COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY POWER COMPANY FOR APPROVAL OF ITS 2011 ENVIRONMENTAL COMPLIANCE PLAN, FOR APPROVAL OF ITS AMENDED ENVIRONMENTAL COST RECOVERY SURCHARGE TARIFF, AND FOR THE GRANT OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE CONSTRUCTION AND ACQUISITION OF RELATED FACILITIES	)	CASE NO. 2011-00401

TOM VIERHELLER, BEVERLY MAY, AND THE SIERRA CLUB'S RESPONSES TO COMMISSION STAFF'S FIRST REQUEST FOR INFORMATION

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PUBLIC SERVICE COMMISSION

REQUEST NO. 1. Refer to page 6, starting at Line 1 of the Direct Testimony of J. Richard Hornby. It states, "KPCo System Sales Clause, Tariff S.S.C., the Company retains forty percent of the margin revenue from off-system and credits retail customers with the remaining sixty percent." In Tariff S.S.C.,[1] Effective Date June 29, 2010, issued by Commission Order in Case No. 2009-00459 dated June 28, 2010, the Rate Section, at paragraph 1, states, "[w]hen the monthly net revenues from system sales are above or below the monthly base net revenues from system sales, as provided in paragraph 3 below, an additional credit or charge equal to the product of the KWHs and a system sales adjustment factor (A) shall be made, where 'A', calculated to the nearest 0.0001 mill per kilowatt-hour, is defined as set forth below." Also, reflected in Tariff S.S.C., Rate Section, is the System Sales Adjustment Factor equation. That is defined as:

System Sales Adjustment Factor (A) – (.6 [Tm-Tb])/Sm.

a. Explain whether the ".6" from the formula identified above is applied to the total off-system sales revenues, or whether the formula is applied to the difference between the total off-system sales revenues and the monthly base off-system sales amount.

b. Explain what assumptions Dr. Fisher used in allocating the off-system sales between the ratepayer and shareholder.

c. Explain how Dr. Fisher concluded that the shareholders receive 40 percent of the off-system sales revenues.

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[1] Kentucky Power Company Schedule of Tariffs, Terms and Conditions of Service Governing Sale of Electricity, Tariff S.S.C., Issued by Order in Case No. 2009-00459, Application of Kentucky Power Company for a General Adjustment of Rates (Ky. PSC June 28, 2010). Effective Date, June 29, 2010.

RESPONSE NO. 1

a. The ".6" from the formula is applied to the difference between the monthly net revenues from system sales and the monthly base net revenues from system sales defined in paragraph 3 of Tariff S.S.C.,* Effective Date June 29, 2010, issued by Commission Order in Case No. 2009-00459 dated June 28, 2010.

Witness: J. Richard Hornby

b. Dr. Fisher allocated revenues from off-system sales (OSS) 60 percent to ratepayers and 40 percent to shareholders based upon Mr. Hornby's assumption that this is the effective allocation of all net revenues from OSS under Tariff S.S.C., as explained in response KPSC 1-3.

Upon further review, Dr. Fisher has noted that his calculations have allocated total revenues from OSS rather than net revenues, i.e. , the calculations did not deduct the variable cost of production incurred to make the OSS from the total OSS revenues. Dr. Fisher has revised his calculations to use an estimate of net revenues from OSS. We will provide parties with revised exhibits that reflect that revised calculation. This revision does not change the nature of Dr. Fisher's conclusions and findings in any significant way.

The allocation of revenues from OSS as originally filed and as corrected are described below:

<u>As originally filed:</u> The projection of total revenues from off system sales (termed "Econ Energy Sales ('000)" in Strategist) were allocated between shareholders (40%) and ratepayers (60%). The annual stream of costs for each option was modified by replacing "Market revenue / (Costs)" [in KPSC DR 1-48] with a

modified column which included only 60% of OSS revenues.(*Note that KPCO calculates Market Revenue/Costs as Econ Energy Sales minus Econ Energy Purchases*) For the full formulation as originally filed, see columns AT through AV in tab "StratComp – Syn" of workbook "Exhibit JIF-2, 3 & 6 Strategist_Compilation_Workbook_Synapse.xlsx" provided in response to KPCO data request 1-7.

As corrected: It is assumed, for the purposes of this simplified analysis, that net revenues from OSS profits equal total revenues from OSS minus our estimate of the variable production costs KPCo incurred to make OSS. We assume that those variable production costs are proportional to the fraction of generation that is sold out of system, which is calculated as "Econ Energy Sales (GWh)" / "Therm[al] generation (GWh)." This fraction is multiplied by the sum of fuel, variable O&M, and emissions allowance costs to determine the variable operating cost of generation associated with OSS. This variable operating cost is deducted from total OSS revenues ("Econ Energy Sales ('000)) to result in an OSS, net of variable operating costs. Finally 40% of this value is deducted from the stream of "Market revenue / (Cost)" and a new annual net power cost calculated.

For the full formulation of the corrected estimate, see columns AZ through BJ in tab "StratComp – Syn" of workbook "Exhibit JIF-2, 3 & 6 Strategist_Compilation_Workbook_Synapse.xlsx" provided in response to KPCO data request 1-7.

Witness: Jeremy Fisher

c. See response to KPSC 1- 1 (b).

Witness: Jeremy Fisher

REQUEST NO. 2. Refer to page 15, starting at Line 9 of the Direct Testimony of Jeremy Fisher, Ph.D. It states, "I deducted 40% of the gross market sales from the KPCo system on an annual basis, and, following the Company's method for calculating the total cumulative present worth (CPW), subtracted the remaining revenues from the stream of costs and calculated a new CPW." Also, refer to Dr. Fisher's testimony at page 15, starting at line 14 where it states, "[t]he result of allocating 40% of OSS revenues to shareholders drives up the cost seen by ratepayers – but drives it up faster in those scenarios where KPCo has greater off-system sales, in this case in Option 1."

a. Provide the gross market sales amount on an annual basis and the time-period used in your Strategist analysis of the Kentucky Power Company ("Kentucky Power") system.

b. Explain how the 40 percent off-system sales revenues to shareholders was determined. Provide all calculations necessary to support that 40 percent of off-system sales revenues are going to shareholders.

RESPONSE NO. 2

a. Gross market sales (in '000$, nominal) vary by option. For the eight runs examined specifically in the Sierra Club filing (Options 1-4B, and Options 1, 2, and 4A with Synapse Low CO_2 Price), the gross market sales ("Econ Energy Sales" in Strategist) are shown below. These values can also be found in column I of in tab "StratComp – Syn" of workbook "Exhibit JIF-2, 3 & 6 Strategist_Compilation_Workbook_Synapse.xlsx" provided in response to KPCO data request 1-7; the table below is provided as an attachment to this response as well in "KPSC 1-2a.xlsx"

Market Sales from Strategist Model ('000$ Nominal)

	Company Strategist Runs (BASE Commodity Price)					Synapse Low CO2 Price		
Year	Option 1	Option 2	Option 3	Option 4A	Option 4B	Option 1	Option 2	Option 4A
2011	52,478	52,478	52,478	52,477	52,477	52,478	52,478	52,478
2012	98,389	98,389	98,389	98,389	98,389	98,389	98,389	98,389
2013	62,692	62,692	62,692	62,692	62,692	62,692	62,692	62,692
2014	79,152	79,152	79,152	79,152	79,152	79,152	79,152	79,152
2015	57,102	57,102	98,751	57,101	57,101	57,102	57,102	57,102
2016	38,706	22,784	20,280	0	0	38,706	22,784	0
2017	45,362	17,458	15,530	0	0	45,362	17,458	0
2018	60,402	20,564	18,344	0	0	60,402	20,564	0
2019	42,560	17,866	15,840	0	0	42,560	17,866	0
2020	61,123	22,257	19,871	22,257	0	44,044	16,630	16,630
2021	67,203	25,439	22,767	25,439	0	48,337	18,649	18,649
2022	68,111	29,556	26,764	29,556	0	62,420	27,197	27,197
2023	30,750	20,843	18,563	20,842	0	26,299	18,912	18,912
2024	48,955	22,549	20,119	22,548	0	41,351	20,125	20,125
2025	147,664	127,556	122,441	127,555	127,555	124,569	31,507	111,169
2026	165,337	125,504	119,845	125,504	125,504	141,998	25,761	105,407
2027	154,502	131,760	126,154	131,759	131,759	118,710	26,658	108,616
2028	166,958	126,000	120,350	126,000	126,000	133,267	22,859	100,665
2029	154,577	118,331	112,598	118,331	118,331	123,003	16,727	95,391
2030	155,475	130,655	124,712	130,654	130,654	114,426	16,288	101,667
2031	158,856	124,931	119,064	124,931	124,931	124,587	14,641	95,526
2032	179,061	140,262	134,021	140,261	140,261	133,990	14,848	104,272
2033	176,763	134,750	129,032	134,749	134,749	122,042	12,135	89,821
2034	147,960	134,483	126,515	134,483	134,483	112,458	11,211	80,147
2035	144,082	115,512	109,147	115,511	115,511	106,504	9,889	66,747
2036	144,617	116,043	109,347	116,042	116,042	101,469	9,799	58,497
2037	154,908	119,278	113,204	119,277	119,277	107,121	9,831	56,574
2038	131,734	106,128	99,712	106,127	106,127	95,697	9,805	46,758
2039	139,177	108,854	102,244	108,853	108,853	95,469	10,559	44,491
2040	127,580	97,876	92,515	97,876	97,876	87,120	11,235	38,728

b. See response to KPSC 1-1b.

Witness: Jeremy Fisher

Market Sales from Strategist Model ('000$ Nominal)

	Company Strategist Runs (BASE Commodity Price)					Synapse Low CO2 Price		
Year	Option 1	Option 2	Option 3	Option 4A	Option 4B	Option 1	Option 2	Option 4A
2011	52,478	52,478	52,478	52,477	52,477	52,478	52,478	52,478
2012	98,389	98,389	98,389	98,389	98,389	98,389	98,389	98,389
2013	62,692	62,692	62,692	62,692	62,692	62,692	62,692	62,692
2014	79,152	79,152	79,152	79,152	79,152	79,152	79,152	79,152
2015	57,102	57,102	98,751	57,101	57,101	57,102	57,102	57,102
2016	38,706	22,784	20,280	0	0	38,706	22,784	0
2017	45,362	17,458	15,530	0	0	45,362	17,458	0
2018	60,402	20,564	18,344	0	0	60,402	20,564	0
2019	42,560	17,866	15,840	0	0	42,560	17,866	0
2020	61,123	22,257	19,871	22,257	0	44,044	16,630	16,630
2021	67,203	25,439	22,767	25,439	0	48,337	18,649	18,649
2022	68,111	29,556	26,764	29,556	0	62,420	27,197	27,197
2023	30,750	20,843	18,563	20,842	0	26,299	18,912	18,912
2024	48,955	22,549	20,119	22,548	0	41,351	20,125	20,125
2025	147,664	127,556	122,441	127,555	127,555	124,569	31,507	111,169
2026	165,337	125,504	119,845	125,504	125,504	141,998	25,761	105,407
2027	154,502	131,760	126,154	131,759	131,759	118,710	26,658	108,616
2028	166,958	126,000	120,350	126,000	126,000	133,267	22,859	100,665
2029	154,577	118,331	112,598	118,331	118,331	123,003	16,727	95,391
2030	155,475	130,655	124,712	130,654	130,654	114,426	16,288	101,667
2031	158,856	124,931	119,064	124,931	124,931	124,587	14,641	95,526
2032	179,061	140,262	134,021	140,261	140,261	133,990	14,848	104,272
2033	176,763	134,750	129,032	134,749	134,749	122,042	12,135	89,821
2034	147,960	134,483	126,515	134,483	134,483	112,458	11,211	80,147
2035	144,082	115,512	109,147	115,511	115,511	106,504	9,889	66,747
2036	144,617	116,043	109,347	116,042	116,042	101,469	9,799	58,497
2037	154,908	119,278	113,204	119,277	119,277	107,121	9,831	56,574
2038	131,734	106,128	99,712	106,127	106,127	95,697	9,805	46,758
2039	139,177	108,854	102,244	108,853	108,853	95,469	10,559	44,491
2040	127,580	97,876	92,515	97,876	97,876	87,120	11,235	38,728

REQUEST NO. 3. Does the Sierra Club recognize that Kentucky Power's base rates include approximately $15.29 million in off-system sales revenues with a specific base amount therefrom assigned to each month; and that, on a monthly basis, the difference between the off-system sales revenues and the base amount for that month is shared with 60 percent allocated to the ratepayer and 40 percent allocated to the shareholders?

a. If no, explain Sierra Club's understanding of how the off-system sales revenues are shared between the ratepayers and the shareholders.

b. If yes, explain the Sierra Club's position that the shareholders receive 40 percent of the off-system sales revenues.

c. Explain whether Sierra Club maintains that the ratepayers of Kentucky Power could receive no more than 60 percent of annual off-system sales revenues in a 12-month period.

d. Using the allocation methodology as stated in Item 1 above and using Sierra Club's Strategist analysis, explain whether Sierra Club's conclusion or testimony would change as to the 40 percent of off-system sales revenues to the shareholders.

RESPONSE NO. 3.

Mr. Hornby recognizes that Kentucky Power's base rates include approximately $15.29 million in net revenues from off-system sales (OSS) with a specific base amount therefrom assigned to each month; and that, on a monthly basis, 60 percent of the difference between actual net revenues from OSS and the base amount of net revenues from OSS for that month is credited to ratepayers, if positive, or recovered from ratepayers, if negative.

a. Not applicable.

b. Mr. Hornby is not familiar with all of the Orders and history underlying the currently effective KPCo System Sales Clause, including the base monthly net revenues totaling $15.29 million. His position that shareholders receive 40 percent of net revenues from OSS is based on his interpretation of the KPCo System Sales Clause and his assumption that the $15.29 million referred to in that clause, and reflected in KPCO current base rates, is a net annual credit from off-system sales to ratepayers that was assumed for the purpose of setting KPCo's base rates and. His interpretation is based upon his reading of Tariff S.S.C., which effectively states that in a given month in which monthly net revenues from system sales are below the monthly base net revenues from system sales, as provided in paragraph 3, KPCO will levy an additional charge to collect that shortfall. Mr. Hornby interprets that provision to mean that in a month in which monthly net revenues from system sales are zero, KPCo will collect revenues equal to the monthly base net revenues from system sales for that month through a charge equal to that amount divided by sales for that month. For example, if monthly net revenues from system sales are zero in March, KPCo would set this charge to collect $1,530,489 from ratepayers. Extending this interpretation to a year in which monthly net revenues from system sales are zero, KPCo would collect $15.29 million in additional revenue from ratepayers.

c. Mr. Hornby has interpreted the currently effective KPCo System Sales Clause to mean that ratepayers of Kentucky Power could receive no more than 60 percent of annual net revenues from OSS in a 12-month period.

d. No. Mr. Hornby's interpretation of the currently effective KPCo System Sales Clause is the same in response to Data Request 1 a as in response to Data Request 3 a.

Witness: J. Richard Hornby

REQUEST NO. 4. Refer to page 10, lines 1-3, of Dr. Fisher's testimony. Provide the source of dry flue gas desulfurization ("DFGD") system cost estimates that differ from the Kentucky Power's estimates.

RESPONSE NO. 4

The estimated cost for both the DFGD system and replacement options that are discussed by Dr. Fisher in his testimony are all from Kentucky Power Company. Dr. Fisher did not challenge the Company's EPC cost estimate of $769M ("as spent" $), according to the testimony of Mr. Weaver, of the DFGD. Dr. Fisher's testimony simply notes that the Company appears to have used a different and lower estimate for the capital cost in the Company Strategist Compilation Workbook.

Dr. Fisher states in his testimony (p10 at 1-6):

> In my assessment, the Company appears to have carried something akin to this "scrivener's error" through their supporting Strategist model, resulting in a surprisingly low capital cost for the FGD as portrayed in their fundamental Strategist analysis, while simultaneously inflating the expected capital cost of replacement options by 33-42% in the model relative to values presented in direct testimony.

This statement highlights the significant difference between the Company's estimate of DFGD system costs presented in the testimony (and accompanying discovery responses) of witness Weaver and the Company's estimate of DFGD system costs used in the Company Strategist Compilation Workbook, as described in Dr. Fisher's testimony. This difference is portrayed visually in Figure 3 of Dr. Fisher's testimony.

Witness: Jeremy Fisher

REQUEST NO. 5. Refer to page 10, lines 3-6, of Dr. Fisher's testimony. Provide the source of cost estimates for replacement options that differ from the Company's options.

RESPONSE NO. 5:

See response to KPSC 1-4.

Witness: Jeremy Fisher

REQUEST NO. 6. Refer to page 33, lines 1-2, and Exhibit JIF-7A of Dr. Fisher's testimony. The testimony maintains that the Company's estimate for carbon dioxide emissions is below industry estimates. Explain the impact of the recent Energy Information Administration ("EIA") AEO-2012 Early Release report that CO_2 emissions will remain below the 2005 thru 2035 previously forecasted levels.

RESPONSE NO. 6:

Dr. Fisher's testimony maintains that the Company's forecast of the price for carbon dioxide emissions is below other industry price forecasts (see page 31 at lines 10-11). Dr. Fisher does not comment on the Company's projections of the physical quantities of carbon dioxide emissions under each of the options analyzed.

In terms of future prices for carbon dioxide emissions, Dr. Fisher does not expect that the projection from the EIA AEO-2012 Early Release (ER) that the physical quantity of CO_2 emissions will remain below 2005 levels thru 2035 to have a material impact.

The reduction in projected CO_2 emissions from the electric sector through 2035 between AEO 2011 and AEO 2012 ER is notable – about a 3-5% reduction relative to AEO 2011.

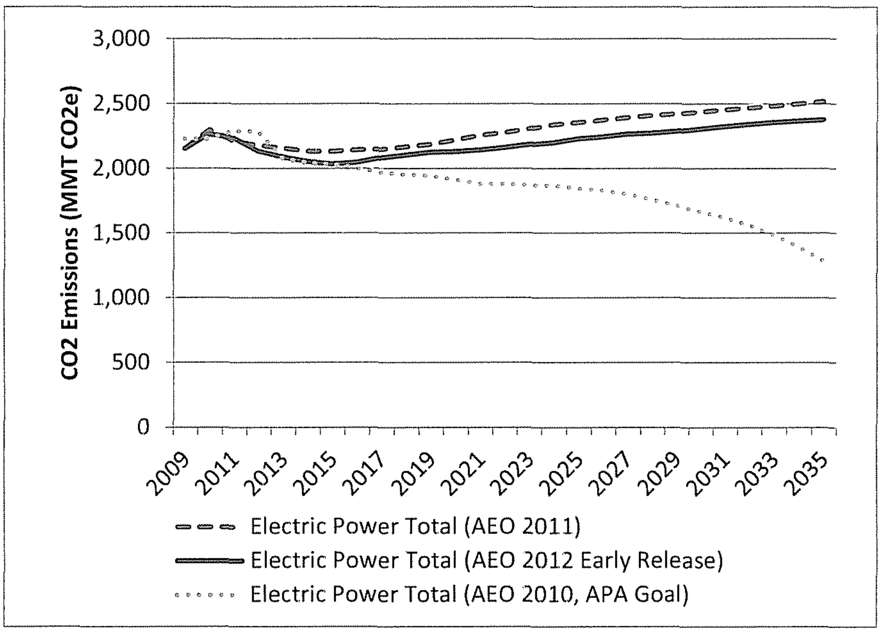
Explaining this reduction, in the section entitled "Energy-Related Carbon Dioxide Emissions," the EIA's AEO 2012 Early Release ("AEO 2012") report states:

> Although total U.S. energy-related CO_2 emissions increased by almost 4 percent in 2010, they do not return to their 2005 level (5,996 million metric tons) by the end of the AEO2012 projection period (see Figure 4 on page 2). Emissions per capita fall by an average of 1 percent per year from 2005 to 2035, as growth in demand for transportation fuels is moderated by higher energy prices and Federal CAFE standards. In addition, electricity-related emissions are tempered by efficiency standards, State RPS requirements, and implementation of the CSAPR,

which helps shift the fuel mix away from coal toward lower carbon fuels. (emphasis added)

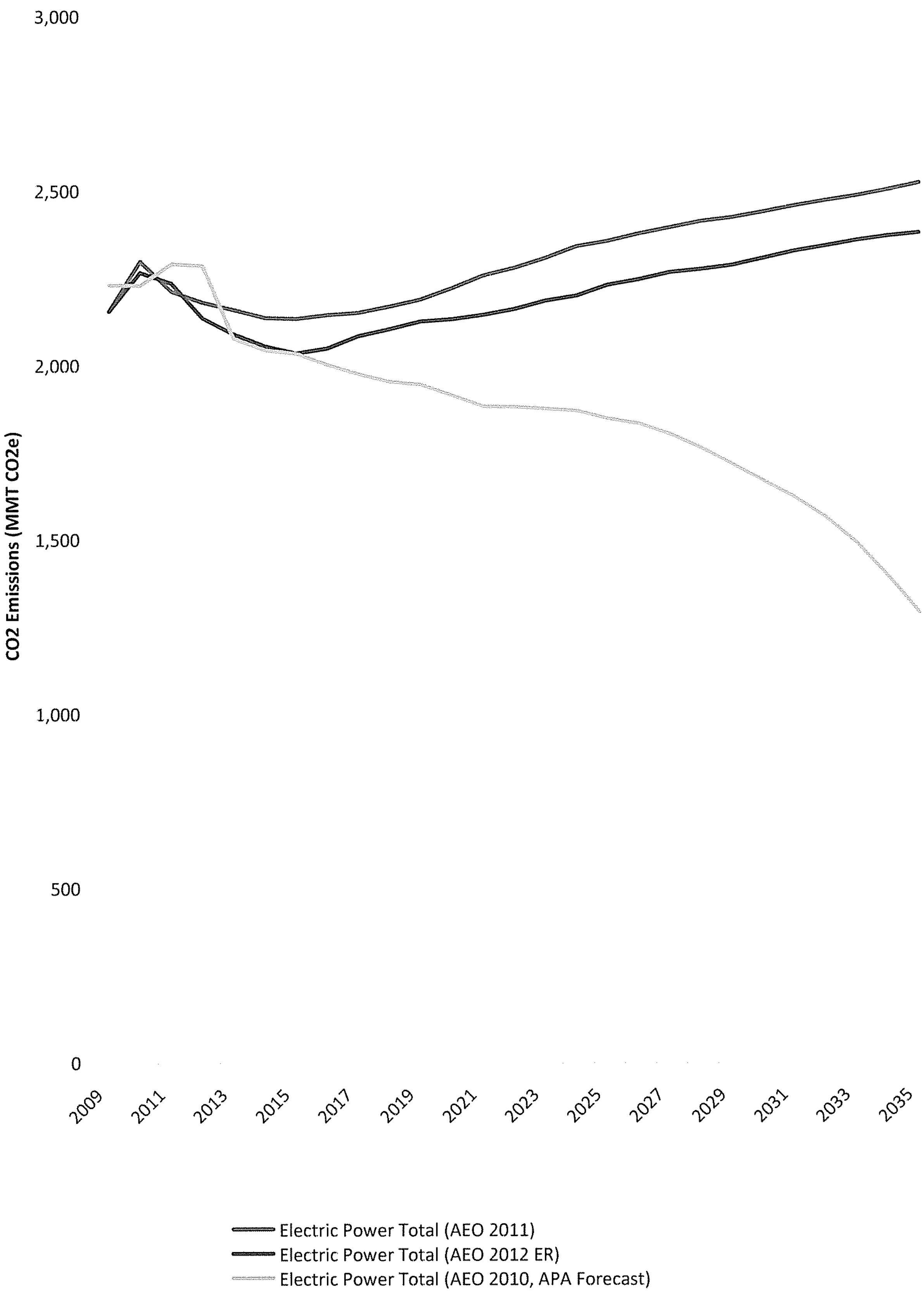
However, that reduction is small compared to the minimum reduction required by 2035 in order to mitigate climate change, i.e. achieve a global concentration of greenhouse gasses that will not force more than 2°C of warming on average.

