 2009	Projected 2010	Projected 2011	Projected 2012	Projected 2013	Projected 2014	Projected 2015
Projected Delivery Price Without Environmental Programs:[1]	7.67	7.84	8.00	8.17	8.34	8.52	8.69
Projected Commodity Price Without Environmental Programs:[2]	8.28	9.73	10.20	10.73	11.33	12.01	12.80
Projected Avg. Price without Environmental Programs (cents per kWh):	15.96	17.57	18.20	18.90	19.67	20.53	21.49

Impacts of Environmental Programs (cents per kWh)

	2009	2010	2011	2012	2013	2014	2015
Projected SBC Cost:	0.16	0.16	0.08	0.00	0.00	0.00	0.00
Projected SBC Reallocation Cost:	0.00	0.00	0.08	0.17	0.17	0.17	0.17
Projected RPS Cost:	0.09	0.11	0.13	0.15	0.18	0.18	0.18
Projected EEPS Cost:	0.19	0.19	0.19	0.00	0.00	0.00	0.00
Proposed EE Program Cost	0.097	0.139	0.157	0.158	0.159	0.160	0.160
Projected RGGI Cost:	0.05	0.05	0.06	0.07	0.08	0.09	0.10
Projected Lost Delivery Revenue Cost:	0.07	0.25	0.46	0.64	0.79	0.94	1.08
Projected Delivery Price with Environmental Programs:	8.27	8.68	9.11	9.28	9.64	9.96	10.29
Projected Commodity Price with Environmental Programs:	8.33	9.62	10.02	10.47	11.00	11.61	12.32
Projected Avg. Price with Environmental Programs:	16.61	18.31	19.13	19.75	20.63	21.57	22.61
Proposed EE Program Cost -	$ 2,192,395	$ 5,020,070	$ 5,020,070	$ 5,020,070	$ 5,020,070	$ 5,020,070	$ 5,020,070
Lost Delivery Revenue associated with EE Program	$ 182,509	$ 383,341	$ 391,391	$ 399,610	$ 408,002	$ 416,570	$ 425,318
Total Costs associated with EE Program	$ 2,374,904	$ 5,403,411	$ 5,411,461	$ 5,419,680	$ 5,428,072	$ 5,436,640	$ 5,445,388
Total Projected Increase to bill (cents per kWh)	0.009	0.020	0.020	0.020	0.020	0.021	0.021
Levelized Increase to bill (cents per kWh)	0.019	0.019	0.019	0.019	0.019	0.019	0.019
Electric Rate Impact							
Increase in Delivery Rate	0.112%	0.252%	0.251%	0.248%	0.245%	0.241%	0.237%
Levelized Increase in Delivery Rate	0.227%	0.227%	0.227%	0.227%	0.227%	0.227%	0.227%
Increase in Overall Rate	0.054%	0.112%	0.110%	0.107%	0.104%	0.100%	0.096%
Levelized Increase in Overall Rate	0.098%	0.098%	0.098%	0.098%	0.098%	0.098%	0.098%
Electric Rate Impact per mWh saved							
Levelized Rate Impact per mWh saved - Delivery Rate	5.01%	5.01%	5.01%	5.01%	5.01%	5.01%	5.01%
Levelized Rate Impact per mWh saved - Overall Rate	2.17%	2.17%	2.17%	2.17%	2.17%	2.17%	2.17%
Electric Rate Impact per mW saved							
Levelized Rate Impact per mW saved - Delivery Rate	0.77%	0.77%	0.77%	0.77%	0.77%	0.77%	0.77%
Levelized Rate Impact per mW saved - Overall Rate	0.33%	0.33%	0.33%	0.33%	0.33%	0.33%	0.33%

(1) Delivery costs were inflated at the long-term inflation estimate of 2.1%.
(2) Commodity costs were inflated based on company-specific energy price MAPS runs and an avoided cost forecast for capacity.

National Grid - Residential
Residential Pricing Pilot with Load Control

	cents per kWh
2009 Forecasted Price (Full Service Customers):	16.21
2009 Forecasted SBC Charge	0.16
2009 Forecasted RPS Charge	0.09
2009 Forecasted Price Excl. SBC & RPS:	15.96

	Projected 2009	Projected 2010	Projected 2011	Projected 2012	Projected 2013	Projected 2014	Projected 2015
Projected Delivery Price Without Environmental Programs:[1]	7.67	7.84	8.00	8.17	8.34	8.52	8.69
Projected Commodity Price Without Environmental Programs:[2]	8.28	9.73	10.20	10.73	11.33	12.01	12.80
Projected Avg. Price without Environmental Programs (cents per kWh):	15.96	17.57	18.20	18.90	19.67	20.53	21.49

Impacts of Environmental Programs (cents per kWh)

	2009	2010	2011	2012	2013	2014	2015
Projected SBC Cost:	0.16	0.16	0.08	0.00	0.00	0.00	0.00
Projected SBC Reallocation Cost:	0.00	0.00	0.08	0.17	0.17	0.17	0.17
Projected RPS Cost:	0.09	0.11	0.13	0.15	0.18	0.18	0.18
Projected EEPS Cost:	0.19	0.19	0.19	0.00	0.00	0.00	0.00
Proposed EE Program Cost	0.097	0.139	0.157	0.158	0.159	0.160	0.160
Projected RGGI Cost:	0.05	0.05	0.06	0.07	0.08	0.09	0.10
Projected Lost Delivery Revenue Cost:	0.07	0.25	0.46	0.64	0.79	0.94	1.08
Projected Delivery Price with Environmental Programs:	8.27	8.68	9.11	9.28	9.64	9.96	10.29
Projected Commodity Price with Environmental Programs:	8.33	9.62	10.02	10.47	11.00	11.61	12.32
Projected Avg. Price with Environmental Programs:	16.61	18.31	19.13	19.75	20.63	21.57	22.61
Proposed EE Program Cost -	$ 420,000	$ 1,863,750	$ 131,250	$ 131,250	$ 131,250	$ 131,250	$ 131,250
Lost Delivery Revenue associated with EE Program	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Costs associated with EE Program	$ 420,000	$ 1,863,750	$ 131,250	$ 131,250	$ 131,250	$ 131,250	$ 131,250
Total Projected Increase to bill (cents per kWh)	0.002	0.007	0.000	0.000	0.000	0.000	0.000
Levelized Increase to bill (cents per kWh)	0.002	0.002	0.002	0.002	0.002	0.002	0.002
Electric Rate Impact							
Increase in Delivery Rate	0.020%	0.087%	0.006%	0.006%	0.006%	0.006%	0.006%
Levelized Increase in Delivery Rate	0.019%	0.019%	0.019%	0.019%	0.019%	0.019%	0.019%
Increase in Overall Rate	0.009%	0.039%	0.003%	0.003%	0.003%	0.002%	0.002%
Levelized Increase in Overall Rate	0.008%	0.008%	0.008%	0.008%	0.008%	0.008%	0.008%
Electric Rate Impact per mWh saved							
Levelized Rate Impact per mWh saved - Delivery Rate	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Levelized Rate Impact per mWh saved - Overall Rate	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Electric Rate Impact per mW saved							
Levelized Rate Impact per mW saved - Delivery Rate	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Levelized Rate Impact per mW saved - Overall Rate	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

(1) Delivery costs were inflated at the long-term inflation estimate of 2.1%.
(2) Commodity costs were inflated based on company-specific energy price MAPS runs and an avoided cost forecast for capacity.

National Grid - Residential
Energy Initiative

	cents per kWh
2009 Forecasted Price (Full Service Customers):	16.21
2009 Forecasted SBC Charge	0.16
2009 Forecasted RPS Charge	0.09
2009 Forecasted Price Excl. SBC & RPS:	15.96

	Projected 2009	Projected 2010	Projected 2011	Projected 2012	Projected 2013	Projected 2014	Projected 2015
Projected Delivery Price Without Environmental Programs:[1]	7.67	7.84	8.00	8.17	8.34	8.52	8.69
Projected Commodity Price Without Environmental Programs:[2]	8.28	9.73	10.20	10.73	11.33	12.01	12.80
Projected Avg. Price without Environmental Programs (cents per kWh):	15.96	17.57	18.20	18.90	19.67	20.53	21.49

Impacts of Environmental Programs (cents per kWh)

	2009	2010	2011	2012	2013	2014	2015
Projected SBC Cost:	0.16	0.16	0.08	0.00	0.00	0.00	0.00
Projected SBC Reallocation Cost:	0.00	0.00	0.08	0.17	0.17	0.17	0.17
Projected RPS Cost:	0.09	0.11	0.13	0.15	0.18	0.18	0.18
Projected EEPS Cost:	0.19	0.19	0.19	0.00	0.00	0.00	0.00
Proposed EE Program Cost	0.097	0.139	0.157	0.158	0.159	0.160	0.160
Projected RGGI Cost:	0.05	0.05	0.06	0.07	0.08	0.09	0.10
Projected Lost Delivery Revenue Cost:	0.07	0.25	0.46	0.64	0.79	0.94	1.08
Projected Delivery Price with Environmental Programs:	8.27	8.68	9.11	9.28	9.64	9.96	10.29
Projected Commodity Price with Environmental Programs:	8.33	9.62	10.02	10.47	11.00	11.61	12.32
Projected Avg. Price with Environmental Programs:	16.61	18.31	19.13	19.75	20.63	21.57	22.61
Proposed EE Program Cost -	$ 19,282,803	$ 24,103,504	$ 30,129,379	$ 30,129,379	$ 30,129,379	$ 30,129,379	$ 30,129,379
Lost Delivery Revenue associated with EE Program	$ 5,962,713	$ 7,609,932	$ 9,712,135	$ 9,916,090	$ 10,124,328	$ 10,336,939	$ 10,554,015
Total Costs associated with EE Program	$ 25,245,516	$ 31,713,436	$ 39,841,514	$ 40,045,469	$ 40,253,707	$ 40,466,318	$ 40,683,394
Total Projected Increase to bill (cents per kWh)	0.091	0.116	0.148	0.150	0.152	0.153	0.154
Levelized Increase to bill (cents per kWh)	0.137	0.137	0.137	0.137	0.137	0.137	0.137
Electric Rate Impact							
Increase in Delivery Rate	1.187%	1.480%	1.847%	1.836%	1.817%	1.797%	1.774%
Levelized Increase in Delivery Rate	1.679%	1.679%	1.679%	1.679%	1.679%	1.679%	1.679%
Increase in Overall Rate	0.571%	0.660%	0.812%	0.793%	0.770%	0.745%	0.718%
Levelized Increase in Overall Rate	0.726%	0.726%	0.726%	0.726%	0.726%	0.726%	0.726%
Electric Rate Impact per mWh saved							
Levelized Rate Impact per mWh saved - Delivery Rate	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%
Levelized Rate Impact per mWh saved - Overall Rate	0.65%	0.65%	0.65%	0.65%	0.65%	0.65%	0.65%
Electric Rate Impact per mW saved							
Levelized Rate Impact per mW saved - Delivery Rate	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%
Levelized Rate Impact per mW saved - Overall Rate	0.04%	0.04%	0.04%	0.04%	0.04%	0.04%	0.04%

(1) Delivery costs were inflated at the long-term inflation estimate of 2.1%.
(2) Commodity costs were inflated based on company-specific energy price MAPS runs and an avoided cost forecast for capacity.

