Appendix A (revised January 2004): Renewable Resource Costs & Characteristics

A.1 Introduction and Overview

As described in Section IV-B of the report, we developed two independent supply curves: the "Main Tier" comprised of generators that will compete head-to-head for RPS demand and which are expected to sell their output into the bulk wholesale market (and which are expected to earn wholesale commodity market revenue); and the "SBC-like Tier", comprised of generators expected to be installed by end-users (whose commodity value will be a function of the displaced retail rate.[1]) Resources in this latter tier may contribute to meeting RPS demand to the extent system benefit fund or similar funds are available to pay for premiums under SBC programs. This Appendix describes the key assumptions made regarding the supply curve of renewable resources assumed to be available to meet New York RPS demand:

- the cost, location, and availability of renewable resources;
- the commodity energy market value of the renewable generation;
- the information sources that we relied upon; and
- how these assumptions were combined to yield a "premium" for numerous blocks of potential renewable generating resources.

Table 1 summarizes the results for the Main Tier, while Table 2 summarizes the results for the SBC-like Tier. In both tables, each row represents a resource "block" – representing a potential quantity of a resource of uniform type, cost, location, and where useful, resource quality – and its key characteristics for purposes of this analysis:

- the block's location within New York (or delivery point for imports);
- the maximum potential developable quantity (in MW and GWh/yr);
- the maximum fraction of the resource block potentially available in a given year; and
- the real levelized cost premium (in 2003$) under a long-term contract required by a plant in each resource block brought on-line in a given year.

Commodity Revenues and Aggregation of New York Zones. The cost-effectiveness of renewables will depend, in part, on the (commodity) market value of their electrical output. Under the New York wholesale market design, commodity market revenues will depend on energy locational based marginal prices (LBMP) available to resources located in each of the eleven NYISO zones. For purposes of efficiency and transparency of the analysis, we aggregated the 11 NYISO zones (shown in Figure 1) into three "megazones" that capture the vast majority of market price differentials across the state, based on an analysis of zonal market prices:

- Zone 1 = NYISO zones A, B, C, D and E
- Zone 2 = NYISO zones F, G, H and I
- Zone 3 = NYISO zones J and K.

Within each megazone, prices have tended to be very similar, and transmission constraints are minimal relative to the constraints between megazones. As described further below, we derived projections of available supply and market prices within each megazone.

[1] E.g. assuming no standby rates and production less than end-user consumption on a net metering basis.

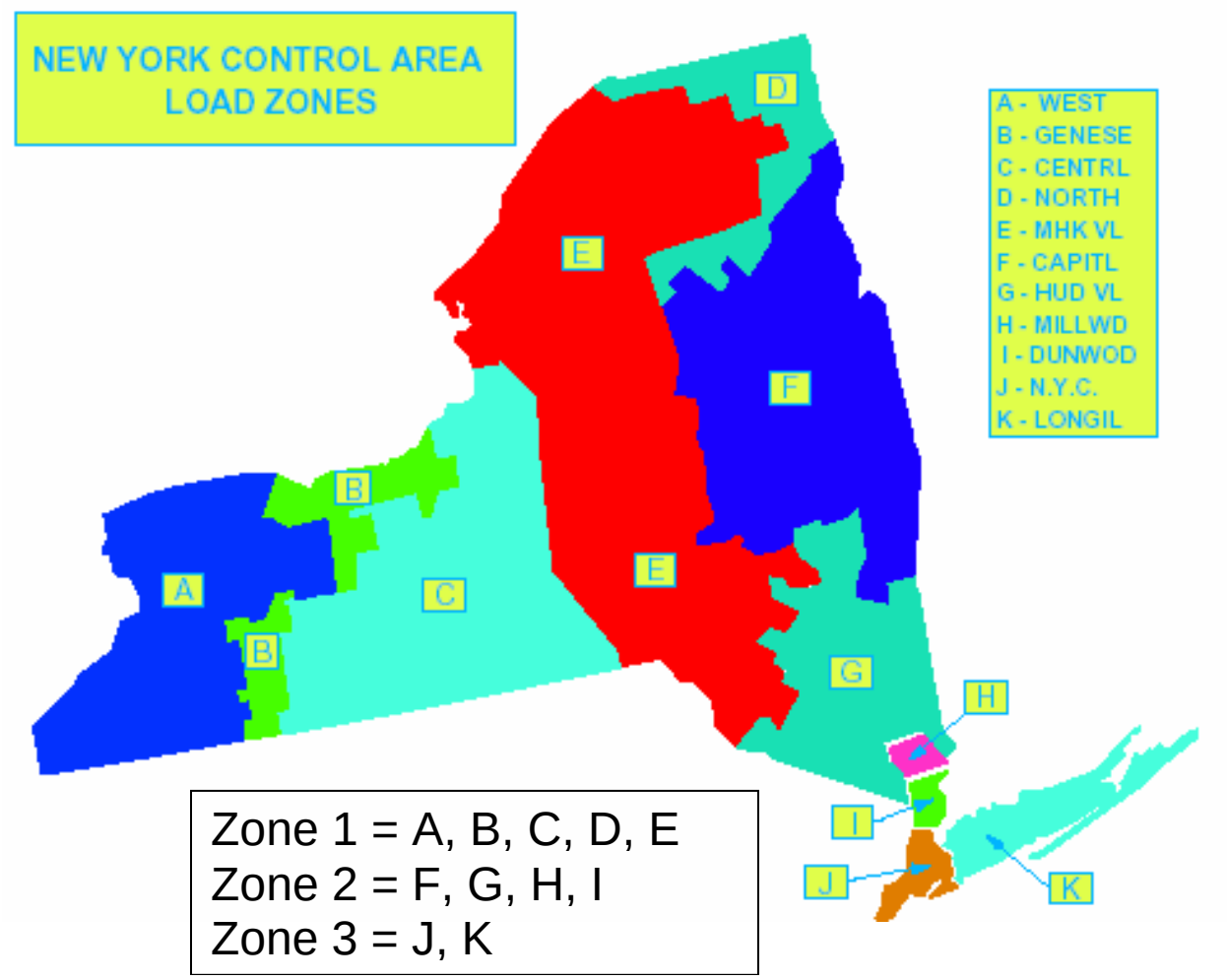

Figure 1: NYISO Zones and "Megazones"

This Appendix is organized as follows. Section A.2 describes the renewable resources considered in this analysis. Section A.3 describes the approach to deriving costs and cost premiums for the renewable resources in the supply curve. In Section A.4, we describe the derivation and meaning of the resource availability assumptions. Section A.5 describes the conditions under which resources from outside of New York are assumed to be available to meet New York RPS demand. In Section A.6, we then describe the assumptions made for each resource type, and the derivation of these assumptions.

Table 1 – Main Tier				Maximum Fraction of Block Available in Year X								Real Levelized Cost Premium $ per MWh ($2003)							
ENERGY SOURCE BLOCK	**Location, Market Index**	**Maximum MW in Block**	**Maximum GWh in Block**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**
Wind Farms NY-z1b1	NY Zone 1	50.0	162	70%	85%	100%	100%	100%	100%	100%	100%	$10.73	$10.01	$9.31	$8.54	$7.78	$7.00	$6.24	$5.46
Wind Farms NY-z1b2	NY Zone 1	450.0	1,301	70%	85%	100%	100%	100%	100%	100%	100%	16.29	15.48	14.69	13.83	12.98	12.10	11.25	10.38
Wind Farms NY-z1b3	NY Zone 1	1400.0	3,557	30%	40%	50%	60%	70%	80%	90%	100%	23.12	22.19	21.28	20.30	19.33	18.33	17.37	16.37
Wind Farms NY-z2b1	NY Zone 2	0.0	-	30%	40%	50%	60%	70%	80%	90%	100%	8.27	7.68	7.07	6.35	5.60	4.82	4.07	3.29
Wind Farms NY-z2b2	NY Zone 2	50.0	145	70%	85%	100%	100%	100%	100%	100%	100%	13.83	13.15	12.45	11.64	10.80	9.92	9.09	8.21
Wind Farms NY-z2b3	NY Zone 2	50.0	127	70%	85%	100%	100%	100%	100%	100%	100%	20.66	19.86	19.04	18.11	17.15	16.16	15.20	14.21
Wind Clusters NY-z1b1	NY Zone 1	20.0	65	70%	85%	100%	100%	100%	100%	100%	100%	20.57	19.79	18.98	18.15	17.29	16.43	15.58	14.73
Wind Clusters NY-z1b2	NY Zone 1	150.0	434	50%	60%	70%	80%	90%	100%	100%	100%	27.33	26.44	25.53	24.60	23.64	22.68	21.72	20.76
Wind Clusters NY-z1b3	NY Zone 1	200.0	508	30%	40%	50%	60%	70%	80%	90%	100%	35.68	34.66	33.62	32.55	31.46	30.37	29.28	28.19
Wind Clusters NY-z3b1	NY Zone 3	0.0	-	30%	40%	50%	60%	70%	80%	90%	100%	16.26	15.54	14.76	13.92	13.02	12.13	11.26	10.39
Wind Clusters NY-z3b2	NY Zone 3	15.0	43	70%	85%	100%	100%	100%	100%	100%	100%	23.02	22.20	21.32	20.37	19.37	18.38	17.40	16.43
Wind Clusters NY-z3b3	NY Zone 3	15.0	38	70%	85%	100%	100%	100%	100%	100%	100%	31.37	30.41	29.40	28.33	27.19	26.07	24.96	23.86
Off-Shore Wind Lakes NY-z1	NY Zone 1	311.0	926	30%	60%	100%	100%	100%	100%	100%	100%	40.69	38.91	37.10	35.27	33.41	31.56	29.71	27.86
Off-Shore Wind LI NY-z3	NY Zone 3	579.0	1,724	30%	60%	100%	100%	100%	100%	100%	100%	36.38	34.66	32.88	31.05	29.15	27.26	25.39	23.53
Wind Farms Quebec	Quebec, NY Zone 1	3000.0	8,672	0%	10%	15%	20%	25%	30%	35%	40%	45.37	44.50	43.64	42.72	41.81	40.86	39.96	39.02
Wind Farms Ontario	Ontario, NY Zone 1	3000.0	8,672	5%	10%	15%	20%	25%	30%	35%	40%	47.56	46.72	45.90	45.02	44.15	43.24	42.37	41.46
Wind Farms PJM b1	PJM, NY Zone 1	250.00	723	30%	40%	50%	60%	70%	80%	90%	100%	26.38	25.54	24.73	23.84	22.98	22.07	21.21	20.31
Manure Digestion NY-z1	NY Zone 1	38.4	202	50%	65%	80%	100%	100%	100%	100%	100%	28.50	28.57	28.63	28.66	28.66	28.66	28.66	28.66
Manure Digestion NY-z2	NY Zone 2	6.2	33	50%	65%	80%	100%	100%	100%	100%	100%	25.57	25.76	25.89	25.95	25.95	25.95	25.95	25.95
Biomass Co-firing w/Coal NY-z1 b1	NY Zone 1	38.0	233	30%	40%	50%	60%	70%	80%	90%	100%	4.44	4.44	4.35	4.25	4.16	4.07	3.98	3.98
Biomass Co-firing w/Coal NY-z1 b2	NY Zone 1	63.0	386	30%	40%	50%	60%	70%	80%	90%	100%	20.72	20.72	20.62	20.53	20.43	20.34	20.25	20.25

Table 1 – Main Tier				Maximum Fraction of Block Available in Year X								Real Levelized Cost Premium $ per MWh ($2003)							
ENERGY SOURCE BLOCK	**Location, Market Index**	**Maximum MW in Block**	**Maximum GWh in Block**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**
Biomass Co-firing w/Coal NY-z1 b3	NY Zone 1	137.0	660	30%	40%	50%	60%	70%	80%	90%	100%	23.52	23.52	23.40	23.28	23.16	23.04	22.93	22.93
Biomass Co-firing w/Coal NY-z2	NY Zone 2	56.0	294	30%	40%	50%	60%	70%	80%	90%	100%	9.66	9.66	9.54	9.43	9.33	9.22	9.11	9.11
Biomass Co-firing w/Coal Ontario	Ontario, NY Zone 1	667.0	3,214	100%	100%	100%	100%	100%	100%	100%	100%	30.23	30.23	30.11	29.98	29.86	29.74	29.62	29.62
Biomass Co-firing w/Coal PJM	PJM, NY Zone 1	600.0	3,416	30%	40%	50%	60%	70%	80%	90%	100%	27.82	27.82	27.71	27.61	27.51	27.41	27.31	27.31
Biomass Gasification NY z1 b1	NY Zone 1	54.6	383	0%	0%	5%	15%	35%	55%	75%	100%	43.62	43.70	43.20	42.69	42.17	41.65	41.15	41.15
Biomass Gasification NY z1 b2	NY Zone 1	91.0	638	0%	0%	5%	15%	35%	55%	75%	100%	49.25	49.33	48.83	48.33	47.80	47.28	46.78	46.78
Biomass Gasification NY z1 b3	NY Zone 1	127.3	892	0%	0%	5%	15%	35%	55%	75%	100%	54.97	55.05	54.56	54.05	53.52	53.00	52.50	52.50
Biomass Gasification NY z1 b4	NY Zone 1	177.8	1,246	0%	0%	5%	15%	35%	55%	75%	100%	45.84	45.91	45.42	44.91	44.39	43.87	43.36	43.36
Biomass Gasification NY z2 b1	NY Zone 2	20.1	141	0%	0%	5%	15%	35%	55%	75%	100%	40.64	40.83	40.41	39.94	39.41	38.88	38.38	38.38
Biomass Gasification NY z2 b2	NY Zone 2	159.3	1,116	0%	0%	5%	15%	35%	55%	75%	100%	44.85	45.04	44.62	44.15	43.62	43.10	42.59	42.59
Biomass Gasification NY z2 b3	NY Zone 2	35.4	248	0%	0%	5%	15%	35%	55%	75%	100%	46.32	46.51	46.09	45.62	45.09	44.57	44.06	44.06
New Biomass CHP NY z1 2007	NY Zone 1	18.0	134	25%	50%	75%	100%	100%	100%	100%	100%	80.80	80.88	80.93	80.96	80.97	80.97	80.97	80.98
New Biomass CHP NY z1 2012	NY Zone 1	22.5	168	0%	0%	0%	0%	25%	50%	75%	100%	80.16	80.24	80.29	80.33	80.33	80.34	80.34	80.34
New Low-Impact Hydro NY z1	NY Zone 1	34.0	174	15%	15%	30%	44%	58%	73%	87%	100%	44.99	45.06	45.11	45.13	45.13	45.12	45.12	45.12
New Low-Impact Hydro NY z2	NY Zone 2	9.2	47	12%	12%	27%	42%	57%	72%	87%	100%	42.24	42.43	42.56	42.62	42.62	42.62	42.62	42.62
New Low-Impact Hydro NY z3	NY Zone 3	0.1	0	14%	14%	29%	43%	58%	72%	87%	100%	40.59	40.71	40.77	40.78	40.73	40.69	40.66	40.65