The figure below shows forecast electric sector CO_2 emissions from AEO 2011, AEO 2012, and from a carbon policy case tested in AEO 2010 (the American Power Act, or APA, requiring 80% reductions by 2050). The reductions realized through changing commodity prices (i.e. gas prices) and economics (i.e. the downturn), as well as more protective regulations, will have resulted in a CO_2 trajectory approximating the APA from today through 2015. From 2017 to 2024, the reductions the EIA projects in AEO 2012 ER are only about 30% of the reduction required under the 2010 APA case. Beyond 2024, the reductions forecast in AEO 2012 ER are a diminishing fraction of required reductions, down to about 15% by 2031 (see attached workbook KPSC 1-6.xlsx).



Given the magnitude of reductions required to mitigate climate change, the projections of future reductions in CO_2 we have seen thus far will not significantly change the marginal price of abatement.

Witness: Jeremy Fisher


3,000
2,500
2,000
1,500
1,000
500
0
CO2 Emissions (MMT CO2e)
2009
2011
2013
2015
2017
2019
2021
2023
2025
2027
2029
2031
2033
2035
Electric Power Total (AEO 2011)
Electric Power Total (AEO 2012 ER)
Electric Power Total (AEO 2010, APA Forecast)

CO2 Emissions	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Electric Power Total (AEO 2011)	2160	2303	2217	2185	2164	2141	2138	2149	2155	2173	2193	2225	2261	2283
Electric Power Total (AEO 2012 ER)	2159	2271	2240	2140	2094	2059	2039	2053	2088	2108	2130	2136	2148	2165
Electric Power Total (AEO 2010, APA Forecast)	2235	2234	2296	2291	2081	2048	2038	2006	1979	1957	1949	1918	1886	1885
Reduction AEO 2011 to 2012					*70*	*82*	*99*	*96*	*67*	*65*	*63*	*89*	*113*	*118*
Fraction reduction					3.2%	3.8%	4.6%	4.5%	3.1%	3.0%	2.9%	4.0%	5.0%	5.2%
Reduction AEO 2011 to APA					83	93	100	143	176	216	244	307	375	398
Fraction of APA reduction realized with 2011-2012 reduction					84.3%	88.2%	99.0%	67.1%	38.1%	30.1%	25.8%	29.0%	30.1%	29.6%

CO2 Emissions	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Electric Power Total (AEO 2011)	2311	2345	2360	2381	2399	2417	2428	2444	2461	2476	2490	2507	2526
Electric Power Total (AEO 2012 ER)	2189	2203	2234	2250	2270	2279	2291	2311	2331	2346	2362	2374	2383
Electric Power Total (AEO 2010, APA Forecast)	1879	1873	1851	1836	1806	1766	1720	1672	1625	1568	1493	1399	1294
Reduction AEO 2011 to 2012	*122*	*142*	*126*	*131*	*129*	*138*	*137*	*133*	*130*	*130*	*128*	*133*	*143*
Fraction reduction	5.3%	6.1%	5.3%	5.5%	5.4%	5.7%	5.6%	5.4%	5.3%	5.3%	5.1%	5.3%	5.7%
Reduction AEO 2011 to APA	432	472	509	545	593	651	708	772	836	908	997	1108	1232
Fraction of APA reduction realized with 2011-2012 reduction	28.2%	30.1%	24.8%	24.0%	21.8%	21.2%	19.4%	17.2%	15.6%	14.3%	12.8%	12.0%	11.6%

Energy-Related Carbon Dioxide Emissions by Sector and Source, United States, AEO2011 Reference case
(million metric tons carbon dioxide equivalent, unless otherwise noted)

Sector and Source	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	Growth Rate (2010-2035)
Residential																												
Petroleum	83	78	79	77	75	74	73	72	71	70	69	68	67	66	65	65	64	63	62	62	61	61	60	60	59	59	58	-1.20%
Natural Gas	259	260	259	260	261	262	262	263	263	263	263	264	263	263	263	264	263	263	263	264	263	263	263	263	261	261	260	0.00%
Coal	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	-1.10%
Electricity 1/	824	894	815	800	775	764	757	759	759	764	770	780	791	801	812	826	833	842	850	860	864	872	879	887	893	900	909	0.10%
Total	1166	1233	1154	1138	1112	1101	1092	1095	1093	1097	1103	1112	1122	1131	1141	1156	1160	1169	1177	1187	1189	1196	1202	1210	1214	1220	1228	0.00%
Commercial																												
Petroleum	44	39	39	40	39	39	39	39	38	38	38	38	38	38	38	38	38	37	37	37	37	37	37	37	37	37	37	-0.20%
Natural Gas	169	169	175	176	179	182	184	186	187	189	190	190	191	192	192	193	194	195	196	197	199	200	202	203	205	206	208	0.80%
Coal	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	0.20%
Electricity 1/	800	829	814	800	792	792	795	804	812	825	838	854	872	886	902	920	933	947	961	974	985	998	1010	1022	1035	1048	1063	1.00%
Total	1018	1042	1034	1022	1016	1018	1023	1034	1044	1058	1071	1088	1107	1121	1138	1157	1170	1185	1200	1214	1227	1241	1255	1269	1284	1298	1314	0.90%
Industrial 2/																												
Petroleum	343	366	373	403	411	410	410	411	410	406	404	402	404	405	404	402	402	401	400	400	400	400	402	403	404	405	405	0.40%
Natural Gas 3/	383	412	432	444	465	476	489	491	492	495	497	500	498	494	494	493	492	491	490	490	491	493	493	493	493	493	493	0.70%
Coal	128	149	149	150	154	152	162	162	163	163	163	164	165	171	178	182	187	191	197	202	209	215	222	229	236	242	249	2.10%
Electricity 1/	533	576	584	581	593	581	582	581	579	579	580	586	591	590	590	591	588	584	579	574	569	565	561	555	551	546	542	-0.20%
Total	1387	1503	1538	1578	1623	1619	1643	1644	1644	1643	1644	1651	1658	1660	1666	1669	1668	1667	1666	1666	1669	1673	1679	1680	1683	1686	1689	0.50%
Transportation																												
Petroleum 4/	1816	1824	1834	1844	1867	1872	1878	1884	1884	1883	1881	1881	1893	1888	1889	1886	1892	1902	1911	1922	1927	1945	1961	1977	1992	2005	2023	0.40%
Natural Gas 5/	34	37	36	36	37	37	38	38	38	38	38	38	39	39	39	39	40	40	40	41	41	42	43	43	43	44	44	0.70%
Electricity 1/	4	4	4	4	4	4	5	5	5	5	5	6	6	6	7	7	8	8	9	9	9	10	10	11	11	12	12	4.40%
Total	1854	1865	1875	1885	1909	1914	1921	1927	1927	1926	1924	1925	1937	1933	1935	1933	1940	1950	1959	1972	1978	1997	2014	2030	2047	2061	2080	0.40%
Electric Power 6/																												
Petroleum	34	35	34	34	34	33	33	34	34	33	34	35	35	35	35	35	35	35	35	35	35	35	36	36	36	36	37	0.20%
Natural Gas	373	405	381	370	373	374	379	375	378	381	382	372	364	363	363	358	362	362	370	378	388	399	409	414	418	422	428	0.20%
Coal	1742	1851	1789	1769	1744	1722	1714	1729	1731	1747	1766	1806	1850	1873	1901	1939	1951	1971	1982	1992	1994	1998	2004	2015	2024	2036	2049	0.40%
Other 7/	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	0.00%
Total	2160	2303	2217	2185	2164	2141	2138	2149	2155	2173	2193	2225	2261	2283	2311	2345	2360	2381	2399	2417	2428	2444	2461	2476	2490	2507	2526	0.40%
Total by Fuel																												
Petroleum 3/	2319	2343	2360	2398	2427	2428	2434	2439	2437	2430	2425	2423	2436	2431	2431	2426	2430	2438	2445	2456	2461	2479	2496	2513	2529	2543	2561	0.40%
Natural Gas	1218	1282	1284	1287	1315	1331	1352	1351	1357	1365	1370	1365	1354	1351	1351	1348	1351	1352	1360	1370	1382	1398	1409	1416	1421	1426	1434	0.40%
Coal	1877	2006	1945	1925	1905	1881	1882	1898	1901	1917	1935	1977	2022	2050	2085	2128	2144	2169	2185	2201	2208	2219	2233	2250	2266	2285	2304	0.60%
Other 7/	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	0.00%
Total	5426	5643	5601	5622	5659	5651	5680	5700	5707	5724	5742	5777	5825	5845	5879	5914	5938	5971	6002	6039	6063	6107	6150	6190	6227	6265	6311	0.40%
Carbon Dioxide Emissions (tons carbon dioxide equivalent per person)	17.6	18.2	17.8	17.7	17.7	17.5	17.4	17.3	17.2	17.1	16.9	16.9	16.9	16.8	16.7	16.7	16.6	16.5	16.5	16.4	16.3	16.3	16.3	16.3	16.2	16.2	16.2	-0.50%

1/ Emissions from the electric power sector are distributed to the end-use sectors.
2/ Fuel consumption includes energy for combined heat and power plants, except those plants whose primary business is to sell electricity, or electricity and heat, to the public.
3/ Includes lease and plant fuel.
4/ This includes carbon dioxide from international bunker fuels, both civilian and military, which are excluded from the accounting of carbon dioxide emissions under the United Nations convention. From 1990 through 2010, international bunker fuels accounted for 90 to 126 million metric tons annually.
5/ Includes pipeline fuel natural gas and compressed natural gas used as vehicle fuel.
6/ Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
7/ Includes emissions from geothermal power and nonbiogenic emissions from municipal waste.
- - = Not applicable.

Note: By convention, the direct emissions from biogenic energy sources are excluded from energy-related CO2 emissions. The release of carbon from these sources is assumed to be balanced by the uptake of carbon when the feedstock is grown, resulting in zero net emissions over some period of time. If, however, increased use of biomass energy results in a decline in terrestrial carbon stocks, a net positive release of carbon may occur. See "Energy-Related Carbon Dioxide Emissions by End Use" for the emissions from biogenic energy sources as an indication of the potential net release of carbon dioxide in the absence of offsetting sequestration. Totals may not equal sum of components due to independent rounding. Data for 2009 and 2010 are model results and may differ slightly from official EIA data reports.

Sources: 2009 and 2010 emissions and emission factors: U.S. Energy Information Administration (EIA), Monthly Energy Review, October 2011, DOE/EIA-0035(2011/10) (Washington, DC, October 2011).
Projections: EIA, AEO2012 National Energy Modeling System.

Energy-Related Carbon Dioxide Emissions by Sector and Source, United States, Reference case
(million metric tons carbon dioxide equivalent, unless otherwise noted)

Sector and Source	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	Growth Rate (2010-2035)
Residential																												
Petroleum	81	85	82	81	77	76	74	73	71	70	69	69	68	67	66	65	65	64	63	63	62	61	61	60	60	59	59	-1.50%
Natural Gas	259	267	268	274	265	265	265	264	264	263	263	262	262	261	260	260	259	259	258	257	257	257	256	255	254	253	253	-0.20%
Coal	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	-1.30%
Electricity 1/	819	879	861	818	791	772	759	761	773	780	788	791	796	804	816	824	838	847	858	864	872	883	894	903	911	918	925	0.20%
Total	**1159**	**1232**	**1211**	**1174**	**1134**	**1113**	**1098**	**1099**	**1109**	**1114**	**1121**	**1122**	**1126**	**1132**	**1142**	**1150**	**1163**	**1170**	**1180**	**1185**	**1192**	**1202**	**1211**	**1219**	**1226**	**1231**	**1236**	**0.00%**
Commercial																												
Petroleum	49	51	50	46	45	45	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	-0.60%
Natural Gas	169	173	176	180	178	180	181	182	183	184	184	185	185	185	185	185	186	186	187	188	189	190	191	191	192	193	194	0.50%
Coal	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	0.00%
Electricity 1/	785	805	793	765	752	739	734	740	752	761	770	776	782	790	803	811	826	835	847	854	861	872	883	892	901	909	916	0.50%
Total	**1009**	**1035**	**1025**	**997**	**980**	**969**	**965**	**972**	**985**	**994**	**1005**	**1010**	**1017**	**1025**	**1037**	**1046**	**1061**	**1071**	**1083**	**1091**	**1100**	**1111**	**1123**	**1133**	**1143**	**1152**	**1159**	**0.50%**
Industrial 2/																												
Petroleum	339	344	378	349	352	358	362	364	365	363	362	361	360	359	358	358	358	359	359	357	357	357	359	361	360	362	362	0.20%
Natural Gas 3/	383	408	433	431	431	438	442	447	452	454	456	457	457	457	454	453	452	450	448	447	447	448	447	448	449	448	451	0.40%
Coal	128	157	161	151	149	149	147	160	163	165	167	169	170	172	173	173	174	175	176	177	179	180	181	182	184	185	186	0.70%
Electricity 1/	551	583	581	553	547	544	542	548	559	562	566	565	565	565	564	561	563	560	558	553	549	547	545	542	539	535	531	-0.40%
Total	**1401**	**1492**	**1554**	**1483**	**1479**	**1489**	**1493**	**1519**	**1538**	**1545**	**1551**	**1552**	**1552**	**1553**	**1549**	**1546**	**1547**	**1544**	**1540**	**1535**	**1532**	**1532**	**1532**	**1532**	**1530**	**1531**	**1529**	**0.10%**
Transportation																												
Petroleum 4/	1818	1836	1802	1811	1823	1832	1833	1841	1838	1833	1826	1818	1811	1805	1803	1799	1798	1797	1796	1796	1796	1798	1804	1807	1812	1820	1824	0.00%
Natural Gas 5/	34	36	38	40	39	39	40	40	40	40	41	41	41	42	42	42	42	42	42	42	43	43	44	44	44	45	45	0.90%
Electricity 1/	4	4	4	4	4	4	4	4	4	5	5	5	5	6	6	6	7	7	8	8	9	9	10	10	11	12	12	4.50%
Total	**1856**	**1876**	**1844**	**1855**	**1865**	**1876**	**1877**	**1885**	**1882**	**1878**	**1871**	**1864**	**1858**	**1853**	**1850**	**1847**	**1846**	**1846**	**1846**	**1846**	**1847**	**1850**	**1858**	**1861**	**1867**	**1876**	**1881**	**0.00%**
Electric Power 6/																												
Petroleum	34	33	24	24	24	24	24	24	24	24	24	24	24	25	25	25	25	25	25	25	25	26	26	26	26	26	26	-0.90%
Natural Gas	373	399	407	424	405	422	439	431	422	424	427	428	430	430	424	424	417	422	426	435	444	455	463	472	479	483	483	0.80%
Coal	1741	1828	1796	1680	1653	1601	1565	1587	1631	1649	1667	1673	1681	1699	1728	1743	1780	1791	1807	1807	1810	1818	1831	1836	1845	1854	1862	0.10%
Other 7/	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	0.00%
Total	**2159**	**2271**	**2240**	**2140**	**2094**	**2059**	**2039**	**2053**	**2088**	**2108**	**2130**	**2136**	**2148**	**2165**	**2189**	**2203**	**2234**	**2250**	**2270**	**2279**	**2291**	**2311**	**2331**	**2346**	**2362**	**2374**	**2383**	**0.20%**
Total by Fuel																												
Petroleum 3/	2320	2349	2337	2311	2320	2335	2338	2346	2342	2334	2326	2317	2307	2300	2295	2292	2290	2289	2287	2285	2284	2286	2294	2298	2302	2312	2315	-0.10%
Natural Gas	1218	1283	1321	1350	1318	1344	1366	1365	1361	1365	1371	1373	1376	1374	1365	1364	1356	1359	1360	1370	1381	1393	1401	1410	1419	1422	1425	0.40%
Coal	1876	1990	1964	1837	1809	1756	1718	1753	1800	1820	1839	1847	1858	1877	1907	1922	1961	1973	1990	1991	1995	2004	2018	2025	2034	2045	2054	0.10%
Other 7/	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	0.00%
Total	**5425**	**5634**	**5634**	**5510**	**5458**	**5447**	**5434**	**5475**	**5514**	**5531**	**5548**	**5549**	**5552**	**5563**	**5579**	**5589**	**5618**	**5632**	**5649**	**5657**	**5671**	**5695**	**5725**	**5745**	**5766**	**5790**	**5806**	**0.10%**
Carbon Dioxide Emissions (tons carbon dioxide equivalent per person)	**17.6**	**18.1**	**18**	**17.4**	**17.1**	**16.9**	**16.7**	**16.6**	**16.6**	**16.5**	**16.4**	**16.2**	**16.1**	**16**	**15.9**	**15.8**	**15.7**	**15.6**	**15.5**	**15.4**	**15.3**	**15.2**	**15.2**	**15.1**	**15**	**15**	**14.9**	**-0.80%**

1/ Emissions from the electric power sector are distributed to the end-use sectors.
2/ Fuel consumption includes energy for combined heat and power plants, except those plants whose primary business is to sell electricity, or electricity and heat, to the public.
3/ Includes lease and plant fuel.
4/ This includes carbon dioxide from international bunker fuels, both civilian and military, which are excluded from the accounting of carbon dioxide emissions under the United Nations convention. From 1990 through 2010, international bunker fuels accounted for 90 to 126 million metric tons annually.
5/ Includes pipeline fuel natural gas and compressed natural gas used as vehicle fuel.
6/ Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
7/ Includes emissions from geothermal power and nonbiogenic emissions from municipal waste.
- - = Not applicable.

Note: By convention, the direct emissions from biogenic energy sources are excluded from energy-related CO2 emissions. The release of carbon from these sources is assumed to be balanced by the uptake of carbon when the feedstock is grown, resulting in zero net emissions over some period of time. If, however, increased use of biomass energy results in a decline in terrestrial carbon stocks, a net positive release of carbon may occur. See "Energy-Related Carbon Dioxide Emissions by End Use" for the emissions from biogenic energy sources as an indication of the potential net release of carbon dioxide in the absence of offsetting sequestration. Totals may not equal sum of components due to independent rounding. Data for 2009 and 2010 are model results and may differ slightly from official EIA data reports.

Sources: 2009 and 2010 emissions and emission factors: U.S. Energy Information Administration (EIA), Monthly Energy Review, October 2011, DOE/EIA-0035(2011/10) (Washington, DC, October 2011).
Projections: EIA, AEO2012 National Energy Modeling System.

Carbon Dioxide Emissions by Sector and Source, United States, APA Basic
(million metric tons carbon dioxide equivalent, unless otherwise noted)

Sector and Source	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	Growth Rate (2008-2035)
Residential																														
Petroleum	87	80	82	81	78	76	74	72	70	69	68	67	66	65	64	63	62	62	61	60	60	59	59	58	58	57	57	56	56	-1.30%
Natural Gas	257	265	260	262	254	254	254	255	256	256	256	257	258	260	260	261	261	262	261	261	260	260	258	256	256	256	255	255	255	-0.10%
Coal	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	-1.30%
Electricity 1/	891	875	857	857	866	853	756	741	735	723	712	703	699	689	678	679	678	678	670	666	657	645	628	611	594	574	546	512	474	-2.20%
Total	1235	1220	1200	1201	1199	1184	1085	1069	1062	1050	1036	1026	1023	1014	1002	1004	1003	1002	993	988	978	964	945	926	908	888	858	823	785	-1.60%
Commercial																														
Petroleum	44	41	41	38	39	41	39	39	39	38	38	38	38	38	37	37	37	37	37	37	37	37	37	37	37	37	37	36	36	-0.50%
Natural Gas	164	170	168	175	174	174	174	174	175	174	174	174	175	176	178	179	180	180	181	182	182	183	183	184	185	187	188	190	192	0.40%
Coal	7	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	0.00%
Electricity 1/	856	858	826	837	862	858	782	772	771	760	753	746	744	734	725	729	730	730	726	723	715	703	689	673	657	637	609	573	531	-1.80%
Total	1071	1075	1041	1055	1082	1079	1002	992	991	979	972	964	963	954	947	952	954	954	950	948	940	929	915	900	886	866	840	805	766	-1.30%
Industrial 2/																														
Petroleum	417	385	386	385	402	405	403	406	406	401	398	395	393	389	388	386	386	385	383	382	379	378	374	373	372	371	370	368	369	-0.20%
Natural Gas 3/	404	409	382	383	388	402	407	408	409	412	414	418	422	427	431	429	426	426	423	422	422	419	417	413	412	411	411	411	411	0.00%
Coal	177	172	123	127	135	145	150	154	155	155	156	156	156	156	155	154	152	152	151	149	147	145	143	140	138	136	134	131	129	-1.10%
Electricity 1/	658	623	547	537	563	575	538	532	529	518	511	505	502	491	479	472	466	460	451	442	429	414	398	382	368	352	332	309	284	-2.90%
Total	1655	1589	1438	1432	1488	1528	1498	1500	1499	1487	1478	1474	1473	1463	1453	1441	1431	1422	1407	1395	1377	1356	1332	1309	1291	1269	1246	1220	1193	-1.10%
Transportation																														
Petroleum 4/	1985	1889	1805	1812	1847	1865	1864	1865	1862	1860	1858	1859	1859	1862	1864	1867	1872	1873	1876	1879	1875	1876	1872	1880	1884	1889	1897	1907	1917	0.10%
Natural Gas 5/	35	36	36	36	35	35	35	35	36	37	37	37	38	40	43	44	45	46	46	47	48	48	49	49	49	50	51	51	52	1.40%
Electricity 1/	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	5	5	5	5	5	5	5	6	6	6	6	6	5	5	0.80%
Total	2025	1929	1845	1852	1886	1904	1903	1904	1902	1900	1899	1901	1901	1907	1912	1916	1922	1924	1927	1931	1928	1930	1926	1934	1939	1945	1954	1964	1974	0.10%
Electric Power 6/																														
Petroleum	55	40	36	50	51	51	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	49	49	49	49	48	47	47	0.60%
Natural Gas	372	362	362	342	323	302	297	299	314	326	331	334	335	342	357	367	370	373	375	375	372	371	364	351	344	344	346	351	347	-0.20%
Coal	1971	1946	1825	1830	1911	1926	1722	1688	1663	1618	1587	1562	1552	1515	1467	1457	1448	1438	1415	1399	1372	1335	1295	1260	1221	1164	1088	989	889	-2.90%
Other 7/	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	0.00%
Total	2409	2359	2235	2234	2296	2291	2081	2048	2038	2006	1979	1957	1949	1918	1886	1885	1879	1873	1851	1836	1806	1766	1720	1672	1625	1568	1493	1399	1294	-2.20%
Total by Fuel																														
Petroleum 3/	2589	2436	2350	2365	2416	2438	2430	2431	2426	2418	2411	2408	2405	2404	2403	2404	2409	2408	2407	2408	2401	2400	2391	2397	2400	2403	2408	2416	2424	0.00%
Natural Gas	1232	1242	1208	1198	1174	1168	1168	1172	1191	1205	1212	1220	1228	1245	1270	1279	1282	1287	1286	1286	1284	1280	1270	1254	1246	1248	1250	1258	1256	0.00%
Coal	2155	2125	1955	1964	2053	2078	1879	1849	1824	1781	1749	1725	1715	1678	1629	1617	1607	1596	1573	1556	1527	1487	1445	1407	1366	1307	1229	1127	1025	-2.70%
Other 7/	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	0.00%
Total	5986	5814	5523	5539	5655	5696	5488	5464	5454	5416	5385	5365	5360	5338	5314	5312	5309	5303	5278	5261	5223	5179	5118	5069	5024	4968	4898	4812	4717	-0.80%
Carbon Dioxide Emissions (tons carbon dioxide equivalent per person)	19.8	19	17.9	17.8	18	17.9	17.1	16.9	16.7	16.4	16.2	16	15.8	15.6	15.4	15.2	15.1	14.9	14.7	14.5	14.3	14.1	13.8	13.5	13.3	13	12.7	12.4	12.1	-1.70%

1/ Emissions from the electric power sector are distributed to the end-use sectors.