National Grid - Non-Residential
Total Suite of Electric Energy Efficiency Programs

2009 Forecasted Price (Full Service Customers):	12.91
2009 Forecasted SBC Charge:	0.16
2009 Forecasted RPS Charge:	0.09
2009 Forecasted Price Excl. SBC & RPS:	12.66

	Projected 2009	Projected 2010	Projected 2011	Projected 2012	Projected 2013	Projected 2014	Projected 2015
Projected Delivery Price Without Environmental Programs:(1)	4.60	4.70	4.80	4.90	5.00	5.11	5.22
Projected Commodity Price Without Environmental Programs:(2)	8.05	9.46	9.92	10.43	11.01	11.68	12.44
Projected Avg. Price without Environmental Programs:	12.66	14.16	14.72	15.33	16.02	16.79	17.66

Impacts of Environmental Programs (Cents per kWh)

	2009	2010	2011	2012	2013	2014	2015
Projected SBC Cost:	0.16	0.16	0.08	0.00	0.00	0.00	0.00
Projected SBC Reallocation Cost:	0.00	0.00	0.08	0.17	0.17	0.17	0.17
Projected RPS Cost:	0.09	0.11	0.13	0.15	0.18	0.18	0.18
Projected EEPS Cost:	0.19	0.19	0.19	0.00	0.00	0.00	0.00
Proposed EE Program Cost	0.097	0.139	0.157	0.158	0.159	0.160	0.160
Projected RGGI Cost:	0.05	0.05	0.06	0.07	0.08	0.09	0.10
Projected Lost Delivery Revenue Cost:	0.07	0.25	0.46	0.64	0.79	0.94	1.08
Projected Delivery Price with Environmental Programs:	5.11	5.41	5.75	5.86	6.14	6.40	6.65
Projected Commodity Price with Environmental Programs:	9.02	9.36	9.74	10.18	10.69	11.29	11.98
Projected Avg. Price with Environmental Programs:	14.13	14.77	15.49	16.04	16.83	17.68	18.63
Proposed EE Program Cost -	$ 26,975,173	$ 38,002,204	$ 42,295,579	$ 42,295,579	$ 42,295,579	$ 42,295,579	$ 42,295,579
Lost Delivery Revenue associated with EE Program	$ 7,414,191	$ 9,707,729	$ 11,853,986	$ 12,102,920	$ 12,357,081	$ 12,616,580	$ 12,881,528
Total Costs associated with EE Program	$ 34,389,364	$ 47,709,933	$ 54,149,565	$ 54,398,499	$ 54,652,660	$ 54,912,159	$ 55,177,107
Total Projected Increase to bill (cents per kWh)	0.124	0.174	0.201	0.204	0.206	0.208	0.209
Levelized Increase to bill (cents per kWh)	0.189	0.189	0.189	0.189	0.189	0.189	0.189
Electric Rate Impact							
Increase in Delivery Rate	2.696%	3.710%	4.185%	4.156%	4.111%	4.064%	4.011%
Levelized Increase in Delivery Rate	3.852%	3.852%	3.852%	3.852%	3.852%	3.852%	3.852%
Increase in Overall Rate	0.981%	1.232%	1.365%	1.329%	1.284%	1.237%	1.185%
Levelized Increase in Overall Rate	1.232%	1.232%	1.232%	1.232%	1.232%	1.232%	1.232%
Electric Rate Impact per mWh saved							
Levelized Rate Impact per mWh saved - Delivery Rate	2.80%	2.80%	2.80%	2.80%	2.80%	2.80%	2.80%
Levelized Rate Impact per mWh saved - Overall Rate	0.90%	0.90%	0.90%	0.90%	0.90%	0.90%	0.90%
Electric Rate Impact per mW saved							
Levelized Rate Impact per mW saved - Delivery Rate	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%
Levelized Rate Impact per mW saved - Overall Rate	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%

(1) Delivery costs were inflated at the long-term inflation estimate of 2.1%.
(2) Commodity costs were inflated based on company-specific energy price MAPS runs and an avoided cost forecast for capacity.

National Grid - Non-Residential
Enhanced Home Sealing Incentives

2009 Forecasted Price (Full Service Customers):	12.91
2009 Forecasted SBC Charge:	0.16
2009 Forecasted RPS Charge:	0.09
2009 Forecasted Price Excl. SBC & RPS:	12.66

	Projected 2009	Projected 2010	Projected 2011	Projected 2012	Projected 2013	Projected 2014	Projected 2015
Projected Delivery Price Without Environmental Programs:[1]	4.60	4.70	4.80	4.90	5.00	5.11	5.22
Projected Commodity Price Without Environmental Programs:[2]	8.05	9.46	9.92	10.43	11.01	11.68	12.44
Projected Avg. Price without Environmental Programs:	12.66	14.16	14.72	15.33	16.02	16.79	17.66

Impacts of Environmental Programs (Cents per kWh)

	2009	2010	2011	2012	2013	2014	2015
Projected SBC Cost:	0.16	0.16	0.08	0.00	0.00	0.00	0.00
Projected SBC Reallocation Cost:	0.00	0.00	0.08	0.17	0.17	0.17	0.17
Projected RPS Cost:	0.09	0.11	0.13	0.15	0.18	0.18	0.18
Projected EEPS Cost:	0.19	0.19	0.19	0.00	0.00	0.00	0.00
Proposed EE Program Cost	0.097	0.139	0.157	0.158	0.159	0.160	0.160
Projected RGGI Cost:	0.05	0.05	0.06	0.07	0.08	0.09	0.10
Projected Lost Delivery Revenue Cost:	0.07	0.25	0.46	0.64	0.79	0.94	1.08
Projected Delivery Price with Environmental Programs:	5.11	5.41	5.75	5.86	6.14	6.40	6.65
Projected Commodity Price with Environmental Programs:	9.02	9.36	9.74	10.18	10.69	11.29	11.98
Projected Avg. Price with Environmental Programs:	14.13	14.77	15.49	16.04	16.83	17.68	18.63
Proposed EE Program Cost -	$ 766,516	$ 1,308,154	$ 1,308,154	$ 1,308,154	$ 1,308,154	$ 1,308,154	$ 1,308,154
Lost Delivery Revenue associated with EE Program	$ 51,882	$ 97,089	$ 99,128	$ 101,210	$ 103,335	$ 105,505	$ 107,721
Total Costs associated with EE Program	$ 818,398	$ 1,405,243	$ 1,407,282	$ 1,409,364	$ 1,411,489	$ 1,413,659	$ 1,415,875
Total Projected Increase to bill (cents per kWh)	0.003	0.005	0.005	0.005	0.005	0.005	0.005
Levelized Increase to bill (cents per kWh)	0.005	0.005	0.005	0.005	0.005	0.005	0.005
Electric Rate Impact							
Increase in Delivery Rate	0.064%	0.109%	0.109%	0.108%	0.106%	0.105%	0.103%
Levelized Increase in Delivery Rate	0.101%	0.101%	0.101%	0.101%	0.101%	0.101%	0.101%
Increase in Overall Rate	0.023%	0.036%	0.035%	0.034%	0.033%	0.032%	0.030%
Levelized Increase in Overall Rate	0.032%	0.032%	0.032%	0.032%	0.032%	0.032%	0.032%
Electric Rate Impact per mWh saved							
Levelized Rate Impact per mWh saved - Delivery Rate	8.68%	8.68%	8.68%	8.68%	8.68%	8.68%	8.68%
Levelized Rate Impact per mWh saved - Overall Rate	2.78%	2.78%	2.78%	2.78%	2.78%	2.78%	2.78%
Electric Rate Impact per mW saved							
Levelized Rate Impact per mW saved - Delivery Rate	21.34%	21.34%	21.34%	21.34%	21.34%	21.34%	21.34%
Levelized Rate Impact per mW saved - Overall Rate	6.83%	6.83%	6.83%	6.83%	6.83%	6.83%	6.83%

(1) Delivery costs were inflated at the long-term inflation estimate of 2.1%.
(2) Commodity costs were inflated based on company-specific energy price MAPS runs and an avoided cost forecast for capacity.

2009 Forecasted Price (Full Service Customers):	12.91
2009 Forecasted SBC Charge:	0.16
2009 Forecasted RPS Charge:	0.09
2009 Forecasted Price Excl. SBC & RPS:	12.66

	Projected 2009	Projected 2010	Projected 2011	Projected 2012	Projected 2013	Projected 2014	Projected 2015
Projected Delivery Price Without Environmental Programs:(1)	4.60	4.70	4.80	4.90	5.00	5.11	5.22
Projected Commodity Price Without Environmental Programs:(2)	8.05	9.46	9.92	10.43	11.01	11.68	12.44
Projected Avg. Price without Environmental Programs:	12.66	14.16	14.72	15.33	16.02	16.79	17.66

Impacts of Environmental Programs (Cents per kWh)

	2009	2010	2011	2012	2013	2014	2015
Projected SBC Cost:	0.16	0.16	0.08	0.00	0.00	0.00	0.00
Projected SBC Reallocation Cost:	0.00	0.00	0.08	0.17	0.17	0.17	0.17
Projected RPS Cost:	0.09	0.11	0.13	0.15	0.18	0.18	0.18
Projected EEPS Cost:	0.19	0.19	0.19	0.00	0.00	0.00	0.00
Proposed EE Program Cost	0.097	0.139	0.157	0.158	0.159	0.160	0.160
Projected RGGI Cost:	0.05	0.05	0.06	0.07	0.08	0.09	0.10
Projected Lost Delivery Revenue Cost:	0.07	0.25	0.46	0.64	0.79	0.94	1.08
Projected Delivery Price with Environmental Programs:	5.11	5.41	5.75	5.86	6.14	6.40	6.65
Projected Commodity Price with Environmental Programs:	9.02	9.36	9.74	10.18	10.69	11.29	11.98
Projected Avg. Price with Environmental Programs:	14.13	14.77	15.49	16.04	16.83	17.68	18.63
Proposed EE Program Cost -	$ 2,547,318	$ 3,940,585	$ 3,940,585	$ 3,940,585	$ 3,940,585	$ 3,940,585	$ 3,940,585
Lost Delivery Revenue associated with EE Program	$ 365,095	$ 747,484	$ 763,181	$ 779,208	$ 795,571	$ 812,278	$ 829,336
Total Costs associated with EE Program	$ 2,912,413	$ 4,688,069	$ 4,703,766	$ 4,719,793	$ 4,736,156	$ 4,752,863	$ 4,769,921
Total Projected Increase to bill (cents per kWh)	0.011	0.017	0.017	0.018	0.018	0.018	0.018
Levelized Increase to bill (cents per kWh)	0.017	0.017	0.017	0.017	0.017	0.017	0.017
Electric Rate Impact							
Increase in Delivery Rate	0.228%	0.365%	0.363%	0.361%	0.356%	0.352%	0.347%
Levelized Increase in Delivery Rate	0.339%	0.339%	0.339%	0.339%	0.339%	0.339%	0.339%
Increase in Overall Rate	0.083%	0.121%	0.119%	0.115%	0.111%	0.107%	0.102%
Levelized Increase in Overall Rate	0.108%	0.108%	0.108%	0.108%	0.108%	0.108%	0.108%
Electric Rate Impact per mWh saved							
Levelized Rate Impact per mWh saved - Delivery Rate	3.83%	3.83%	3.83%	3.83%	3.83%	3.83%	3.83%
Levelized Rate Impact per mWh saved - Overall Rate	1.22%	1.22%	1.22%	1.22%	1.22%	1.22%	1.22%
Electric Rate Impact per mW saved							
Levelized Rate Impact per mW saved - Delivery Rate	0.36%	0.36%	0.36%	0.36%	0.36%	0.36%	0.36%
Levelized Rate Impact per mW saved - Overall Rate	0.12%	0.12%	0.12%	0.12%	0.12%	0.12%	0.12%

(1) Delivery costs were inflated at the long-term inflation estimate of 2.1%.
(2) Commodity costs were inflated based on company-specific energy price MAPS runs and an avoided cost forecast for capacity.