Table 1 – Main Tier				Maximum Fraction of Block Available in Year X								Real Levelized Cost Premium $ per MWh ($2003)							
ENERGY SOURCE BLOCK	**Location, Market Index**	**Maximum MW in Block**	**Maximum GWh in Block**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**
New Low-Impact Hydro Quebec	Quebec, NY Zone 1	212.5	931	30%	40%	50%	60%	70%	80%	90%	100%	31.71	31.78	31.83	31.85	31.85	31.85	31.84	31.84
New Low-Impact Hydro Ontario	Ontario, NY Zone 1	200.0	1,226	100%	100%	100%	100%	100%	100%	100%	100%	25.90	25.97	26.02	26.04	26.04	26.03	26.03	26.03
Hydro Upgrades NY z1	NY Zone 1	124.9	335	91%	91%	92%	94%	95%	97%	98%	100%	56.06	56.13	56.18	56.20	56.20	56.19	56.19	56.19
Hydro Upgrades NY z2	NY Zone 2	22.9	52	0%	0%	17%	33%	50%	67%	83%	100%	28.75	28.94	29.07	29.13	29.13	29.13	29.13	29.13
Hydro Upgrades NY z3	NY Zone 3	0.0	-	0%	0%	0%	0%	0%	0%	0%	0%	58.08	58.20	58.26	58.27	58.22	58.18	58.15	58.14
Hydro Upgrades Quebec	Quebec, NY Zone 1	300.0	1,183	30%	40%	50%	60%	70%	80%	90%	100%	20.68	20.75	20.80	20.82	20.82	20.82	20.81	20.81
Hydro Upgrades Ontario	Ontario, NY Zone 1	800.0	3,000	25%	50%	75%	100%	100%	100%	100%	100%	22.00	22.07	22.12	22.14	22.14	22.13	22.13	22.13
Very Small New Hydro NY z1	NY Zone 1	10.4	53	15%	15%	30%	44%	58%	73%	87%	100%	79.72	79.79	79.84	79.86	79.85	79.85	79.85	79.85
Very Small New Hydro NY z2	NY Zone 2	2.8	14	12%	12%	27%	42%	57%	72%	87%	100%	76.97	77.16	77.29	77.35	77.35	77.35	77.34	77.34
Very Small New Hydro NY z3	NY Zone 3	0.0	0	14%	14%	29%	43%	58%	72%	87%	100%	75.32	75.44	75.50	75.51	75.46	75.42	75.39	75.38
Landfill Gas IC Engines NY z1	NY Zone 1	88.1	734	50%	79%	82%	86%	89%	92%	96%	100%	2.83	2.91	2.96	2.99	2.99	2.99	3.00	3.00
Landfill Gas IC Engines NY z2	NY Zone 2	25.7	214	64%	94%	94%	95%	96%	96%	97%	100%	2.03	2.22	2.35	2.41	2.41	2.41	2.41	2.41
Landfill Gas IC Engines NY z3	NY Zone 3	3.2	27	148%	197%	179%	161%	144%	126%	108%	100%	15.73	15.85	15.91	15.92	15.87	15.83	15.80	15.79
Landfill Gas Micro turbines NY z1	NY Zone 1	2.9	24	40%	62%	68%	75%	81%	88%	94%	100%	29.63	29.00	28.34	27.66	26.96	26.39	25.82	25.26
Landfill Gas Micro turbines NY z2	NY Zone 2	1.1	9	52%	74%	79%	84%	88%	93%	98%	100%	28.12	27.60	27.02	26.37	25.66	25.10	24.53	23.96
Landfill Gas Micro turbines NY z3	NY Zone 3	0.2	1	177%	140%	133%	127%	120%	114%	107%	100%	30.67	30.08	29.43	28.73	27.97	27.37	26.77	26.19

Table 2 – SBC-like Tier			Maximum Fraction of Block Available in Year X								Real Levelized Cost Premium $ per MWh ($2003)							
ENERGY SOURCE BLOCK	Max MW	Max. GWh	2006	2007	2008	2009	2010	2011	2012	2013	2006	2007	2008	2009	2010	2011	2012	2013
Residential Solar PV NY z1b1	557	789	1.5%	2.3%	5.7%	9.1%	12.5%	15.9%	19.3%	100%	174.42	152.36	143.54	134.72	$125.90	117.08	108.25	103.84
Residential Solar PV NY z2b1	481	682	1.6%	2.5%	5.9%	9.2%	12.6%	16.0%	19.4%	100%	144.69	122.64	113.81	104.99	96.17	87.35	78.53	74.12
Residential Solar PV NY z3b1	788	1,117	1.5%	2.4%	5.8%	9.2%	12.6%	16.0%	19.4%	100%	118.34	96.28	87.46	78.64	69.82	61.00	52.18	47.76
C/I Solar PV NY z1b1	264	394	2%	3%	7%	11%	15%	19%	23%	100%	239.58	215.38	204.63	193.88	183.13	172.37	161.62	155.17
C/I Solar PV NY z2b1	228	339	2%	3%	7%	11%	15%	19%	23%	100%	209.79	185.60	174.84	164.09	153.34	142.59	131.83	125.38
C/I Solar PV NY z3b1	373	556	2%	3%	7%	11%	15%	19%	23%	100%	183.38	159.19	148.44	137.68	126.93	116.18	105.42	98.97
BIPV NY z1b1	32	31	2%	4%	8%	13%	18%	22%	27%	100%	283.20	250.85	237.91	224.97	212.03	199.09	186.15	179.68
BIPV NY z2b1	28	27	2%	4%	8%	13%	18%	22%	27%	100%	253.45	221.10	208.16	195.22	182.28	169.34	156.40	149.93
BIPV NY z3b1	45	44	2%	4%	8%	13%	18%	22%	27%	100%	227.08	194.73	181.79	168.85	155.91	142.97	130.03	123.56
Small Wind NY-z1	54	69	25.4%	40.5%	49.9%	59.3%	68.7%	78.1%	87.5%	100%	91.72	89.87	88.38	86.89	85.40	83.91	82.42	80.94
Small Wind NY-z2	26	33	25.4%	40.5%	49.9%	59.3%	68.7%	78.1%	87.5%	100%	61.91	60.06	58.57	57.08	55.59	54.10	52.61	51.13
Small Wind NY-z3	26	33	25.4%	40.5%	49.9%	59.3%	68.7%	78.1%	87.5%	100%	35.49	33.64	32.15	30.66	29.17	27.68	26.19	24.71
Fuel Cell PEM NY z1	40	182	1.3%	1.5%	11.9%	22.3%	32.7%	43.1%	53.5%	100%	72.99	67.44	60.93	54.42	47.91	41.40	34.88	30.00
Fuel Cell PEM NY z2	31	142	1.3%	1.5%	11.9%	22.3%	32.7%	43.1%	53.5%	100%	43.18	37.63	31.12	24.61	18.10	11.59	5.08	0.19
Fuel Cell PEM NY z3	55	252	1.3%	1.5%	11.9%	22.3%	32.7%	43.1%	53.5%	100%	16.76	11.21	4.70	(1.81)	(8.33)	(14.84)	(21.35)	(26.23)
Fuel Cell PAFC NY z1	62	465	8%	10%	24%	38%	51%	65%	78%	100%	(1.62)	(3.90)	(6.20)	(8.50)	(10.81)	(13.11)	(15.41)	(17.42)
Fuel Cell PAFC NY z2	50	370	8%	10%	24%	38%	51%	65%	78%	100%	(31.42)	(33.71)	(36.01)	(38.31)	(40.61)	(42.91)	(45.21)	(47.22)
Fuel Cell PAFC NY z3	155	1,152	8%	10%	24%	38%	51%	65%	78%	100%	(57.85)	(60.13)	(62.43)	(64.73)	(67.03)	(69.33)	(71.64)	(73.64)
Fuel Cell SOFC NY z1	70	525	6%	9%	20%	31%	43%	54%	66%	100%	(19.06)	(21.12)	(23.35)	(25.58)	(27.80)	(30.03)	(32.26)	(33.68)

Table 2 – SBC-like Tier			Maximum Fraction of Block Available in Year X								Real Levelized Cost Premium $ per MWh ($2003)							
ENERGY SOURCE BLOCK	Max MW	Max. GWh	2006	2007	2008	2009	2010	2011	2012	2013	2006	2007	2008	2009	2010	2011	2012	2013
Fuel Cell SOFC NY z2	55	409	6%	9%	20%	31%	43%	54%	66%	100%	(48.87)	(50.92)	(53.15)	(55.38)	(57.61)	(59.84)	(62.06)	(63.49)
Fuel Cell SOFC NY z3	101	751	6%	9%	20%	31%	43%	54%	66%	100%	(75.29)	(77.35)	(79.57)	(81.80)	(84.03)	(86.26)	(88.49)	(89.91)
Fuel Cell MCFC NY z1	236	1,755	5%	7%	16%	25%	34%	43%	52%	100%	(31.41)	(33.58)	(35.66)	(37.73)	(39.81)	(41.88)	(43.96)	(45.55)
Fuel Cell MCFC NY z2	180	1,341	5%	7%	16%	25%	34%	43%	52%	100%	(61.21)	(63.39)	(65.46)	(67.54)	(69.61)	(71.69)	(73.76)	(75.35)
Fuel Cell MCFC NY z3	52	390	5%	7%	16%	25%	34%	43%	52%	100%	(87.64)	(89.81)	(91.89)	(93.96)	(96.04)	(98.11)	(100.19)	(101.78

A.2 Resources Considered.

Eligibility. This analysis is based on *preliminary* eligibility assumptions from a DPS Staff working definition as of mid-June of 2003. These eligibility assumptions may not accurately reflect *final* RPS design, and to the extent that eligibility rules materially differ, a revision of this analysis may be warranted. As the biomass working group had not yet reached their recommendations at the time this analysis was commenced, biomass eligibility assumptions are perhaps most likely to merit reexamination. Furthermore, if the Commission wishes to test the implications of particular eligibility choices, alternative scenarios of this analysis will likely be warranted.

In constructing this supply curve, the following new renewable resources were assumed to be eligible: Wind; hydroelectric (consisting of *new* low-impact hydro, i.e. <30 MW, run-of-river, no new storage impoundment, and the incremental production associated with any upgrades to existing facilities so long as no new impoundments are created); biomass (including co-firing at coal plants, as well as other technologies using eligible fuels[2] [3] ; electricity generated from landfill methane and manure digesters; solar; geothermal; ocean (e.g. tidal, wave); and fuel cells using any fuel (in the SBC-Like Tier only).

Resources modeled as part of supply curve. The supply curve derived for this analysis contains resources and technologies that are expected to be major contributors to meeting a New York RPS. We started with the assumptions made in the report "Energy Efficiency and Renewable Supply Potential in NY State and Five Load zones" prepared for NYSERDA by Optimal Energy, with VEIC, C.T. Donovan Assoc. and numerous resource experts. This report, in final draft form as of late June 2003 and under review by NYSERDA at the time of this analysis, was referred to as a primary source for the supply curve analysis, and is referred to as the "NYSERDA Technology Assessment" throughout this report.

The NYSERDA Technology Assessment screened the range of potential technologies and selected 30 combined technology type and installation scales for their analysis. These selections were based on "the potential contribution of each technology type and installation scale to New York's energy supply over the next 20 years; the extent to which each technology type and installation scale is commercially available in the U.S. and abroad; the cost-effectiveness of each technology type and installation scale; strategic advantages as they relate to technology advances and New York's renewable resources and market segments; the relative degree of market acceptability of each technology type and installation scale; and the existing and potential regulatory and market barriers to increased renewable energy technology development and use."[4]. We chose to ignore some of these technologies as either not RPS-eligible (for example,

[2] All potential non-waste biomass fuel feed stocks were considered eligible except for contaminated fuels such as particleboard and treated wood.

[3] At the time this analysis was underway, the Biomass Working Group was considering implementing emission limits on biomass resources. For this preliminary analysis, we assumed all biomass sources modeled would meet such a biomass emission limit. Conventional mass burn technology, the approach with the highest emissions, was not considered eligible.

[4] NYSERDA Technology Assessment, draft report , Technology Appendix Table 6.1

storage hydro or new hydro greater than 30 MW and municipal solid waste[5]); or unlikely to compete successfully head-to-head (landfill gas using combustion turbines; solar thermal). We also chose to add manure digestion, given the programs in place to expand the use of that technology within New York. Given additional time, other resource technologies may be reasonable to incorporate as well, for example, biomass using fluidized bed combustion technology. To the extent that we excluded some resources from this analysis that are eligible and might contribute to meeting the RPS demand, our analysis would be conservative with respect to the estimated cost of RPS compliance.

As described further in Section A.6 of this Appendix, we developed input assumptions for the following potential resource blocks. For some resource types, we identified multiple blocks based on the nature of the resource and the nature of the data available. For example, wind cost is a strong function of wind speed as well as scale, so multiple blocks were analyzed. Likewise, for biomass, the cost is a function of the cost of the fuel used, and different fuel sources have different costs and are available in limited quantities in specific locations. The resource blocks evaluated included:

<u>Main Tier:</u>

- Wind Farms in the 3 NY zones, as well as Ontario, Quebec, and PJM. Up to 3 resource quality blocks representing high, average and low wind speeds were selected.
- Wind Clusters in the 3 NY zones. Up to 3 resource quality blocks representing high, average and low wind speeds were selected. Imports of power from wind clusters were assumed to be zero because resource costs, transmission costs and transaction costs would limit imports to larger wind farms.
- Off-Shore Wind in New York's Great Lakes as well as off the shore of Long Island;
- Biomass co-firing at existing coal plants in the 3 NY zones, as well as Ontario and PJM.
- Biomass CHP in the 3 NY zones.
- Biomass Gasification in the 3 NY zones.
- Hydro in the 3 NY zones, as well as Ontario and Quebec, broken up into 3 resource quality blocks: new very small (< 5 MW, NY only); new low-impact (<30 MW); Upgrades to existing facilities (no size limit).
- Landfill gas in the 3 NY zones using two technology scales, internal combustion engines and micro turbines.
- Manure Digestion in the 3 NY zones.