2/ Fuel consumption includes energy for combined heat and power plants, except those plants whose primary business is to sell electricity, or electricity and heat, to the public.

3/ Includes lease and plant fuel.

4/ This includes carbon dioxide from international bunker fuels, both civilian and military, which are excluded from the accounting of carbon dioxide emissions under the United Nations convention. From 1990 through 2008, international bunker fuels accounted for 86 to 130 million metric tons annually.

5/ Includes pipeline fuel natural gas and compressed natural gas used as vehicle fuel.

6/ Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.

7/ Includes emissions from geothermal power and nonbiogenic emissions from municipal waste.

- - = Not applicable.

Note: By convention, the direct emissions from biogenic energy sources are excluded from energy-related CO2 emissions. The release of carbon from these sources is asssumed to be balanced by the uptake of carbon when the feedstock is grown, resulting in zero net emissions over some period of time. If, however, increased use of biomass energy results in a decline in terrestrial carbon stocks, a net positive release of carbon may occur. See "Energy-Related Carbon Dioxide Emissions by End Use" for the emissions from biogenic energy sources as an indication of the potential net release of carbon dioxide in the absence of offsetting sequestration. Totals may not equal sum of components due to independent rounding. Data for 2007 and 2008 are model results and may differ slightly from official EIA data reports.

Sources: 2007 and 2008 emissions and emission factors: Energy Information Administration (EIA), Emissions of Greenhouse Gases in the United States 2008, DOE/EIA-0573(2008) (Washington, DC, December 2009).
Projections: EIA, AEO2010 National Energy Modeling System.

REQUEST NO. 7. Refer to page 33, lines 1-2, and Exhibit JIF-7A of Dr. Fisher's testimony. Did Dr. Fisher consider the recent reports associated with the Regional Greenhouse Gas Initiative that indicates that the recent CO_2 allowance auction resulted in a floor price of $1.86 per ton verses an expected $10 to $15 per ton? Explain the impact of this uncertainty.

RESPONSE NO. 7:

The low value of the Regional Greenhouse Gas Initiative CO_2 allowances does not demonstrates that the CO_2 price in an effective greenhouse gas program would be lower than projected, but rather than the RGGI cap on carbon emissions was set far too high. Emissions from RGGI-covered units have been dropping since 2005 at a faster rate than the RGGI cap, resulting in an oversupply of allowances – and a trading price consistently at the auction floor. The cap was established in 2009 at approximately the 2005 emissions level. The drop in emissions was due to fuel switching with a rise in the price of oil, a moderate increase in non-emitting generation, and stable or declining consumption trends (see attached document KPSC 1-7 ENE_RGGI_Emissions_Report_120110_Final.pdf).

The RGGI market has been clearing at the reserve price for several years and, without a marked change in the cap, is expected to maintain a very low price. Carbon prices cleared in the most recent RGGI market at $1.93/short ton CO_2, the auction's reserve price. In retrospect, the cap was set too high. As a result fewer allowances are being purchased than are being offered, and the price has remained at the reserve price.

Momentum is currently building to tighten the RGGI cap, which would require the quantity of annual emissions to be reduced at a faster pace, and raise the expected auction price. See the attached article from the New York Times, dated January 26, 2012 (KPSC 1-7 NYTimes article on RGGI.pdf).

On March 20, 2012, RGGI presented modeling results for a new, lower cap (see attached document KPSC 1-7 IPM-Modeling_030212.pdf). One of the scenarios analyzed would push the cap down from 165 million metric tons (MMT) to 106 MMT in 2014, which would push prices from their current level to closer to $5 in 2014 (2009$) and $7 in 2020 in the reference case. The ceiling price for this case is set at $10 from 2015-2017 and $15 from 2018-2020.

Witness: Jeremy Fisher

RGGI Emissions Trends

January 2011

ENE
Environment Northeast

Emissions from power plants in the Regional Greenhouse Gas Initiative (RGGI) decreased in 2011 and likely fell to their lowest levels since the program launched in 2009. Based on data through the third quarter of 2011, ENE projects that total 2011 emissions are likely to have fallen slightly below the historic low in 2009.[1] Low emissions are a consequence of fuel-switching to natural gas, increased generation from non-emitting sources, stable electricity consumption, and – to a lesser extent – mild weather and weak economic conditions in the region. The persistence of these underlying conditions through RGGI's first three years suggests a long-lasting structural change in the regional electric system that will keep emissions significantly below the existing cap level for the foreseeable future.

RGGI at a Glance:

- 10 States (ME, MA, NH, VT, RI, CT, NY, NJ, DE and MD)
- Applies to all fossil fuel-fired power plants 25 MW or greater
- Went into effect Jan 1, 2009
- 14th auction conducted on December 7, 2011
- Initial regional cap is 188 million tons CO_2
- Cap is two-phase:
  - Stabilization at initial level for 2009-2014.
  - 2.5% reduction per year 2015-2018 for total 10% reduction
- 3 year compliance period; first permits due 3/1/2012.

Summary of Key Findings:

- Emissions through the first three quarters of 2011 were 11% below emissions over the same period in 2010, and total **2011 emissions likely declined to around 34% below the RGGI cap**.
- Emissions have declined due to **decreasing generation from carbon-intensive fuel oil and coal, increasing generation from natural gas and renewables, and expanding energy efficiency programs**.
- Emissions have decreased without significant investment in new electric generation, indicating that **carbon pollution can be reduced at low cost within a market-based program like RGGI**.
- The persistence of low natural gas prices and increasing commitments to renewables and efficiency suggest that **emissions will remain below the current RGGI cap for the foreseeable future**.

Emissions Data

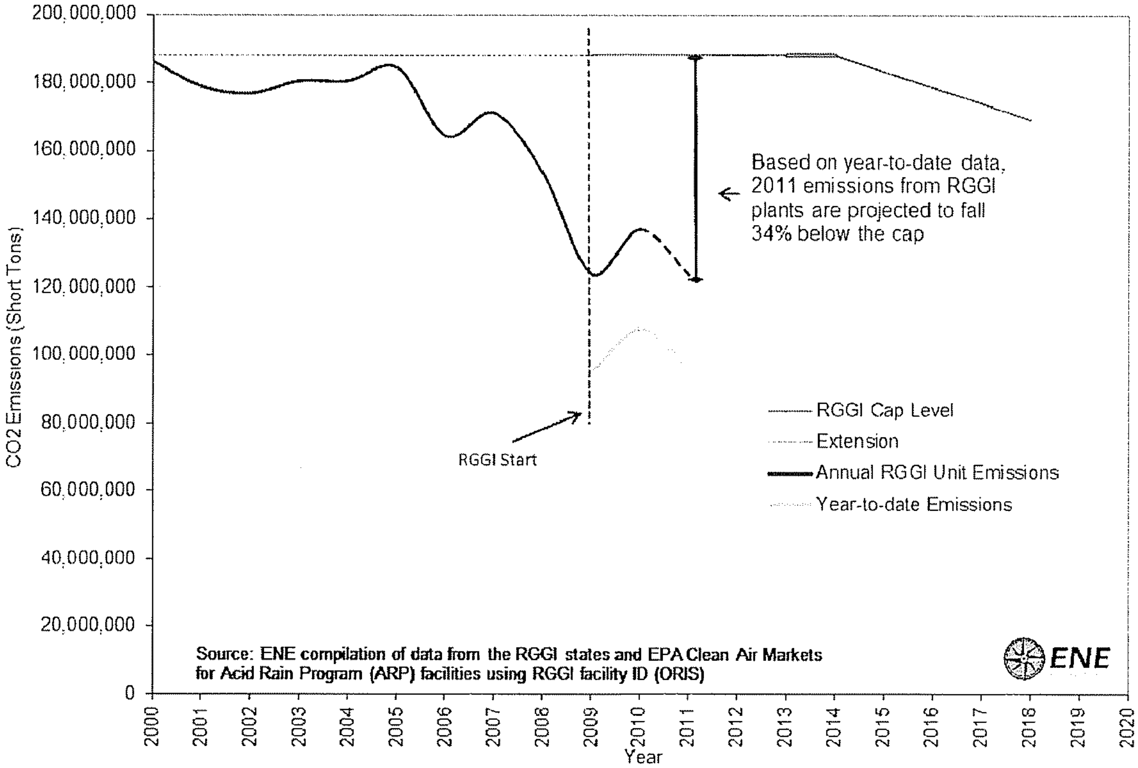
Carbon dioxide emissions from RGGI power plants in the first three quarters of 2011 totaled **96,127,957** tons, a 10.7% decrease from emissions over the first three quarters of 2010 (107,648,602 tons). Based on average fourth quarter emissions in 2009 and 2010, total 2011 emissions are projected to fall about 34% below the regional cap of 188,076,976 tons (Figure 1).

This analysis is based on emissions data made available by the RGGI member states and compiled by RGGI, Inc through the CO_2 Allowance Tracking System (RGGI-COATS).[2]

[1] Emissions data from power plants within the RGGI program is released publically several months after the end of the reporting period, so this report projects 2011 emissions based on available data (through third quarter 2011).

[2] Emissions data available at: https://rggi-coats.org/eats/rggi/, "Public Reports".

Figure 1: RGGI Facility Year-to-Date (YTD)[3] CO_2 Emissions through 2011



Emissions Drivers

Carbon dioxide emissions from power plants in the RGGI program are determined by two main factors: 1) what source the electricity comes from; and 2) how much electricity is consumed. Each of these is determined by a number of sometimes interrelated drivers:

- ***Sources of Electric Generation***
  - *Energy Prices & Natural Gas Generation* – describing the impact of low-cost, lower-emissions natural gas on the regional electricity generation mix, including the near elimination of oil-fired electric generation from the regional system mix;
  - *Non-Fossil Fuel Generation* – describing how increased generation from renewable and nuclear sources has decreased the utilization of fossil fueled plants; and
  - *Imports* – describing the degree to which adding RGGI allowance costs to electricity prices has impacted power flows into the region.
- ***Electricity Consumption***
  - *Economic Conditions & Energy Efficiency* – describing the extent to which the recession and energy efficiency programs have decreased electric demand; noting that economic growth and emissions are not as closely linked as commonly assumed; and
  - *Weather* – describing the impact of weather conditions, (largely air-conditioning) on electricity demand and emissions.

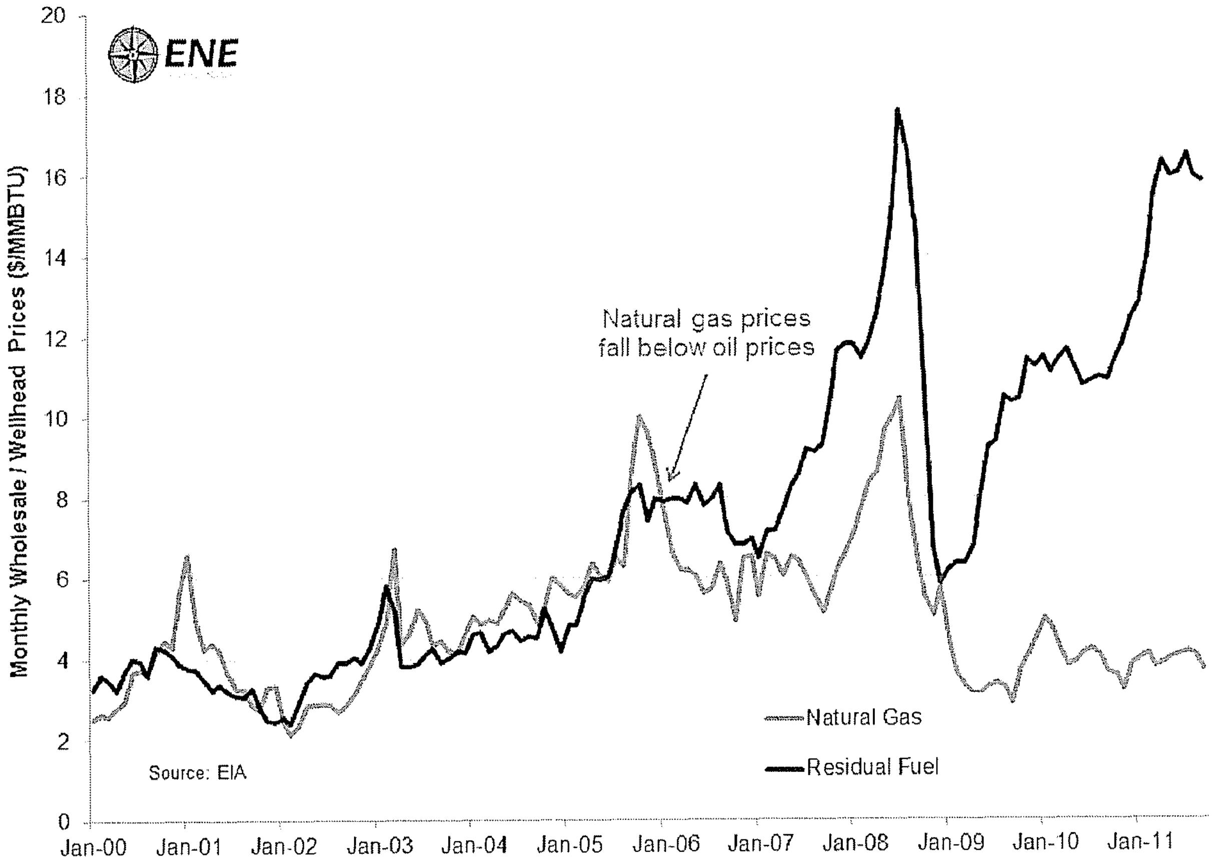
[3] Throughout this report Year-to-Date data is based on latest available reporting, which varies between sources. Where relevant, date ranges are indicated on the y-axis.

Sources of Electric Generation

Energy Prices & Natural Gas Generation

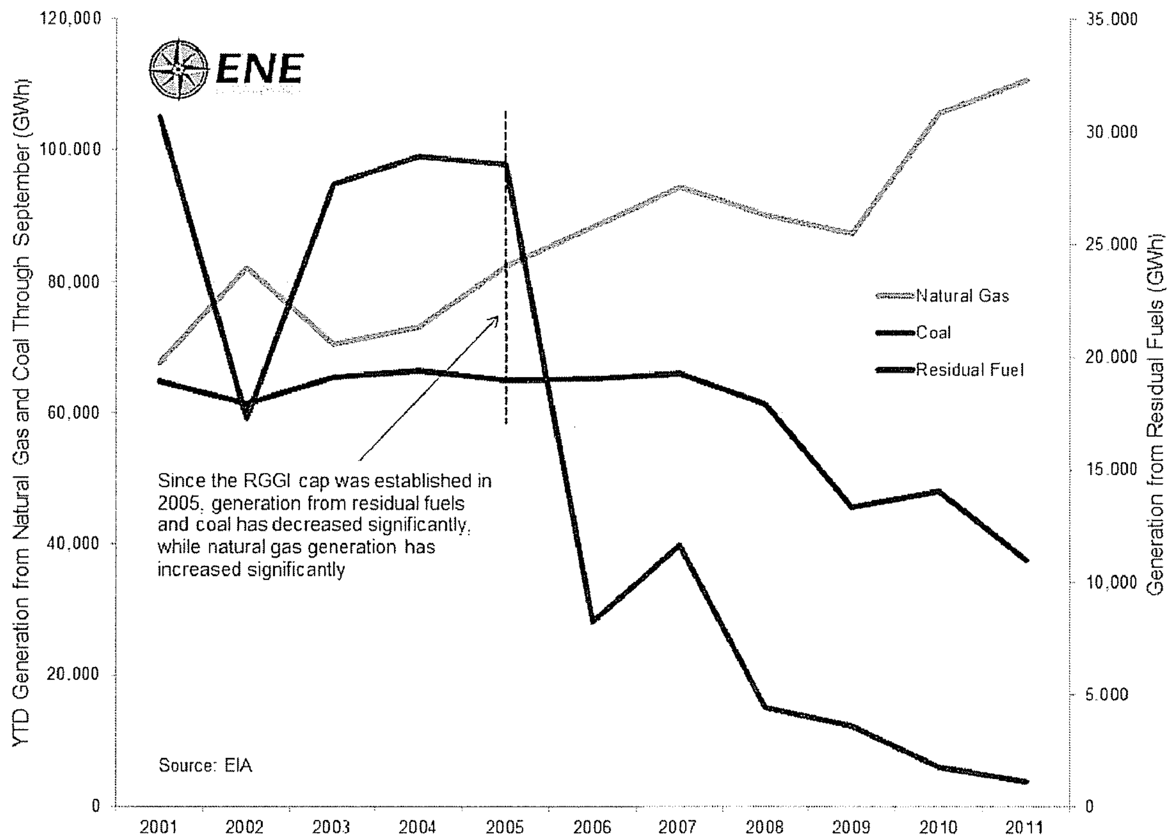
Electric sector emissions are largely determined by the type of fuel used to generate electricity, and increased utilization of low-emissions natural gas has decreased RGGI region emissions significantly. The relative prices of residual fuel and natural gas are particularly important in the RGGI region as significant capacity exists to generate power from either fuel, facilitating the utilization of whichever fuel is cheapest. For the majority of the past 6 years natural gas has been significantly lower priced (Figure 2).

Figure 2: National Spot Prices for Residual Fuel and Natural Gas



Low natural gas prices have led to decreased utilization of residual fuel and coal generation. (Coal prices vary across the region, but have generally increased since 2003, according to EIA.) In the RGGI region residual fuel generation in the first three quarters of 2011 was down 35% from 2010 levels and 96% from 2005 levels, while coal generation decreased 22% from 2010 levels and 42% from 2005 levels (Figure 3). Meanwhile, natural gas generation continued to increase in 2011, up 5% from 2010 levels and up 34% from 2005. Fuel switching from coal and oil to lower-carbon natural gas has had a significant impact on regional emissions. To produce the same amount of heat, natural gas emits 44% less carbon than coal and 33% less carbon than fuel oil,[4] and natural gas plants are typically more efficient.[5]

Figure 3: RGGI Region YTD Electric Generation from Natural Gas, Coal and Residual Fuels



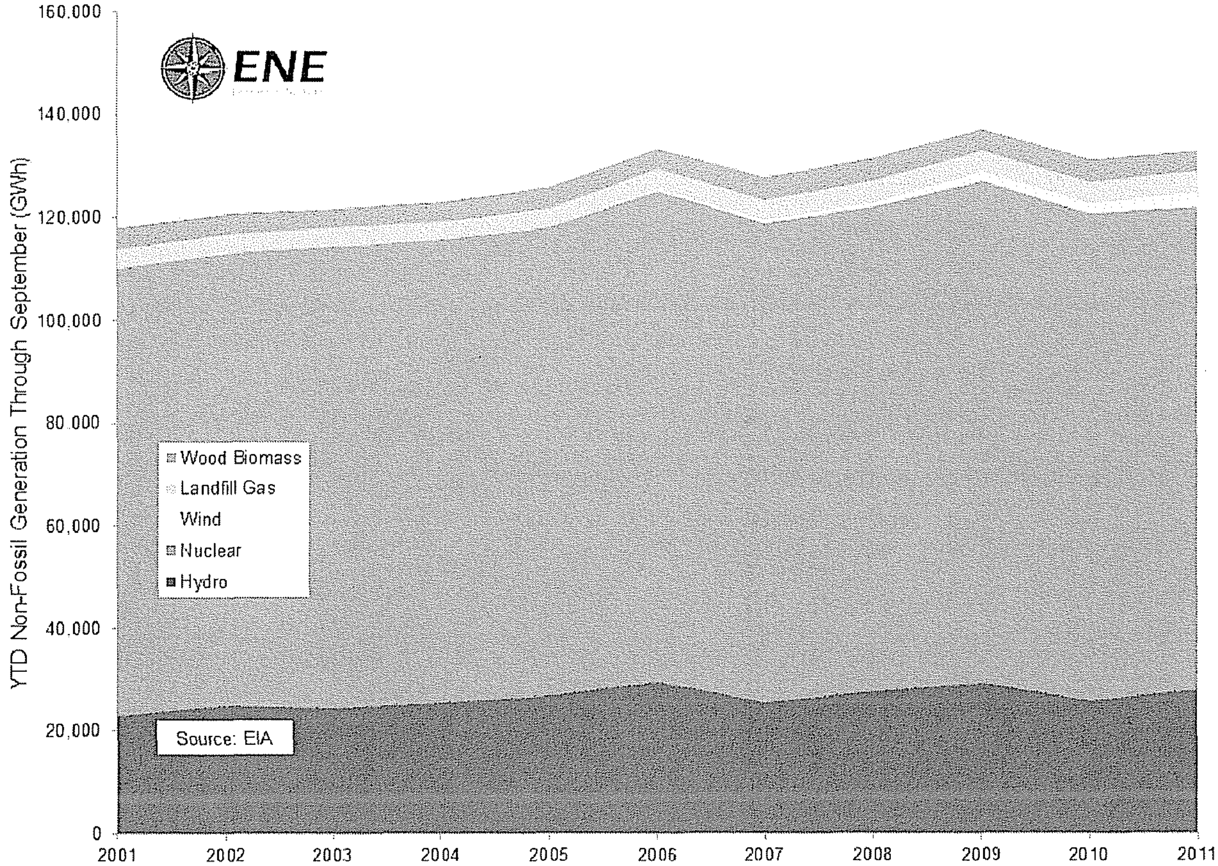
[4] Carbon emissions factors for natural gas (117.0 lbs CO_2/MMBtu), residual fuel oil (173.7 lbs CO_2/MMBtu) and coal (210.0 lbs CO_2/MMBtu) from EIA: www.eia.doe.gov/oiaf/1605/excel/Fuel%20Emission%20Factors.xls

[5] Note that natural gas direct stack emissions are much lower than coal and oil, but there is increasing concern about upstream GHG and other pollution from natural gas, which needs to be more thoroughly investigated and quantified.