National Grid - Non-Residential
Residential Internet Audit Program and E-Commerce Sales

2009 Forecasted Price (Full Service Customers):	12.91
2009 Forecasted SBC Charge:	0.16
2009 Forecasted RPS Charge:	0.09
2009 Forecasted Price Excl. SBC & RPS:	12.66

	Projected 2009	Projected 2010	Projected 2011	Projected 2012	Projected 2013	Projected 2014	Projected 2015
Projected Delivery Price Without Environmental Programs:[1]	4.60	4.70	4.80	4.90	5.00	5.11	5.22
Projected Commodity Price Without Environmental Programs:[2]	8.05	9.46	9.92	10.43	11.01	11.68	12.44
Projected Avg. Price without Environmental Programs:	12.66	14.16	14.72	15.33	16.02	16.79	17.66

Impacts of Environmental Programs (Cents per kWh)

	2009	2010	2011	2012	2013	2014	2015
Projected SBC Cost:	0.16	0.16	0.08	0.00	0.00	0.00	0.00
Projected SBC Reallocation Cost:	0.00	0.00	0.08	0.17	0.17	0.17	0.17
Projected RPS Cost:	0.09	0.11	0.13	0.15	0.18	0.18	0.18
Projected EEPS Cost:	0.19	0.19	0.19	0.00	0.00	0.00	0.00
Proposed EE Program Cost	0.097	0.139	0.157	0.158	0.159	0.160	0.160
Projected RGGI Cost:	0.05	0.05	0.06	0.07	0.08	0.09	0.10
Projected Lost Delivery Revenue Cost:	0.07	0.25	0.46	0.64	0.79	0.94	1.08
Projected Delivery Price with Environmental Programs:	5.11	5.41	5.75	5.86	6.14	6.40	6.65
Projected Commodity Price with Environmental Programs:	9.02	9.36	9.74	10.18	10.69	11.29	11.98
Projected Avg. Price with Environmental Programs:	14.13	14.77	15.49	16.04	16.83	17.68	18.63
Proposed EE Program Cost -	$ 851,591	$ 851,591	$ 851,591	$ 851,591	$ 851,591	$ 851,591	$ 851,591
Lost Delivery Revenue associated with EE Program	$ 230,324	$ 235,161	$ 240,099	$ 245,141	$ 250,289	$ 255,545	$ 260,912
Total Costs associated with EE Program	$ 1,081,915	$ 1,086,752	$ 1,091,690	$ 1,096,732	$ 1,101,880	$ 1,107,136	$ 1,112,503
Total Projected Increase to bill (cents per kWh)	0.004	0.004	0.004	0.004	0.004	0.004	0.004
Levelized Increase to bill (cents per kWh)	0.004	0.004	0.004	0.004	0.004	0.004	0.004
Electric Rate Impact							
Increase in Delivery Rate	0.085%	0.085%	0.084%	0.084%	0.083%	0.082%	0.081%
Levelized Increase in Delivery Rate	0.083%	0.083%	0.083%	0.083%	0.083%	0.083%	0.083%
Increase in Overall Rate	0.031%	0.028%	0.028%	0.027%	0.026%	0.025%	0.024%
Levelized Increase in Overall Rate	0.027%	0.027%	0.027%	0.027%	0.027%	0.027%	0.027%
Electric Rate Impact per mWh saved							
Levelized Rate Impact per mWh saved - Delivery Rate	2.77%	2.77%	2.77%	2.77%	2.77%	2.77%	2.77%
Levelized Rate Impact per mWh saved - Overall Rate	0.89%	0.89%	0.89%	0.89%	0.89%	0.89%	0.89%
Electric Rate Impact per mW saved							
Levelized Rate Impact per mW saved - Delivery Rate	0.42%	0.42%	0.42%	0.42%	0.42%	0.42%	0.42%
Levelized Rate Impact per mW saved - Overall Rate	0.14%	0.14%	0.14%	0.14%	0.14%	0.14%	0.14%

(1) Delivery costs were inflated at the long-term inflation estimate of 2.1%.
(2) Commodity costs were inflated based on company-specific energy price MAPS runs and an avoided cost forecast for capacity.

2009 Forecasted Price (Full Service Customers):	12.91
2009 Forecasted SBC Charge:	0.16
2009 Forecasted RPS Charge:	0.09
2009 Forecasted Price Excl. SBC & RPS:	12.66

	Projected 2009	Projected 2010	Projected 2011	Projected 2012	Projected 2013	Projected 2014	Projected 2015
Projected Delivery Price Without Environmental Programs:[1]	4.60	4.70	4.80	4.90	5.00	5.11	5.22
Projected Commodity Price Without Environmental Programs:[2]	8.05	9.46	9.92	10.43	11.01	11.68	12.44
Projected Avg. Price without Environmental Programs:	12.66	14.16	14.72	15.33	16.02	16.79	17.66

Impacts of Environmental Programs (Cents per kWh)

	2009	2010	2011	2012	2013	2014	2015
Projected SBC Cost:	0.16	0.16	0.08	0.00	0.00	0.00	0.00
Projected SBC Reallocation Cost:	0.00	0.00	0.08	0.17	0.17	0.17	0.17
Projected RPS Cost:	0.09	0.11	0.13	0.15	0.18	0.18	0.18
Projected EEPS Cost:	0.19	0.19	0.19	0.00	0.00	0.00	0.00
Proposed EE Program Cost	0.097	0.139	0.157	0.158	0.159	0.160	0.160
Projected RGGI Cost:	0.05	0.05	0.06	0.07	0.08	0.09	0.10
Projected Lost Delivery Revenue Cost:	0.07	0.25	0.46	0.64	0.79	0.94	1.08
Projected Delivery Price with Environmental Programs:	5.11	5.41	5.75	5.86	6.14	6.40	6.65
Projected Commodity Price with Environmental Programs:	9.02	9.36	9.74	10.18	10.69	11.29	11.98
Projected Avg. Price with Environmental Programs:	14.13	14.77	15.49	16.04	16.83	17.68	18.63
Proposed EE Program Cost -	$ 914,550	$ 914,550	$ 914,550	$ 914,550	$ 914,550	$ 914,550	$ 914,550
Lost Delivery Revenue associated with EE Program	$ 621,668	$ 634,723	$ 648,052	$ 661,661	$ 675,556	$ 689,742	$ 704,227
Total Costs associated with EE Program	$ 1,536,218	$ 1,549,273	$ 1,562,602	$ 1,576,211	$ 1,590,106	$ 1,604,292	$ 1,618,777
Total Projected Increase to bill (cents per kWh)	0.006	0.006	0.006	0.006	0.006	0.006	0.006
Levelized Increase to bill (cents per kWh)	0.006	0.006	0.006	0.006	0.006	0.006	0.006
Electric Rate Impact							
Increase in Delivery Rate	0.120%	0.120%	0.121%	0.120%	0.120%	0.119%	0.118%
Levelized Increase in Delivery Rate	0.120%	0.120%	0.120%	0.120%	0.120%	0.120%	0.120%
Increase in Overall Rate	0.044%	0.040%	0.039%	0.038%	0.037%	0.036%	0.035%
Levelized Increase in Overall Rate	0.038%	0.038%	0.038%	0.038%	0.038%	0.038%	0.038%
Electric Rate Impact per mWh saved							
Levelized Rate Impact per mWh saved - Delivery Rate	1.48%	1.48%	1.48%	1.48%	1.48%	1.48%	1.48%
Levelized Rate Impact per mWh saved - Overall Rate	0.47%	0.47%	0.47%	0.47%	0.47%	0.47%	0.47%
Electric Rate Impact per mW saved							
Levelized Rate Impact per mW saved - Delivery Rate	0.13%	0.13%	0.13%	0.13%	0.13%	0.13%	0.13%
Levelized Rate Impact per mW saved - Overall Rate	0.04%	0.04%	0.04%	0.04%	0.04%	0.04%	0.04%

(1) Delivery costs were inflated at the long-term inflation estimate of 2.1%.
(2) Commodity costs were inflated based on company-specific energy price MAPS runs and an avoided cost forecast for capacity.

National Grid - Non-Residential
Energy*Wise* Program

2009 Forecasted Price (Full Service Customers):	12.91
2009 Forecasted SBC Charge:	0.16
2009 Forecasted RPS Charge:	0.09
2009 Forecasted Price Excl. SBC & RPS:	12.66

	Projected 2009	Projected 2010	Projected 2011	Projected 2012	Projected 2013	Projected 2014	Projected 2015
Projected Delivery Price Without Environmental Programs:[1]	4.60	4.70	4.80	4.90	5.00	5.11	5.22
Projected Commodity Price Without Environmental Programs:[2]	8.05	9.46	9.92	10.43	11.01	11.68	12.44
Projected Avg. Price without Environmental Programs:	12.66	14.16	14.72	15.33	16.02	16.79	17.66

Impacts of Environmental Programs (Cents per kWh)

	2009	2010	2011	2012	2013	2014	2015
Projected SBC Cost:	0.16	0.16	0.08	0.00	0.00	0.00	0.00
Projected SBC Reallocation Cost:	0.00	0.00	0.08	0.17	0.17	0.17	0.17
Projected RPS Cost:	0.09	0.11	0.13	0.15	0.18	0.18	0.18
Projected EEPS Cost:	0.19	0.19	0.19	0.00	0.00	0.00	0.00
Proposed EE Program Cost	0.097	0.139	0.157	0.158	0.159	0.160	0.160
Projected RGGI Cost:	0.05	0.05	0.06	0.07	0.08	0.09	0.10
Projected Lost Delivery Revenue Cost:	0.07	0.25	0.46	0.64	0.79	0.94	1.08
Projected Delivery Price with Environmental Programs:	5.11	5.41	5.75	5.86	6.14	6.40	6.65
Projected Commodity Price with Environmental Programs:	9.02	9.36	9.74	10.18	10.69	11.29	11.98
Projected Avg. Price with Environmental Programs:	14.13	14.77	15.49	16.04	16.83	17.68	18.63

	2009	2010	2011	2012	2013	2014	2015
Proposed EE Program Cost -	$ 2,192,395	$ 5,020,070	$ 5,020,070	$ 5,020,070	$ 5,020,070	$ 5,020,070	$ 5,020,070
Lost Delivery Revenue associated with EE Program	$ 182,509	$ 383,341	$ 391,391	$ 399,610	$ 408,002	$ 416,570	$ 425,318
Total Costs associated with EE Program	$ 2,374,904	$ 5,403,411	$ 5,411,461	$ 5,419,680	$ 5,428,072	$ 5,436,640	$ 5,445,388
Total Projected Increase to bill (cents per kWh)	0.009	0.020	0.020	0.020	0.020	0.021	0.021
Levelized Increase to bill (cents per kWh)	0.019	0.019	0.019	0.019	0.019	0.019	0.019
Electric Rate Impact							
Increase in Delivery Rate	0.186%	0.420%	0.418%	0.414%	0.408%	0.402%	0.396%
Levelized Increase in Delivery Rate	0.378%	0.378%	0.378%	0.378%	0.378%	0.378%	0.378%
Increase in Overall Rate	0.068%	0.139%	0.136%	0.132%	0.128%	0.122%	0.117%
Levelized Increase in Overall Rate	0.121%	0.121%	0.121%	0.121%	0.121%	0.121%	0.121%
Electric Rate Impact per mWh saved							
Levelized Rate Impact per mWh saved - Delivery Rate	8.35%	8.35%	8.35%	8.35%	8.35%	8.35%	8.35%
Levelized Rate Impact per mWh saved - Overall Rate	2.67%	2.67%	2.67%	2.67%	2.67%	2.67%	2.67%
Electric Rate Impact per mW saved							
Levelized Rate Impact per mW saved - Delivery Rate	1.28%	1.28%	1.28%	1.28%	1.28%	1.28%	1.28%
Levelized Rate Impact per mW saved - Overall Rate	0.41%	0.41%	0.41%	0.41%	0.41%	0.41%	0.41%

(1) Delivery costs were inflated at the long-term inflation estimate of 2.1%.
(2) Commodity costs were inflated based on company-specific energy price MAPS runs and an avoided cost forecast for capacity.