<u>SBC-Like Tier</u>

- Solar photovoltaics (PV) in the 3 NY zones, using three technology approaches (residential, commercial/industrial, and building-integrated).
- Small wind in the 3 NY zones.
- Fuel cells in the 3 NY zones using four technologies: PEM, PAFC, SOFC, and MCFC.

After designating potential supply blocks as described above, in some cases we determined that no resource would be available in specific megazones or resource qualities; the resulting non-zero blocks are those that are shown in Tables 1 and 2.

[5] Excluded from the base case, but addressed as sensitivity in Section V-N of this report.

A.3. Resource Costs

Supply curves consist of quantities of resources potentially available to meet the RPS, and their associated cost. The definition and derivation of costs is described in this section, and quantity is discussed in the following Section A.4.

As renewable resources already have commodity markets available to them as a primary revenue source, our task in constructing supply curves is to determine the supplemental revenue stream necessary to attract capital to build a new renewable resource. The difference between the minimum revenue necessary to bring a resource on-line (which from the consumer's perspective represents "cost") and the commodity market value of a plant's production represents this minimum required supplemental revenue stream, which can be referred to as a "*renewable generation premium*" or *RGP*.[6]

For the purposes of this analysis, RGPs, and the resource costs and commodity market values or revenues from which they are calculated, were determined on a real-levelized basis (in $/MWh), for a resource coming on line in a specific year. All costs and revenues were converted to constant 2003$. The supply curve for each year is therefore the RGP for all resources not committed in previous years, all in constant 2003 $/MWh, sorted from least to greatest premium.

Derivation of Real Levelized Resource Cost Real levelized costs are calculated considering such factors as capital and operating costs, project life, financing costs and structure, availability of production tax credits and accelerated depreciation, and interconnection and transmission upgrade costs. For some mature technologies, we have modeled the fixed capital costs as constant in real terms, while for others still undergoing rapid technological advance and improvements in manufacturing scale economies, we projected declining capital costs over time.

Financing: A major component of the total cost of energy from renewable power projects is the up-front project capital cost of procuring and constructing the power producing facility. Applying a carrying charge to the estimated project capital costs provides a way to represent these costs on an annualized basis, for use in the derivation of total cost of energy. Fixed costs typically capitalized at the commencement of commercial operation were converted to real-levelized $/MWh by applying an annual carrying charge (after-tax) applicable to each resource type.

For this analysis, we calculate a carrying charge for each renewable technology by considering the typical economic life of the technology, likely financing requirements, and current tax treatment. We use a market-based rate of return approach to determine the stream of real-levelized revenues that, if attained, would provide return of and on capital. Such an approach mimics the revenues a generator would obtain if it entered into a Power Purchase Agreement with a fixed, inflation-adjusted price over the life of the project. We apply the estimated carrying charge for each technology to all project capital costs, including the cost of transmission upgrades and interconnection.

[6] Grace, Robert C. K. Cory and D. Smith, *Cost Estimate of N.Y. Executive Order 111 Renewable Energy Purchase Provisions*, for New York State Energy Research & Development Authority, October 2001.

The assumptions we use to develop technology-specific carrying charges approximate, in our judgment, the characteristics of a typical project within each technology class. For individual projects, variations may occur based on plant-specific characteristics and risk factors. The assumptions were chosen to represent the middle of the range of potential financial structures and ultimate project revenue requirements. Key assumptions by technology are listed in Tables 4 and 5.

Table 4: Project Financed Technologies

Technology	Economic Life (yrs)	Financing Structure Debt:Equity	Debt Term (years)	Debt Cost	Equity Cost	Tax Depreciation
Biomass co-firing	10	60:40	8	8.0%	16.0%	10 yrs, 1.5 DB
Other biomass	20	60:40	15	8.0%	16.0%	20 yrs, 1.5 DB
Landfill Methane	20	60:40	10	8.0%	16.0%	5 yrs, 2 DB
Wind (on and off-shore)	20	55:45	15	8.0%	19.0%	5 yrs, 2 DB
Fuel Cells	20	60:40	15	8.0%	16.0%	20 yrs, 1.5 DB
Hydro (upgrades)	30	60:40	20	8.0%	16.0%	20 yrs, 1.5 DB
Hydro (new)	50	60:40	20	8.0%	16.0%	20 yrs, 1.5 DB

Table 5: Other Technologies

Technology Class	Economic Life (yrs)	Financing Method
Small Wind	20	Corporate balance sheet financing
PV - Residential & BIPV	20	100% home equity
PV - C&I	20	Corporate balance sheet financing
Manure Digestion	10	Loan financed by dairy farms

- *Economic Life* – Our assumptions above reflect our experience regarding typical projects within each technology class. For new hydro projects, we assume a 50 year life based on the licensing term. We assume any hydro upgrades would be subject to a shorter remaining license term, and selected 30 years as representative. We assumed that, due in part to the advanced age of many existing coal-fired plants, the capital investment associated with biomass co firing would need to be recovered over 10 years.[7]
- *Financing Structure* - As shown above, most technologies were assumed to be financed with a 60:40 debt equity ratio. Such a financing structure allowed the projects to meet industry standard minimum debt coverage ratios while attaining a reasonable equity return. Because the Production Tax Credit provides a substantial portion of a wind project's cash flow, wind

[7] Most of these economic life assumptions were taken from the NYSERDA Technology Assessment. Exceptions include increasing hydro upgrades from a 20 to a 30 year life, reducing PV from a 25 to a 20 year life, and simplifying the fuel cell analysis, selecting a single life of 20 years rather than the technology-specific range of economic life assumptions in the NYSERDA Technology Assessment ranging from 14 years for PEM and MCFC to 26 years for SOFC.

projects supported slightly less leverage (55:45 debt to equity) of the pre-tax revenue stream in order to meet required coverage ratios.

- *Long Term Contracts* - We assumed that new renewables would be purchased under long term contracts, which allow renewable generators to bid the lowest price per kWh that provides them a sufficient return. Absent long-term contracts, we would expect that it would be more difficult, costly and time consuming to finance renewable projects to meet the New York RPS. Therefore, without long-term contracts, we expect RPS compliance costs, particularly in the near term, would be noticeably higher than shown here.
- *Debt Term and Cost* – We assumed the debt term to be a period of approximately 75% of a project's economic life, with a maximum term of 20 years, as per industry standard practice. While we estimate debt costs to currently be in the range of 7%, we used 8% in our analysis, to reflect the fact that interest rates are likely to rise from current levels over the long term.
- *Equity Cost* – Based on our experience with specific projects and discussions with financiers of renewable projects, we assume after-tax equity costs of 19% for wind, and 16% for all other projects requiring equity investment.
- *Tax Depreciation* – The U.S. federal tax code permits five-year MACRS accelerated depreciation for wind and landfill methane projects. We assumed all other technologies would use the standard depreciation allowable for electrical generation plant, or 150% declining balance over the economic life of plant (maximum 20 years).
- *Other taxes* - Property taxes are covered under operations and maintenance costs. For wind projects, production tax credits are also treated outside of the carrying charge calculation, as described below.
- *Small installations* - We assumed that small wind projects and photovoltaics would be undertaken by residential, commercial, and/or industrial users and would be of sufficiently small scale or unique circumstances to warrant a different financing approach. We assume that residential users would use a home equity loan to pay for a small PV project. For commercial and industrial users, we assume that PV and small wind projects would utilize corporate balance sheet financing. The carrying charges used for such projects are representative of the typical after-tax cost of home equity (for PV residential) and the after-tax corporate cost of capital (for small wind and PV commercial & industrial). For digesters, we assume that these projects would primarily be financed by loans to dairy farms. We use the carrying charge assumption from a detailed study on digesters recently undertaken for the Wisconsin RPS.
- *Canada* - In our experience, carrying costs for renewable generators in Canada should approximate those for generators in the U.S., although tax treatments and financing may vary somewhat. Because time constraints did not allow a thorough investigation of Canadian tax law, we relied on findings from Navigant Consulting's June 2003 report, *The Changing Face of Renewable Energy* (publicly available PowerPoint summary). This study concluded that annual carrying charges for a typical developer-financed project in Canada would be approximately 3% greater than similar projects in the US. We applied this 3% adder to all US carrying charges to estimate the relevant Canadian carrying charges.

The results of our carrying charge analysis are shown in Table 6 below.

Table 6: Real Levelized Carrying Charge	
U.S.	
Project Financed Technologies:	
Biomass co-firing	19.0%
Other biomass	13.6%
Landfill Methane	11.8%
Wind (on- and off-shore)	11.0%
Fuel Cells	13.6%
Hydro (upgrades)	12.7%
Hydro (new)	12.4%
WTE	13.6%
Other Technologies:	
Small Wind	8.0%
PV - Residential & BIPV	5.0%
PV - C&I	8.0%
Manure Digestion	10.3%
Canada	
Biomass Co-firing	19.6%
Other biomass	14.0%
Wind (on and off shore)	11.3%
Hydro (upgrades)	13.1%
Hydro (new)	12.8%

Federal Subsidies - *Production Tax Credit*. Wind and closed loop biomass generating resources that begin production before December 31, 2003 (and meet certain other requirements) are currently eligible for a federal production tax credit (PTC) of 1.8 cents per kWh for the first ten years of production, thereby reducing the cost of these resources to consumers. This credit increases annually in step with the GDP – Implicit Price Deflator (GDPIPD). Currently, it is unclear whether the PTC will be extended to apply to facilities that begin production after 2003.

Our supply curve model allows consideration of the cost of wind resources both with and without the PTC. Our base case assumption is that the PTC will be extended for the duration of our analysis and thus all commercial scale wind facilities in the U.S. will receive such a tax credit.[8] Our analysis accounts for the value of the PTC by reducing the cost of all eligible resources by the pre-tax value of the PTC on a real-levelized basis.

[8] Note: because we assume that small wind facilities modeled in the SBC-like Tier are owned by end users, we assume that they fail the requirement for a power sale between unrelated parties for PTC eligibility.

While a number of bills being considered by Congress envision expanding the PTC to other technologies, we have not assumed in this base case analysis that PTC would be applied to technologies other than wind. Should such an expansion occur, the cost to consumers for newly covered technologies will be substantially reduced.

Canada also has a wind incentive, the wind power production incentive (WPPI), which represents a payment of CA$10/MWh for 10 years to wind generators. We have ignored the WPPI in projecting costs for Canadian wind resources, for several reasons. First, the WPPI is subject to a national cap on funds allocated to pay the incentive. Second, that cap is allocated by Province with no more than 300 MW allowed for any one Province. As a result, we assumed it would be fully consumed for a limited quantity of projects whose attributes are sold in Canada.. Furthermore, the current value of US$7/MWh is relatively modest compared to the value of the U.S. PTC.

Interconnection and transmission. Where we felt that our sources for capital costs did not allow for sufficient local and/or upstream transmission investments, we added an estimate to reflect additional costs in these categories.

Commodity Market Value of Renewable Production. The "commodity market value" absent RPS revenues is a function of a generator's seasonal and time-of-day production profile, and the commodity market LBMP prices available at its location. For simplicity, we have projected commodity energy revenues only. Capacity revenues, and in some cases, ancillary services revenues, may also be available to generators. To the extent that such revenues are available, the cost premium required by renewable resources would be lower than projected herein. The potential effect of commodity capacity and ancillary services revenues is described in Sections V-L and V-M of the report.

Location. The commodity market value of a renewable resource will be influenced, in part, by where within New York it is located. Under present wholesale market design, generators are paid for their output based on the specific node at which their output enters the bulk transmission system. The DPS Staff's wholesale market analysis could have been used to quantify the value of renewable projects on a nodal basis. This level of detail would have been more time-consuming, however, and it was not necessary for this purpose. The Staff analysis showed that for many areas of the state (i.e., zones between which there are minimal transmission constraints) market prices are not highly differentiated. For the purpose of testing the cost-effectiveness of renewable resources, we divided the state into three "megazones" that capture the vast majority of projected price differentiation within New York, as described in Section A.1.

Season & Time of Day. The commodity value of a renewable project's output will also depend to some extent on the seasons and times of day during which it generates. This is because different resources have different production profiles, and wholesale market prices tend to be differentiated significantly by season and time of day.