Non-Fossil Fuel Generation

Non-fossil fuel electricity – including nuclear, hydro, wind, and other forms of renewable energy – is displacing fossil fuel generation and reducing emissions across the region. Data indicate that YTD non-fossil fuel generation increased 1.2% from 2010 to 2011, and has risen 5.4% since 2001 (Figure 4).

Figure 4: RGGI Region Electricity Production from Non-Fossil Sources



Between 2005 and 2011 YTD non-fossil generation in the RGGI region has increased by about 6,800 GWh of generation. Of this 6,800 GWh of new non-fossil generation, 2,670 GWh came from wind, 2,860 GWh came from nuclear uprates, and 480 GWh came from landfill gas. Hydro output also increased by 2,200 GWh in 2011, though it remained below the recent peak output of 29,400 GWh in 2006. The overall trends in recent years show that non-emitting generation is increasing, displacing fossil-based electricity and reducing emissions in the RGGI region.[6]

The expansion of non-emitting generation looks likely to continue in years ahead. The Federal Energy Information Administration (EIA) predicts that renewable and nuclear generation will continue to

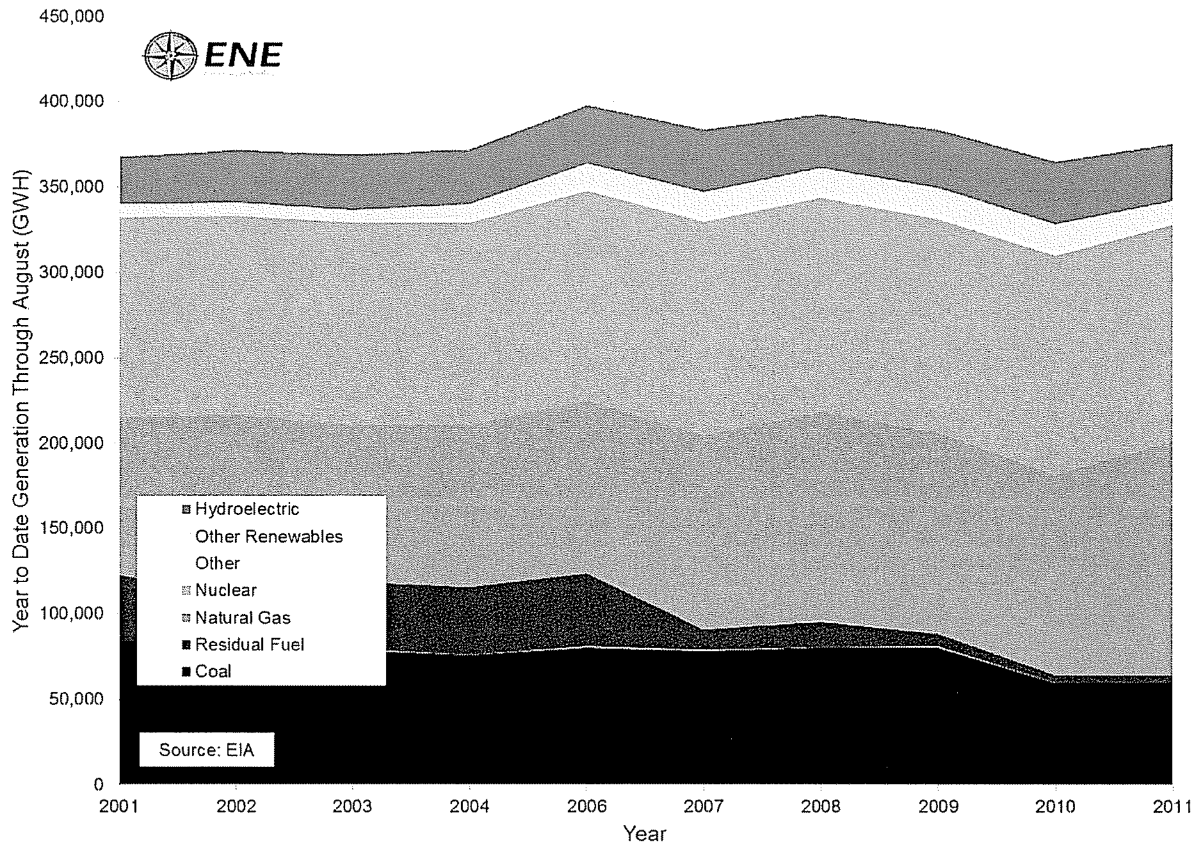
[6] Based a weighted average of emissions intensity for oil and coal generation coming off line since 2005, in 2010 this non-emitting generation avoided approximately 6.8 million tons of CO_2 that would have been emitted to produce an equivalent amount of electricity from oil and coal.

increase nationwide in the near term, in addition to natural gas generation.[7] Additionally, all 10 RGGI states have Renewable Portfolio Standards that require electric utilities to procure increasing quantities of renewable electricity, ensuring continuing growth of renewable generation in the region.[8]

Overall Generation Trends

Electric generation in the RGGI region has reduced in carbon intensity over the last 5 years, due to increased generation from natural gas, nuclear, and renewable sources and decreased output from higher-carbon coal and residual fuel plants (Figure 5). With the exception of steady, incremental growth in wind capacity and modest natural gas additions, this decline in electric sector emissions has occurred without the addition of significant new capacity or capital expenditures. This low-cost transition to lower regional emissions suggests that decreasing emissions may be far more cost-effective than commonly assumed.

Figure 5: RGGI YTD Generation by Fuel Type



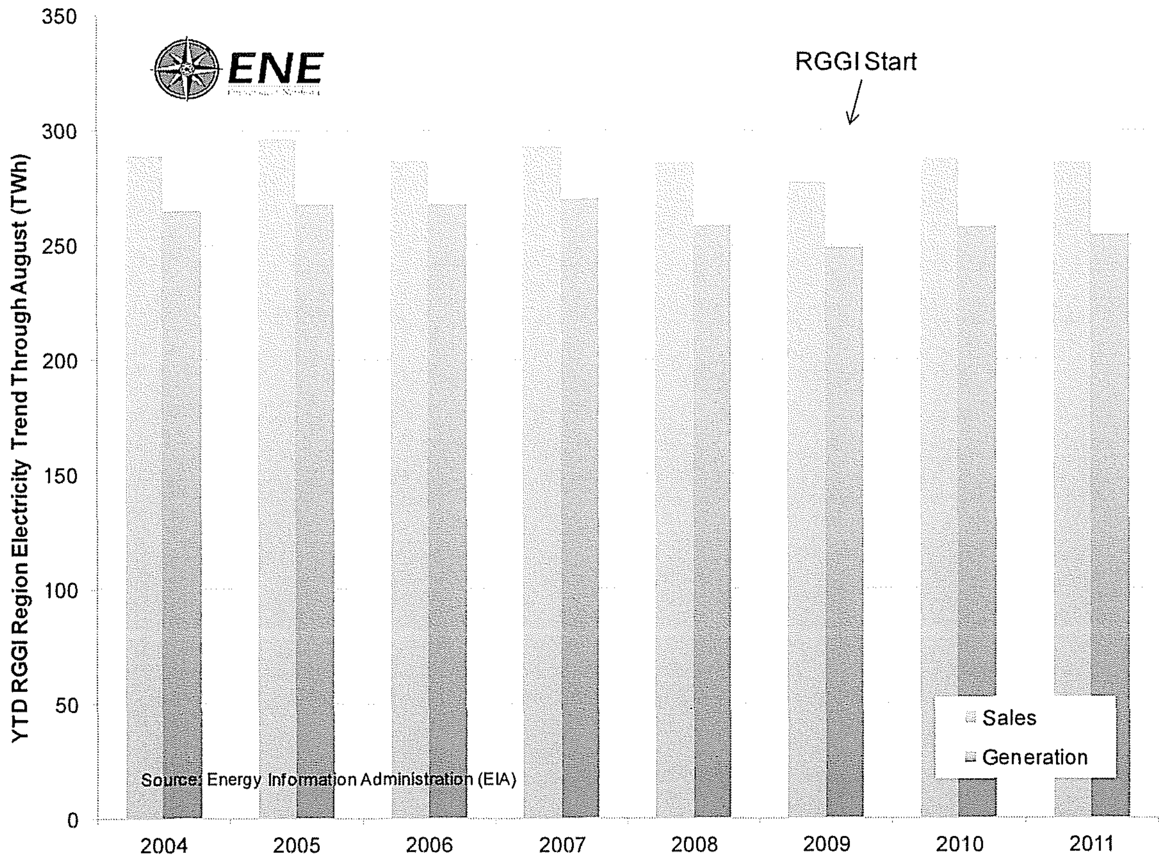
[7] EIA, 2011, *Annual Energy Outlook 2011 Early Release Overview*, Available at: http://www.eia.gov/forecasts/aeo/

[8] For additional information on State Renewable Energy Portfolios see the Department of Energy's EERE State Activities & Partnerships, Available at: http://apps1.eere.energy.gov/states/maps/renewable_portfolio_states.cfm

Electricity Imports and Emissions Leakage

The addition of RGGI allowance costs to electric generation prices does not appear to be causing significant leakage of emissions to generation sources outside of the RGGI region. Since RGGI began adding carbon costs to electricity prices on January 1, 2009, electricity sales region-wide have increased by 3.2%, while generation increased by 2.4%. Slight increases in power imports are driven by many factors including availability of transmission, plant maintenance, electric energy price differentials between regions[9] and other factors, in addition to the modest costs for RGGI allowances. Since RGGI began imports and consumption have varied only slightly (Figure 6), and recent analysis by New York State Energy Research and Development Administration found RGGI allowances prices are not causing significant emissions leakage.[10]

Figure 6: RGGI Region YTD Electricity Sales vs. In-region Generation



[9] For example, demand may be higher in one of two adjacent areas, leading to higher prices and economic incentives for plants to send electricity into the higher priced area.

[10] See: http://rggi.org/docs/ProgramReview/LearningSession1/Presentation_James_Gallagher_NYISO.pdf

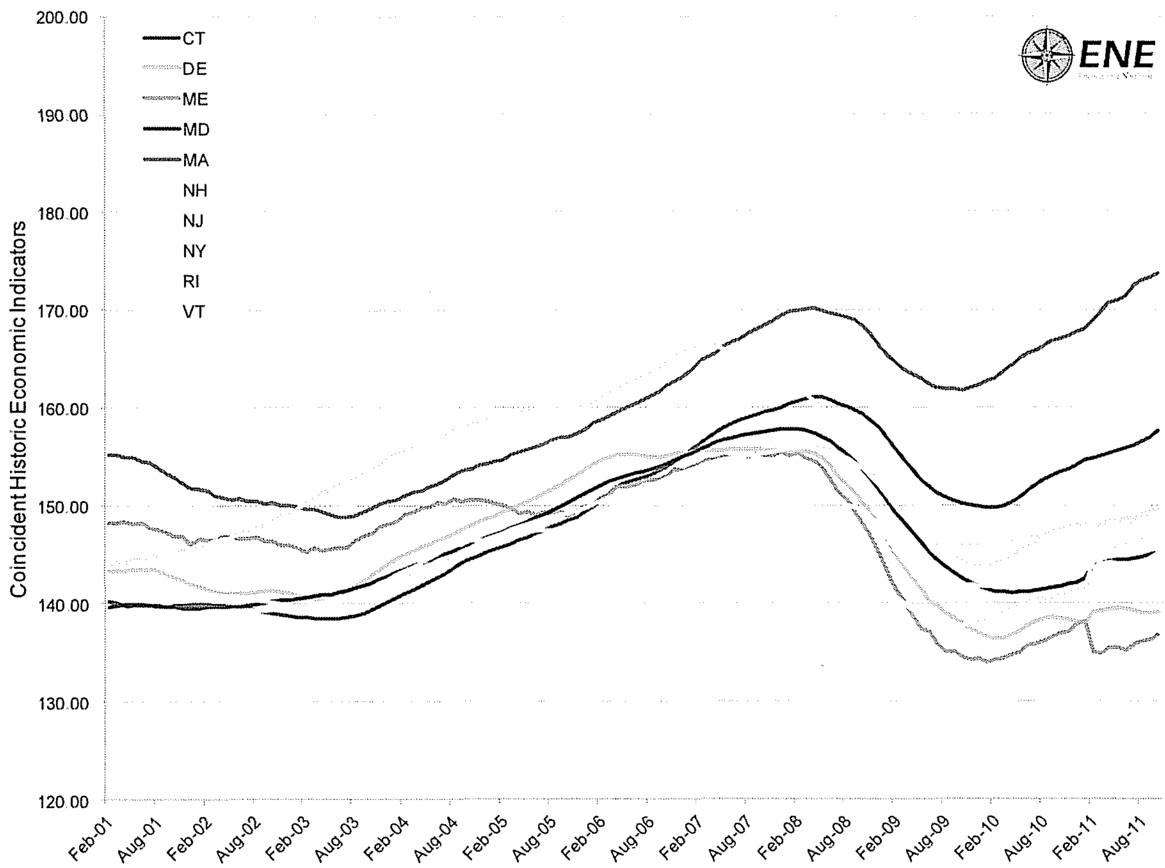
Electricity Consumption

Economic Conditions & Energy Efficiency

Economic growth and the efficiency with which energy is used are significant drivers of RGGI region emissions. Electricity demand has historically been tied to economic growth, with electricity consumption – and related emissions – increasing during periods of economic expansion, and decreasing in economic downturns. However, stable electricity demand during the early 2000s period of economic growth and increasing investments in energy efficiency suggests the link between economic growth and emissions may be weakening, and that emissions may remain low even as the economy recovers from its recent downturn.

The RGGI experience bears this out. RGGI region economies expanded for the majority of the last decade, with the economic downturn reversing this trend in 2008-2009 – as evidenced by coincident indexes from the Federal Reserve Bank of Philadelphia (Figure 7).[11]

Figure 7: RGGI Region Economic Conditions (through October 2011)



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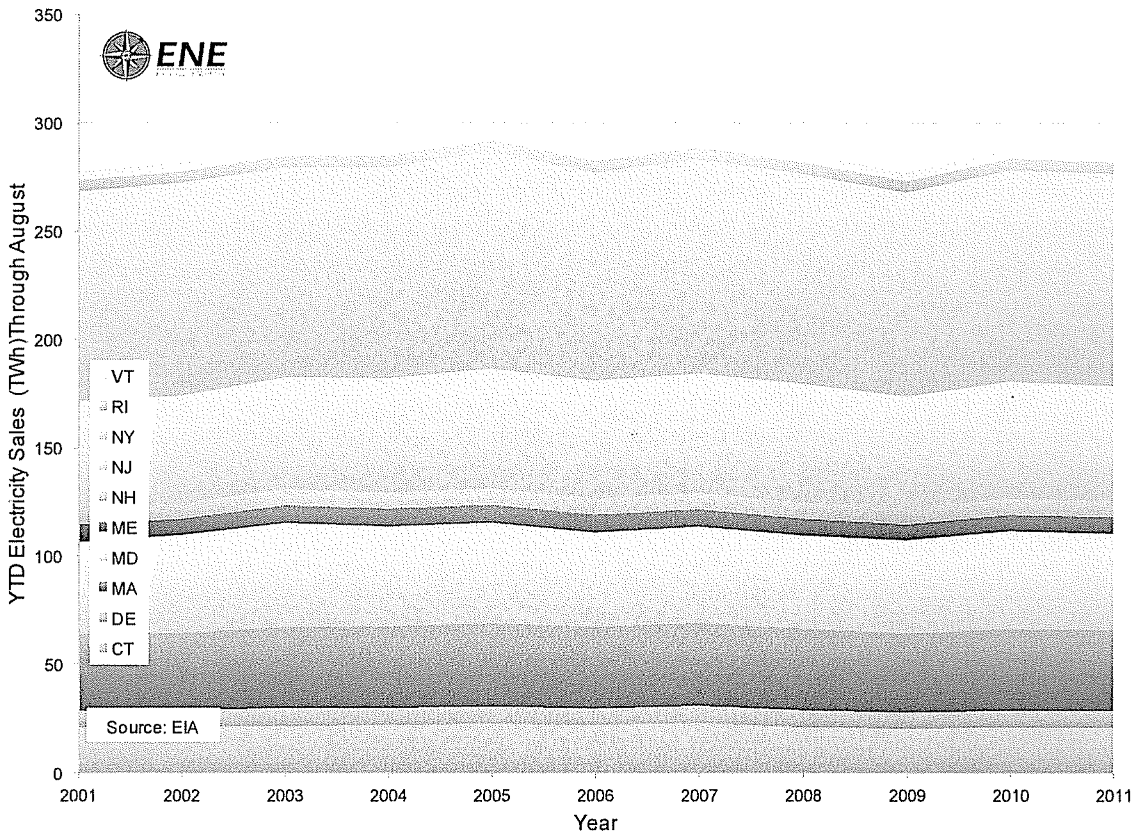
[11] See: http://www.philadelphiafed.org/research-and-data/regional-economy/indexes/coincident/

During the economic recovery from 2002-2005, electricity consumption increased only slightly, and remained stable until the economy slowed in 2008 (Figure 8). This suggests that improved energy efficiency of the economy and successful energy savings programs may have broken the link between economic growth and emissions growth. In the 10 RGGI states' investments in electric efficiency programs more than doubled from $624 million in 2006 to $1.45 billion in 2010,[12] with continuing increases planned. It is worth noting that over $440 million in RGGI auction proceeds has been directed to efficiency programs in member states.[13]

Stable electricity consumption over the last decade and increasing investments in energy efficiency suggest that emissions are likely to remain low when the economy recovers, as demand is unlikely to increase significantly and low- or non-emitting generation continues to displace older, more emissions-intensive coal and oil generation in the region.

Figure 8: RGGI Electricity Consumption



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[12] Annual energy efficiency reports from the Consortium for Energy Efficiency, see: http://www.cee1.org/ee-pe/2010data.php3

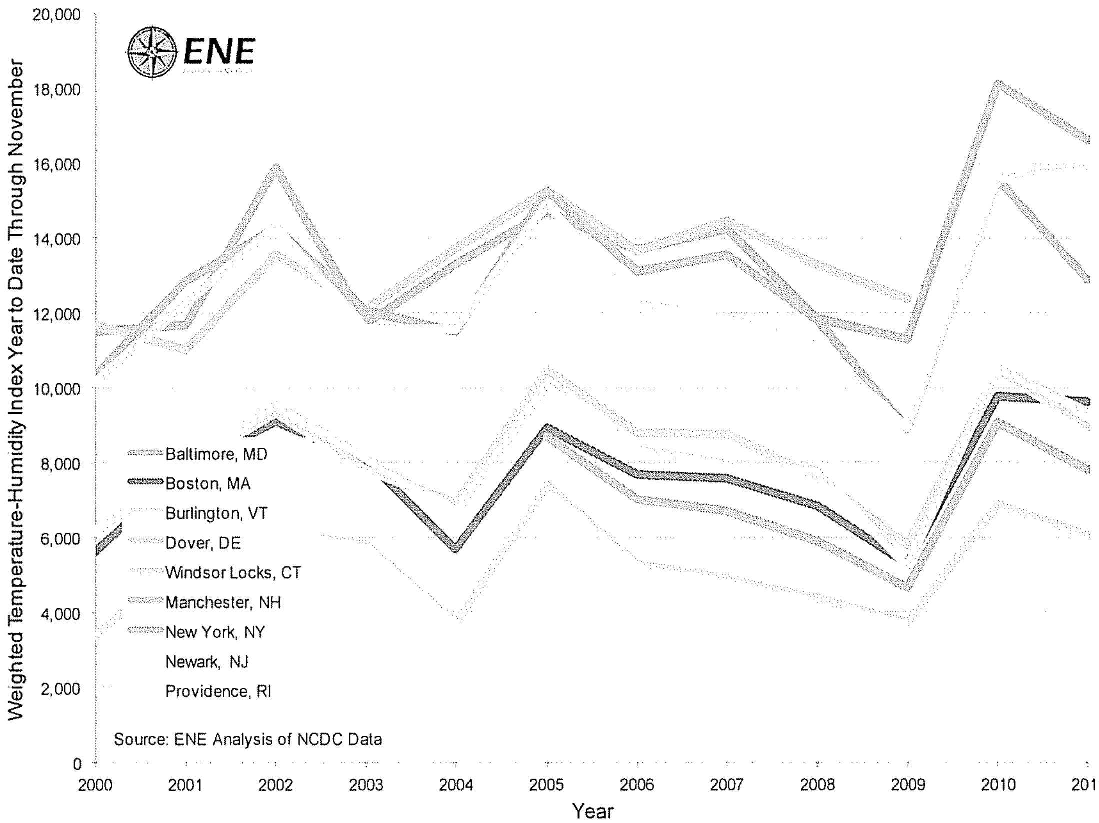
[13] These investments save consumers $1.1 billion in electricity costs and $174 million in fossil fuel costs. Analysis Group report *The Economic Impacts of the Regional Greenhouse Gas Initiative on Ten Northeast and Mid-Atlantic States*, available at: http://www.analysisgroup.com/RGGI.aspx

Weather

Hot and humid summer weather leads to greater electricity consumption for air conditioning, and cold winter weather increases natural gas and heating oil consumption (only a small percentage of buildings in the region are heated with electricity). As home heating fuels are not covered under RGGI, ENE uses the temperature-humidity index (THI) to gauge the impacts of hot and humid weather on electricity consumption and emissions.

The summer of 2011 was less hot and humid than 2010, though the year-to-date THI in 2011 is higher than recent years (Figure 9).[14] Cooler less humid weather in 2011 decreased demand for air conditioning from 2010 levels, thus decreasing electricity demand and emissions. It is worth noting that weather in 2011 produced a higher THI than in 2009, and even with this higher cooling load 2011 emissions are projected to fall below 2009 levels. This suggests that the increased demand is being met with low- and non-emitting sources, and the transition to cleaner sources of power is accelerating.

Figure 9: RGGI Weighted Temperature-Humidity Index



[14] 2010 weather data from Delaware was unavailable at the time of publication.

Conclusion

Emissions from power plants in the RGGI program are projected to reach their lowest level since the programs launched in 2009 due to the accelerating transition to lower emitting and emissions free sources of power. Improved energy efficiency and growing investments in efficiency programs accelerate the transition, as lower demand is matched with cleaner sources of power. Fuel-switching to natural gas, increased non-emitting generation, and support for energy saving programs appear to be long-lasting, suggesting that lower emissions are here to stay for the foreseeable future.