National Grid - Non-Residential
Residential Pricing Pilot with Load Control

2009 Forecasted Price (Full Service Customers):	12.91
2009 Forecasted SBC Charge:	0.16
2009 Forecasted RPS Charge:	0.09
2009 Forecasted Price Excl. SBC & RPS:	12.66

	Projected 2009	Projected 2010	Projected 2011	Projected 2012	Projected 2013	Projected 2014	Projected 2015
Projected Delivery Price Without Environmental Programs:(1)	4.60	4.70	4.80	4.90	5.00	5.11	5.22
Projected Commodity Price Without Environmental Programs:(2)	8.05	9.46	9.92	10.43	11.01	11.68	12.44
Projected Avg. Price without Environmental Programs:	12.66	14.16	14.72	15.33	16.02	16.79	17.66

Impacts of Environmental Programs (Cents per kWh)

	2009	2010	2011	2012	2013	2014	2015
Projected SBC Cost:	0.16	0.16	0.08	0.00	0.00	0.00	0.00
Projected SBC Reallocation Cost:	0.00	0.00	0.08	0.17	0.17	0.17	0.17
Projected RPS Cost:	0.09	0.11	0.13	0.15	0.18	0.18	0.18
Projected EEPS Cost:	0.19	0.19	0.19	0.00	0.00	0.00	0.00
Proposed EE Program Cost	0.097	0.139	0.157	0.158	0.159	0.160	0.160
Projected RGGI Cost:	0.05	0.05	0.06	0.07	0.08	0.09	0.10
Projected Lost Delivery Revenue Cost:	0.07	0.25	0.46	0.64	0.79	0.94	1.08
Projected Delivery Price with Environmental Programs:	5.11	5.41	5.75	5.86	6.14	6.40	6.65
Projected Commodity Price with Environmental Programs:	9.02	9.36	9.74	10.18	10.69	11.29	11.98
Projected Avg. Price with Environmental Programs:	14.13	14.77	15.49	16.04	16.83	17.68	18.63
Proposed EE Program Cost -	$ 420,000	$ 1,863,750	$ 131,250	$ 131,250	$ 131,250	$ 131,250	$ 131,250
Lost Delivery Revenue associated with EE Program	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Costs associated with EE Program	$ 420,000	$ 1,863,750	$ 131,250	$ 131,250	$ 131,250	$ 131,250	$ 131,250
Total Projected Increase to bill (cents per kWh)	0.002	0.007	0.000	0.000	0.000	0.000	0.000
Levelized Increase to bill (cents per kWh)	0.002	0.002	0.002	0.002	0.002	0.002	0.002
Electric Rate Impact							
Increase in Delivery Rate	0.033%	0.145%	0.010%	0.010%	0.010%	0.010%	0.010%
Levelized Increase in Delivery Rate	0.032%	0.032%	0.032%	0.032%	0.032%	0.032%	0.032%
Increase in Overall Rate	0.012%	0.048%	0.003%	0.003%	0.003%	0.003%	0.003%
Levelized Increase in Overall Rate	0.010%	0.010%	0.010%	0.010%	0.010%	0.010%	0.010%
Electric Rate Impact per mWh saved							
Levelized Rate Impact per mWh saved - Delivery Rate	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Levelized Rate Impact per mWh saved - Overall Rate	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Electric Rate Impact per mW saved							
Levelized Rate Impact per mW saved - Delivery Rate	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Levelized Rate Impact per mW saved - Overall Rate	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

(1) Delivery costs were inflated at the long-term inflation estimate of 2.1%.
(2) Commodity costs were inflated based on company-specific energy price MAPS runs and an avoided cost forecast for capacity.

National Grid - Non-Residential
Energy Initiative

2009 Forecasted Price (Full Service Customers):	12.91
2009 Forecasted SBC Charge:	0.16
2009 Forecasted RPS Charge:	0.09
2009 Forecasted Price Excl. SBC & RPS:	12.66

	Projected 2009	Projected 2010	Projected 2011	Projected 2012	Projected 2013	Projected 2014	Projected 2015
Projected Delivery Price Without Environmental Programs:(1)	4.60	4.70	4.80	4.90	5.00	5.11	5.22
Projected Commodity Price Without Environmental Programs:(2)	8.05	9.46	9.92	10.43	11.01	11.68	12.44
Projected Avg. Price without Environmental Programs:	12.66	14.16	14.72	15.33	16.02	16.79	17.66

Impacts of Environmental Programs (Cents per kWh)

	2009	2010	2011	2012	2013	2014	2015
Projected SBC Cost:	0.16	0.16	0.08	0.00	0.00	0.00	0.00
Projected SBC Reallocation Cost:	0.00	0.00	0.08	0.17	0.17	0.17	0.17
Projected RPS Cost:	0.09	0.11	0.13	0.15	0.18	0.18	0.18
Projected EEPS Cost:	0.19	0.19	0.19	0.00	0.00	0.00	0.00
Proposed EE Program Cost	0.097	0.139	0.157	0.158	0.159	0.160	0.160
Projected RGGI Cost:	0.05	0.05	0.06	0.07	0.08	0.09	0.10
Projected Lost Delivery Revenue Cost:	0.07	0.25	0.46	0.64	0.79	0.94	1.08
Projected Delivery Price with Environmental Programs:	5.11	5.41	5.75	5.86	6.14	6.40	6.65
Projected Commodity Price with Environmental Programs:	9.02	9.36	9.74	10.18	10.69	11.29	11.98
Projected Avg. Price with Environmental Programs:	14.13	14.77	15.49	16.04	16.83	17.68	18.63

	2009	2010	2011	2012	2013	2014	2015
Proposed EE Program Cost -	$ 19,282,803	$ 24,103,504	$ 30,129,379	$ 30,129,379	$ 30,129,379	$ 30,129,379	$ 30,129,379
Lost Delivery Revenue associated with EE Program	$ 5,962,713	$ 7,609,932	$ 9,712,135	$ 9,916,090	$ 10,124,328	$ 10,336,939	$ 10,554,015
Total Costs associated with EE Program	$ 25,245,516	$ 31,713,436	$ 39,841,514	$ 40,045,469	$ 40,253,707	$ 40,466,318	$ 40,683,394
Total Projected Increase to bill (cents per kWh)	0.091	0.116	0.148	0.150	0.152	0.153	0.154
Levelized Increase to bill (cents per kWh)	0.137	0.137	0.137	0.137	0.137	0.137	0.137
Electric Rate Impact							
Increase in Delivery Rate	1.979%	2.466%	3.079%	3.060%	3.028%	2.995%	2.957%
Levelized Increase in Delivery Rate	2.799%	2.799%	2.799%	2.799%	2.799%	2.799%	2.799%
Increase in Overall Rate	0.720%	0.819%	1.004%	0.978%	0.946%	0.911%	0.874%
Levelized Increase in Overall Rate	0.895%	0.895%	0.895%	0.895%	0.895%	0.895%	0.895%
Electric Rate Impact per mWh saved							
Levelized Rate Impact per mWh saved - Delivery Rate	2.51%	2.51%	2.51%	2.51%	2.51%	2.51%	2.51%
Levelized Rate Impact per mWh saved - Overall Rate	0.80%	0.80%	0.80%	0.80%	0.80%	0.80%	0.80%
Electric Rate Impact per mW saved							
Levelized Rate Impact per mW saved - Delivery Rate	0.16%	0.16%	0.16%	0.16%	0.16%	0.16%	0.16%
Levelized Rate Impact per mW saved - Overall Rate	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%

(1) Delivery costs were inflated at the long-term inflation estimate of 2.1%.
(2) Commodity costs were inflated based on company-specific energy price MAPS runs and an avoided cost forecast for capacity.

Niagara Mohawk Power Corporation d/b/a National Grid
ENERGY EFFICIENCY PROGRAMS
2009 - 2011 ELECTRIC Cumulative Savings

Annual MWh Savings assuming the programs functions for three years

Electric Programs	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**Cumulative 2009- 2015**
Enhanced Home Sealing Incentives	676	1,916	3,155	3,155	3,155	3,155	3,155	18,367
Residential ENERGY STAR® Products and Recycling Program	4,757	14,296	23,835	23,835	23,835	23,835	23,835	138,228
Residential Internet Audit Program and E-Commerce Sales	3,001	6,002	9,003	9,003	9,003	9,003	6,002	51,018
Residential Building Practices and Demonstration Program	8,100	8,100	8,100	-	-	-	-	24,300
Energy*Wise* Program	2,378	7,271	8,510	8,510	8,510	8,510	8,510	52,200
Residential Pricing Pilot with Load Control	-	-	-	-	-	-	-	-
Energy Initiative	77,691	174,805	296,198	296,198	296,198	296,198	296,198	1,733,485
Grand Total	**96,604**	**212,390**	**348,801**	**340,701**	**340,701**	**340,701**	**337,700**	**2,017,597**

Annual MWh Savings assuming the program continues to expand and extends through 2015

Electric Programs	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**Cumulative 2009- 2015**
Enhanced Home Sealing Incentives	676	1,916	3,155	4,395	5,634	6,873	8,113	30,762
Residential ENERGY STAR® Products and Recycling Program	4,757	14,296	23,835	33,374	42,913	52,452	61,990	233,617
Residential Internet Audit Program and E-Commerce Sales	3,001	6,002	9,003	12,004	15,005	18,006	18,006	81,028
Residential Building Practices and Demonstration Program	8,100	8,100	8,100	8,100	8,100	8,100	8,100	56,700
Energy*Wise* Program	2,378	7,271	8,510	9,750	10,989	12,229	13,468	64,594
Residential Pricing Pilot with Load Control	-	-	-	-	-	-	-	-
Energy Initiative	77,691	174,805	296,198	417,590	538,983	660,375	781,768	2,947,410
Grand Total	**96,604**	**212,390**	**348,801**	**485,212**	**621,624**	**758,035**	**891,445**	**3,414,111**

Niagara Mohawk Power Corporation d/b/a National Grid
ENERGY EFFICIENCY PROGRAMS
2009 - 2011 ELECTRIC Cumulative Savings

Annual MW Savings assuming the programs functions for three years

Electric Programs	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**Cumulative 2009- 2015**
Enhanced Home Sealing Incentives	3	7	12	12	12	12	12	69
Residential ENERGY STAR® Products and Recycling Program	501	1,502	2,504	2,504	2,504	2,504	2,504	14,520
Residential Internet Audit Program and E-Commerce Sales	196	392	588	588	588	588	392	3,333
Residential Building Practices and Demonstration Program	925	925	925	-	-	-	-	2,774
Energy*Wise* Program	154	472	477	477	477	477	477	3,011
Residential Pricing Pilot with Load Control	-	-	-	-	-	-	-	-
Energy Initiative	12,082	27,184	46,062	46,062	46,062	46,062	46,062	269,575
Grand Total	**13,860**	**30,482**	**50,567**	**49,642**	**49,642**	**49,642**	**49,446**	**293,282**

Annual MW Savings assuming the program continues to expand and extends through 2015

Electric Programs	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**Cumulative 2009- 2015**
Enhanced Home Sealing Incentives	3	7	12	16	21	26	30	115
Residential ENERGY STAR® Products and Recycling Program	501	1,502	2,504	3,505	4,506	5,508	6,509	24,534
Residential Internet Audit Program and E-Commerce Sales	196	392	588	784	980	1,176	1,176	5,294
Residential Building Practices and Demonstration Program	925	925	925	925	925	925	925	6,473
Energy*Wise* Program	154	472	477	481	486	491	495	3,057
Residential Pricing Pilot with Load Control	-	-	-	-	-	-	-	-
Energy Initiative	12,082	27,184	46,062	64,940	83,817	102,695	121,573	458,353
Grand Total	**13,860**	**30,482**	**50,567**	**70,651**	**90,736**	**110,821**	**130,709**	**497,826**