The NYSERDA Technology Assessment estimated the relative output of potential renewable resources in terms of the following six different seasonal and time of day categories ("time slices") in which wholesale market prices were expected to be similar:

- Summer On Peak: June – August weekdays, noon to 6 pm
- Summer Off Peak: June – August, midnight to 8 am weekdays; all weekend hours June – August; and May, September and October, all hours
- Summer Shoulder: Weekdays June – August, 8 am to noon and 6pm to midnight
- Winter On Peak: December – February, noon to 8 pm
- Winter Off Peak: December – February, midnight to 8am and all weekend hours; March, April and November, all hours
- Winter Shoulder: Weekdays December – February, 8 am to noon and 8 pm to midnight

Table 7: Real Levelized Commodity Wholesale Market Prices

Zone 1 Real-levelized, $2003	2006	2007	2008	2009	2010	2011	2012	2013
Market Price $/kWh period 1	$ 28.40	$ 28.19	$ 27.99	$ 27.79	$ 27.60	$ 27.45	$ 27.34	$ 27.29
Market Price $/kWh period 2	$ 24.90	$ 24.81	$ 24.74	$ 24.70	$ 24.68	$ 24.66	$ 24.65	$ 24.65
Market Price $/kWh period 3	$ 27.46	$ 27.30	$ 27.16	$ 27.06	$ 26.99	$ 26.93	$ 26.90	$ 26.88
Market Price $/kWh period 4	$ 29.93	$ 29.86	$ 29.83	$ 29.84	$ 29.89	$ 29.93	$ 29.95	$ 29.96
Market Price $/kWh period 5	$ 25.24	$ 25.20	$ 25.18	$ 25.19	$ 25.21	$ 25.23	$ 25.25	$ 25.26
Market Price $/kWh period 6	$ 28.59	$ 28.55	$ 28.55	$ 28.59	$ 28.67	$ 28.74	$ 28.78	$ 28.80

Zone 2 Real-levelized, $2003	2006	2007	2008	2009	2010	2011	2012	2013
Market Price $/kWh period 1	$ 40.22	$ 40.24	$ 40.26	$ 40.30	$ 40.36	$ 40.40	$ 40.43	$ 40.45
Market Price $/kWh period 2	$ 27.60	$ 27.40	$ 27.25	$ 27.18	$ 27.17	$ 27.16	$ 27.15	$ 27.15
Market Price $/kWh period 3	$ 34.22	$ 34.00	$ 33.86	$ 33.80	$ 33.81	$ 33.83	$ 33.84	$ 33.84
Market Price $/kWh period 4	$ 31.92	$ 31.54	$ 31.27	$ 31.12	$ 31.10	$ 31.09	$ 31.08	$ 31.07
Market Price $/kWh period 5	$ 26.90	$ 26.75	$ 26.65	$ 26.60	$ 26.60	$ 26.61	$ 26.61	$ 26.61
Market Price $/kWh period 6	$ 30.48	$ 30.23	$ 30.07	$ 30.00	$ 30.03	$ 30.05	$ 30.06	$ 30.07

Zone 3 Real-levelized, $2003	2006	2007	2008	2009	2010	2011	2012	2013
Market Price $/kWh period 1	$ 42.89	$ 43.03	$ 43.16	$ 43.26	$ 43.33	$ 43.39	$ 43.42	$ 43.44
Market Price $/kWh period 2	$ 29.36	$ 29.25	$ 29.18	$ 29.16	$ 29.20	$ 29.22	$ 29.24	$ 29.25
Market Price $/kWh period 3	$ 37.09	$ 37.03	$ 37.01	$ 37.02	$ 37.07	$ 37.11	$ 37.13	$ 37.15
Market Price $/kWh period 4	$ 33.79	$ 33.48	$ 33.28	$ 33.20	$ 33.25	$ 33.28	$ 33.31	$ 33.32
Market Price $/kWh period 5	$ 28.21	$ 28.10	$ 28.05	$ 28.05	$ 28.10	$ 28.15	$ 28.18	$ 28.19
Market Price $/kWh period 6	$ 31.93	$ 31.71	$ 31.59	$ 31.58	$ 31.66	$ 31.73	$ 31.78	$ 31.80

Wholesale Commodity Market Value – for Main Tier. Using monthly outputs from Staff's MAPS modeling, we assembled average wholesale market prices for each of the three zones into these six time slices. For consistency with cost data, these market prices were converted to real 2003$/MWh. In order to accurately describe the premium for renewable resources, our analysis of the various resources sought to describe the potential quantities and costs of these resources within the locations and time categories described above. Table 7 shows the commodity energy market values derived for each time slice, using an assumed inflation rate of 2% and a discount rate of 10%.

Retail Commodity Market Value – for SBC-like Tier. In order to determine the commodity market value of behind-the-meter renewable resources like solar photovoltaics, small wind and fuel cells, we created retail rate benchmarks for each of the three megazones in New York. For simplicity, we assumed an average retail rate represents the appropriate benchmark, and chose C&I rates based on the assumption that most installations (by production volume) would be at

C&I customer facilities. Because the boundaries of our megazones do not correspond directly to the boundaries of utility service areas, the zonal average retail rate used to value these resources might ideally equal the weighted average of the C&I retail rates of utilities with service areas within the zone. Further, the weights used to calculate this zonal average should reflect the fraction of C&I load that is served by each utility. Due to time and data constraints, however, we developed zonal average rates using a map of the state that overlays the zonal boundaries on the utility service areas.[9] The average C&I rate for each utility was calculated from FERC Form 1 data for 2001 with the exception of LIPA, which is based on data contained in the Biennial Report of the Consulting Engineer and Rate Consultant for the Period January 1, 200 through December 31, 2001. Furthermore, we assumed that retail rates will remain constant in real 2003 dollars, at $86.64/MWh in zone 1, $116.45/MWh in zone 2, and $142.87/MWh in zone 3. Due to time constraints, we have not in this preliminary study derived "time slices" for these commodity retail rate benchmarks. This may cause the costs modeled as avoided by small wind and fuel cells to be slightly overstated, and for costs avoided by solar installations (which tend to produce during Summer, when rates are highest) to be understated.

A.4 Resource Quantities and Availability

Blocks of resources shown in Tables 1 and 2 do not represent resources that will certainly be developed but, rather, upper limits on quantities that might practically be developed if the economics of meeting the RPS dictate. The quantity to be reflected in such a resource block is greater than the "economic potential", a concept that is not generally applicable for an RPS analysis (because if demands are sufficient and there is no lower cost resource available, potential will be developed regardless of cost unless a price cap kicks in). On the other hand, the quantities selected for each block are less than the "technical potential", both because we have tempered technical potential with a view towards what could be successfully developed given a host of real constraints, and we have excluded the "upper end" of the supply curve beyond a level that (in our judgment) would ever be called upon for an RPS. For this reason, we have ignored potentially vast but lower-quality wind resources, solar thermal, etc.

Projections of developable quantities were derived by zone, in order to capture the major differences in electricity market prices and resource availability across New York State, and for neighboring markets.

Finally, while we projected a maximum quantity in MW and GWh/yr for each supply block, it is not realistic in many cases to assume that the entire developable potential could be tapped instantaneously, for a variety of reasons. For example, molten carbonate fuel cells are projected to be a very cost-effective resource some time in the future due to high efficiencies and manufacturing economies of scale. Yet the technology is not expected to be commercially available in 2006 when the RPS would commence. Therefore, we phased in the availability of each supply block over time where logical, to represent a combination of factors such as

[9] For example, Zone 2 comprises portions of the service areas of five utilities. We approximated the average C&I rate by assuming that 33% of Niagara Mohawk's sales, 100% of Central Hudson's, and 50% of Con Ed's, were to customers in that zone. Because the portions of the NYSEG and Orange & Rockland service areas in the zone appear small compared to the other utilities, we excluded them from the average.

evolving market barriers, delivery and manufacturing infrastructure limitations, development lead time, permitting constraints, market acceptance, and technology availability. The maximum figures reflect the total projected developable potential in year 2013, the last year of the analysis. We then developed annual percentages of that maximum quantity that would be available in earlier years, to reflect the phase in.

For most technologies, the NYSERDA Technology Assessment scenarios projected increased potential over time. However, none of the scenarios examined in the NYSERDA Technology Assessment included an RPS, but were rather driven by different objectives. In some cases, their analysis of resource potential proved useful; in other cases, the fact that the NYSERDA Technology Assessment did not reflect RPS market dynamics, such as head-to-head resource competition, meant that their raw projections could not be used without further refinement.

A.5 Imports

Renewable resources eligible to meet the RPS were not limited to generation located within New York. Out of state (and country) generation is assumed to be eligible, under conditions of *strict energy delivery*.[10] A strict energy delivery requirement generally imposes transmission wheeling costs and losses on the transaction, and in some cases other fees such as "uplift" charges. An hourly matching requirement can also expose the importer to basis differences between energy prices in the exporting and importing markets. Further, because of the requirement to schedule transmission between markets, intermittent resources which cannot be precisely controlled or forecasted are exposed to additional costs under an hourly matching requirement, either paying for transmission which is not used for transmitting renewable energy (e.g. during times when the wind does not blow), or experiencing opportunity losses for renewable attributes not transferred (when production exceeds the schedule).

For this analysis, we assumed that strict energy delivery would, for practical purposes, limit economic imports to one "wheel" away. Therefore, resources in Ontario, Quebec and PJM markets were included in the supply curve. Resources in New England were ignored, because New England's RPS requirements are expected to make New England a net importer of renewables from New York.[11]

[10] Under strict energy delivery, attributes may only be imported via an energy import from a specific generator, with energy and attributes scheduled across the border into the sink region via a unit-contingent contract. The energy import must match the generator's production profile in real time, necessitating an hourly settlement. (Grace, Robert and R. Wiser, Transacting Generation Attributes Across Market Boundaries - Compatible Information Systems and the Treatment of Imports and Exports, Prepared for U. S. Department of Energy and New York State Energy Research & Development Authority, published as a Lawrence Berkeley National Laboratory report, 11/02. See: http://eetd.lbl.gov/ea/EMS/reports/51703_exsum.pdf)

[11] Grace, Robert C. and Karlynn Cory, *Massachusetts RPS: 2002 Cost Analysis Update – Sensitivity Analysis*, presented to the MA RPS Advisory Group, December 16, 2002. http://www.state.ma.us/doer/programs/renew/rps-docs/CAU-SAP.pdf

Limits to Imported Quantities

With a requirement for strict energy delivery, under no circumstances could a greater amount of coincident renewable capacity be transmitted across an interface than the available transfer capacity of a transmission interface.[12] We assessed the maximum transmission constraints across each interface as follows:

Table 8: Transmission Constraints into New York

Transmission Constraints	Max MW/Hr	Basis
Quebec --> NY	1500	total transfer capacity
Ontario --> NY	1250	total transfer capacity
PJM --> NY Z1	650	estimate of available transfer capacity
PJM --> NY Z2	100	Estimate of negligible available transfer capacity due to heavy competing uses
PJM --> NY Z3	0	Estimate of negligible available transfer capacity due to heavy competing uses

For PJM, we have assumed less import potential than the transmission lines can physically hold, as noted in Table 8. For the purposes of this study, we assume that this firm service will be available to the renewable resources at PJM tariff rates. However, long term point-to-point firm transmission in PJM is currently secured on a first come first serve basis. Although it is impossible to know how much transmission tie capability will be secured under long term firm reservations, it is reasonable to assume that renewable resources physically located within PJM wishing to sell energy into the NY market will compete with other potential firm transmission customers (non-renewable) for access to the ties. If firm transmission capacity becomes unavailable for the term requested, the potential transmission customer has the option to take partial service or to fund the construction of the facilities needed provide the requested service. We therefore reduced the estimate of transfer capacity to reflect this dynamic.

Even though the interface with Hydro Quebec is heavily utilized at times, we have not derated it's available capacity as was done for PJM. This is because Hydro Quebec is the source of nearly all imports across that intertie, and also controls the vast majority of the renewables that might be imported. If Hydro Quebec were to put in place a sufficient attribute accounting system, there appears to be no reason to assume that much of the energy imported from Quebec couldn't be replaced with renewable energy transactions (if sufficient revenues were at stake). Likewise, based on the usage patterns of the Ontario interface, we saw no reason to derate the Ontario transfer capacity.

[12] Strictly speaking, offsetting flows could allow for greater imports, but the presence of such offsetting flows was viewed as insufficiently reliable to allow for project financing.

Cost of Transmitting Out-of-State Renewables

In the assumed cost of power from each imported resource, we included the estimated cost to transmit power into New York. Our major assumptions for each potential exporting region are as follows:

PJM. We assume that a renewable generator selling into New York would be able to sell to a load-serving entity in New York that would already have full network integration transmission service within New York. Thus, the incremental transmission costs incurred would be the cost of PJM Point-to-Point service to the New York border. The PJM tariff currently offers firm service on a firm and non-firm basis, as well as a daily, weekly, monthly, and yearly basis. We assume that a renewable resource would seek and acquire firm service on an annual basis. In fact, such long-term firm service may be a prerequisite for a resource to obtain long-term financing. These charges are assessed per kW of reserved transmission (as opposed to delivered energy). We estimate the effective cost per MWh of production for a baseload resource (80% capacity factor) and a more intermittent resource (30% capacity factor) at about $3/MWh, and $8/MWh, respectively.[13] In addition, we have assumed a loss factor of 2.5% applied to energy imported from PJM.

Ontario. Exports of electricity from Ontario to New York will be subject to the terms and condition of Rate Schedule ETS-Export Transmission Service. Under this schedule, exporters are billed by Ontario's Independent Electricity Market Operator ("IMO") a rate for each MWh of energy scheduled for export.[14] The currently effective rate for this service is $1.00 per MWh. Thus, to the extent an exporter delivers less energy than was originally scheduled in an hour, the effective rate per MWh of delivered renewable energy will exceed the tariffed rate.

In addition to this export charge, exporters must pay the IMO Uplift Charge and the IMO Intertie Congestion Price. The Uplift Charge is an hourly charge to recover on a $ per MWh basis the cost to Ontario of imports priced above the real time market clearing price, line losses, the cost of settling imbalances at interties, operating reserve payments and out-of-merit congestion management credits paid to generators. For this analysis, we assumed that renewable imports from Ontario would face Uplift Charges comparable to the average of $4.4 per MWh observed over the 12 months ending June 2003. The Intertie Congestion Price (ICP) is an hourly price equal to the difference between the Ontario market clearing price and the market clearing price of the importing or exporting zone. The ICP represents a price risk to exporters because they

[13] Transmission scheduling challenges may also affect the cost of delivering renewable energy to New York. On one hand, at present there are scheduling and maximum ramp allowance differences between PJM and NY-ISO that make the sale of intermittent power between the two markets difficult. The result is the imposition of an imbalance energy risk at the border, which may result in additional costs to the renewable generator. Should the two markets resolve these "seams" issues in the future, the imbalance risk would be largely mitigated. On the other hand, we have assumed that an intermittent resource would pay to reserve transmission capability up to its maximum output, around the clock. During days or hours when the renewable generator is not producing at full output, it would likely be able to extract some economic value for its underutilized transmission reservation. For the purposes of this study, we assume that the value of such unused transmission capability would offset any additional costs due to imbalances.

[14] The IMO is responsible for collecting transmission service charges from participants in the IMO-administered electricity market and distributing the revenues to the transmission system owners.

must pay the IMO this price whenever the intertie is congested.[15] Exporters can hedge this risk by purchasing financial transmission rights (FTR) on the intertie connecting Ontario to the importing zone. The results of a recent one-year auction for the Ontario-New York intertie suggest an export value of approximately $2,300 per MW year. This is equivalent to a price of $0.34/MWh for a base load generator with an 80 percent capacity factor.

Based on the above, we have estimated the transmission cost to export power from a baseload, schedulable resource over the IMO-administered transmission network to New York via the Ontario/New York intertie to be approximately $6.00/MWh, comprising a $1/MWh Export Fee, a $4.4/MWh Uplift Charge, and a $0.34/MWh Intertie Congestion Price, rounded up slightly to account for transaction costs. As with PJM, we have assumed that intermittent and lower capacity factor resources would be unable to use transmission over the interface efficiently, resulting in a projection of $12/MWh to import from a wind plant, and $8/MWh from a hydro plant.

Quebec. Imports from Quebec were assumed to be subject to the costs projected for imports from Quebec to New England in a recent Massachusetts RPS cost study[16]: $5/MWh for baseload resources and $8/MWh for intermittent wind generation. In addition, a 4% loss factor was applied.