For Further Information:

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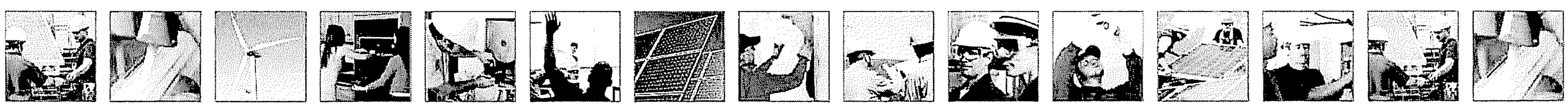
THE REGIONAL GREENHOUSE GAS INITIATIVE

An Initiative of the Northeast and Mid-Atlantic States of the U.S.

Potential Scenarios for Modeling: Overview

March 20, 2012 Stakeholder Meeting

www.rggi.org



RGGI Program Review

- Over the past eighteen months the RGGI states have been conducting stakeholder meetings to gather comments on the implementation of the RGGI program, RGGI design elements and potential program changes

- The RGGI states have also been convening Learning Sessions with experts and stakeholders on program design elements and other key topics

Analysis of RGGI Program Design Elements

- RGGI states have used IPM electricity sector modeling to inform program review

- The IPM modeling analyzes three key program design elements
  - RGGI CO_2 Cap Level
  - Flexibility Mechanism-Cost Containment Allowance Reserve (CCR)
  - Flexibility Mechanism-Offsets

Analysis of RGGI Program Design Elements

RGGI CO_2 Cap and First Control Period Emissions

	Current RGGI CO_2 Cap (2012)	Estimated Three Year CO_2 Emissions Average (2009-2011)
10 State RGGI Region	188 MM tons	126 MM tons
9 State RGGI Region	165 MM tons	108 MM tons

Analysis of RGGI Program Design Elements

Flexibility Mechanisms-CCR and Offsets

- Stakeholders recommend analysis of a cost containment reserve (CCR) as a flexibility mechanism
- Experts recommend limiting the size of the CCR and establishing price triggers for the use of the CCR
- Stakeholders and experts have reiterated the importance of a viable offset program and examining ways to expand the offset program while maintaining environmental integrity

IPM Modeling Potential Scenario Results

- The following slides present the IPM modeling results
- These analyses inform program review and do not reflect a preference for or selection of any specific policy

Review of IPM Reference Case and Sensitivity Analyses

March 20, 2012

RGGI Reference and Sensitivity Cases

- RGGI updated its Reference Case in 2011 to include new information on load growth and other inputs that became available.
- The Reference Case accounts for New Jersey's departure from the program at the beginning of 2012.
- There are also 6 sensitivity cases of the Reference Case:
  1. Higher Load Growth
  2. Lower Load Growth
  3. Higher Natural Gas Prices & Lower Oil Prices
  4. Lower Natural Gas Prices
  5. High Emissions Combination
  6. Low Emissions Combination
- This presentation summarizes the results of the Reference Case and High and Low Load Growth sensitivity cases, which are important to the potential scenario discussion that follows.
- These projections are draft and may change as ICF makes refinements based on state review and input.

Sources of Reference Case Assumptions

Parameter	Sources				
	ISOs	States	EPA	EIA	Other
Electric Demand	X	X			
Reserve Requirements	X				
Firmly Planned Capacity Additions	X	X			
Coal and Nuclear Capacity Limits		X			
Cost and Performance of New Capacity			X		
Transmission Capability	X				
Firmly Planned Transmission Additions	X	X			
Fuel Prices				X	
Federal Air Regulations		X			
State Air Regulations		X			
Offsets		X	X		
Renewable Portfolio Standards		X			
Firmly Planned Controls		X	X		
Cost and Performance of New Controls			X		

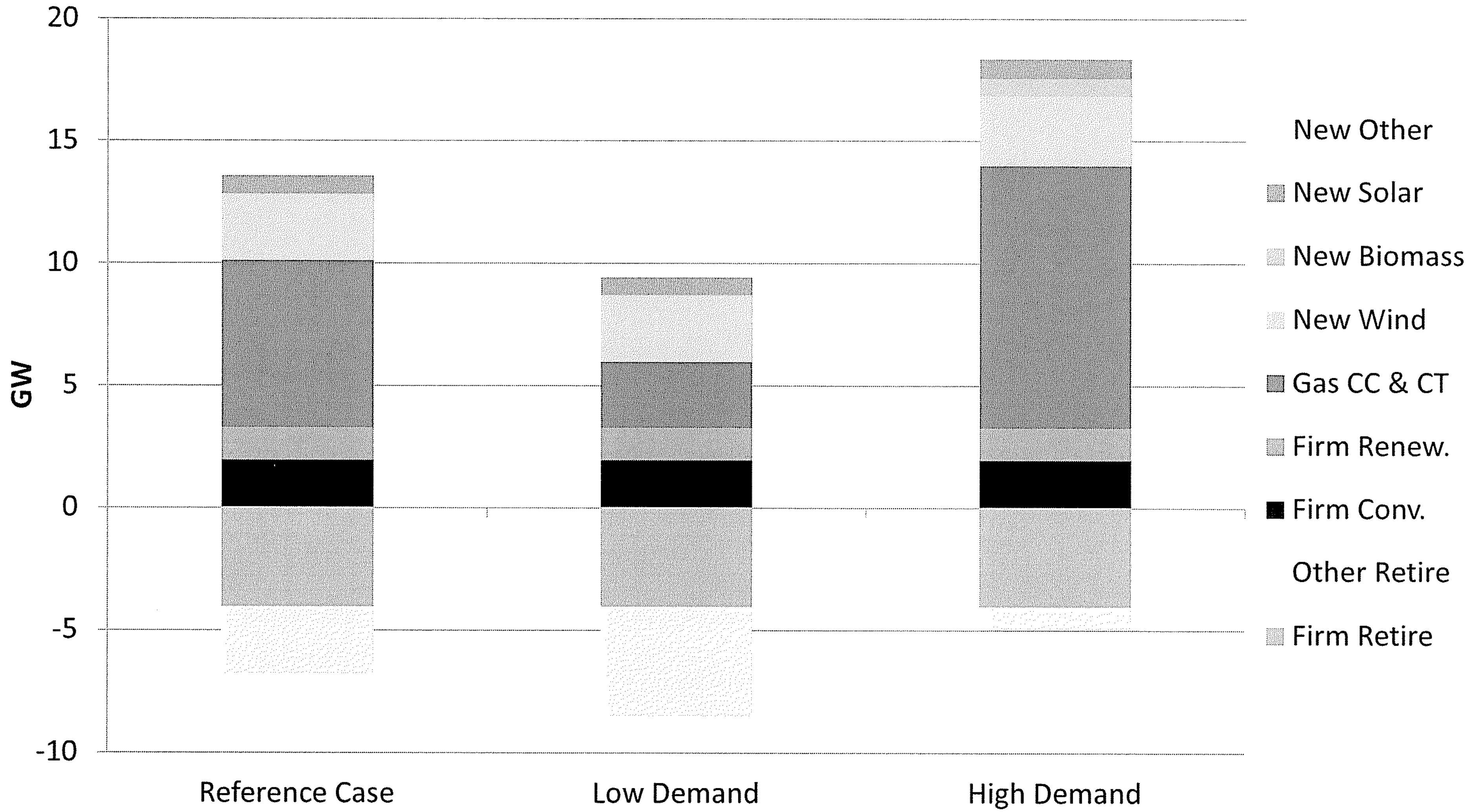
RGGI Sensitivity Case Specifications

Load Growth Sensitivity Cases

Sensitivity Run	Category of Change	Components	Assumptions
1 HIGH LOAD	Higher load growth	• Economy • Weather • Additional load, e.g. Electric Vehicles	• Higher economic growth • EV 1% penetration rate per year of the current fleet. The forecast is 1.6% and 2.4% higher than the reference case in 2020 and 2030, respectively. • Weather proposal-10% increase over normalized weather • Includes reference case energy efficiency estimates • Above is estimated to result in average annual growth rate of 1.3% per year
2 LOW LOAD	Lower load growth	• Increased Energy Efficiency	• State by state calculation of more aggressive EE targets than reference case

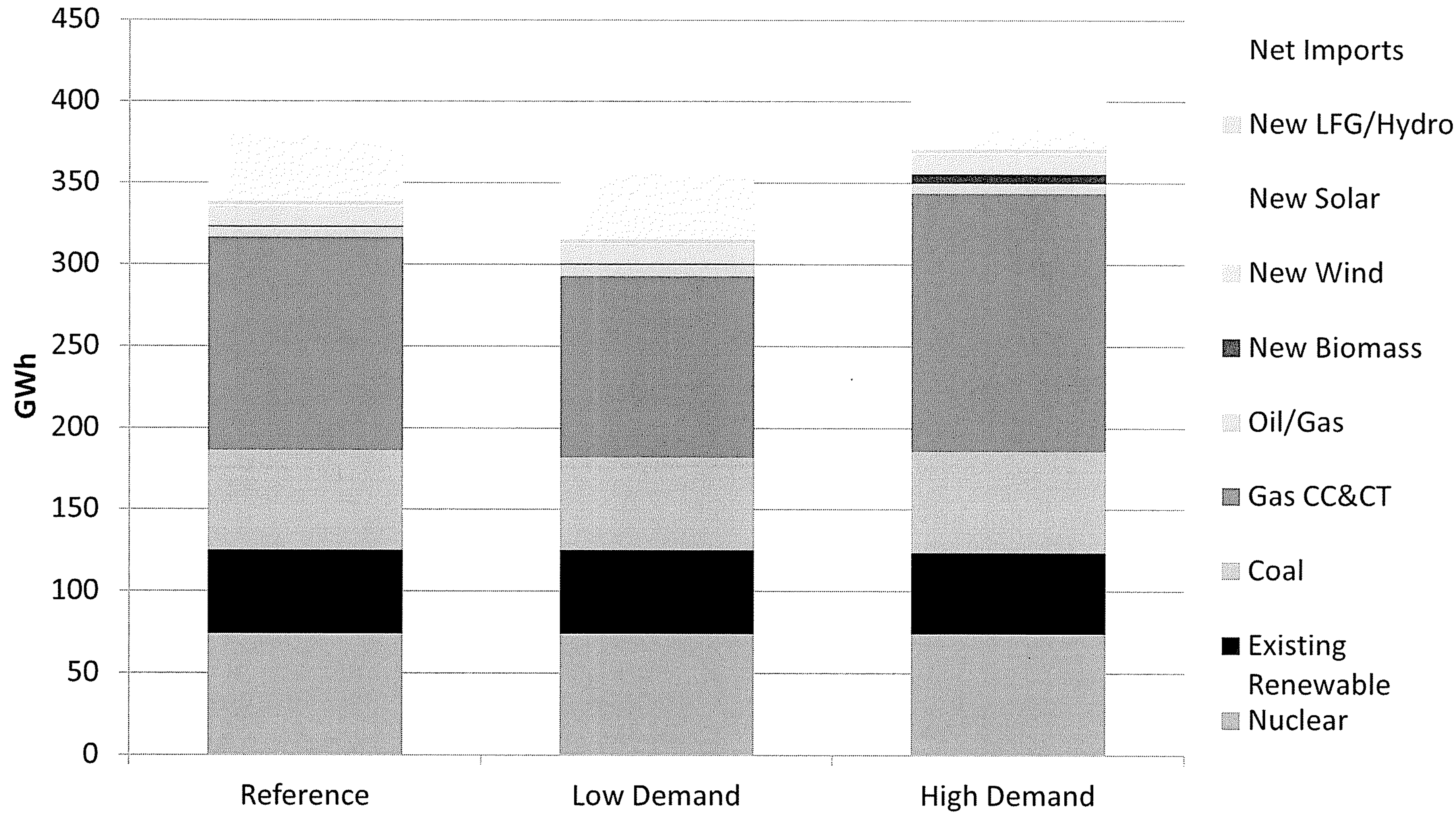
Cumulative Capacity Changes through 2020 in RGGI

Reference Case, Low and High Demand Sensitivities



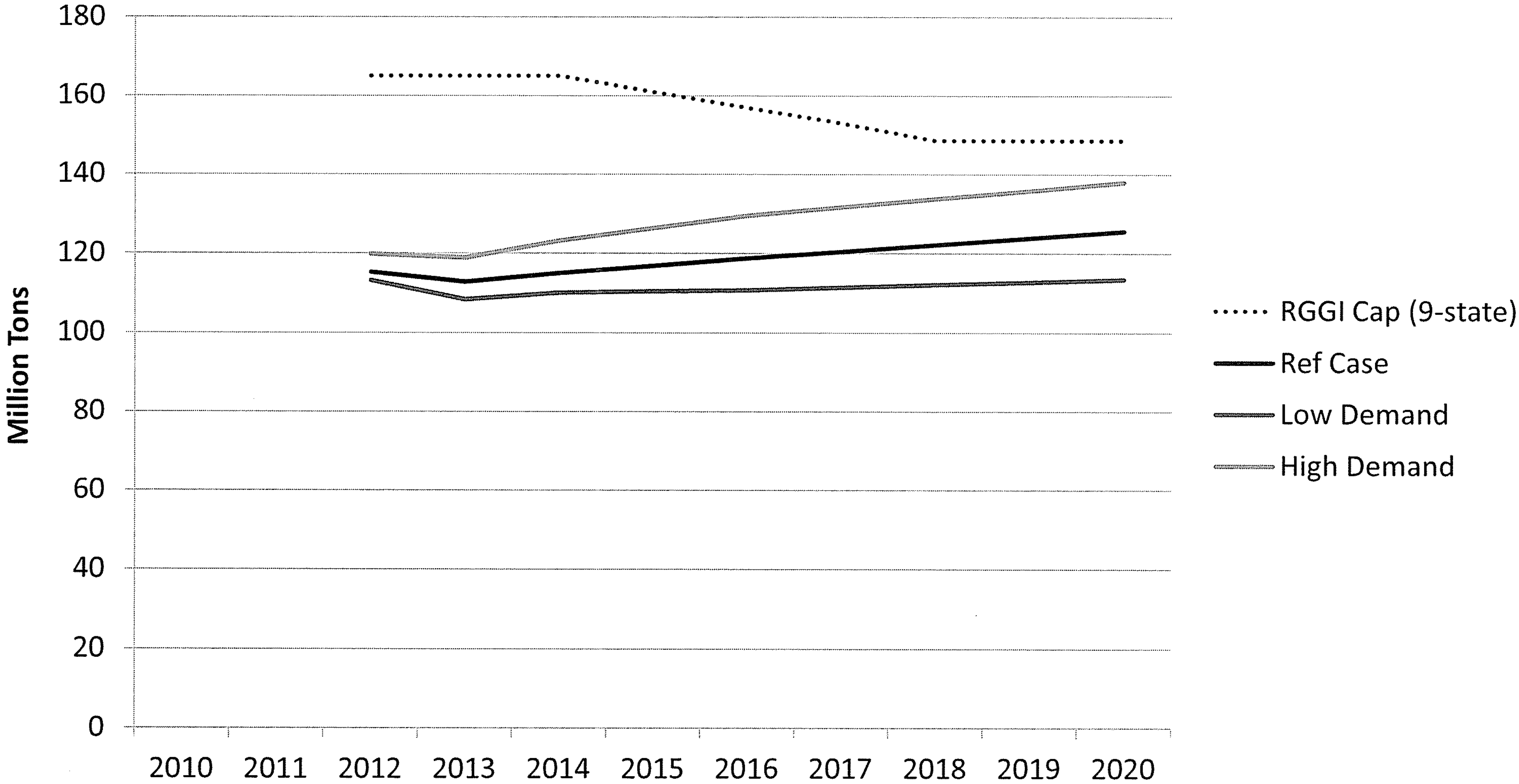
Generation Mix for RGGI in 2020

Reference Case, Low and High Demand Sensitivities



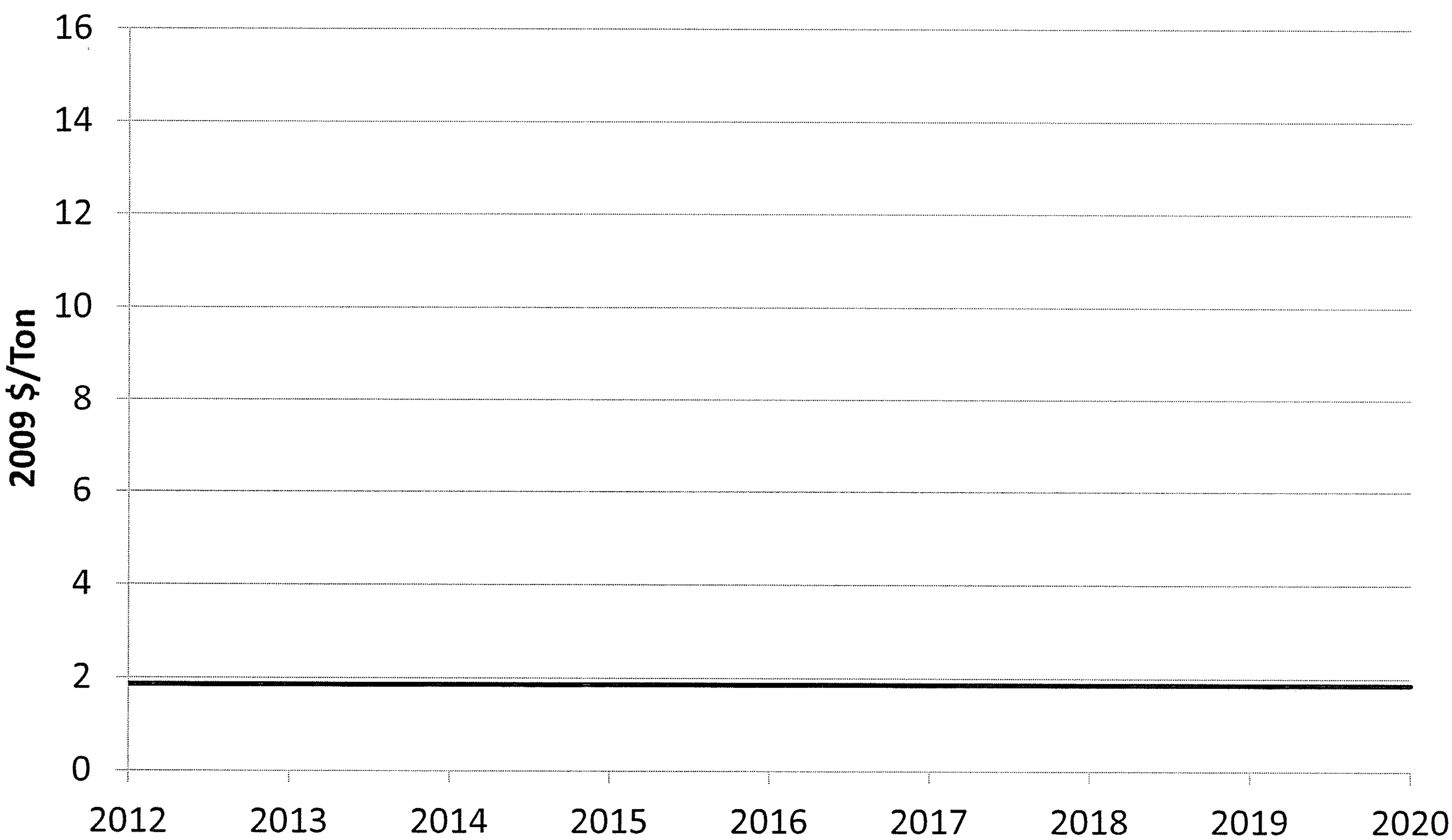
RGGI CO_2 Emissions from Affected Sources

Reference Case, Low and High Demand Sensitivities



RGGI Allowance Prices

All Cases



IPM Analysis of Potential Scenarios for Modeling

March 20, 2012

DRAFT RGGI Potential Scenario Analysis
Purpose

- This analysis provides information for the overall program review process. The scenario specifications do not reflect a preference for or selection of any specific policy.

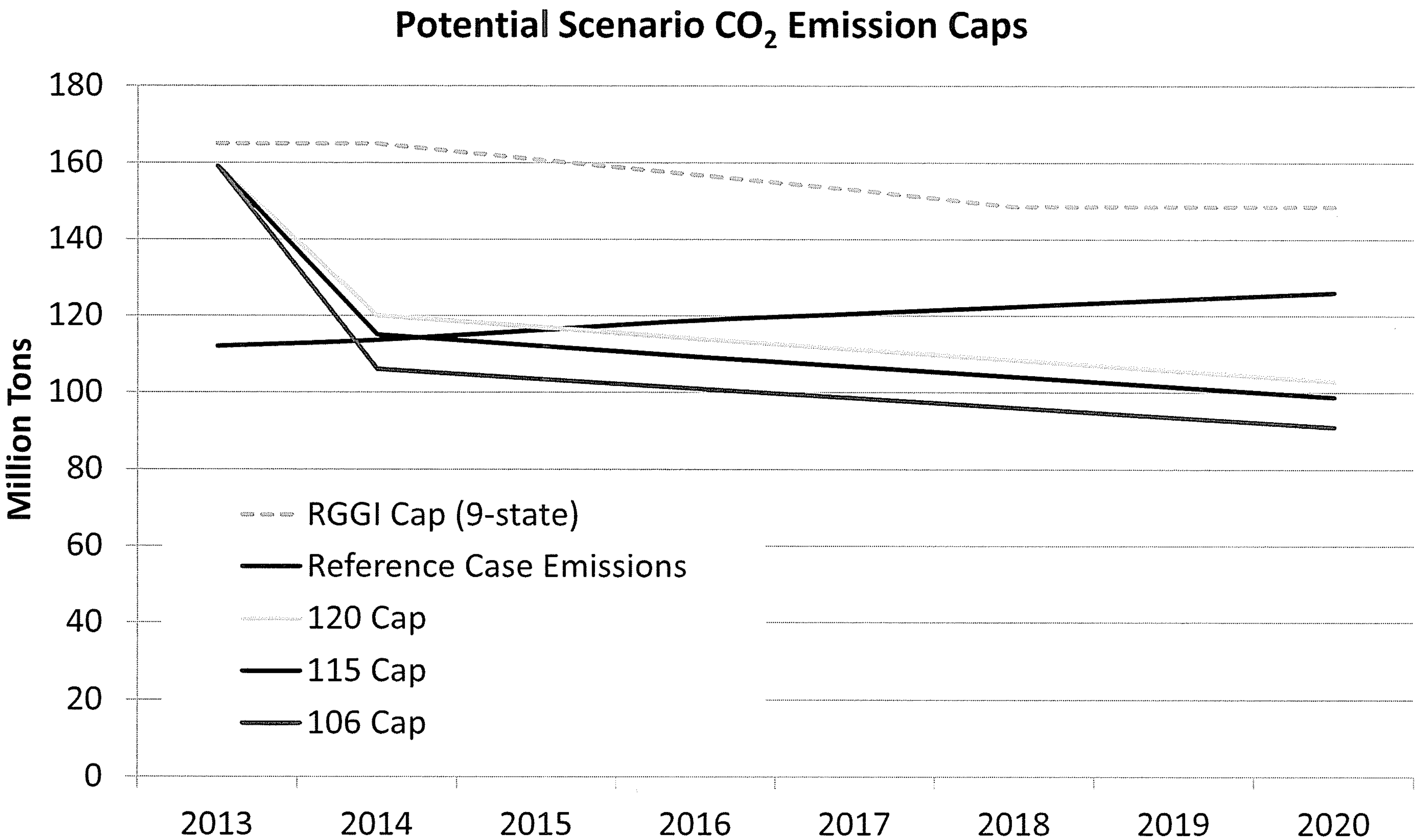
- For this exercise, the RGGI states defined potential scenarios using combinations of three components:
  - Emissions cap
  - Cost containment reserve (CCR), including price collar and tons in reserve
  - Private allowance bank

- Potential scenarios were also tested against alternative electric demand growth and offset availability assumptions.