Niagara Mohawk Power Corporation d/b/a National Grid
ENERGY EFFICIENCY PROGRAMS
Peak Coincidence Factor of MWh Saved in 2015

$$\text{Peak Coincidence Factor} = \frac{\text{[annual MWh saved]}}{\text{[(MW saved on peak) x (8760 hours)]}}$$

Electric Programs	**2009**	**2010**	**2011**	**2009 - 2011**
Enhanced Home Sealing Incentives	30.4	30.4	30.4	30.4
Residential ENERGY STAR® Products and Recycling Program	1.1	1.1	1.1	1.1
Residential Internet Audit Program and E-Commerce Sales	1.7	1.7	1.7	1.7
Residential Building Practices and Demonstration Program	1.0	1.0	1.0	1.0
Energy*Wise* Program	1.8	1.8	1.8	1.8
Residential Pricing Pilot with Load Control				
Energy Initiative	0.7	0.7	0.7	0.7
Grand Total	**0.8**	**0.8**	**0.8**	**0.8**

NUMBER OF PARTICIPANTS AS A PERCENTAGE OF THE NUMBER OF CUSTOMERS IN THE CLASS

Participant Type	Service Class		Electric Programs	Number of Participants 2011	Forecasted Customers in Class 2011	%
Residential	SC1		Enhanced Home Sealing Incentives	360	1,443,814	0.02%
Residential	SC1		Residential ENERGY STAR® Products and Recycling Program	18,100	1,443,814	1.25%
Residential	SC1		Residential Internet Audit Program and E-Commerce Sales	50,000	1,443,814	3.46%
Residential	SC1		Residential Building Practices and Demonstration Program	50,000	1,443,814	3.46%
Residential	SC1		Energy*Wise* Program	1,750	1,443,814	0.12%
Residential	SC1		Residential Pricing Pilot with Load Control	139	1,443,814	0.01%
Residential	SC1	*	High Efficiency Air Conditioning	690	1,443,814	0.05%
Small Business	SC2	*	Small Business Services Energy Efficiency Program	114	105,108	0.11%
Small Business	SC2D	*	Small Business Services Energy Efficiency Program	840	53,967	1.56%
Large Business	SC3		Energy Initiative	420	4,650	9.03%
Large Business	SC3A		Energy Initiative	191	351	54.42%

* Expedited programs included in the August 22, 2008 Filing.

NUMBER OF PARTICIPANTS AS A PERCENTAGE OF THE NUMBER OF CUSTOMERS IN THE CLASS

Participant Type	Gas Programs	Number of Participants 2011	Forecasted Customers in Class 2011	%
Residential	Enhanced Home Sealing Incentives	501	533,556	0.09%
Residential	Residential ENERGY STAR® Products Program	1,300	533,556	0.24%
Residential	Residential Low Income Program	4,020	533,556	0.75%
Residential	Residential Building Practices and Demonstration Program	151,080	533,556	28.32%
Non-Residential	Energy*Wise* Gas Program	5,400	47,988	11.25%
Non-Residential	Commercial and Industrial Energy Efficiency Program	1,350	47,988	2.81%
Non-Residential	Commercial High-Efficiency Heating and Water Heating Program	750	47,988	1.56%
Non-Residential	Building Practices and Demonstration Program	44	47,988	0.09%

Niagara Mohawk Power Corporation d/b/a National Grid
ENERGY EFFICIENCY PROGRAMS
2009 - 2011 TRC BENEFIT COST TEST with Carbon Externality Added

Summary of Benefit , Costs (2009 $s)
Total Resource Cost Test

	2009			2010			2011			2009 - 2011		
Electric Programs	**TRC Benefit/ Cost**	**Total NPV Benefits ($000)**	**Total NPV Costs ($000)**	**TRC Benefit/ Cost**	**Total NPV Benefits ($000)**	**Total NPV Costs ($000)**	**TRC Benefit/ Cost**	**Total NPV Benefits ($000)**	**Total NPV Costs ($000)**	**TRC Benefit/ Cost**	**Total NPV Benefits ($000)**	**Total NPV Costs ($000)**
Enhanced Home Sealing Incentives	1.01	$827	$ 815	1.18	$1,565	$ 1,324	1.30	$1,629	$ 1,255	1.18	$4,021	$ 3,394
Residential ENERGY STAR® Products and Recycling Program	1.38	$3,526	$2,548	1.95	$7,278	$3,738	2.14	$7,574	$3,543	1.87	$18,378	$9,829
Residential Internet Audit Program and E-Commerce Sales	1.84	$1,631	$887	1.97	$1,657	$840	2.16	$1,717	$797	1.98	$5,005	$2,524
Residential Building Practices and Demonstration Program	1.12	$965	$865	1.14	$934	$819	1.23	$953	$777	1.16	$2,851	$2,461
Energy*Wise* Program	1.03	$2,894	$2,812	1.03	$6,155	$5,966	1.13	$6,411	$5,655	1.07	$15,459	$14,432
Residential Pricing Pilot with Load Control	n/a	n/a	$420	n/a	n/a	$1,767	n/a	n/a	$118	n/a	n/a	$2,305
Energy Initiative	3.03	$96,045	$31,745	3.30	$123,965	$37,613	3.62	$161,357	$44,565	3.35	$381,368	$113,923
Grand Total	**2.64**	**$105,888**	**$40,091**	**2.72**	**$141,554**	**$52,067**	**3.17**	**$179,641**	**$56,709**	**2.87**	**$427,083**	**$148,867**

Summary of Benefit , Costs (2009 $s)
Total Resource Cost Test

	2009			2010			2011			2009 - 2011		
Gas Programs	**TRC Benefit/ Cost**	**Total NPV Benefits ($000)**	**Total NPV Costs ($000)**	**TRC Benefit/ Cost**	**Total NPV Benefits ($000)**	**Total NPV Costs ($000)**	**TRC Benefit/ Cost**	**Total NPV Benefits ($000)**	**Total NPV Costs ($000)**	**TRC Benefit/ Cost**	**Total NPV Benefits ($000)**	**Total NPV Costs ($000)**
Enhanced Home Sealing Incentives	0.97	$589	$ 609	1.44	$906	$ 628	1.63	$932	$ 572	1.34	$2,427	$ 1,808
Residential ENERGY STAR® Products Program	1.42	$115	$81	1.74	$197	$113	1.90	$203	$107	1.71	$516	$302
Residential Low Income Program	n/a	n/a	$5,000	n/a	n/a	$4,739	n/a	n/a	$4,492	n/a	n/a	$14,232
Residential Building Practices and Demonstration Program	1.30	$953	$736	1.59	$848	$533	2.14	$1,082	$505	1.63	$2,884	$1,774
Energy*Wise* Program	1.02	$1,062	$1,038	1.10	$1,080	$983	0.93	$862	$932	1.02	$3,004	$2,952
Commercial and Industrial Energy Efficiency Program	1.52	$5,979	$3,926	1.72	$7,344	$4,280	1.88	$8,197	$4,361	1.71	$21,520	$12,567
Commercial High-Efficiency Heating and Water Heating Program	2.36	$1,019	$432	3.22	$3,127	$970	3.44	$3,753	$1,092	3.17	$7,899	$2,494
Building Practices and Demonstration Program	3.39	$2,111	$623	3.64	$2,145	$589	3.93	$2,196	$558	3.64	$6,453	$1,770
Grand Total	**0.95**	**$11,828**	**$12,445**	**1.22**	**$15,647**	**$12,835**	**1.37**	**$17,226**	**$12,619**	**1.18**	**$44,702**	**$37,899**

Niagara Mohawk Power Corporation d/b/a National Grid

Gas Rate Impact

$/dth	2009	2010	2011	2012	2013	2014
Forecasted Average Price:	$ 13.9558	$ 13.9448	$ 13.8790	$ 13.7810	$ 13.8180	$ 14.7790
Forecasted SBC Charge:	$ 0.1246	$ 0.1242	$ 0.1239	$ 0.0007	$ 0.0007	$ 0.0007
Forecasted Price Plus SBC:	$ 14.0804	$ 14.0690	$ 14.0029	$ 13.7817	$ 13.8187	$ 14.7797

$/dth	2009	2010	2011	2012	2013	2014
Projected Delivery Price Without Environmental Programs:	$ 3.6180	$ 3.6520	$ 3.6930	$ 3.7220	$ 3.7690	$ 3.8090
Projected Commodity Price Without Environmental Programs:	$ 10.2028	$ 10.1578	$ 10.0520	$ 9.9250	$ 9.9140	$ 10.9040
Gross Revenue Tax	$ 0.1350	$ 0.1350	$ 0.1340	$ 0.1340	$ 0.1350	$ 0.0660
Total Projected Avg. Price without Environmental Programs:	**$ 13.9558**	**$ 13.9448**	**$ 13.8790**	**$ 13.7810**	**$ 13.8180**	**$ 14.7790**
Total Residential Throughput - dth	51,825,056	51,349,518	50,877,859	50,527,029	49,881,696	49,240,625

Impacts of Environmental Gas Programs

	2009	2010	2011
Program Cost			
Enhanced Home Sealing Incentives	$ 548,635	$ 572,008	$ 545,992
Residential ENERGY STAR® Products Program	$ 57,240	$ 79,291	$ 79,305
Residential Low Income Program	$ 5,000,000	$ 5,000,000	$ 5,000,000
Residential Building Practices and Demonstration Program	$ 694,203	$ 612,307	$ 612,544
Total Program Cost	$ 6,300,078	$ 6,263,606	$ 6,237,841
Program Cost per dth			
Enhanced Home Sealing Incentives	$ 0.0106	$ 0.0110	$ 0.0105
Residential ENERGY STAR® Products Program	$ 0.0011	$ 0.0015	$ 0.0015
Residential Low Income Program	$ 0.0965	$ 0.0965	$ 0.0965
Residential Building Practices and Demonstration Program	$ 0.0134	$ 0.0118	$ 0.0118
Total Program Cost per dth	$ 0.1216	$ 0.1209	$ 0.1204
Projected Delivery Rate Impact			
Enhanced Home Sealing Incentives	0.2926%	0.3022%	0.2853%
Residential ENERGY STAR® Products Program	0.0305%	0.0419%	0.0414%
Residential Low Income Program	2.6666%	2.6418%	2.6125%
Residential Building Practices and Demonstration Program	0.3702%	0.3235%	0.3201%
Total Projected Delivery Price with Environmental Programs	3.3600%	3.3094%	3.2592%
Projected Delivery Rate plus Commodity Impact			
Enhanced Home Sealing Incentives	0.0766%	0.0799%	0.0766%
Residential ENERGY STAR® Products Program	0.0080%	0.0111%	0.0111%
Residential Low Income Program	0.6981%	0.6986%	0.7019%
Residential Building Practices and Demonstration Program	0.0969%	0.0856%	0.0860%
Total Projected Delivery Price with Environmental Programs	0.8796%	0.8752%	0.8757%

Niagara Mohawk Power Corporation d/b/a National Grid

Impacts of Projected Lost Delivery Revenue - Collected through Lost Revenue Recovery Mechanism or RDM