New England. For the purpose of this study, New England was assumed to have no renewables available for export to New York.

A.6 Resource-Specific Assumptions

This section details the assumptions made for fixed and O&M costs as well as developable quantities (capacity and capacity factor) and production profiles, for each of the resources modeled as part of the NY RPS supply curve.

Table 9 shows the production profiles we used to assign the output of renewable resources in New York, PJM, Ontario, and Quebec.

Table 9: Resource Production Profiles by Time Period

New York Resources	Fraction of Annual Resource Output by Time Period					
	#1	#2	#3	#4	#5	#6
Wind Farms & Clusters Zone 1	2.4%	31.0%	3.6%	8.3%	46.7%	7.9%
Wind Farms & Clusters Zone 2	2.4%	31.0%	3.6%	8.3%	46.7%	7.9%
Wind Farms & Clusters Zone 3	3.2%	28.4%	4.4%	9.1%	45.7%	9.2%
Small Wind Zone 1	2.4%	31.0%	3.6%	8.3%	46.7%	7.9%

[15] If the ICP is paid to the IMO on each constrained MW, this suggests that the IMO must in turn compensate the importer for the failure to deliver the contracted quantities.

[16] Grace, Robert C. and Karlynn Cory, *Massachusetts RPS: 2002 Cost Analysis Update – Sensitivity Analysis*, presented to the MA RPS Advisory Group, December 16, 2002. http://www.state.ma.us/doer/programs/renew/rps-docs/CAU-SAP.pdf

New York Resources	Fraction of Annual Resource Output by Time Period					
	#1	#2	#3	#4	#5	#6
Small Wind Zone 2	2.4%	31.0%	3.6%	8.3%	46.7%	7.9%
Small Wind Zone 3	3.2%	28.4%	4.4%	9.1%	45.7%	9.2%
Offshore Wind LI	3.2%	28.4%	4.4%	9.1%	45.7%	9.2%
Offshore Wind Lakes	2.4%	31.0%	3.6%	8.3%	46.7%	7.9%
Manure Digestion, Landfill Gas	4.5%	38.5%	7.4%	5.8%	37.9%	5.8%
Biomass co-firing	4.5%	38.4%	7.5%	5.9%	37.8%	5.9%
Fluidized Bed Biomass	4.5%	38.4%	7.5%	5.9%	37.8%	5.9%
Wood Gasification	4.5%	38.4%	7.5%	5.9%	37.8%	5.9%
Biomass CHP	5.9%	36.9%	7.6%	7.4%	36.4%	5.8%
Residential Solar PV	14.1%	37.0%	8.6%	6.2%	27.8%	6.0%
C&I Solar PV	14.8%	38.0%	9.3%	5.5%	27.0%	5.3%
BIPV	10.6%	38.0%	7.9%	6.9%	29.5%	6.9%
Large Hydro Upgrade	3.7%	32.1%	6.2%	6.9%	44.3%	6.8%
Low-impact Hydro	4.0%	32.0%	6.0%	7.0%	44.0%	7.0%
Very Small Hydro	4.0%	32.0%	6.0%	7.0%	44.0%	7.0%
Fuel Cell PEM	6.0%	35.1%	8.5%	7.2%	36.4%	6.8%
Fuel Cell PAFC	4.5%	38.4%	7.5%	5.8%	37.9%	5.8%
Fuel Cell SOFC	4.5%	38.4%	7.5%	5.8%	37.9%	5.8%
Fuel Cell MCFC	7.8%	36.0%	6.3%	7.6%	36.5%	5.8%
WTE	4.5%	38.5%	7.4%	5.8%	37.9%	5.8%

Wind profiles were based on an analysis of actual New York wind data and a Vestas V47 production curve for Western New York (applied to zones 1 and 2 as well as off-shore wind in the Great Lakes) and Long Island (applied to Zone 3 wind and Long Island off-shore). Biomass, hydro, fuel cell and solar profiles came from the NYSERDA Technical Assessment. All other New York resources were assumed to be baseload, with production allocated in proportion to the hours in each timer period.

Production profiles for Ontario, Quebec and PJM resources were assumed to be the same as the same resource types in New York (for wind, used the Western New York profile).

A.6.1 Wind Resources

The NYSERDA Technology Assessment identified land based wind farms (more than 10 wind turbines), wind turbine clusters (2 to 10 turbine configurations) and off-shore wind projects as major sources of renewable energy for New York. This is consistent with the growth of wind projects around the world. The assumptions for wind costs and availability are summarized in Table 10.

Table 10 Major Assumptions and Results: Wind								
Block Name	Capacity Factor	Maximum MW in Block	Total Installed Cost (2003$/kW of rated Max Output)		Other Fixed Costs (2003$/kW)	O&M and Fuel Costs (2003$/kW)	Real Levelized Cost per MWh (2003$)	
			In 2006:	In 2013:			In 2006:	In 2013:
Wind Farms NY-z1b1	37%	50	$ 1,010	$ 852	$ 100	$ 16.00	$ 36.67	$ 31.31
Wind Farms NY-z1b2	33%	450	$ 1,010	$ 852	$ 100	$ 17.00	$ 42.24	$ 36.23
Wind Farms NY-z1b3	29%	1400	$ 1,010	$ 852	$ 100	$ 18.00	$ 49.06	$ 42.22
Wind Farms NY-z2b2	33%	50	$ 1,010	$ 852	$ 100	$ 17.00	$ 42.24	$ 36.23
Wind Farms NY-z2b3	29%	50	$ 1,010	$ 852	$ 100	$ 18.00	$ 49.06	$ 42.22
Wind Clusters NY-z1b1	37%	20	$ 1,300	$ 1,125	$ 100	$ 16.00	$ 46.51	$ 40.57
Wind Clusters NY-z1b2	33%	150	$ 1,300	$ 1,125	$ 100	$ 17.00	$ 53.27	$ 46.61
Wind Clusters NY-z1b3	29%	200	$ 1,300	$ 1,125	$ 100	$ 18.00	$ 61.62	$ 54.04
Wind Clusters NY-z3b2	33%	15	$ 1,300	$ 1,125	$ 100	$ 17.00	$ 53.27	$ 46.61
Wind Clusters NY-z3b3	29%	15	$ 1,300	$ 1,125	$ 100	$ 18.00	$ 61.62	$ 54.04
Off-Shore Wind Lakes NY-z1	34%	311	$ 1,650	$ 1,300	$ 100	$ 19.00	$ 66.63	$ 53.71
Off-Shore Wind LI NY-z3	34%	579	$ 1,650	$ 1,300	$ 100	$ 19.00	$ 66.63	$ 53.71
Wind Farms Quebec	33%	3000	$ 1,010	$ 852	$ 100	$ 18.00	$ 71.32	$ 64.87
Wind Farms Ontario	33%	3000	$ 1,010	$ 852	$ 100	$ 18.00	$ 73.50	$ 67.31
Wind Farms PJM b1	33%	250	$ 1,010	$ 852	$ 100	$ 18.00	$ 52.32	$ 46.15

New York Wind Farms

The NYSERDA Technology Assessment identified 1008 MW of new land based wind farm technical potential for 2012 and over 4000 MW of potential for 2022. The presence of an aggressive RPS (which the Assessment did not address) has the potential to stimulate more rapid development in the early years, so the development of 2000 MW (one-half of Assessment's 2022 technical potential estimates) by 2013 was selected as the developable potential. We allocated this total potential into three potential blocks by strength of the wind resource, with block 1 corresponding to Wind Class 5 (assumed to only be present and developable in zone 1); block 2 corresponding to Wind Class 4 and block 3 corresponding to Wind Class 3. A 1994 NREL study[17] of windy land within 10 miles of transmission lines (after moderate land use and environmental screening) showed approximately 90% of the developable NY resource is Class 3, 9% is Class 4 and 1% is Class 5. However, rather than apply these figures directly to the total technical potential, we modified the data to reflect (a) the expectation that higher wind speed land (class 4 and 5 in New York) is, while scarce, the most attractive to build upon, and will be sought out first. This will leave areas of Class 3 wind land undeveloped.

Wind capacity factors improve with wind speed. The performance for Class 4 is currently estimated at a 31% capacity factor; however, improved performance is expected over the forecast period (for example, a recently released Navigant Report[18] estimates an improvement to 37%), so a capacity factor of 33% was selected for the Class 4 resource throughout the period. From that base, we estimated a 37% capacity factor for Class 5 resources and 29% for Class 3 resources.

The NYSERDA Technology Assessment estimated wind farm capacity would be allocated 8% in Zone 3, 1% in Zone 2 and 91% Zone 1. We feel that land-based wind farms will be particularly difficult to implement in Zone 3, and therefore revised the estimate to Zone 1: 95%, Zone 2: 5% and Zone 3: 0%. We have assumed that the phase-in of the available wind resources would be biased to the better wind classes in the early years.

[17] Parsons, Brian, Eric Hammond and Yih-huei Wan, *U.S. Wind Reserves Accessible to Transmission Lines*, (external review draft), National Renewable Energy Laboratory, December 1994.
[18] Navigant Consulting, Inc., *The Changing Face of Renewable Energy*, June, 2003 ("Navigant Report').

The NYSERDA Technology Assessment's base case estimated a wind farm installed cost of $1,100 per kW of capacity in 2003, $987.5 in 2007, and $875 in 2012 (all in $2003). We found these estimates to be reasonable but added $100 per kW (separately identified) to reflect the potential need for transmission improvements necessary to accommodate the power on the transmission grid. For total O & M costs, we used our knowledge of property taxes/PILOT, landowner and administrative costs. We relied on estimates of maintenance costs presented by William Vachon at the American Wind Energy Association Conference in 2002.[19] The Vachon estimates reflect the long-term maintenance requirements and were used on a ¢/kWh basis according to the capacity factor for the resource.

New York Clusters

The NYSERDA Technology Assessment estimated a technical potential for wind clusters at 200 MW in 2012. With the RPS as an important stimulus, we again estimated that double the 2012 technical potential (i.e., 400 MW) would be available by 2013, with a steady ramp-up. The allocation by Zone was taken from the NYSERDA Technology Assessment report, and the allocation by wind class was Class 5: 5%; Class 4: 41%; and Class 3: 54%. These reflected the basic wind resource for NY and our rough judgment of the way it will be developed with a priority for faster development of a greater percentage of the better sites. We used the Assessment's installed costs per kW (in 2003 $) of $1,400 for 2003, $1,275 in 2007 and $1,150 in 2012, reflecting poorer scale economies than larger wind farms. We also used the same long-term O&M costs as for wind farms assuming that the substantial development of wind power in NY will allow clusters to benefit from the same operating economies.

Off-shore Wind Resources

Off-shore resources are in an early stage of development in the US. The Assessment's technical potential for 2012 was estimated as 890 MW, allocated 65% to Zone 3 and 35% to Zone 1. We used these data and a capacity factor of 34% for this resource.[20] We chose not to project a larger off-shore potential by 2013 because of the generally uncertain status of large off-shore wind farms. Installed cost data came from the Navigant Report showing $1,800 per kW in 2003 and $1,300 in 2013. For O & M costs, we referenced the Vachon report which estimates maintenance for off-shore projects as 17% higher than for on-shore projects. Since maintenance costs are approximately 60% of total O&M, we estimated that total off-shore O&M will cost approximately 10% more than on-shore projects.

PJM Wind Farms

Wind resources are also expected to be available from PJM; the PJM resource available for export to NY was first estimated to be 500 MW based on transmission availability, but this value was cut in half, to 250 MW, to reflect potential increased demand for this resource within PJM. Transmission issues also indicate that this resource will be delivered to New York Zone 1. The

[19] Vachon, William A., *Long-Term O & M Costs of Wind Turbines Based on Failure Rates and Repair Costs*, June, 2002.

[20] This figure was recommended by Bruce Bailey of AWS Scientific. While off-shore wind farms are expected to access higher speed and more laminar winds, consistent with higher c.f.s consistent with improvements cited earlier for land-based turbines, the off-shore environment is far harsher, suggesting a poorer availability. Given the limited long-term experience with off-shore wind, we felt that a conservative assumption was merited for this analysis.

NREL data[21] show that the bulk of this resource will be found in Pennsylvania where 37% of the wind resource is estimated as Class 4 and 63% as Class 3. Capital and operating costs are assumed to be the same as in New York, except that these resources will require transmission service and associated costs to be delivered to New York.

Wind in Ontario and Quebec

A 1992 study for the Canadian Centre for Mineral and Energy Technology (CANMET) contains data on the technical potential of Canadian wind energy.[22] The technical potentials for Quebec (10,000 MW) and Ontario (8,000 MW) are based on the assumption that reliability concerns limit the capacity of wind generators connected to the grid to half the system average load. However, GPCo. Inc. of Varennes, Quebec, a firm specializing in wind resource assessment, projects that the technical potential for Quebec is unlikely to be more than 3,700 to 5,600 MW, which is 10-15% of Hydro Quebec's total installed capacity.[23]

According to the Ontario Wind Power Task Force, Ontario's wind energy potential is in the range 2,000 to 6,000 MW (5,000 – 16,000 GWh/yr).[24] The report Generating Investment in Ontario[25] states that at least 200-2,000 MW of this potential is located offshore.[26] Ontario Power Generation estimates the onshore wind energy potential in Ontario at 3,000 MW.[27] Based on the above, we have made the following assumptions:

- A total of 6,000 MW of wind power (split equally between Quebec and Ontario) could be developed over the 8 year period beginning 2006, given sufficient market revenues.
- The annual c.f. for new wind development will be 33% for Ontario and Quebec.
- Only about 10% of the Quebec potential will be available for export in 2007, with an additional 5% added in each of the next six years. This translates to a potential export resource of 300 MW in 2007, and 1,200 MW in 2013.
- In Ontario, we assumed that only 5% of the wind energy potential becomes available for export in 2006, with an additional 5% added in each of the next seven years. This translates to a potential export resource of 150 MW in 2006, and 1,200 MW in 2013.
- These assumptions together produce the 2006 real levelized prices shown in Table 10, which include the cost of transmission to New York.