DRAFT RGGI Potential Scenario Analysis
Emission Caps

- Each potential scenario includes one of three CO_2 emission cap trajectories. The regional caps cover the same affected sources as the current program over the 9-state RGGI area.
- The three CO_2 cap trajectories assume the existing cap in 2013 of roughly 165 MMTons, followed by a reduction in the cap in 2014 to one of three levels:
  - 120 MMTons
  - 115 MMTons
  - 106 MMTons
- The caps decline from those 2014 levels at 2.5% per year. For the purpose of this analysis, that decline continues through the modeled time horizon, or 2020.
- For the purpose of this presentation, the scenarios are referred to as "120 Cap", "115 Cap", and "106 Cap", consistent with the assumed cap in 2014.
- Except for when stated otherwise, scenarios include the existing offset triggers at $7/ton and $10/ton.

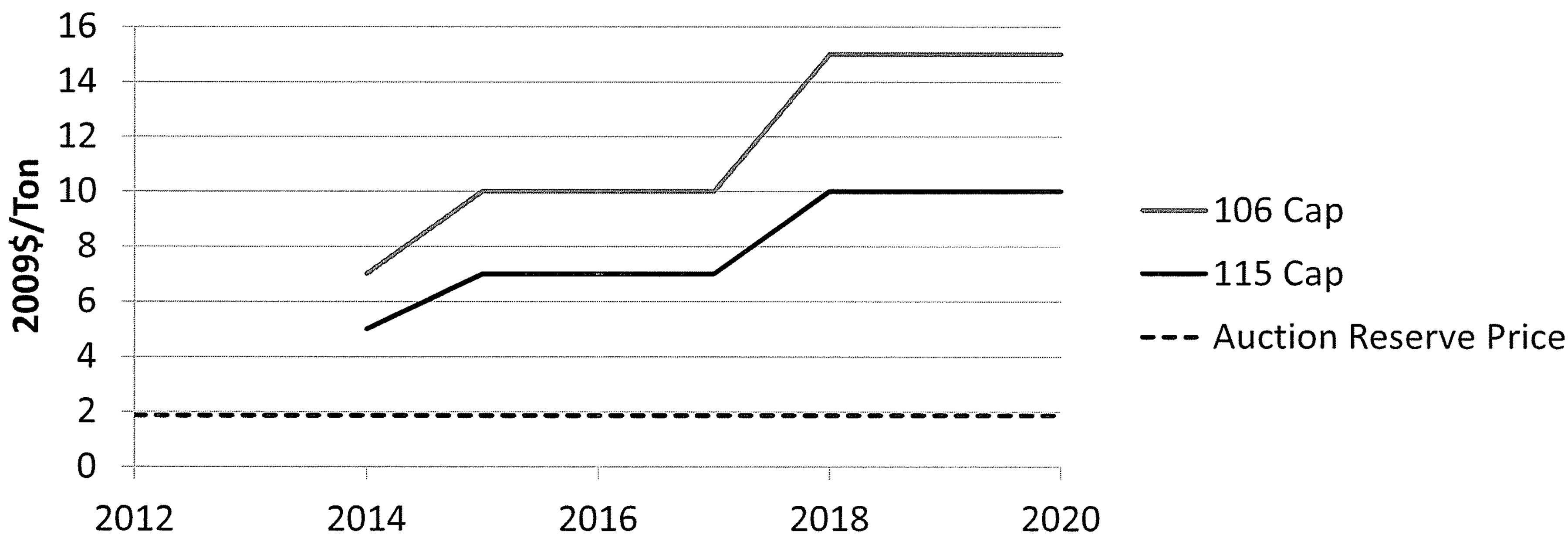
DRAFT RGGI Potential Scenario Analysis
Emission Caps



DRAFT RGGI Potential Scenario Analysis
Cost Containment Reserve

- The 115 and 106 Cap potential scenarios each include provisions for a cost containment reserve (CCR).
- The CCR includes a price collar that sets a floor on allowance prices in each year (the current auction reserve price) and a “CCR trigger” price, at which some number of allowances will be released to relieve pressure on the allowance price. The price collars are shown below.
- The scenarios assumed that up to 10 MM allowances could be released at the CCR trigger price in any year.

Cost Containment Reserve Price Collars



DRAFT RGGI Potential Scenario Analysis
Estimated Allowances Banked by Market Participants

- For this analysis, the potential scenarios assume that the market is made aware of the new policies in 2013, meaning that it can choose to bank allowances in that year for use under the new scenario.

- In 2013, with the existing emission cap still in place, market participants are projected to bank between 47 and 53 MM allowances under reference case demand growth assumptions, depending on the potential scenario.

- The potential scenarios also include an estimated 44 MM first control period allowances banked by market participants. This estimate is based upon estimated first control period allowances in circulation and first control period emissions.

- Combining these two sources of banked allowances, the total bank of allowances held by market participants carried into 2014 for each scenario (with reference case demand growth) is:
  - 120 Cap Scenario: 92 MM
  - 115 Cap Scenario: 94 MM
  - 106 Cap Scenario: 97 MM

DRAFT RGGI Potential Scenario Analysis

Scenarios Analyzed

Case Name (_Demand Assumption)	CO_2 Cap	CCR Price Collar	CCR Tons available at Ceiling
120 Cap_Reference	2014: 120 MM Tons Declines 2.5%/yr. 2020: 103 MM Tons	None	None
115 Cap_CCR _Reference	2014: 115 MM Tons Declines 2.5%/yr. 2020: 99 MM Tons	<u>Ceiling Prices</u> 2014: $5/ton 2015-17:$7/ton 2018-20: $10/ton Use reserve price as floor	No more than 10 MM released in any year 2014-2020
106 Cap_CCR _Reference	2014: 106 MM Tons Declines 2.5%/yr. 2020: 91 MM Tons	<u>Ceiling Prices</u> 2014: $7/ton 2015-17:$10/ton 2018-20: $15/ton Use reserve price as floor	No more than 10 MM released in any year 2014-2020

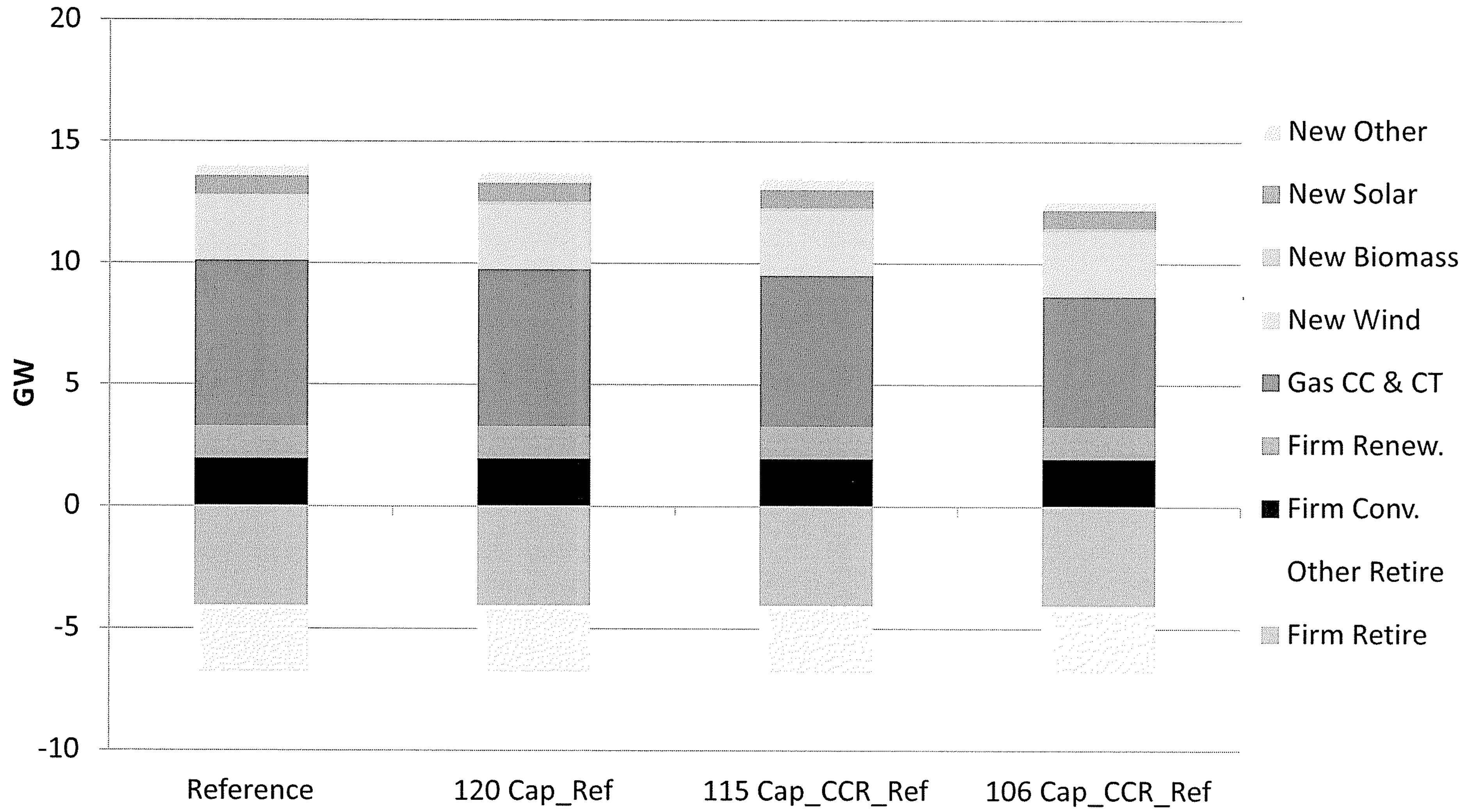
- In addition to the reference cases best estimates for demand, the 115 Cap_CCR and 106 Cap_CCR scenarios were also analyzed using lower and higher demand assumptions.
  - 115 Cap_CCR_High (High demand)
  - 115 Cap_CCR_Low (Low demand)
  - 106 Cap_CCR_High (High demand)
  - 106 Cap_CCR_Low (Low demand)

DRAFT RGGI Potential Scenario Results

- The following slides present projections from the latest RGGI Reference Case and draft potential scenarios.
- These projections are draft and may change as ICF makes refinements based on state review and input.
- The potential scenario results are compared to the Reference Case and to each other.
  - Note that the scenario sensitivity cases based on high and low demand growth should be compared to reference case sensitivity analyses projections with the same load growth assumptions (i.e., high and low, respectively).

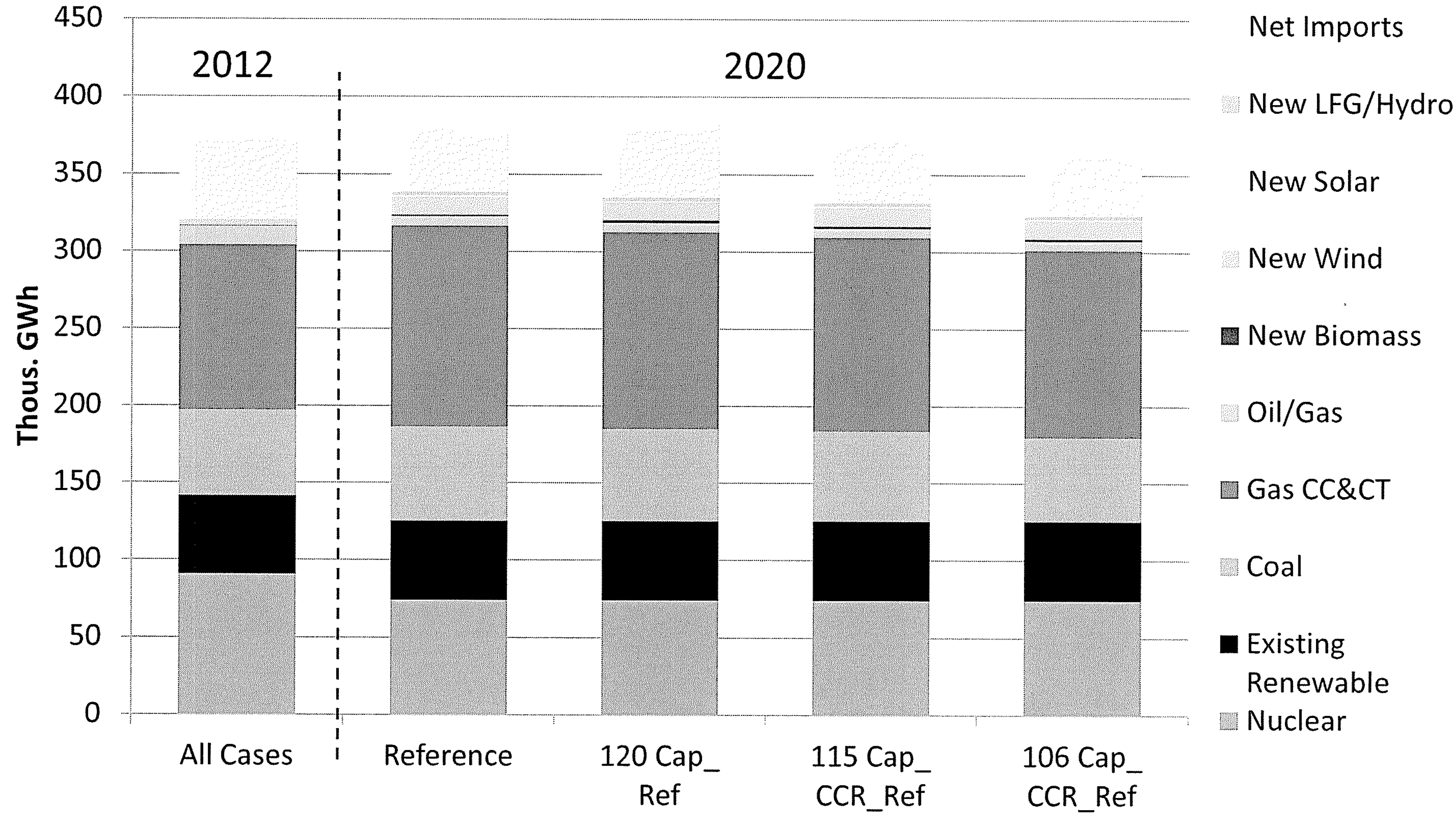
Cumulative Capacity Changes through 2020 in RGGI

Reference Demand Growth Cases



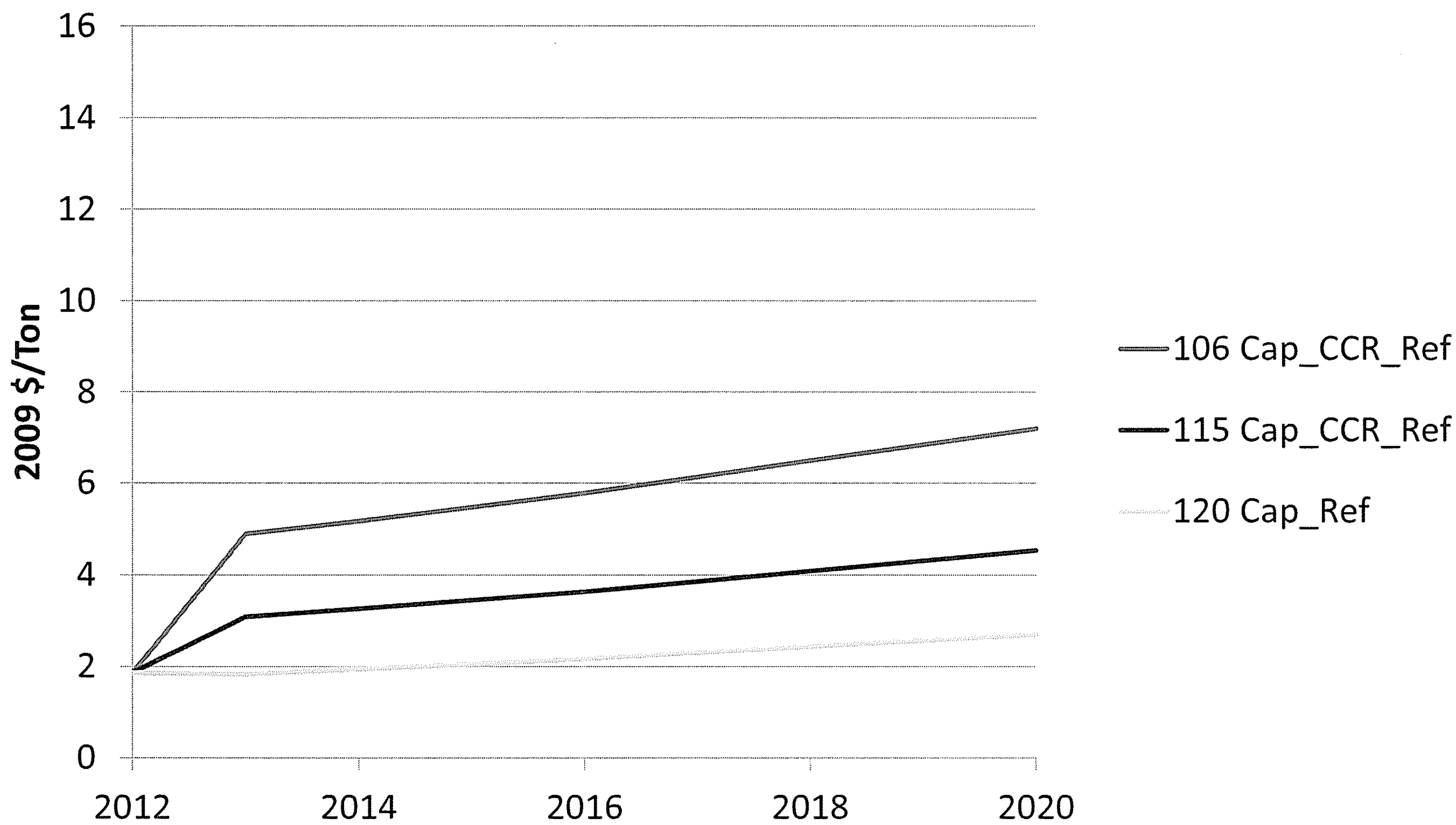
Generation Mix for RGGI in 2012 and 2020