	2009	2010	2011			
MMBTU Savings						
Enhanced Home Sealing Incentives	4,140	6,227	6,227			
Residential ENERGY STAR® Products Program	606	1,009	1,009			
Residential Low Income Program	0	0	0			
Residential Building Practices and Demonstration Program	73,152	69,750	69,750			
Total Savings	77,898	76,986	76,986			
	2009	**2010**	**2011**	**2012**	**2013**	**2014**
MMBTU Savings Accumulated						
Enhanced Home Sealing Incentives	4,140	10,367	16,594	16,594	16,594	16,594
Residential ENERGY STAR® Products Program	606	1,615	2,624	2,624	2,624	2,624
Residential Low Income Program	0	0	0	0	0	0
Residential Building Practices and Demonstration Program	73,152	73,152	69,750	0	0	0
Total Savings Accumulated	77,898	85,134	88,968	19,218	19,218	19,218
	2009	**2010**	**2011**	**2012**	**2013**	**2014**
Lost Delivery Revenue						
Enhanced Home Sealing Incentives	$ 8,267	$ 20,701	$ 33,135	$ 33,135	$ 33,135	$ 33,135
Residential ENERGY STAR® Products Program	$ 1,210	$ 3,225	$ 5,240	$ 5,240	$ 5,240	$ 5,240
Residential Low Income Program	$ -	$ -	$ -	$ -	$ -	$ -
Residential Building Practices and Demonstration Program	$ 150,379	$ 150,379	$ 143,386	$ -	$ -	$ -
Total Lost Revenues	$ 159,856	$ 174,305	$ 181,760	$ 38,375	$ 38,375	$ 38,375
Lost Delivery Revenue per dth						
Enhanced Home Sealing Incentives	$ 0.0002	$ 0.0004	$ 0.0006	$ 0.0006	$ 0.0006	$ 0.0006
Residential ENERGY STAR® Products Program	$ 0.0000	$ 0.0001	$ 0.0001	$ 0.0001	$ 0.0001	$ 0.0001
Residential Low Income Program	$ -	$ -	$ -	$ -	$ -	$ -
Residential Building Practices and Demonstration Program	$ 0.0029	$ 0.0029	$ 0.0028	$ -	$ -	$ -
Total Lost Delivery Revenue per dth	$ 0.0031	$ 0.0034	$ 0.0035	$ 0.0007	$ 0.0007	$ 0.0007
Gas Rate Impacts - Percentage Increase						
Due to Lost Delivery Revenue	0.0853%	0.0921%	0.0950%	0.0199%	0.0196%	0.0194%
Due to Lost Delivery Revenue + Program Cost/ Delivery Price	3.4452%	3.4015%	3.3542%	0.0199%	0.0196%	0.0194%
Due to Lost Delivery Revenue + Program Cost/ Delivery Plus Commodity	0.8932%	0.8908%	0.8925%	0.0054%	0.0054%	0.0050%
Gas Delivery Rate Impact per dth saved [$/dth]	$82.9281	$75.6209	$72.1563			

Assumptions:

Screening Metric 9 has been calculated as of 2011 as the number of Program Participants is only available as of 2011.
Screening Metric 11 has been calculated by summing the program cost and the estimated lost revenue and dividing by the accumulated MMBTU's saved.
Screening Metric 11 is affected by the fact that the Low Income Program does not contain any MMBTU's saved.
These metrics have not been "levelized" as indicated by the June 23, 2008 Order.
The MMBTU's saved have been reflected at 100% rather than ramped up at a lower level.

Niagara Mohawk Power Corporation d/b/a National Grid

Non-Residential

	2009	2010	2011			
Gas Rate Impact						
$/dth	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**
Forecasted Average Price:	$ 11.5260	$ 11.4760	$ 11.3830	$ 11.2770	$ 11.2770	$ 12.1240
Forecasted SBC Charge:	$ 0.0831	$ 0.1000	$ 0.1126	$ 0.0167	$ 0.0167	$ 0.0167
Forecasted Price Plus SBC:	$ 11.6091	$ 11.5760	$ 11.4956	$ 11.2937	$ 11.2937	$ 12.1407
$/dth	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**
Projected Delivery Price Without Environmental Programs:	$ 1.4920	$ 1.5000	$ 1.5120	$ 1.5210	$ 1.5320	$ 1.5410
Projected Commodity Price Without Environmental Programs:	$ 10.0140	$ 9.9560	$ 9.8510	$ 9.7360	$ 9.7240	$ 10.5600
Gross Revenue Tax	$ 0.0200	$ 0.0200	$ 0.0200	$ 0.0200	$ 0.0210	$ 0.0230
Total Projected Avg. Price without Environmental Programs:	**$ 11.5260**	**$ 11.4760**	**$ 11.3830**	**$ 11.2770**	**$ 11.2770**	**$ 12.1240**
Throughput - dth	47,016,102	47,114,822	47,133,581	47,175,073	46,991,058	46,671,690

Impacts of Environmental Gas Programs

	2009	2010	2011
Program Cost			
Energy*Wise* Program	$ 637,565	$ 636,689	$ 636,826
Commercial and Industrial Energy Efficiency Program	$ 2,372,685	$ 2,584,089	$ 2,754,544
Commercial High-Efficiency Heating and Water Heating Program	$ 292,000	$ 603,750	$ 725,340
Building Practices and Demonstration Program	$ 389,665	$ 388,138	$ 388,138
Total Program Cost	$ 3,691,915	$ 4,212,666	$ 4,504,848
Program Cost per dth			
Energy*Wise* Program	$ 0.0136	$ 0.0135	$ 0.0135
Commercial and Industrial Energy Efficiency Program	$ 0.0505	$ 0.0550	$ 0.0586
Commercial High-Efficiency Heating and Water Heating Program	$ 0.0062	$ 0.0128	$ 0.0154
Building Practices and Demonstration Program	$ 0.0083	$ 0.0083	$ 0.0083
Total Program Cost	$ 0.0785	$ 0.0896	$ 0.0958
Projected Delivery Rate Impact			
Energy*Wise* Program	0.9089%	0.9028%	0.8958%
Commercial and Industrial Energy Efficiency Program	3.3824%	3.6641%	3.8748%
Commercial High-Efficiency Heating and Water Heating Program	0.4163%	0.8561%	1.0203%
Building Practices and Demonstration Program	0.5555%	0.5504%	0.5460%
Total Projected Delivery Price with Environmental Programs	5.2630%	5.9734%	6.3370%
Projected Delivery Rate plus Commodity Impact			
Energy*Wise* Program	0.1179%	0.1182%	0.1192%
Commercial and Industrial Energy Efficiency Program	0.4386%	0.4798%	0.5156%
Commercial High-Efficiency Heating and Water Heating Program	0.0540%	0.1121%	0.1358%
Building Practices and Demonstration Program	0.0720%	0.0721%	0.0727%
Total Projected Delivery Price with Environmental Programs	0.6825%	0.7821%	0.8432%

Niagara Mohawk Power Corporation d/b/a National Grid

Impacts of Projected Lost Delivery Revenue - Collected through Lost Revenue Recovery Mechanism or RDM

	2009	2010	2011	2012	2013	2014
MMBTU Savings						
Energy*Wise* Program	9,396	9,396	9,396			
Commercial and Industrial Energy Efficiency Program	57,683	69,911	76,405			
Commercial High-Efficiency Heating and Water Heating Program	7,164	21,492	25,074			
Building Practices and Demonstration Program	19,047	19,046	19,046			
Total Savings	93,290	119,845	129,921			

	2009	2010	2011	2012	2013	2014
MMBTU Savings Accumulated						
Energy*Wise* Program	9,396	18,792	28,188	28,188	28,188	28,188
Commercial and Industrial Energy Efficiency Program	57,683	127,594	203,999	203,999	203,999	203,999
Commercial High-Efficiency Heating and Water Heating Program	7,164	28,656	53,730	53,730	53,730	53,730
Building Practices and Demonstration Program	19,047	38,093	57,139	57,139	57,139	57,139
Total Savings Accumulated	93,290	213,135	343,056	343,056	343,056	343,056

	2009	2010	2011	2012	2013	2014
Lost Delivery Revenue						
Energy*Wise* Program	$ 21,825	$ 43,650	$ 65,475	$ 65,475	$ 65,475	$ 65,475
Commercial and Industrial Energy Efficiency Program	$ 132,148	$ 292,309	$ 467,348	$ 467,348	$ 467,348	$ 467,348
Commercial High-Efficiency Heating and Water Heating Program	$ 16,412	$ 65,649	$ 123,092	$ 123,092	$ 123,092	$ 123,092
Building Practices and Demonstration Program	$ 43,635	$ 87,269	$ 130,902	$ 130,902	$ 130,902	$ 130,902
Total Lost Revenues	$ 214,021	$ 488,877	$ 786,817	$ 786,817	$ 786,817	$ 786,817
Lost Delivery Revenue per dth						
Energy*Wise* Program	$ 0.0005	$ 0.0009	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014
Commercial and Industrial Energy Efficiency Program	$ 0.0028	$ 0.0062	$ 0.0099	$ 0.0099	$ 0.0099	$ 0.0099
Commercial High-Efficiency Heating and Water Heating Program	$ 0.0003	$ 0.0014	$ 0.0026	$ 0.0026	$ 0.0026	$ 0.0026
Building Practices and Demonstration Program	$ 0.0009	$ 0.0019	$ 0.0028	$ 0.0028	$ 0.0028	$ 0.0028
Total Lost Delivery Revenue per dth	$ 0.0046	$ 0.0104	$ 0.0167	$ 0.0167	$ 0.0167	$ 0.0167

Gas Rate Impacts - Percentage Increase						
Due to Lost Delivery Revenue	0.3051%	0.6932%	1.1068%	1.1003%	1.0924%	1.0860%
Due to Lost Delivery Revenue + Program Cost/ Delivery Price	5.5681%	6.6666%	7.4438%	1.1003%	1.0924%	1.0860%
Due to Lost Delivery Revenue + Program Cost/ Delivery Plus Commodity	0.7208%	0.8714%	0.9888%	0.1484%	0.1484%	0.1380%

Gas Delivery Rate Impact per dth saved [$/dth]	$41.8688	$22.0590	$15.4251

Assumptions:

Screening Metric 9 has been calculated as of 2011 as the number of Program Participants is only available as of 2011.
Screening Metric 11 has been calculated by summing the program cost and the estimated lost revenue and dividing by the accumulated MMBTU's saved.
These metrics have not been "levelized" as indicated by the June 23, 2008 Order.
The MMBTU's saved have been reflected at 100% rather than ramped up at a lower level.

Appendix G

APPENDIX G

Sample Status Report

Year to Date June 2008[1]

New York

Residential

PROGRAM/INITIATIVE	Program Planning & Administration Expenditures YTD	Program Marketing Expenditures YTD	Customer Incentives Expenditures YTD	Program Implementation Expenditures YTD	Evaluation & Market Research Expenditures YTD	Total Expenditures YTD	2007 - 2008 Budget YTD	Annual 2007 - 2008 Budget	No. of Rebates or Participants YTD	Participant Goal YTD	Annual Participant 2007-2008 Goals	Total Annual Savings (Therms) YTD	Savings Goal YTD	Annual Savings 2007-2008 Goals
Residential														
ENERGY STAR Homes	$4,124	$8,676	$0	$151	$302	$13,253	$131,668	$274,309	0	96	200	0	26,304	54,800
High Efficiency Heating Rebate	$25,159	$87,113	$16,989	($1,660)	$1,844	$129,446	$765,678	$1,595,162	43	720	1,500	7,095	126,000	262,500
High Efficiency Water Heating Rebate	$19,920	$74,312	$6,600	$198	$1,460	$102,491	$131,542	$274,046	33	192	400	2,541	15,168	31,600
Insulation & Air Sealing	$32,370	$111,530	$18,153	$2,121	$2,373	$166,547	$319,705	$666,052	36	240	500	13,248	88,320	184,000
Energy Analysis: Internet Audit Guide	$25,094	$84,329	$0	$17,849	$1,840	$129,111	$15,068	$31,392	2,070	1,200	2,500	N/A	N/A	N/A
Residential Technology Demonstration	$18,951	$65,145	$2,101	$0	$1,246	$87,443	$19,426	$40,471	1	5	10	0	1,680	3,500
Energy Audit/Home Performance	$61,263	$148,510	$24,766	$76,175	$4,491	$315,206	$261,346	$544,470	294	480	1,000	N/A	N/A	N/A
Energy Star Products[2]	$40,447	$149,926	$13,441	$1,327	$2,965	$208,106	$164,605	$342,927	457	2,400	5,000	15,193	180,000	375,000
Total Residential	**$227,326**	**$729,542**	**$82,051**	**$96,161**	**$16,523**	**$1,151,602**	**$1,809,038**	**$3,768,829**	**2,934**	**5,333**	**11,110**	**38,077**	**437,472**	**911,400**