A.6.2 Biomass Generation

Our analysis considers three different biomass technologies: cofiring of existing coal-fired plants with biomass fuel, combined heat and power ("CHP"), and gasification. While a number of other biomass technologies are available and could be used in New York, we have not assessed their role here. To the extent that other technologies, such as fluidized bed, are eligible and more

[21] Parsons, et al.
[22] Canadian Wind Energy Technical and Market Potential, October 1992.
[23] Based on conversation with Guy Painchaud dated July 14, 2003.
[24] Ontario Wind Power Task Force: Industry Report and Recommendations, February 2002, page xx.
[25] Appendix 2, Table 1.
[26] Unfortunately, none of the individuals contacted with knowledge of the Ontario wind energy situation could provide a breakdown of the estimated potential by wind class.
[27] Based on a conversation with James Perry of OPG dated July 9, 2003.

economic, then their omission will result in overstating potential RPS costs. The key cost and availability assumptions are shown in Table 11, along with the results.

Table 11

Major Assumptions and Results: Biomass

Block Name	Capacity Factor	Maximum MW in Block	Total Installed Cost (2003$/kW of rated max output)		Other Fixed Costs (2003$/kw)	O&M and Fuel Costs (2003$/MWh)	Real Levelized Cost per MWh ($2003)	
			in 2006:	in 2013:			In 2006:	In 2013:
Biomass Co-firing w/Coal NY-z1 b1	70%	38	$ 235	$ 220	$ -	$ (2.84)	$ 4.44	$ 3.98
Biomass Co-firing w/Coal NY-z1 b2	70%	63	$ 235	$ 220	$ -	$ 13.43	$ 20.72	$ 20.25
Biomass Co-firing w/Coal NY-z1 b3	55%	137	$ 235	$ 220	$ -	$ 14.25	$ 23.52	$ 22.93
Biomass Co-firing w/Coal NY-z2	60%	56	$ 235	$ 220	$ -	$ 1.16	$ 9.66	$ 9.11
Biomass Co-firing w/Coal Ontario	55%	667	$ 235	$ 220	$ -	$ 14.67	$ 30.23	$ 29.62
Biomass Co-firing w/Coal PJM	65%	600	$ 235	$ 220	$ -	$ 16.78	$ 27.82	$ 27.31
Biomass Gasification NY z1 b1	80%	55	$ 1,600	$ 1,464	$ 25	$ 37.98	$ 69.51	$ 66.87
Biomass Gasification NY z1 b2	80%	91	$ 1,600	$ 1,464	$ 25	$ 43.61	$ 75.14	$ 72.50
Biomass Gasification NY z1 b3	80%	127	$ 1,600	$ 1,464	$ 25	$ 49.33	$ 80.86	$ 78.22
Biomass Gasification NY z1 b4	80%	178	$ 1,600	$ 1,464	$ 25	$ 40.19	$ 71.73	$ 69.09
Biomass Gasification NY z2 b1	80%	20	$ 1,600	$ 1,464	$ 25	$ 37.93	$ 69.47	$ 66.83
Biomass Gasification NY z2 b2	80%	159	$ 1,600	$ 1,464	$ 25	$ 42.14	$ 73.68	$ 71.04
Biomass Gasification NY z2 b3	80%	35	$ 1,600	$ 1,464	$ 25	$ 43.61	$ 75.15	$ 72.51
New Biomass CHP NY z1 2007	85%	18	$ 3,960	$ 3,960	$ -	$ 34.48	$ 106.81	$ 106.81
New Biomass CHP NY z1 2012	85%	23	$ 3,960	$ 3,960	$ -	$ 33.84	$ 106.17	$ 106.17

Biomass Fuel

The availability and price of biomass fuel is an important consideration in the determination of biomass energy potential. For this, we relied on estimates made in the NYSERDA Technology Assessment of the amount and price of biomass fuel available over time, by zone. The Assessment forecasts that New York State currently has over 200 trillion btus of biomass fuel available, and will have approximately double that amount by 2022. This would be sufficient to fuel roughly 3,300 – 5,500 MW of baseload biomass electricity generation. The total amount of fuel does not appear to be a constraining factor in determining the amount of biomass potential on a statewide basis. Other practical considerations, described in more detail below, will likely bound the size of the achievable biomass resource.

The Assessment describes the term biomass to include "*a wide-variety of closed-loop and open-loop organic energy resources. Closed-loop resources are those that are grown exclusively for the purpose of being consumed as an energy feedstock. Closed-loop resources can be either woody (e.g., hybrid poplar or willow) or herbaceous (e.g., switchgrass). Open-loop resources are typically either woody residues produced as by-products in the wood processing industry or are clean woody waste materials intercepted from the municipal solid waste stream.*" The resources included in Assessment's fuel supply curve include: mill residues, silviculture and silviculture residues, site conversion residues, woody yard trimmings, construction and demolition residues, pallets and other waste wood, agricultural residues, bio-energy crops, farm animal manure and wastewater methane. The last two sources are excluded from the quantity estimates. Construction and demolition residues are defined to include only the "clean and available" portion of such debris, to exclude that part of discarded wood that is not considered to be useable and recoverable due to excess contamination (e.g., treated wood not suitable for combustion, composting, or mulching), excessive commingling with other waste, or not

recoverable for other reasons. As a result, we deemed the entire fuel supply curve identified in the Assessment to meet biomass eligibility requirements.

At the same time, we considered technical constraints regarding fuel type and application in determining biomass fuel costs. In particular, some of the fuels listed in the NYSERDA Technology Assessment are only suitable for specific biomass technologies. The biomass fuels considered in the NYSERDA Technology Assessment, as well as their application, are listed in Table 12 below. Taking these technical constraints into account, our analysis assigned the most economic fuel to the most economic biomass technologies, as described in more detail below.

Table 12: Technical Constraints on Biomass Fuel Use by Technology

Fuel Type	Application
Primary mill residues	CHP or Co-firing
Silviculture residues	CHP or Co-firing
Sustainable harvest silviculture	CHP or Co-firing
Site conversion	All applications
Woody yard trimmings	Direct fire biomass or CHP
Construction residues	CHP or Gasification
Demolition residues	CHP or Gasification
Other wood waste	All applications
Agricultural residues	All applications
Bio-energy crops	All applications

The NYSERDA Technology Assessment identifies some fuels (woody yard trimmings, wood waste, construction and demolition residues) as having a negative cost. This cost represents the tipping fees, or receiving charge, for the collection of some biomass fuel types. We assume that in the presence of an RPS, there would be sufficient demand for these resources (or sufficient transportation costs required to deliver them to electric generating plants) to yield an effective floor price of $0.50/mmBTU for all biomass fuels. To the extent that some volumes are actually available to new renewable resources at lower (including negative) prices, our analysis is conservative.

Existing Use of Biomass Fuel in NY

In order to describe the cost of biomass fuel available for new resources, we began by adjusting the NYSERDA Technology Assessment's fuel data to reflect the current use of biomass fuel for electric generation. The Assessment identifies a 40 MW direct fire biomass facility, as well as 68 MW of CHP generating capacity at paper mill facilities. We estimated the amount and types of fuel these resources would require and eliminated this fuel from consideration for new resources. Specifically, we assumed the existing CHP units would primarily utilize mill residues, and as necessary, fuel from silviculture. We also assumed that the existing direct fire biomass resource would utilize some portions of the most economic available fuel in its zone, i.e. woody yard trimmings and other wood waste.

Co-firing with Coal (New York)

Co-firing technology is a well-developed, proven technology. Co-firing with coal requires modification of the fuel handling systems of existing coal plants to allow burning of biomass fuel in its existing boilers. Current technology allows co-firing of up about 15% of output by biomass, subject to fuel availability. Generally, a co-firing coal plant does not suffer a

significant efficiency loss, relative to stand-alone coal-fired operation. Co-firing is estimated to be the lowest-cost biomass technology considered in this analysis.

The renewable energy cost premium for cofiring represents the incremental cost of operating the plant, relative to coal-fired operation. The incremental cost is composed of the following components:

- Incremental capital costs – this is the cost of modifying the existing fuel handling systems in the coal plant to allow the plant to co-fire.
- Incremental O&M costs associated with co-firing – *[add few words on what this involves - i.e. cleaning boilers for biomass debris or whatever]*
- Incremental cost of biomass fuel relative to coal – Biomass fuel in large quantities is generally more expensive than coal, although it may be cheaper depending on the location and the type of biomass fuel used.

Amount:
The amount of cofiring is bounded by the amount of coal-fired generating capacity in New York. This amount is presently approximately 4,000 MW, and we assumed for the purpose of this analysis that no new coal-fired plants would be constructed during the next decade. Using the characteristics of the current coal units, the assumptions we used to estimate co-firing potential in New York are as follows:

- Plant-specific factors (e.g., age, technical constraints) would limit the achievable cofiring potential to half of the existing coal plants in New York.
- Each of these plants could co-fire at about 15% of its total output, without any loss in efficiency.
- Co-firing would not appreciably change the dispatch of the existing New York coal plants, which typically are utilized at annual capacity factors of 40 to 80 percent.

These assumptions indicate a potential of about 300 MW of cofiring output.

Cost:

- Incremental co-firing capital costs are estimated at $235/kW, decreasing slightly over time, based on the NYSERDA Technology Assessment. The Assessment also estimates variable O&M costs at $4.60/MWh and fixed O&M at $12.40/kw-year.
- We first segregated the co-firing potential by zone and then by capacity factor to create cost blocks. In general, the premium per unit of energy will be lower in high capacity factor plants, as capital and any fixed O&M will be spread out over greater energy production.
- We then looked at all technically feasible fuels (as described above) by zone and assigned the most economic of these fuels to the co-firing resources within the zone. We created additional cost blocks at significant fuel cost breakpoints. The results of our analysis are shown in Table 11.

Co-Firing with Coal (PJM)

PJM co-firing estimates were developed in a similar manner to projections for New York. The 600 MW block is based on an assumption that 50% of PJM West coal plant capacity could co-fire at 15%. We estimated the O&M costs to be somewhat higher than in New York, at $16.78 per MWh, based on an assumed biomass cost of $1.00 per MMBtu (2003$) above the cost of coal. The capital costs were assumed to be the same as for New York.

Co-Firing with Coal (Ontario)

Ontario Power Generation owns five coal-fired power plants with a total installed capacity of 7,558 MW that generally operate in intermediate duty cycles. The co-firing potential of these plants is 1,134 MW (or 5,070 GWh/yr), assuming 15% of the output could be fueled by biomass. However, two of these plants are due to retire before 2013 and one, Lakeview, may soon be converted to natural gas in order to reduce emissions in the province. Our assumptions regarding potential cofiring in Ontario are as follows:

- 667 MW of co-firing capacity could be installed in Ontario, if cost-effective. This figure assumes three of the five existing coal-fired plants could be cofired to burn biomass. The average annual capacity factor of these plants was about 55% based on 1999 operations data.
- Delivered prices for biomass fuels will exceed the delivered cost of coal by $0.75 per MMBtu, similar to the cost differential projected for New York Zone 2.
- We assumed that there will be sufficient biomass fuel to support this level of cofiring. The amount of biomass fuel required to achieve this level of cofiring would be small relative to the total supply in neighboring New York, suggesting that fuel will not limit the cofiring potential in Ontario if its supply is of a similar magnitude to New York. On the other hand, the Ontario coal capacity that could be co-fired is concentrated at only a few stations. It is possible that local biomass fuel supply issues could limit the feasible cofiring potential, or increase the price.
- The installed cost and annual O&M costs associated with co-firing Ontario coal-fired plants is assumed to be the same as the US. These assumptions result in real levelized costs as shown in Table 11, which include the cost of transmission over the Ontario-New York intertie.

Combined Heat and Power (CHP)

Biomass CHP, a relatively mature technology, involves the production of heat and electricity from biomass fuel. Currently, the majority of CHP applications involve pulp and paper facilities. As noted in the NYSERDA Technology Assessment, CHP is generally an end-use market application, although electricity can be sold back into the wholesale market. Newer biomass CHP technologies, however, are becoming practical in smaller sizes with broader application. Biomass CHP is generally less economic than co-firing. When assessing potential fuel cost, we therefore assume that only fuels not used for existing biomass applications or forecasted new co-firing applications are available for biomass CHP.

The NYSERDA Technology Assessment assumes that all of the pulp and paper industry's growth in electrical capacity would be met by biomass CHP. Based on projections of the industry's growth, it estimates that by 2022, there will be an additional 43 MW of biomass CHP capacity in NY State. We recognize that applications of biomass-fired CHP could, particularly if a substantial RPS requirement is implemented, expand to other industrial applications. We have reflected this possibility by doubling the Optimal assumptions. We assume that all new CHP would be located in Zone 1, where most potential biomass fuel is located.

Assuming steady growth in biomass CHP through 2022, we developed two CHP blocks, one representing biomass CHP characteristics for 2007, and the other the characteristics for 2012.

Based on typical biomass CHP production profiles, we then estimated the amount of fuel required by each of these CHP blocks. We assumed capital costs of $3960/kW, and fixed O&M of $198/kw-year, as described in the NYSERDA Technology Assessment.

Biomass Gasification

Although undergoing rapid improvements in technology, biomass gasification is a relatively immature technology, with no current applications in NY State. It involves the conversion of biomass to gas prior to combustion. The gas is then used as fuel in a combined cycle generation plant.

As biomass gasification is expected to be higher cost than the other biomass technologies already discussed, we assumed that all biomass fuel technically feasible for gasification that was not utilized for co-firing or CHP could potentially be used for gasification. Some types of biomass fuel would have to be dried to be usable for gasification, entailing additional costs. However, because there was a reasonably significant cost difference between various types of fuel available for gasification, we felt that in some instances it would pay to dry fuel otherwise not suitable for gasification to make it suitable, despite the additional cost. We assumed an additional drying cost of $.50/mmbtu of fuel that would otherwise be too wet to use in a gasifier.

Based on these assumptions and the NYSERDA Technology Assessment fuel data, the amount of fuel available for gasification in zone 1 by 2022 would support approximately 4,000 MW of gasification capacity. This suggests that fuel supply would not be a technical constraint on the amount of potential new gasification capacity. However, we offer two observations regarding potential new gasification capacity:

- The vast majority of the fuel available for gasification in the long term consists of biocrops that do not exist today, and would need to be developed over a period of years. The Optimal team indicates that such fuel would also require drying.
- Regardless of fuel availability, gasification is presently a relatively new and unproven technology.

Based on these factors, we have limited the amount of potential biomass gasification in New York to 200 MW in Zone 2 and 450 MW in Zone 1. As for the other biomass technologies, we have divided up gasification into blocks based on significant fuel price breakpoints and zonal locations.

A.6.3 Hydroelectric

Our major assumptions and costs results for hydropower resources are summarized in Table 13.