Reference Demand Growth Cases

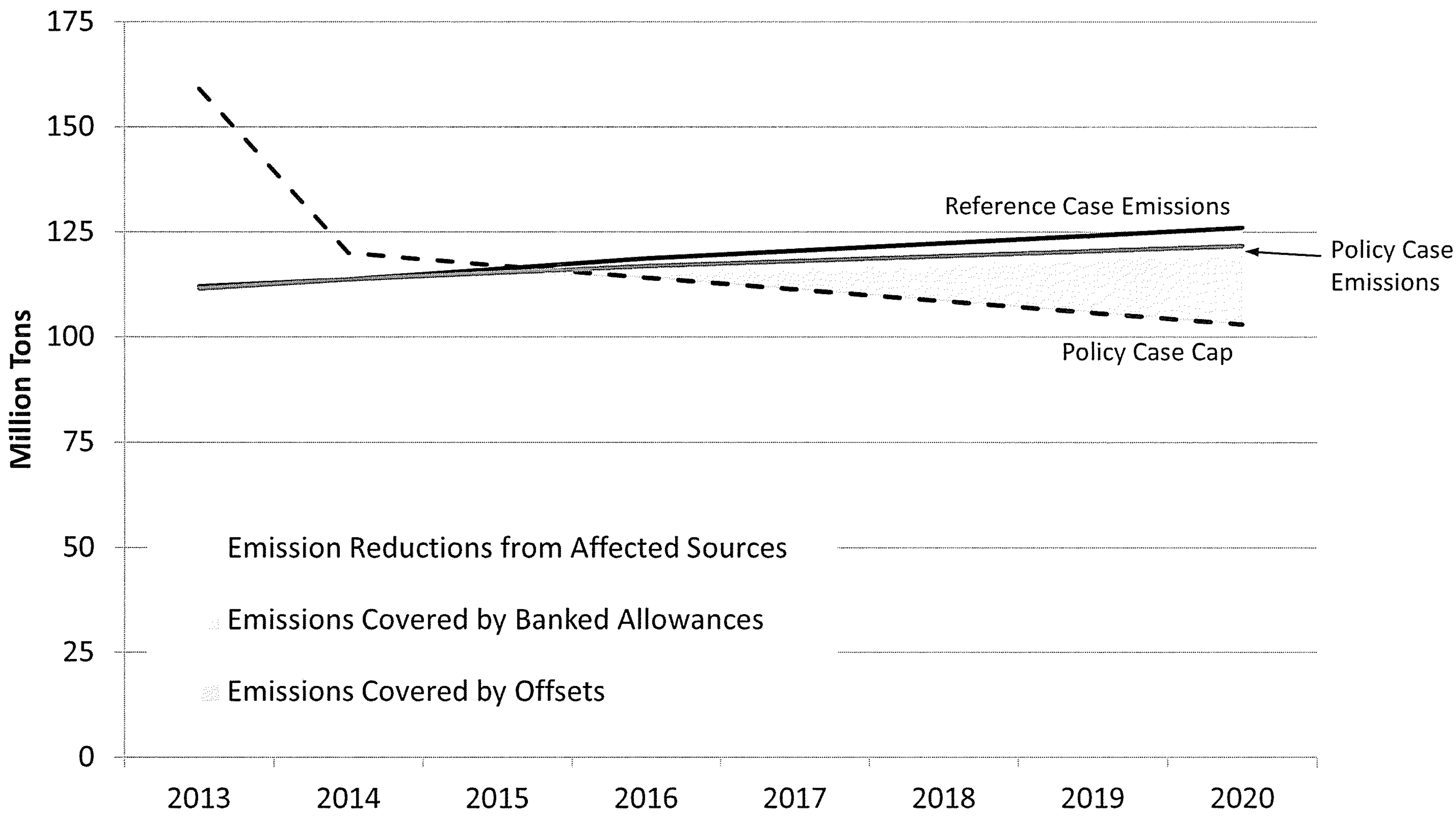


RGGI Allowance Price Projections

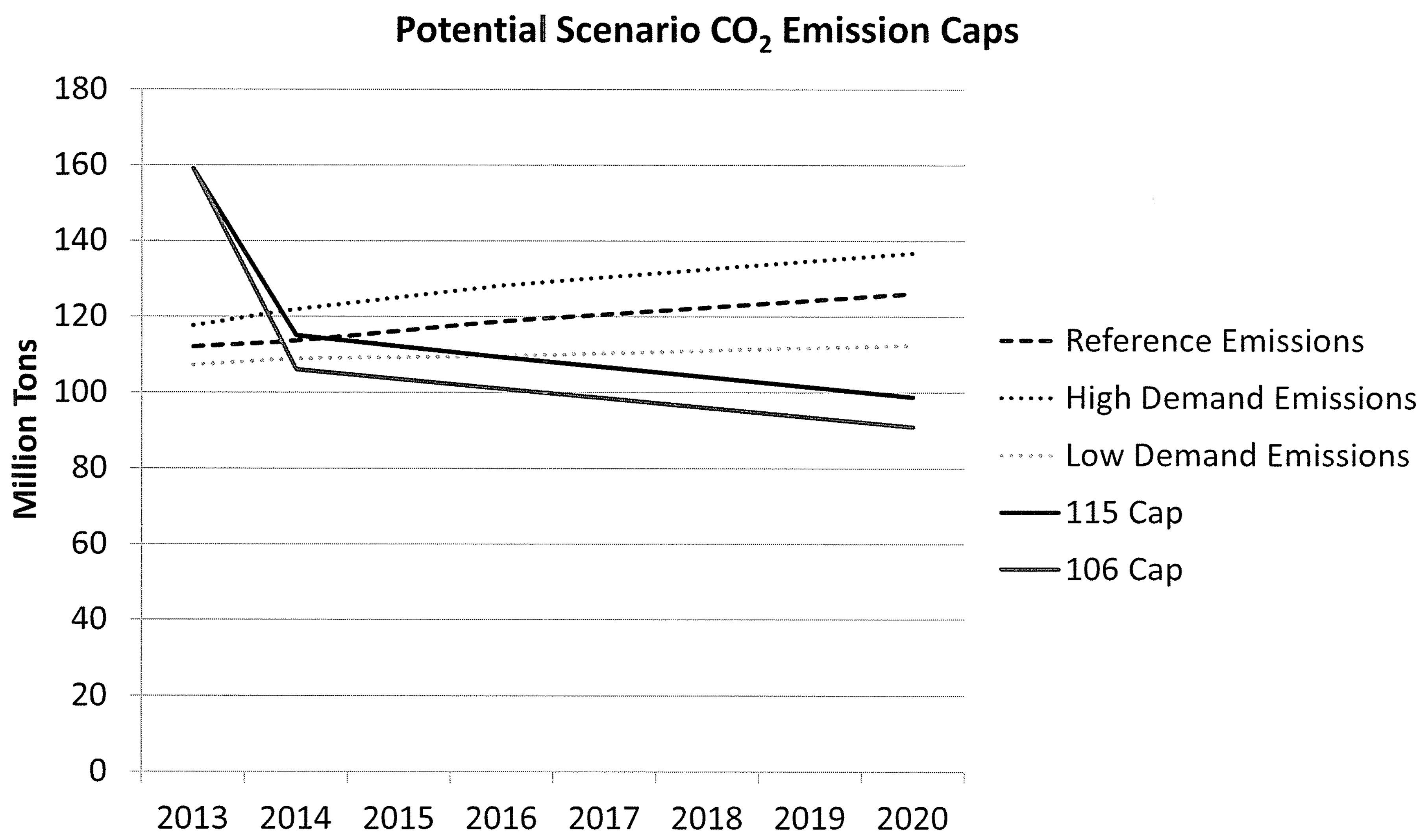
Reference Demand Growth Cases



Sources of Emission Reductions
120 Cap CCR Reference Case

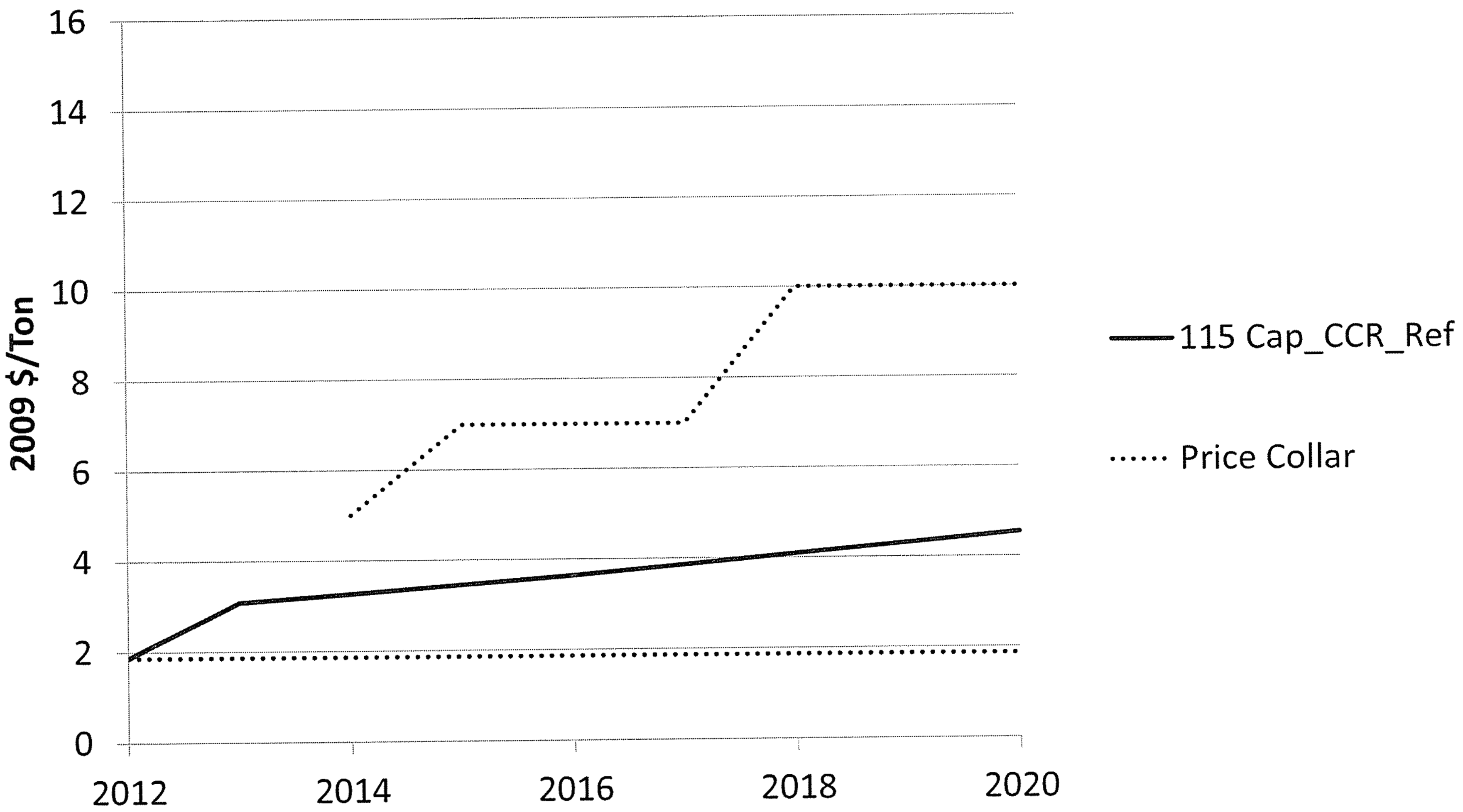


RGGI Potential Scenario Analysis
Caps compared to Emissions



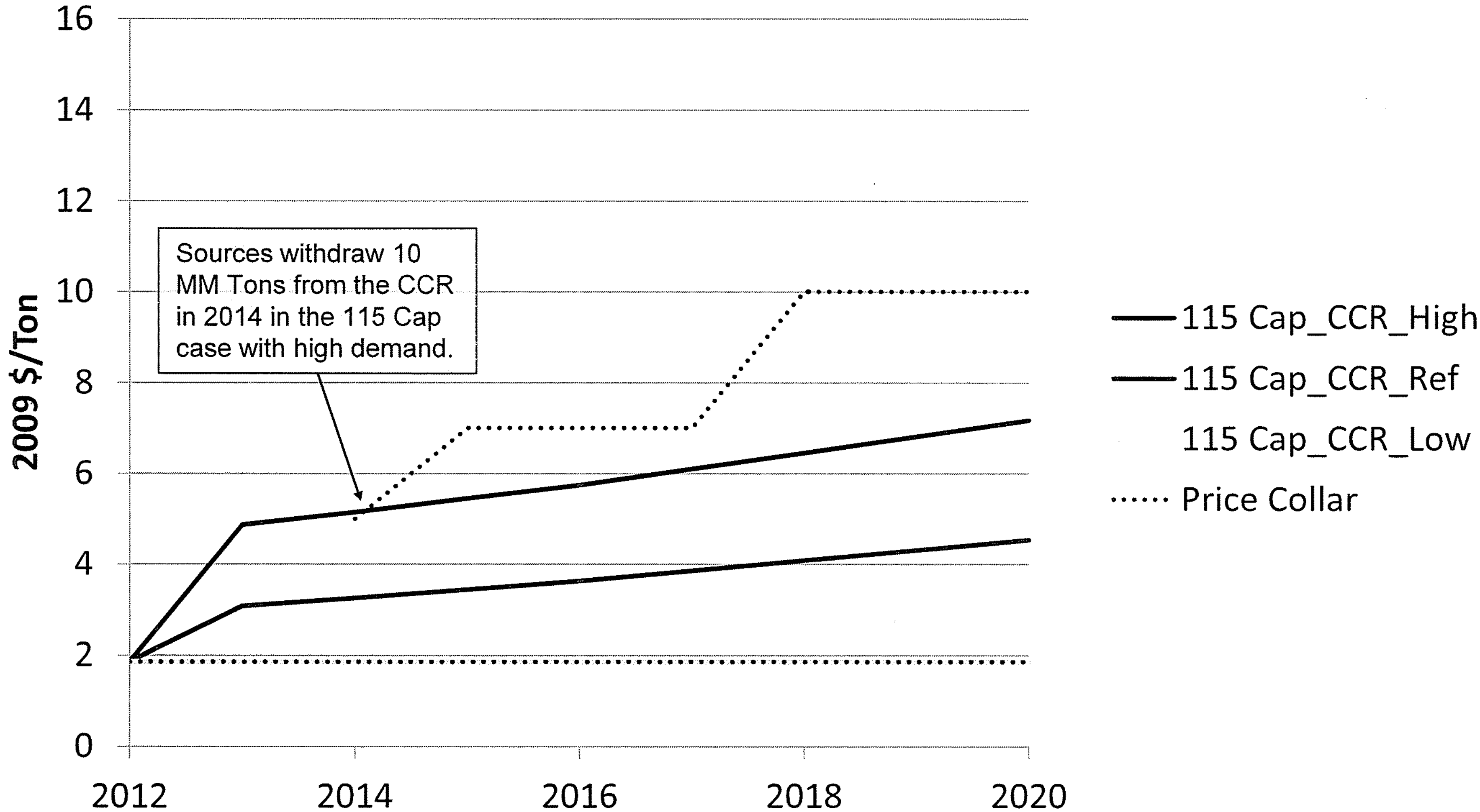
RGGI Allowance Price Projections

115 Cap CCR Reference Case



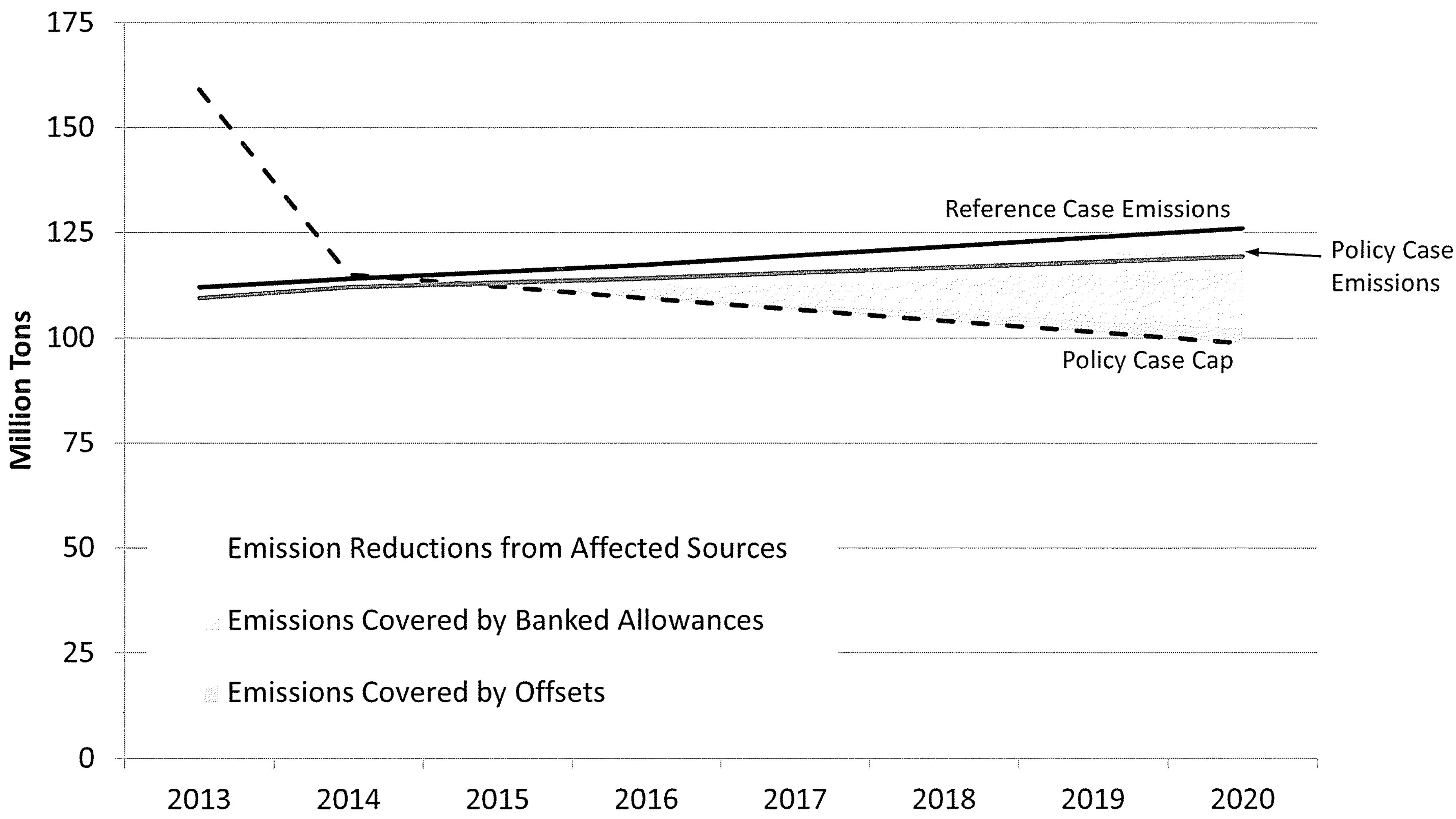
RGGI Allowance Price Projections

115 Cap CCR Cases (Reference, High Demand, Low Demand)



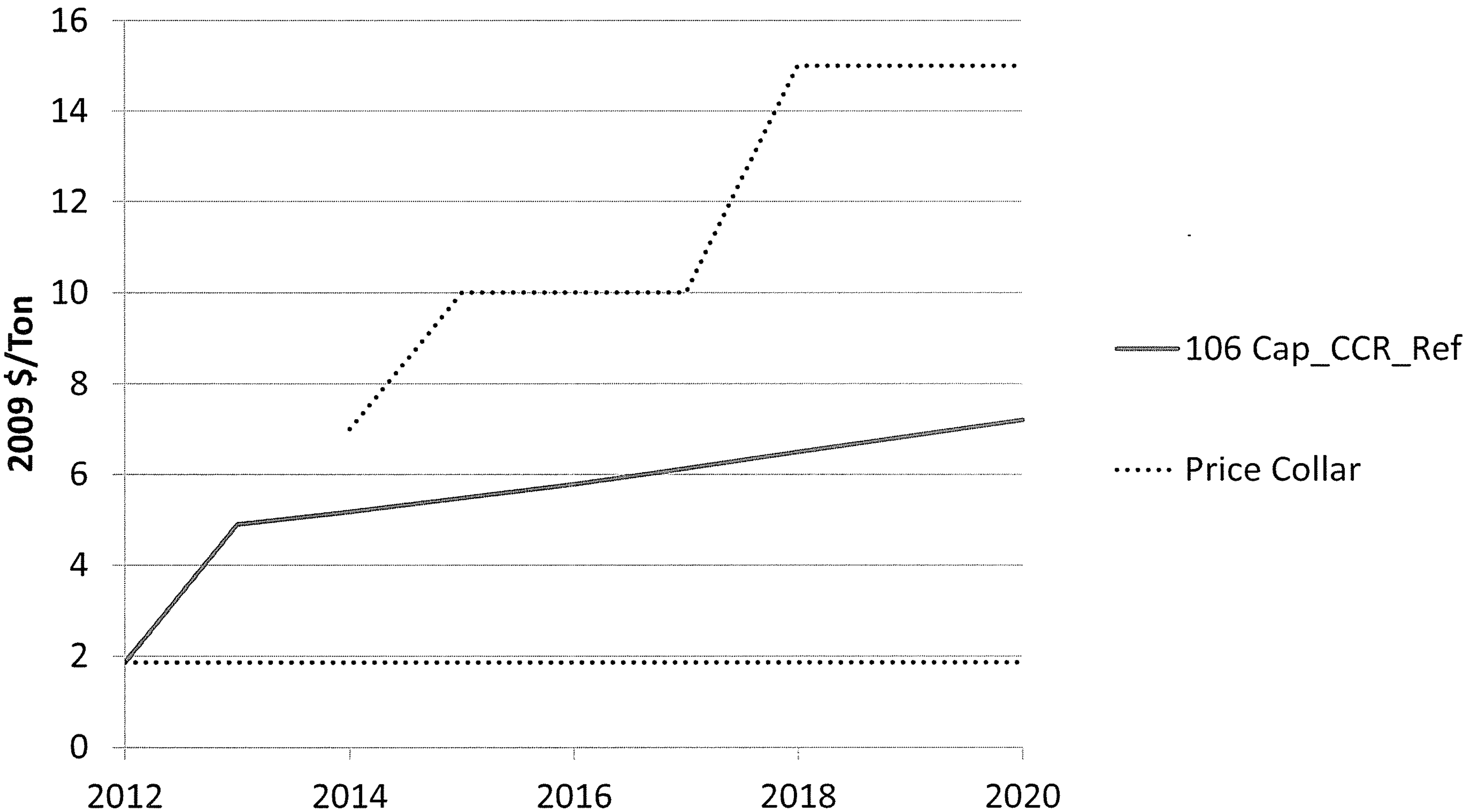
Sources of Emission Reductions

115 Cap CCR Reference Case



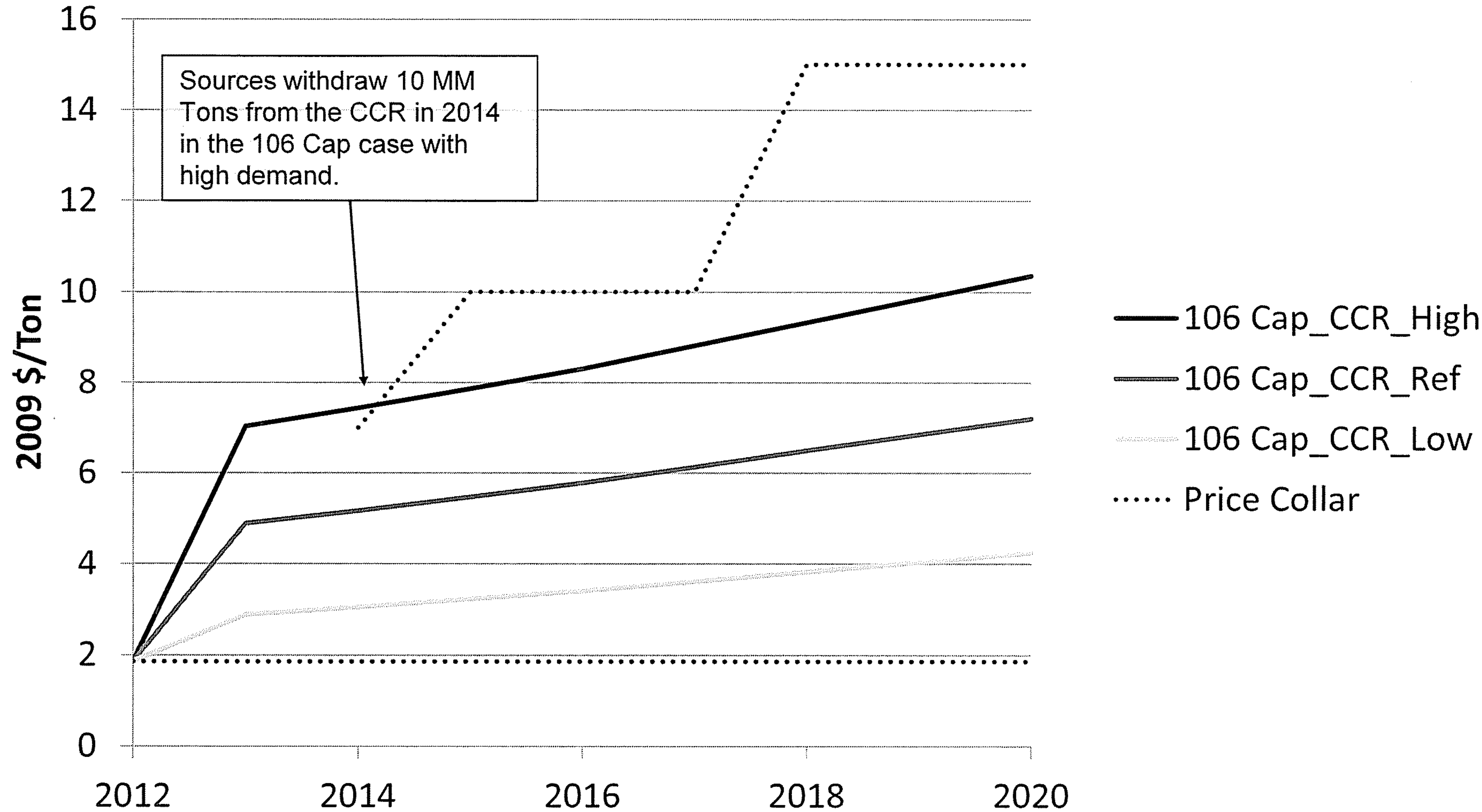
RGGI Allowance Price Projections

106 Cap CCR Reference Case



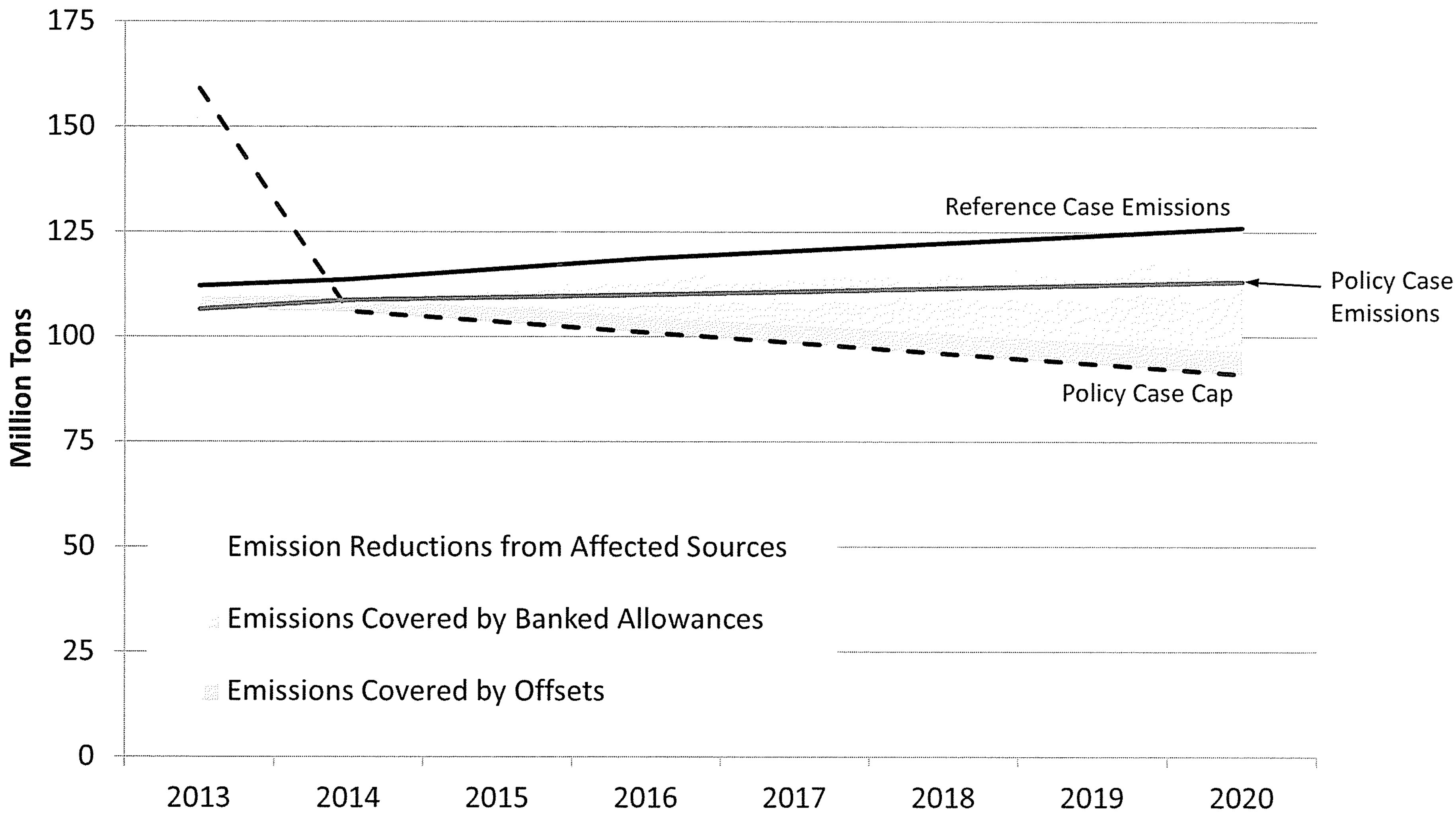
RGGI Allowance Price Projections

106 Cap CCR Cases (Reference, High Demand, Low Demand)



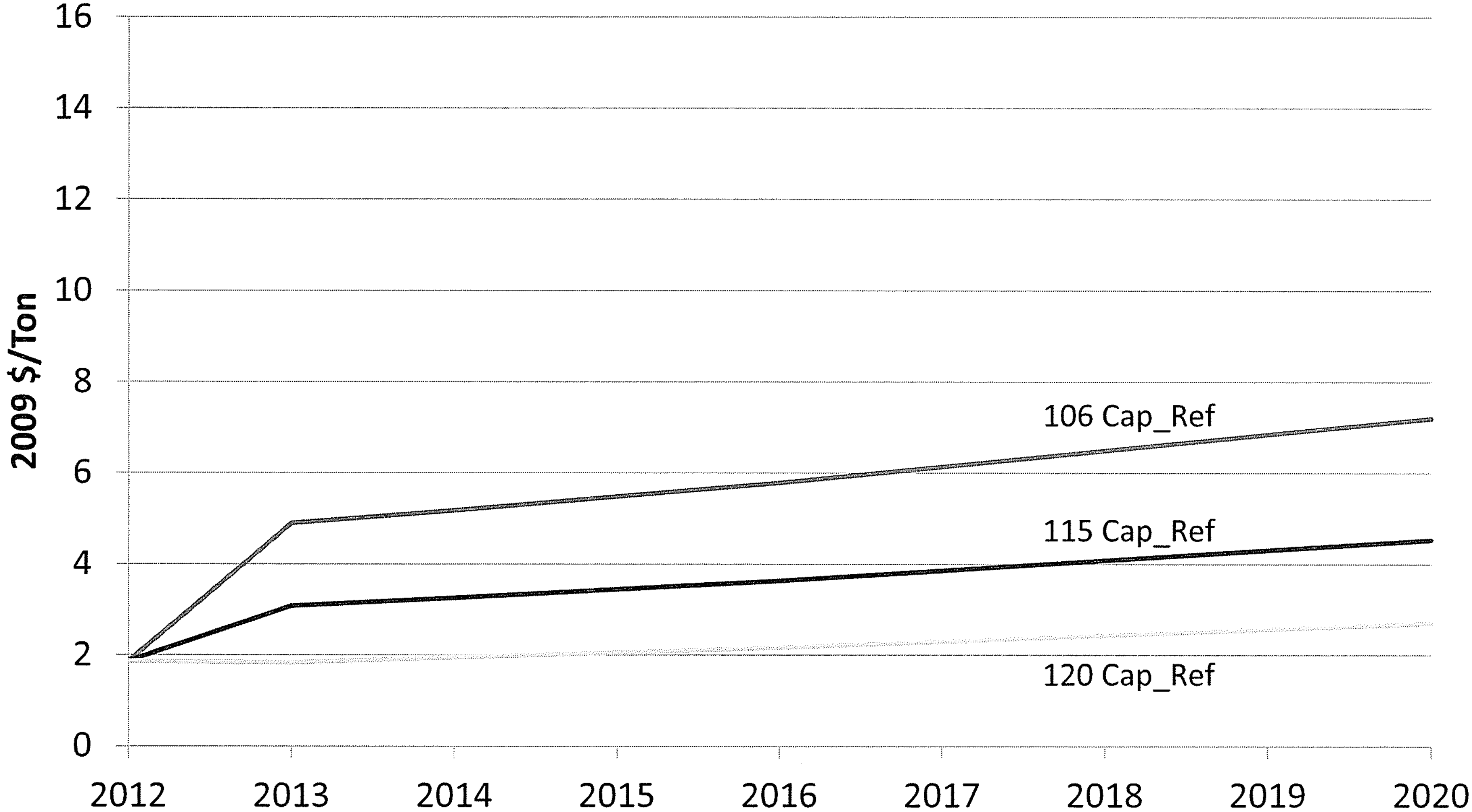
Sources of Emission Reductions

106 Cap CCR Reference Case



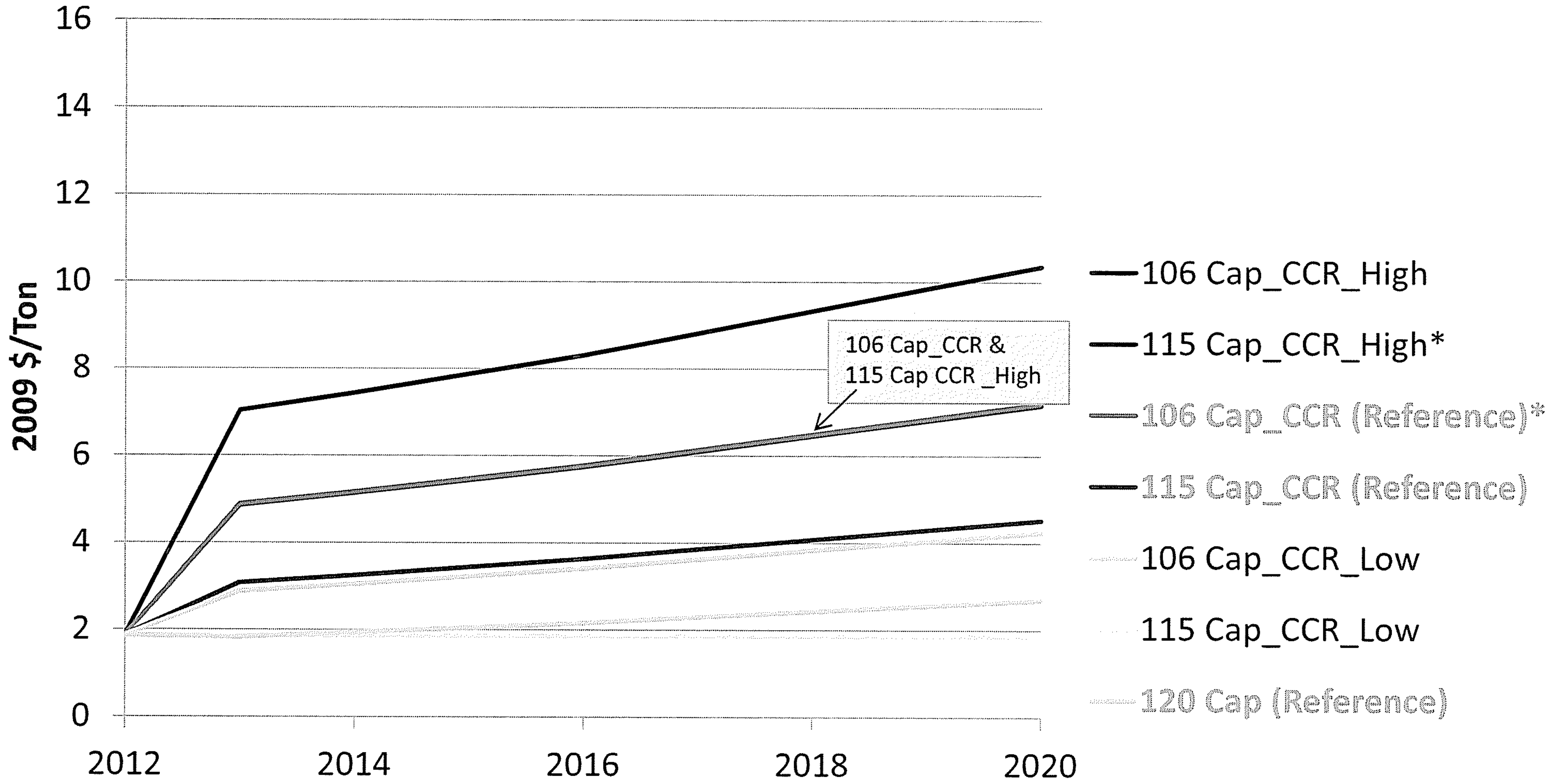
RGGI Allowance Price Projections

Reference Demand Growth Cases



All cases: 106 Cap, 115 Cap and 120 Cap

Allowance Prices