PROGRAM/INITIATIVE	Program Planning & Administration Expenditures YTD	Program Marketing Expenditures YTD	Customer Incentives Expenditures YTD	Program Implementation Expenditures YTD	Evaluation & Market Research Expenditures YTD	Total Expenditures YTD	2007 - 2008 Budget YTD	Annual 2007 - 2008 Budget	No. of Rebates or Participants YTD	Participant Goal YTD	Annual Participant 2007-2008 Goals	Total Annual Savings (Therms) YTD	Savings Goal YTD	Annual Savings 2007-2008 Goals
Low-Income	$706,686	$2,892	$1,490,205	$19,248	$51,809	$2,270,840	$2,823,530	$5,882,354	839	842	1,754	283,582	284,569	592,852
Total Low-Income	**$706,686**	**$2,892**	**$1,490,205**	**$19,248**	**$51,809**	**$2,270,840**	**$2,823,530**	**$5,882,354**	**839**	**842**	**1,754**	**283,582**	**284,569**	**592,852**

Commercial and Multifamily

PROGRAM/INITIATIVE	Program Planning & Administration Expenditures YTD	Program Marketing Expenditures YTD	Customer Incentives Expenditures YTD	Program Implementation Expenditures YTD	Evaluation & Market Research Expenditures YTD	Total Expenditures YTD	2007 - 2008 Budget YTD	Annual 2007 - 2008 Budget	No. of Rebates or Participants YTD	Participant Goal YTD	Annual Participant 2007-2008 Goals	Total Annual Savings (Therms) YTD	Savings Goal YTD	Annual Savings 2007-2008 Goals
Commercial & Industrial														
C&I and Multifamily High Efficiency Heating Rebate	$44,256	$100,186	$8,900	$71,116	$3,245	$227,702	$548,054	$1,141,780	23	192	400	1,100	248,640	518,000
C&I Building Practices & Demonstrations	$4,241	$12,867	$0	$4,403	$311	$21,822	$419,727	$874,432	0	7	14	0	170,587	355,390
Economic Redevelopment	$6,905	$20,629	$0	$7,486	$506	$35,526	$777,756	$1,620,324	0	11	22	0	149,815	312,114
Multi-Family Energy Efficiency	$37,190	$98,887	$52,545	$0	$2,727	$191,348	$1,694,230	$3,529,645	6	188	392	3,021	381,588	794,976
Commercial Energy Efficiency	$14,773	$40,986	$10,960	$4,224	$1,025	$71,968	$1,052,314	$2,192,321	18	431	898	295,692	402,160	837,834
Business Analyzer: Internet Audit	$4,392	$13,732	$0	$2,798	$3,128	$24,050	$155,352	$323,651	60	1,358	2,830	N/A	N/A	N/A
Total C&I	**$111,757**	**$287,286**	**$72,405**	**$90,026**	**$10,941**	**$572,416**	**$4,647,433**	**$9,682,153**	**107**	**2,187**	**4,556**	**299,813**	**1,352,791**	**2,818,314**
On-Bill Financing	**$0**					**$0**	**$320,000**	**$666,667**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**
PROGRAM TOTALS	**$1,045,769**	**$1,019,720**	**$1,644,661**	**$205,435**	**$79,273**	**$3,994,858**	**$9,600,001**	**$20,000,003**	**3,880**	**8,362**	**17,420**	**621,472**	**2,074,832**	**4,322,566**

*The credits shown above reflect the sum of charges and corrections from the beginning of the program year.

[1]June YTD includes activity from September 1 through December 31 (Interim Program)

[2]The methodology for capturing participants has changed from per window to per rebate for the windows program within the Energy Star Products program.

Appendix H

APPENDIX H

PSC 207 Electricity SBC Statement 14 and Workpapers

Statement No. 14
Applicable to:
P.S.C. No. 207 Electricity and
P.S.C. No. 214 Electricity

NIAGARA MOHAWK POWER CORPORATION
STATEMENT OF SYSTEM BENEFITS CHARGE
EFFECTIVE: JANUARY 1, 2009
APPLICABLE TO BILLINGS UNDER P.S.C. NO. 207 and 214 ELECTRICITY

	Per kWh
SBC Effective Rate of Adjustment Per SBC III (Case No. 05-M-0090, issued December 21, 2005)	$0.001600
NYSERDA "Fast Track" and "Expedited" Utility Programs (Case No. 07-M-0548, issued June 23, 2008)	$0.001815
Company SBC EE Rate of Adjustment	$0.001050
SBC TOTAL RATE OF ADJUSTMENT-EFFECTIVE JANUARY 1, 2009	$0.004465

Service Classifications subject to the System Benefits Charge Rate of Adjustment are defined in Rule 41 of the general electric tariff.

Rate of Adjustment shown is exclusive of Gross Receipt Taxes

Issued by: Thomas B. King, President, Syracuse, New York
Dated:

Development of SBC 14 Collection Rate

			Factor of Adjustment
Line 1	SBC Adjustment Factor per SBC III, Issued December 21, 2005 in Case No. 05-M-0090-Effective January 1, 2009-December 31, 2009	$45,057,668	**$0.001600**
Line 2	SBC Adjustment Factor for "Fast Track" NYSERDA and "Expedited" Utility Programs in Case No. 07-M-0548-Issued June 23, 2008. Effective January 1, 2009-December 31, 2009	$51,255,023	**$0.001815**
Line 3	Company's SBC collection amount for January 1, 2009-December 31, 2009		
	(a) Program Costs (Planning, Marketing, Implementation, Research)	$23,222,115	
	(b) Lost Revenue	$2,543,911	
	(c) Shareholder Incentive	$3,753,058	
	(d) Total Collection Amount	$29,519,084	**$0.001050**
Line 4	2009 Forecast Sales subject to SBC(kWh) (Appendix H, Page 3 of 3)	28,237,284,647	
Line 5	**Total SBC Factor Effective January 1, 2009 (Line 1 + Line 2 + Line 3(d))**		**$0.004465**

Footnotes:

Line 1 Estimated 2009 SBC Adjustment Factor based on Company specific $45,057,668 collection in SBC III-Case No. 05-M-0090, effective December 21, 2005.

Line 2 Company specific collection for 2009 "Fast Track" NYSERDA Programs of $27,376,785 and "Expedited" Utility programs of $23,878,238 per Case No. 07-M-0548.

Line 3 Company's Total SBC Collection Amount by Program Costs, Lost Revenue, and Shareholder Incentive.

Line 4 Forecast Sales subject to SBC for Calendar Year 2009 per Company's Third CTC Reset in Case No. 01-M-0075 (Attachment 3).

Line 5 Total SBC 14 adjustment factor effective January 1, 2009.

Company Applicable Sales (kWh) for the Collection Period of January 1, 2009-December 31, 2009

	Forecasted Sales January 1, 2009-December 31. 2009 (1)	Sales Subject To SBC
PSC 207		
SC1,1C	11,544,600,000	11,544,600,000
SC2 ND/D	5,257,918,000	5,257,918,000
SC3	6,742,488,000	6,742,488,000
SC3A	3,877,200,000	3,877,200,000
SC4	271,980,000	271,980,000
SC7	210,678,427	210,678,427
SC11&12(2)	2,465,451,000	542,399,220
PSC 214	223,670,000	223,670,000
Ind. Spec.	3,764,257,000	0
PFJR	794,144,767	0
EDPR	127,311,233	0
EZR (3)	0	(433,649,000)
Total	35,279,698,427	28,237,284,647

Note 1: Forecast for 2009 is from the Company's Third CTC Reset CY09 sales forecast as updated in Information Request No. 38 submitted to the Commission on October 29, 2007 in Case No.01-M-0075.

Note 2: Assumes 22% of customers' use served on SC Nos. 11 and 12 are subject to the SBC during the forecast period January 1, 2009 through December 31, 2009.

Note 3: EZR sales are not subject to the SBC. The sales are treated as a credit because EZR sales are included within the PSC 207 sales, above. This EZR forecast is from the Company's Third CTC Reset Forecast as noted in Note 1 above.

Appendix I

APPENDIX I

Determination of Electric Lost Revenue

EXPLANATION OF DETERMINATION OF LOST REVENUE AND ANNUAL RECONCILIATION

1.0 INTRODUCTION

1.1 This document explains the determination of lost revenues arising from the approval of National Grid's proposed electric energy efficiency Programs for 2009 through 2011 as submitted in compliance with Case 07-M-0548 on September 22, 2008 in regard to fast track programs and on August 22, 2008 in regard to expedited fast track programs. An explanation is provided for the initial 12-month forecast of lost revenues from January 1, 2009 through December 31, 2009, the proposed method of reconciling this initial 12-month forecast with actual lost revenues, and an illustration of the method of forecasting the remaining two years of the electric energy efficiency programs that incorporates the annual reconciliation of forecasted to actual lost revenues.

2.0 2009 FORECAST OF LOST REVENUES

2.1 Lost revenues are defined as the product of the forecasted annual number of participants for a given energy efficiency program, the estimated annual kWh savings per participant per energy efficiency program, and the estimated unit lost revenue factor expressed in dollars per kWh applicable to that program.

2.2 The forecasted annual number of participants for a given energy efficiency program and the estimated annual kWh savings per energy efficiency program are specified in the *Electric and Gas Energy Efficiency Program Proposals* document. The estimated unit lost revenue factor expressed in dollars per kWh is determined in Appendix I, Schedule 2.

2.3 For 2009, the development of estimated unit lost revenue factor for each PSC No. 207 Electricity Tariff Service Classification affected is shown on page 2 of Appendix I, Schedule 2. Unit base rate lost revenue factors for each service classification are developed from 2009 base rates as approved by the Commission in the Company's Third CTC Reset Compliance proceeding in Case 01-M-0075 in December 2007 by multiplying the service class billing determinants times the approved usage-based rates then dividing the resulting product by total service class kWh to produce a unit base rate lost revenue factor. Forecasted 2009 Transmission Revenue Adjustment Charge (TRAC) and 2009 Commodity Adjustment Charge (CAC)

EXPLANATION OF DETERMINATION OF LOST REVENUE AND ANNUAL RECONCILIATION

factors[1] are added to the unit base rate lost revenue factor to produce the service class unit lost revenue factor. All forecasted billing determinants, TRAC factor, and CAC factors are from the Company's Response to Information Request No. 38 in Case 01-M-0075 Third CTC Reset Compliance proceeding submitted to the Commission on October 29, 2007. These calculations are shown page 2 of Appendix I, Schedule 2.

2.4 The calculation in Section 2.3 above yields average lost revenue factors based on the properties of the entire service classifications. This is appropriate because the Company has no historical basis upon which to develop a more precise calculation reflective of the billing determinant characteristics of energy efficiency program recipients. Customer charge revenues for each service class are excluded from the calculations as such revenues are not lost as a result of installing energy efficiency measures. Certain adjustments are made in developing the Service Classification Nos. 3 and 3-A lost revenue factors as stated in the footnotes on page 3 of Appendix I, Schedule 2.

2.5 The forecasted lost revenues computed in Sections 2.2 through 2.4 as shown on page 1 of Appendix I, Schedule 2 as Total Lost Revenue are the full year value of lost revenue. Since the energy efficiency measures giving rise to the lost revenue will occur ratably over the entire year only a fraction of the full year lost revenue will be incurred in 2009. Thus, the Company has reduced the forecasted lost revenue to be recovered in the System Benefits Charge (SBC) under Rule No. 41 of PSC 207 Electricity from January 1, 2009 through December 31, 2009 to one-half the full year value. This reduction or de-rating procedure will be required for the incremental energy efficiency program spending in each year.