Table 13
Major Assumptions and Results: Hydro

Block Name	Capacity Factor	Maximum MW in Block	Total Installed Cost (2003$/kW of rated Max Output)		Other Fixed Costs (2003$/kW)	O&M and Fuel Costs (2003$/kW)	Real Levelized Cost per MWh (2003$)	
			In 2006:	In 2013:			In 2006:	In 2013:
New Low-Impact Hydro NY z1	58%	34.03	$ 2,300	$ 2,300	$ -	$ 15.00	$ 70.94	$ 70.94
New Low-Impact Hydro NY z2	58%	9.15	$ 2,300	$ 2,300	$ -	$ 15.00	$ 70.94	$ 70.94
New Low-Impact Hydro NY z3	58%	0.08	$ 2,300	$ 2,300	$ -	$ 15.00	$ 70.94	$ 70.94
New Low-Impact Hydro Quebec	50%	212.50	$ 1,500	$ 1,500	$ -	$ 5.00	$ 57.66	$ 57.66
New Low-Impact Hydro Ontario	70%	200.00	$ 1,861	$ 1,861	$ -	$ 5.00	$ 51.85	$ 51.85
Hydro Upgrades NY z1	31%	124.90	$ 1,439	$ 1,439	$ -	$ 13.92	$ 81.99	$ 81.99
Hydro Upgrades NY z2	26%	22.90	$ 771	$ 771	$ -	$ 13.92	$ 57.41	$ 57.41
Hydro Upgrades Quebec	45%	300.00	$ 1,000	$ 1,000	$ -	$ 5.00	$ 46.62	$ 46.62
Hydro Upgrades Ontario	43%	800.00	$ 1,000	$ 1,000	$ -	$ 5.00	$ 47.93	$ 47.93
Very Small New Hydro NY z1	58%	10.44	$ 2,700	$ 2,700	$ -	$ 40.00	$ 105.67	$ 105.67
Very Small New Hydro NY z2	58%	2.81	$ 2,700	$ 2,700	$ -	$ 40.00	$ 105.67	$ 105.67
Very Small New Hydro NY z3	58%	0.03	$ 2,700	$ 2,700	$ -	$ 40.00	$ 105.67	$ 105.67

As noted in Section A.2, the RPS proposal being modeled treats as eligible two categories of hydroelectric resources: *new* low-impact hydro, defined as new facilities of up to 30 MW, so long as they are run-of-river, with no new storage impoundment, and the incremental production associated with any upgrades to existing facilities so long as no new impoundments are created. The first category has been subdivided to carve out as a separate block very small hydro of less than 5 MW, because hydro cost is a strong function of size. The three blocks modeled for the supply curve were therefore defined as:

(1) *New Low-Impact Hydro (5-30 MW)*
(2) *Very Small New Hydro* (<= 5 MW) and
(3) *Hydro Upgrades*.

The NYSERDA Technology Assessment identified four classifications of incremental hydro production, which include (1) *Repowering & Modernization*, (2) *Expanded Capacity at Existing Dams*, (3) *New Capacity at Existing Dam* and (4) *New Capacity at New Dams*, projecting quantities in by five different capacity sizes, (1) *Micro* (<10 kW), (2) *Mini* (between 10 and 100 kW), (3) *Small* (between 100 kW and 5 MW), (4) *Medium* (between 5 and 50 MW) and (5) *Large* (>50 MW). The Assessment, however, did not study in detail the Micro hydro, the total potential of which is trivial.

The Assessment's data provided a useful and detailed starting point, but as its categories did not align perfectly with the eligibility requirements, several adjustments were required, as described below. The data provided in the Assessment was used to calculate the maximum block size (MW), capacity factor, installed costs and O&M costs. The Technology Assessment projected quantities for New York statewide, as well as for 5 specific NYISO zones (A, F, G, J and K), for discrete years (2003, 2007, 2012, and 2022). The remainder (other 6 NYISO zones) was then allocated to the remaining 6 NYISO zones based on the locational distribution of existing hydro summer capability amongst NYISO zones.[28] Finally, production was aggregated into our 3 megazones, and we interpolated quantities between years for which data was provided.

[28] The inventory of existing NYCA hydro capacity is found on the NYISO website at: http://www.nyiso.com/services/documents/planning/pdf/nyca_generators_2002.xls.

Capacity Factor
We utilized data for year 2012 from the Assessment as a proxy for the annual capacity factor for all years. We computed a weighted average for the three types of upgrades which resulted in a capacity factor of 26% for upgrades and 58% for both New Low-Impact and Very Small New Hydro.

New Low-Impact Hydro
Adjustments made to the Assessment's technical potential for new hydro dams include scaling back the total capacity by four compounded factors:
(1) 33% of the total technical potential was assumed to potentially be permitable;
(2) 46.5% of this new total was assumed to fall under the medium size category (5-50 MW);[29]
(3) We assumed that 75% of the remainder is less than or equal to 30 MW; and
(4) 75% of the original capacity is considered Run of River ("RoR"), and therefore eligible.

New Very Small Hydro
Adjustments made to the Assessment's technical potential for new hydro dams to determine the size of the New Very Small hydro category include scaling back the total capacity detailed in the Assessment by three compounded factors:
(1) 33% of the total technical potential was assumed to potentially be permitable;
(2) 10.7% of the total was assumed to fall under the mini and small categories (< 5 MW); [30] and
(3) 75% of the original capacity is considered Run of River ("RoR"), and therefore eligible.

Hydro Upgrades
Upgrades potential was assumed to be the sum of three categories from the NYSERDA Technology Assessment: Repowering, Expanded Capacity at Existing Dams, and New Capacity at Existing Dams.

We adjusted the data provided in the Assessment for Repowering projects to remove 20 MW of St. Lawrence Upgrades, and 217.5 MW of Niagara upgrades, which were included in the baseline. The only other calculation we made was to allocate any of the capability for repowering projects to zones not expressly detailed in the Appendix.

For Expanded Capacity at Existing Dams we made the same compounded adjustments described above:
(1) 33% of the total technical potential was assumed to potentially be permitable;
(2) 14.5% of the total was assumed to fall under the mini and small categories (< 5 MW); [31] and
(3) 75% of the original capacity is considered Run of River ("RoR"), and therefore eligible.
For the medium sized units we made similar adjustments, except that 55.9% of the total was assumed to fall under the medium size category, with 75% of that total assumed to be less than or equal to 30 MW.

[29] Table 5 of the NYSERDA Technology Assessment's Hydro chapter
[30] Table 5 of the NYSERDA Technology Assessment's Hydro chapter
[31] Table 5 of the NYSERDA Technology Assessment's Hydro chapter

We followed the exact same procedures in the preceding paragraph to adjust the New Capacity at Existing Dams using an adjustment of 62.4% for medium sized units and 24.8% for mini and small plants.

Installed Capital Costs ($/kW)

Capital costs were taken directly from the NYSERDA Technology Assessment, with the following exceptions. In order to calculate the capital costs for the New Low-Impact Hydro and the Very Small New Hydro we used the data presented in NYSERDA Technology Assessment's hydro chapter[32], subject to some judgment-based adjustments. For instance, for Medium-sized new hydro, the Assessment's capital costs are reported to be $2150/kW. However, as the Medium-sized hydro include projects above 30 MW whose costs may have been lower than average for the category, we make an upwards adjustment of $150/kW, to total $2300/kW to reflect the removal of the non-eligible larger sized hydro projects. Another judgment we made was in calculating the capital costs for the Very Small New Hydros. The Assessment (Table 3 of the hydro chapter) details capital costs for mini-sized units of $2900/kW and $2600/kW for small-sized units. It is our assumption that more small sized units will be developed than mini, for reasons including overall cost and economies of scale. As such, rather than take an average, we assumed capital cost of $2700/kW as closer to the small-sized unit's end of the scale.

Calculating the installed capital costs for repowering projects for Megazone 1 was slightly more complicated than for the other two megazones. Megazone 1 capital costs were calculated based on the weighted average costs for the statewide and zone A as detailed in Table 5 of the Assessment's hydro section.[33] Installed capital costs for Megazone 2 were based solely on the data within Table 5, or $100/kW.

Operation and Maintenance Cost ($/MWh)

Table 3 of the Assessment's hydro section was used as the source for our O&M cost calculation for both New Low-Impact Hydro and Very Small New Hydro, with some adjustments. The medium sized units are reported to have O&M costs of $10/MWh; however it is our belief that the ineligible Medium-sized units above 30 MW suppressed this cost slightly, so we adjusted the cost upward to $15/MWh for New Low-Impact Hydro. As for Very Small New Hydro units, we used the simple average of the Mini and Small units, for a total of $40/MWh. As for upgrades, we relied again upon Table 5 and used the reported operating cost of $13.92/MWh.

Hydroelectric Resources in Ontario

The Ontario Waterpower Association (OWA) estimated in August 2001 the hydroelectric potential in Ontario to range from 1,000 to 2,000 MW (4,000 to 6,000 GWh/yr).[34] The breakdown is as follows:

Category	Capacity (MW)	Energy (GWh/yr)
Known New Developments	200 – 300	1,000 – 1,500
Redevelopments[35]	600 – 1,300	2,000 - 3,000

[32] Table 3 of the NYSERDA Technology Assessment's Hydro chapter

[33]. The total repowering capability was based on year 2012 projections of capacity in each zone. .

[34] See Ontario Wind Power Task Force: Industry Report and Recommendations, February 2002, page 73-74. The estimate excludes the potential of waterways in the northern most parts of Ontario that are remote from the grid.

Upgrades[36]	200 – 400	1,000 - 1,500
Total	1,000 – 2,000	4,000 – 6,000

According to the report Generating Investment in Ontario,[37] a fourth category, Additional New Developments, could contribute a minimum of 200 MW and 1,000 GWh annually. Although the size of the individual projects that comprise the "Known New Developments" category is unknown, all of the hydroelectric projects completed in Ontario since January 2001 are smaller than the 30 MW limit on new developments in the New York RPS.[38] We have made the following assumptions regarding potential new hydroelectric resources in Ontario:

- 200 MW of new development will be available for export.
- The installed cost of these facilities is assumed to be $1,861/kW and variable O&M $5/MWh.[39] The assumed capacity factor is 70%.

With respect to potential modifications to existing hydroelectric plants in Ontario, we made the following assumptions:

- 200 MW of upgrades and 600 MW of redevelopments will be available for export, if a sufficient long term price is offered.
- Lacking any specific data for the cost of these resources, we assumed placeholder installed costs of US$1,000/kW and variable O&M US$5/MWh. The assumed capacity factor 43%.[40]

Hydroelectric Resources in Quebec

The theoretical potential for small hydroelectric facilities in Quebec has been estimated 10,000 MW, of which 4,000 MW is located in the southern portion of the province within reasonable distance of the transmission grid. We were unable to find additional data with which to make a more precise calculation, so for this preliminary study have assumed 300 MW of eligible upgrade capacity at a 45% capacity factor as available for import. Lacking any specific data for the cost of these resources, we assumed placeholder installed costs of US$1,000/kW and variable O&M US$5/MWh.

Quebec's Ministry of Natural Resources has identified 36 potential sites for new hydroelectric plants of 50 MW or less.[41] News reports indicate that these projects could produce 425 MW, beginning 2004 or 2005.[42] We have assumed the following:

- Half of the 36 dams could be developed by 2006, producing 212.5 MW.

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[35] A redevelopment is defined as a facility where the power house and associated physical infrastructure are substantially replaced.
[36] An upgrade is defined as a hydroelectric facility at which improvements increase annual production by at least two per cent. We were unable to determine the percentage of upgrades classified as impoundments.
[37] Generating Investment in Ontario: Final report of the Renewable Energy Task Force, Appendix 2, Table 2
[38] Ibid, Appendix 1.
[39] Based on data in Generating Investment in Ontario, December 12, 2002, Appendix 1 relating to recently completed small hydroelectric projects in Ontario.
[40] Ontario Waterpower Association estimated in August 2001.
[41] Ministry of Natural Resources Press Release, May 24, 2001.
[42] Quebec Proposes 36 Hydroelectric Dams on 24 Rivers, Environmental News Service, July 25, 2001.

- The installed cost of these facilities will be US$1,500/kW and the capacity factor 45%. Variable O&M costs are assumed to be US$5/MWh. These costs are also placeholder estimates.

A.6.4 Landfill Gas

Table 14 summarizes the assumptions and results for landfill gas generation. While landfill gas generation is expected in neighboring markets, experience to date suggests that this resource is the first to be snapped up in the earliest stages of those region's RPS or green power markets. We have therefore ignored any potential imports.

Table 14

Major Assumptions and Results: Landfill Gas

Block Name	Capacity Factor	Maximum MW in Block	Total Installed Cost (2003$/kW of rated max output)		Other Fixed Costs (2003$/kw)	O&M and Fuel Costs (2003$/MWh)	Real Levelized Cost per MWh ($2003)	
			in 2006:	in 2013:			In 2006:	In 2013:
Landfill Gas IC Engines NY z1	95%	88	$ 1,775	$ 1,775	$ 250	$ -	$ 28.71	$ 28.71
Landfill Gas IC Engines NY z2	95%	26	$ 1,925	$ 1,925	$ 250	$ -	$ 30.84	$ 30.84
Landfill Gas IC Engines NY z3	95%	3	$ 3,011	$ 3,011	$ 250	$ -	$ 46.24	$ 46.24
Landfill Gas Microturbines NY z1	95%	3	$ 3,675	$ 3,355	$ 240	$ -	$ 55.51	$ 50.97
Landfill Gas Microturbines NY z2	95%	1	$ 3,775	$ 3,455	$ 240	$ -	$ 56.93	$ 52.39
Landfill Gas Microturbines NY z3	95%	0.2	$ 4,075	$ 3,755	$ 240	$ -	$ 61.18	$ 56.65

The NYSERDA Technology Assessment identified three landfill gas conversion technologies either in widespread use today or expected to have significant usage during our study period -- large combustion turbines (CTs, rated 3 to 15 MW), internal combustion engines (rated 400 kW to 5 MW), and micro turbines (rated 30 to 600 kW) – and projected quantities of each based on a detailed analysis of specific landfills and waste generation patterns in New York. The NYSERDA Technology Assessment considered but rejected additional conversion technologies. We combined the expected methane production from the NYSERDA Technology Assessment's large systems and internal combustion (IC) engine categories and applied the combined fuel volume to IC engines, since Optimal's allocation of methane to large system capacity resulted in quantities smaller than the size of one large system. While larger CTs are used on rare occasions, in practice, it is developer choice. We expect nearly all landfill gas to electricity installations to be IC engines. We accepted the NYSERDA Technology Assessment's allocation of methane production from landfills too small for IC engines to micro turbines, landfills where economics allowed.