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[1] In subsequent year forecasts and reconciliations of forecasted lost revenues with actual lost revenues, lost or gained revenues attributable to PSC 207 Electricity Rule 40, NYPA Residential Hydropower Benefit, will be accounted for and unit factors will be developed. The forecasted 2009 NYPA Residential Hydropower Benefit is zero.

EXPLANATION OF DETERMINATION OF LOST REVENUE AND ANNUAL RECONCILIATION

3.0 RECONCILATION OF FORECASTED AND ACTUAL LOST REVENUES

3.1 Forecasted and actual lost revenues are reconciled by subtracting the forecasted lost revenues calculated in Section 2.5 above from the actual lost revenues.

3.2 Actual lost revenues are the product of the average number of participants for a given energy efficiency program during a program year, the estimated annual kWh savings per participant per energy efficiency program, and the actual unit lost revenue factor based on the program participants' service classifications, voltage delivery levels, and twelve-month historical billing determinants prior to the installation of the energy efficiency measures.

3.3 For 2010, the actual lost revenue calculation will be based on ten months actual data (January 2009 through October 2009). For 2011 and 2012, the actual lost revenue calculation will be based on twelve months actual data (November and December of two years prior, and January through October of the prior year). In 2012, a change in the SBC Energy Efficiency ('EE") Adjustment for the actual lost revenue calculation based on two months actual data (November and December 2011) will be proposed by the Company for effect from March 1, 2012 through December 31, 2012.

4.0 FORECAST OF FOLLOWING YEARS' LOST REVENUE

4.1 For 2010 and 2011, the lost revenue is defined as in Section 2 above, but the calculation is altered to take into account information gained from program experience. Specifically, a better estimate of unit lost revenue factors is provided by the actual unit lost revenue factor based on the program participants' service classifications, voltage delivery levels, and twelve-month historical billing determinants prior to the installation of the energy efficiency measures

4.2 The forecasted lost revenue for recovery in the EE Adjustment for any given year is the algebraic sum of the over/under recovery of lost revenue for the previous year, the expected lost revenue in the current year for measures installed in the previous year and the forecasted lost revenue for the current for measures to be installed in the current year. Lost revenue is cumulative. The lost revenue attributable to efficiency

EXPLANATION OF DETERMINATION OF LOST REVENUE AND ANNUAL RECONCILIATION

measures installed in the prior years of the programs must be accounted for in each year's forecasted lost revenue for recovery through the SBC.

4.3 The computation of the over/under recovery of lost revenue for prior years is discussed in Section 3 above.

4.4 The expected lost revenue in the current year for measures installed in the prior year is the product of the annual number of participants for a given energy efficiency program during the prior year, the estimated annual kWh savings per participant per energy efficiency program, and the forecasted unit lost revenue factor for the current year based on current year unit base rates developed from the program participants' service classifications, voltage delivery levels, and twelve-month historical billing determinants prior to the installation of the energy efficiency measures during the prior year plus forecasted current year TRAC and CAC factors.

4.5 Forecasted lost revenue for the current year for measures to be installed in the current year is one-half of the product of the forecasted annual number of participants for a given energy efficiency program for the current year from the *Electric and Gas Energy Efficiency Program Proposals* document, the estimated annual kWh savings per participant per energy efficiency program, and the forecasted unit lost revenue factor for the current year based on the current year unit base rates developed from the program participants' service classifications, voltage delivery levels, and twelve-month historical billing determinants prior to the installation of the energy efficiency measures during prior year plus forecasted current year TRAC and CAC factors.

CALCULATION OF LOST REVENUE
FOR ELECTRIC ENERGY EFFICIENCY PROGRAMS
2009

Participant Type	Service Class		Program	Number of Participants	Annual kWh Saved per Participant	Total Annual kWh's saved	Per kWh lost revenue	Total Lost Revenue
Residential	SC1	*	High Efficiency Air Conditioning	690	143	98,532	0.05130	5,055
Residential	SC1		Residential ENERGY STAR® Products Program	18,100	263	4,757,230	0.05130	244,046
Residential	SC1		Residential Internet Audit Program and E-Commerce Sales	50,000	60	3,001,050	0.05130	153,954
Residential	SC1		Residential Building Practices and Demonstration Program	50,000	162	8,100,000	0.05130	415,530
Residential	SC1		EnergyWise	1,750	1,359	2,378,250	0.05130	122,004
Residential	SC1		Enhanced Home Sealing Incentives	360	1,878	676,080	0.05130	34,683
Small Business	SC2	*	Small Business Services Energy Efficiency Program	114	14,209	1,617,527	0.06510	105,301
Small Business	SC2D	*	Small Business Services Energy Efficiency Program	840	14,209	11,933,248	0.05400	644,395
Large Business	SC3 - Sec.		Energy Initiative	271	127,139	34,457,558	0.05724	1,972,351
	SC3 - Pri			121	127,139	15,380,435	0.04871	749,181
	SC3 - Subt			28	127,139	3,589,551	0.04205	150,941
	SC3A - Sec.			26	127,139	3,355,320	0.02669	89,553
	SC3A - Pri			69	127,139	8,721,913	0.02314	201,825
	SC3A - Subt			96	127,139	12,186,415	0.01633	199,004
				611		77,691,192		3,362,855
				122,465		**110,253,109**		**$ 5,087,823**
					First Year Implementation De-rating Factor			**50%**
								$ 2,543,911

* Expedited programs included in the August 22, 2008 Filing.

CALCULATION OF PER KWH LOST REVENUE RATES
FOR ELECTRIC ENERGY EFFICIENCY PROGRAMS
2009

	kWhr				Rates effective 1/1/2009					Per kWhr	Per kWhr Revised			
			Total kWhr	KW	per kWh	per kWh	per KW	Demand Revenue	Energy Revenue	Total Revenue	Assumptions (1) (2)	TRAC	CAC	**Total**
SC1			11,099,536,789		$ 0.04846			$ -	$ 537,855,537	0.04846	0.04846	0.00218	0.00066	**0.05130**
SC1C			445,063,211		$ 0.03867			$ -	$ 17,208,955	0.03867	0.03867	0.00258	0.00066	**0.04191**
SC2			630,434,754		$ 0.06169			$ -	$ 38,893,125	0.06169	0.06169	0.00293	0.00048	**0.06510**
SC2D			4,651,009,088	15,501,150	$ 0.01748		$ 10.10	$ 156,561,620	$ 81,301,871	0.05114	0.05114	0.00284	0.00002	**0.05400**
	Block 1	Block 2			Block 1	Block 2								
SC3 Sec	4,516,315,260	311,494,217	4,827,809,477	12,458,926	$ 0.01135	$ 0.00384	$ 16.65	$ 207,453,240	$ 52,453,846	0.05384	0.05432	0.00292		**0.05724**
SC3 Pri	1,954,454,088	200,481,194	2,154,935,281	4,946,487	$ 0.01351	$ 0.00521	$ 14.20	$ 70,249,286	$ 27,450,570	0.04534	0.04611	0.00260		**0.04871**
SC3 Sub	459,798,813	43,129,095	502,927,909	1,326,634	$ 0.01314	$ 0.00530	$ 9.70	$ 12,863,192	$ 6,272,395	0.03805	0.03872	0.00332		**0.04205**
SC3 Tran	72,782,699	8,443,961	81,226,660	192,164	$ 0.01211	$ 0.00458	$ 9.31	$ 1,789,059	$ 920,107	0.03335	0.03414	0.00133		**0.03547**
	1st Block kWhr (250 hrs.)				1st Block kWhr									
	On	Off			On	Off								
SC3A Sec	75,274,367	79,774,397	470,110,101	974,470	$ 0.00400	$ 0.00292	$ 11.35	$ 11,055,413	$ 533,753	0.02465	0.02352	0.00318		**0.02669**
SC3A Pri	271,952,265	316,867,391	1,222,017,322	2,545,300	$ 0.00512	$ 0.00387	$ 9.96	$ 25,362,103	$ 2,619,477	0.02290	0.02075	0.00239		**0.02314**
SC3A Sub	381,469,093	429,335,678	1,707,424,812	3,447,709	$ 0.00562	$ 0.00429	$ 7.31	$ 25,188,955	$ 3,985,838	0.01709	0.01475	0.00158		**0.01633**
SC3A Tran	795,517,076	1,007,281,154	3,371,964,791	7,555,324	$ 0.00365	$ 0.00284	$ 6.23	$ 47,062,513	$ 5,760,090	0.01567	0.01396	0.00081		**0.01476**
			31,164,460,194	48,948,165.7										

(1) Per kWhr rate = Demand Revenue / Total kWhr + per kWhr rate for Block 1. Average hours use does not cause the average customer to have kWhr in the second block.

SC3 Sec	387	(kWhr/KW)
SC3 Pri	436	
SC3 Sub	379	
SC3 Tran	423	

(2) Assumes that SC3A customers will not see any reduction in KWhr in 1st Block, which is where all the volumetric charge is.

Appendix J

APPENDIX J

Determination of Gas Lost Revenue

Determination of Gas Lost Revenue

Until such time as the Company implements a Revenue Decoupling Mechanism approved by the Public Service Commission, the Company is entitled to recover Lost Revenue arising from the approval of gas energy efficiency programs for 2009-2011 submitted in compliance with Case No. 07-M-0548 on September 22, 2008 in regard to fast track programs and on August 22, 2008 in regard to one expedited fast track program. If the approved Revenue Decoupling Mechanism does not apply to every service classification participating in the gas energy efficiency programs, lost revenues will continue to be calculated and recovered from the participating firm service classes not subject to a revenue decoupling mechanism.

The Company will be allowed to defer its Lost Revenue net of the associated deferred New York State and federal income taxes, plus carrying charges at the same rate as the allowance for funds used during construction (AFUDC), for later recovery from customers. The Company's Lost Revenue will be calculated pursuant to the method set forth in the Joint Proposal for Interim Energy Efficiency Programs, which was filed on August 1, 2008 and adopted by the Commission on September 18, 2008 in Case 08-G-0609. Such Lost Revenue will be recovered through an increase to the Company's existing System Benefits Charge for all customers in Service Class Nos. 1, 2, 3, 5, 7, 8, 12 and 13 upon approval of the programs in this proceeding.

Appendix K

APPENDIX K

Performance Incentives

Niagara Mohawk Power Corporation d/b/a National Grid
Performance-Based Shareholder Incentive - Electric Energy Efficiency Programs

	(1)	(2)	(3)	(4)	(5)	(6)
Year	Annual Savings Goal (MWh)	Threshold Savings (MWh)	Incentive Per MWh	Maximum Potential Incentive	Annual Savings Threshold Subject to a Penalty (MWh)	Maximum Potential Penalty
2009	96,604	77,283	$38.85	$3,753,058	67,623	$1,876,529
2010	123,886	99,109	$38.85	$4,812,963	86,720	$2,406,481
2011	148,164	118,531	$38.85	$5,756,182	103,715	$2,878,091

Notes:
(1) Annual savings goal in MWh. See Appendix B.
(2) Equal to 80% of the Annual Savings Goal provided in Column (1). If the Company achieves above this threshold amount of savings, it may earn an incentive on all energy savings up to the Annual Savings Goal in Column (1).
(3) Incentive per saved MWh as authorized by the Commission. *See* Order Concerning Utility Financial Incentives, issued and effective August 22, 2008, in Case 07-M-0548.
(4) Equal to Column (1) x Column (3). This represents the maximum incentive that can be earned.
(5) Equal to 70% of Column (1). If the Company achieves at or below this threshold amount of savings, it will be penalized.
(6) Equal to 50% of Column (1) x Column (3).