Quantities of New Landfill Gas Generation:
The NYSERDA Technology Assessment's estimates of methane production and installed capacity, based on a detailed study of landfills and waste generation, were used to generate our projected quantities, with the following adjustments. The NYSERDA Technology Assessment projected quantities for New York statewide, as well as for 5 specific NYISO zones (A, F, G, J and K), for discrete years (2003, 2007, 2012, and 2022). We first backed out an estimate of the future production from existing facilities. The remainder (other 6 NYISO zones) was then assumed to be allocated evenly to the remaining 6 NYISO zones. Then production was

aggregated into our 3 megazones, and we interpolated quantities between years for which data was provided.

The quantity of capacity is stated as equivalent capacity, assuming a 95% capacity factor. In practice, nameplate generation is not always reflective of capacity utilization. For instance, available methane production declines over time at each closed landfill, so the task of sizing engines to the gas flow is a dynamic and imperfect exercise. The NYSERDA Technology Assessment observes that existing LFG facilities generate the equivalent of 35 MW @ 95% c.f. using equipment with nameplate of 56 MW. We used the same convention, assuming 95% capacity factor and projecting maximum MW of capacity available on 2013 based on projected methane production accordingly.

The availability phase-in also reflects interpolation of the NYSERDA Technology Assessment projections, adjusted to back out declining production from existing facilities. Because zone 3 landfills are closing over time, while no new landfills are being sited in this zone, our phase-in percentages (shown in Table 1) decline to reach 100% in 2013; in zones 1 and 2, phase-in percentages increase to 100% in 2013 as additional waste is put in place, as shown in Table 1.

Costs

The NYSERDA Technology Assessment provided projections of capital costs and operating costs for each technology, broken down into generation and collection systems. While Federal Section 29 tax credits have been a major cost driver for landfill methane generation in the past, going forward, these credits are virtually exhausted on existing systems (vested wells expire in 2002 through 2008, according to NYSERDA Technology Assessment). We therefore ignored the tax credits in this analysis. The NYSERDA Technology Assessment also projected zonal differences for generator capital cost, which we used in deriving costs for each megazone. For IC engines, a mature technology, the NYSERDA Technology Assessment provided capital and operating costs that are constant in real terms; for micro turbines, the NYSERDA Technology Assessment projected cost decreases over time as the technology matures. We adopted these cost projections, with the following adjustment. After consultation with Peter Kuniholm of SCS Engineers (author of the landfill gas portions of the NYSERDA Technology Assessment), we also assumed that (a) all landfills going forward will require collection system/flare; and (b) landfill owners can recover 50% of the capital cost equivalent over time as gas royalties from the generator, while owners paid for the other 50%. To capture this assumption, we reduced collection system costs by 50%. (*Note: operating costs were provided on a $/kW basis and were entered as "other fixed costs" in Table 14.*)

A.6.5 Manure Digesters

Our major assumptions and costs results for manure digesters are summarized in Table 15.

Table 15

Major Assumptions and Results: Manure Digestion

Block Name	Capacity Factor	Maximum MW in Block	Total Installed Cost (2003$/kW of rated max output)		Other Fixed Costs (2003$/kw)	O&M and Fuel Costs (2003$/MWh)	Real Levelized Cost per MWh ($2003)	
			in 2006:	in 2013:			In 2006:	In 2013:
Manure Digestion NY-z1	60%	38	$ 3,266	$ 3,266	$ (1,000)	$ 10.00	$ 54.38	$ 54.38
Manure Digestion NY-z2	60%	6	$ 3,266	$ 3,266	$ (1,000)	$ 10.00	$ 54.38	$ 54.38

Quantity

To derive an estimate of manure digestion potential, we first focused exclusively on dairy farms as the major source of manure. We used an estimate of kWh digester production per cow per year of 1200 kWh.[43] We then identified the number of dairy farms in NY, the number of milk cows in NY, and the fraction with herds of over 200.[44,45] From this data, we estimated the number of cows in herds of over 200 head. Assuming 85% of these farms could install manure digesters with electricity generation in a CHP configuration, we derived a total potential of 195,500 cows generating 234,600 MWh/yr of electricity. At an estimated 60% c.f. this translates into 44.6 MW of potential capacity. Distribution of manure digester potential by megazone was derived from estimates of energy potential by county.[46] County-specific subtotals were aggregated by megazone to produce the distribution shown in Table 1.

Phase-in: The percentage phase-in shown in Table 1 represents the potential for a rapid saturation of the potential over a period of three years to reach full potential as early as 2009, if digester generation competes successfully for RPS demand

Cost

We evaluated the budgets for 12 digester projects at dairy farms in New York State supported by NYSERDA[47], on a per-cow basis. After omitting the highest and lowest cost installations as outliers; the average cost of the remaining 10 installations was used to determine the average cost per cow. The per-cow cost figure was used with the data described above to derive a $3266/kW installed cost. We then assumed that of this total, a placeholder of $1000/kW was attributed to the avoided capital cost of a combination of the thermal production of the CHP plant and the cost of solving environmental and oder problems that are dirving much of the manure digester activity in the state. For O&M costs, $10/MWh was used, from a recent Wisconsin RPS analysis of digester potential.

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[43] Norman Scott and Jianguo Ma, Report to NYSERDA PO 4841 (05/26/2003) - *Progress Report - Application of GIS in Biomass Resource Evaluation and Optimal Siting for Dairy Farm-Based Distributed Generation in New York*, Department of Biological and Environmental Engineering, Cornell University, Ithaca, NY.

[44] New York Agricultural Statistics Service, 2000.

[45] 200 head was suggested as a practical scale threshold for manure digester applications by Tom Fiesinger of NYSERDA.

[46] Scott and Ma , Table 4 Estimate of Energy Potential of Dairy Manure by County

[47] from NYSERDA Project List: Anaerobic Digestion, http://www.manuremanagement.cornell.edu/Documents.htm

A.6.6 Solar PV

We developed supply curve blocks for each of three solar photovoltaic (PV) technologies identified in the NYSERDA Technology Assessment, as shown in Table 16. These included residential PV installations (res), commercial/industrial PV installations (C&I), and building integrated PV (BIPV).

Table 16

Major Assumptions and Results: Photovoltaics

Block Name	Capacity Factor	Maximum MW in Block	Total Installed Cost (2003$/kW of rated max output)		Other Fixed Costs (2003$/kw)	O&M and Fuel Costs (2003$/MWh)	Real Levelized Cost per MWh ($2003)	
			in 2006:	in 2013:			In 2006:	In 2013:
Residential Solar PV NY z1b1	16%	557	$ 6,625	$ 4,625	$ 500	$ 9.41	$ 260.82	$ 190.25
Residential Solar PV NY z2b1	16%	481	$ 6,625	$ 4,625	$ 500	$ 9.41	$ 260.82	$ 190.25
Residential Solar PV NY z3b1	16%	788	$ 6,625	$ 4,625	$ 500	$ 9.41	$ 260.82	$ 190.25
C/I Solar PV NY z1b1	17%	264	$ 5,650	$ 4,080	$ 250	$ 8.96	$ 326.16	$ 241.75
C/I Solar PV NY z2b1	17%	228	$ 5,650	$ 4,080	$ 250	$ 8.96	$ 326.16	$ 241.75
C/I Solar PV NY z3b1	17%	373	$ 5,650	$ 4,080	$ 250	$ 8.96	$ 326.16	$ 241.75
BIPV NY z1b1	11%	32	$ 6,625	$ 4,625	$ 250	$ 13.80	$ 369.65	$ 266.13
BIPV NY z2b1	11%	28	$ 6,625	$ 4,625	$ 250	$ 13.80	$ 369.65	$ 266.13
BIPV NY z3b1	11%	45	$ 6,625	$ 4,625	$ 250	$ 13.80	$ 369.65	$ 266.13

Quantities

Developable quantities of solar PV are not constrained by substantial permitting or land use barriers, but far more so by economics. We therefore utilized the NYSERDA Technology Assessment's technical potential figures. The NYSERDA Technology Assessment projected quantities for New York statewide, as well as for 5 specific NYISO zones (A, F, G, J and K), for discrete years (2003, 2007, 2012, and 2022). The remainder (other 6 NYISO zones) was then assumed to be allocated evenly to the remaining 6 NYISO zones. Then production was aggregated into our 3 megazones, and we interpolated quantities between years for which data was provided to derive the phase-in schedule shown in Table 2.

Capacity factors were also taken from the NYSERDA Technology Assessment, as shown in Table 16. The BIPV c.f. was lower than the other 2 applications, reflecting less idealized orientation to the sun.

Costs

Capital and operating costs were taken from the NYSERDA Technology Assessment. An additional $500/kW of capital cost was added, as it was unclear whether the Optimal data reflected the full cost of installation. Note that C&I costs were lower; while NYSERDA Technology Assessment was unclear on this, we interpreted it as reflecting a commercial income tax credit as a direct reduction to capital cost.

A.6.7 Fuel cells

We developed supply curve blocks for each of four fuel cell technologies identified in the NYSERDA Technology Assessment, as shown in Table 17. These included proton exchange membrane (PEM), phosphoric acid (PAFC), solid oxide (SOFC), and molten carbonate fuel cells (MCFC).

Table 17

Major Assumptions and Results: Fuel Cells

Block Name	Capacity Factor	Maximum MW in Block	Total Installed Cost (2003$/kW of rated max output)		Other Fixed Costs (2003$/kw)	O&M and Fuel Costs (2003$/MWh)	Real Levelized Cost per MWh ($2003)	
			in 2006:	in 2013:			In 2006:	In 2013:
Fuel Cell PEM NY z1b1	52%	40	$ 4,938	$ 3,485	$ -	$ 13.49	$ 159.63	$ 116.64
Fuel Cell PEM NY z2b1	52%	31	$ 4,938	$ 3,485	$ -	$ 13.49	$ 159.63	$ 116.64
Fuel Cell PEM NY z3b1	52%	55	$ 4,938	$ 3,485	$ -	$ 13.49	$ 159.63	$ 116.64
Fuel Cell PAFC NY z1b1	85%	62	$ 4,125	$ 3,260	$ -	$ 9.67	$ 85.01	$ 69.21
Fuel Cell PAFC NY z2b1	85%	50	$ 4,125	$ 3,260	$ -	$ 9.67	$ 85.01	$ 69.21
Fuel Cell PAFC NY z3b1	85%	155	$ 4,125	$ 3,260	$ -	$ 9.67	$ 85.01	$ 69.21
Fuel Cell SOFC NY z1b1	85%	70	$ 3,163	$ 2,362	$ -	$ 9.80	$ 67.57	$ 52.95
Fuel Cell SOFC NY z2b1	85%	55	$ 3,163	$ 2,362	$ -	$ 9.80	$ 67.57	$ 52.95
Fuel Cell SOFC NY z3b1	85%	101	$ 3,163	$ 2,362	$ -	$ 9.80	$ 67.57	$ 52.95
Fuel Cell MCFC NY z1b1	85%	236	$ 2,443	$ 1,669	$ -	$ 10.61	$ 55.23	$ 41.09
Fuel Cell MCFC NY z2b1	85%	180	$ 2,443	$ 1,669	$ -	$ 10.61	$ 55.23	$ 41.09
Fuel Cell MCFC NY z3b1	85%	52	$ 2,443	$ 1,669	$ -	$ 10.61	$ 55.23	$ 41.09

Quantities

Developable quantities of fuel cells are not constrained by substantial permitting or land use barriers, far more so by economics. We therefore utilized the NYSERDA Technology Assessment's technical potential figures. The NYSERDA Technology Assessment projected quantities for New York statewide, as well as for 5 specific NYISO zones (A, F, G, J and K), for discrete years (2003, 2007, 2012, and 2022). The remainder (other 6 NYISO zones) was then assumed to be allocated evenly to the remaining 6 NYISO zones. Then production was aggregated into our 3 megazones, and we interpolated developable quantities between years for which data was provided to derive the phase-in schedule shown in Table 2.

Capacity factors were also taken from the NYSERDA Technology Assessment, as shown in Table 17.

Costs

Capital and operating costs were taken from the NYSERDA Technology Assessment.

A.6.8 Small Wind

We developed supply curve blocks for small wind, shown in Table 18, based primarily on information from the NYSERDA Technology Assessment. The NYSERDA Technology Assessment defines small wind as between 1 and 300 kW nameplate capacity.

Table 18

Major Assumptions and Results: Small Wind

Block Name	Capacity Factor	Maximum MW in Block	Total Installed Cost (2003$/kW of rated max output)		Other Fixed Costs (2003$/kw)	O&M and Fuel Costs (2003$/MWh)	Real Levelized Cost per MWh ($2003)	
			in 2006:	in 2013:			In 2006:	In 2013:
Small Wind NY-z1	14.5%	54	$ 2,262	$ 2,092	$ -	$ 35.52	$ 178.36	$ 167.58
Small Wind NY-z2	14.5%	26	$ 2,262	$ 2,092	$ -	$ 35.52	$ 178.36	$ 167.58
Small Wind NY-z3	14.5%	26	$ 2,262	$ 2,092	$ -	$ 35.52	$ 178.36	$ 167.58

Quantities

Developable quantities of small wind were taken from the NYSERDA Technology Assessment's technical potential figures. The NYSERDA Technology Assessment projected quantities for New York statewide, as well as for 5 specific NYISO zones (A, F, G, J and K), for discrete years (2003, 2007, 2012, and 2022). The remainder (other 6 NYISO zones) was then assumed to be allocated evenly to the remaining 6 NYISO zones. Then production was aggregated into our 3 megazones, and we interpolated developable quantities between years for which data was provided to derive the phase-in schedule shown in Table 2.

Capacity factor of 14.5% was also taken from the NYSERDA Technology Assessment 2007 figure, as shown in Table 18. While the NYSERDA Technology Assessment projected improvements in c.f. over time, we ignored these advances for the purposes of this study, a conservative assumption given the recent history of c.f. improvements in the wind industry.

Costs

Capital and operating costs were taken from the NYSERDA Technology Assessment (CPI case for capital costs, tech potential case for O&M). While the NYSERDA Technology Assessment projected improvements in operating costs over time, we ignored these advances for the purposes of this study, a conservative assumption given the recent history of operating cost improvements in the wind industry.