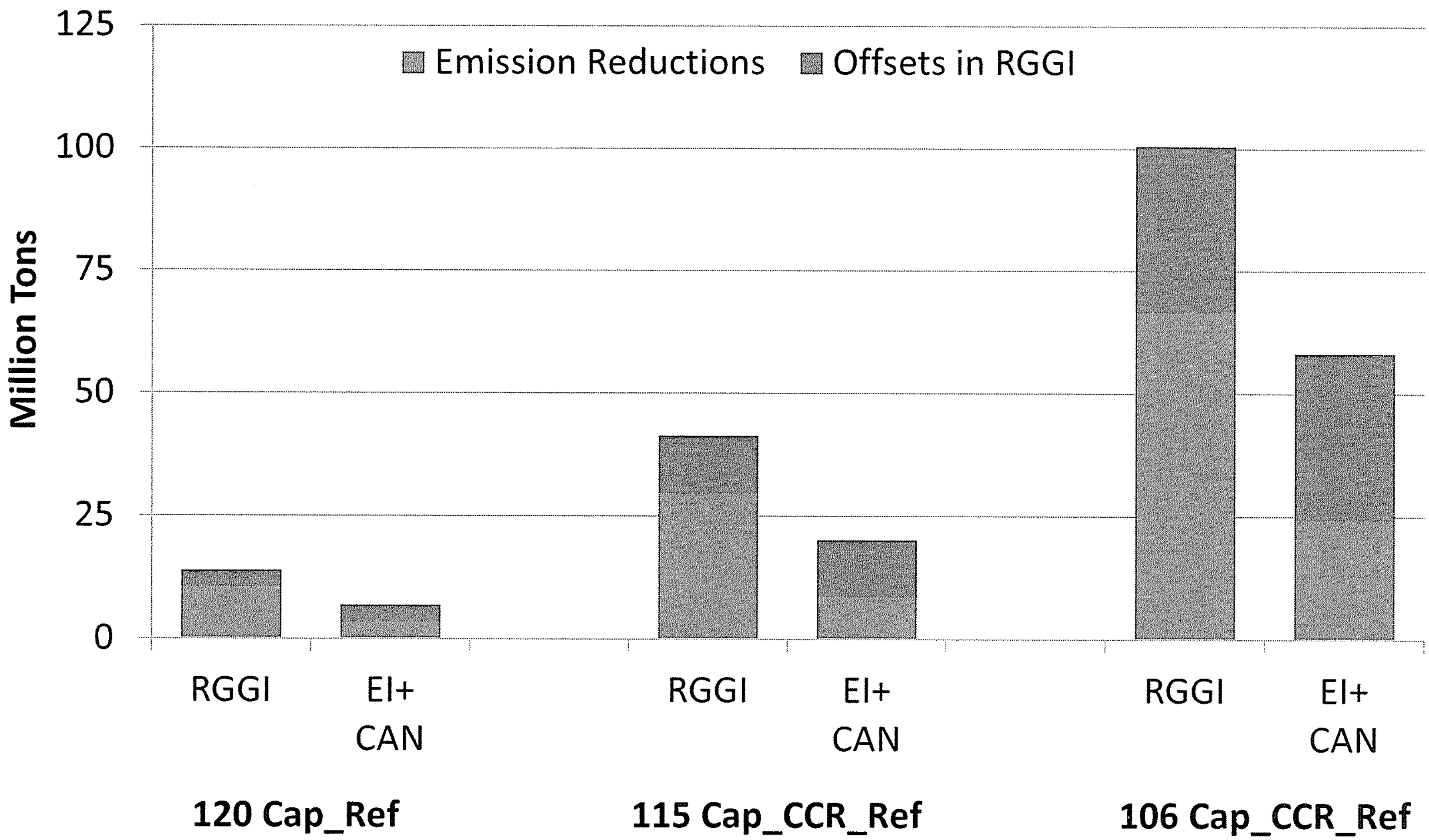
*The 115 Cap_CCR_High and 106 Cap_CCR results appear on the chart as single line

*Sources withdraw 10 MM Tons from the CCR in 2014 in both the 106 Cap_CCR_High (at $7) and 115 Cap_CCR_High (at $5)

Cumulative Emission Reductions, 2013 to 2020

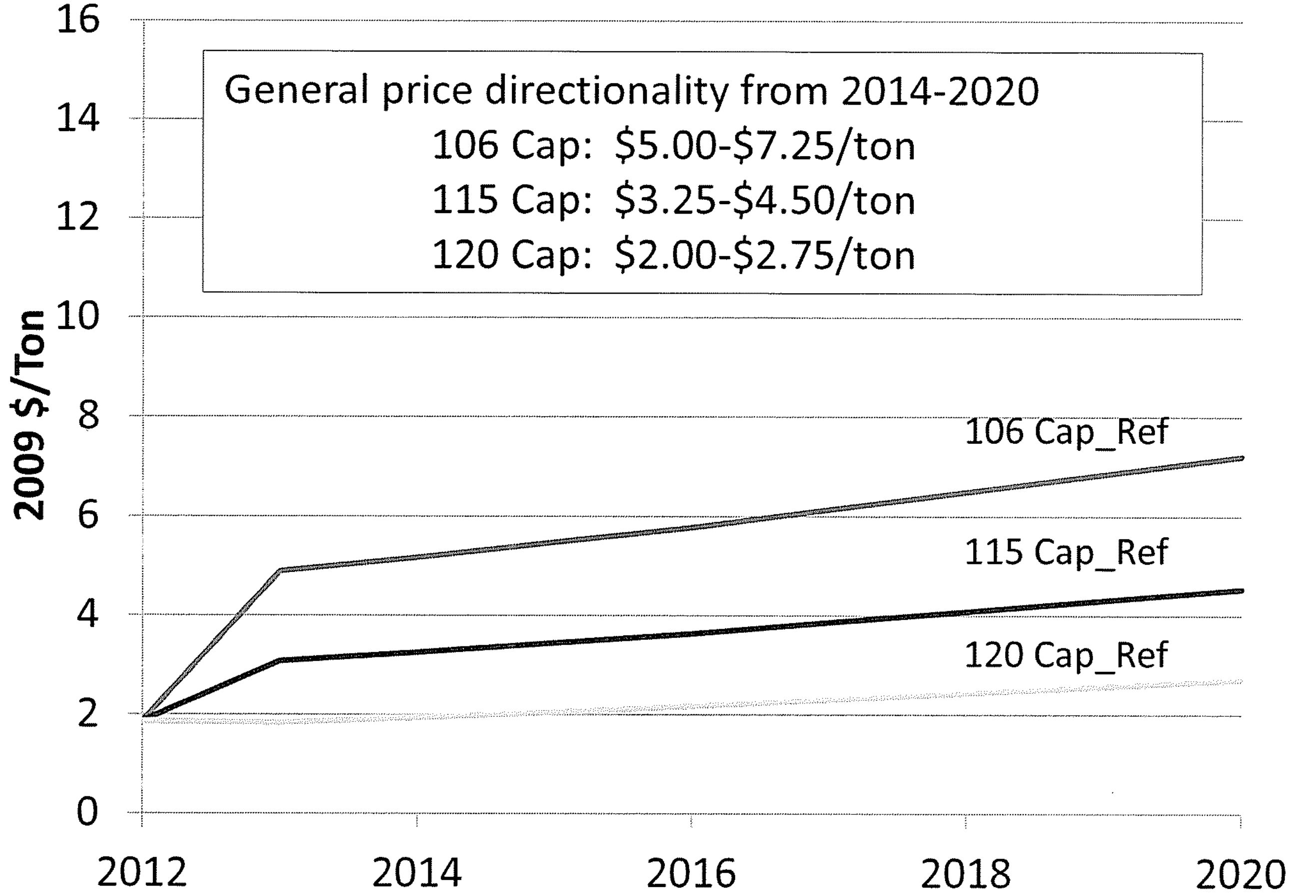
Reference Demand Growth Cases

Emission reductions for RGGI and the Eastern Interconnect (including RGGI) and eastern Canada (EI+CAN)



RGGI Allowance Price Projections-Recap

Reference demand cases reflect the best estimated projections for each cap scenario



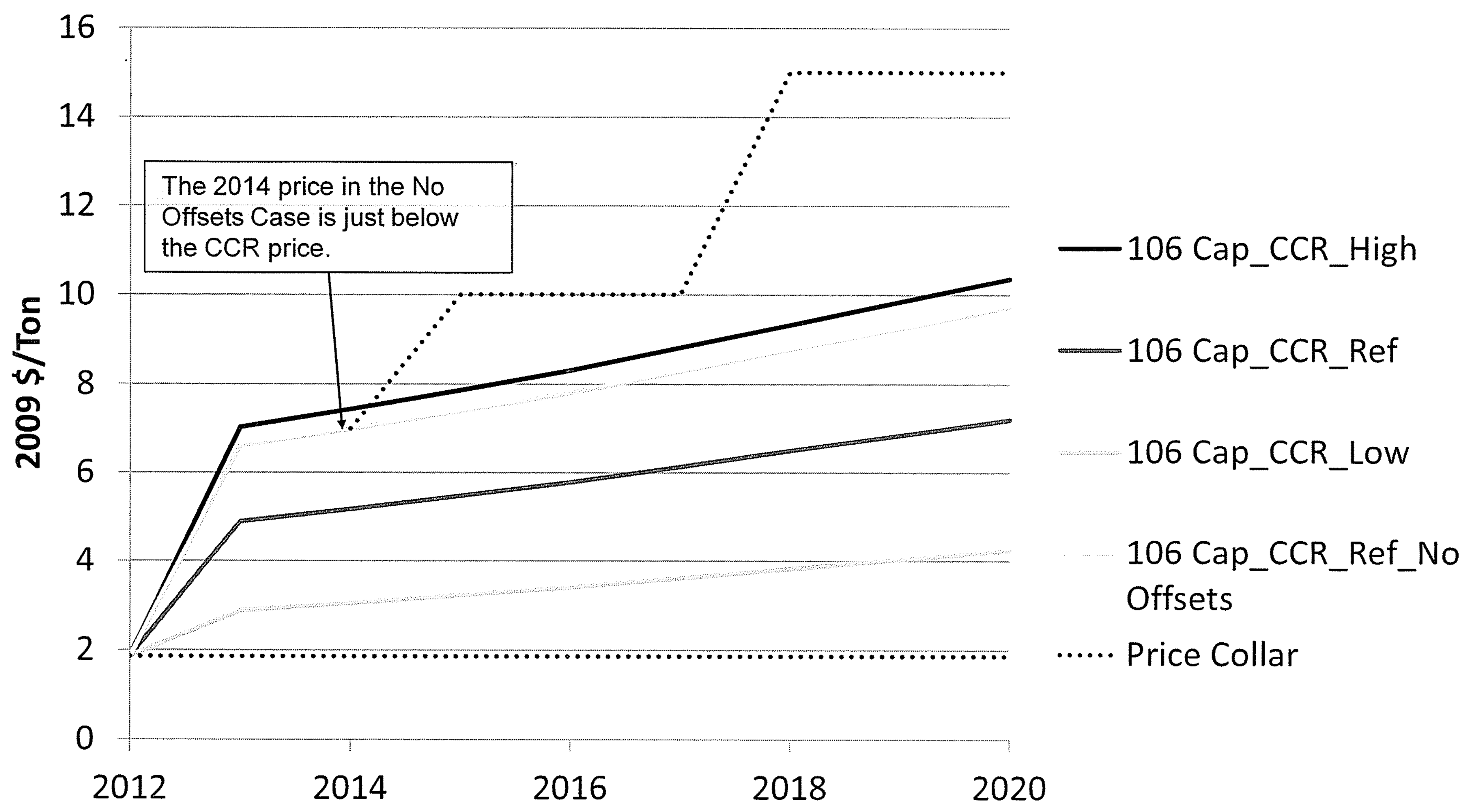
Offsets Analysis-*106 Cap CCR Reference without Offsets*

Case Name	CO_2 Cap	CCR - Reserve	CCR – Price Collar	Offsets
106 Cap_CCR _Reference w/o offsets	2014: 106 MM Tons Declines 2.5%/yr. 2020: 91 MM Tons	No more than 10 MM released each year 2014-2020	2014: $7/ton 2015-17: $10/ton 2018-20: $15/ton Use reserve price as floor	No offsets are available for compliance Removes 3.3% compliance and 5% and 10% at 7$/ton and 10$/ton price triggers

Note: This analysis evaluates the possibility that offsets would not be available; it is not evaluating removal of offsets from the program

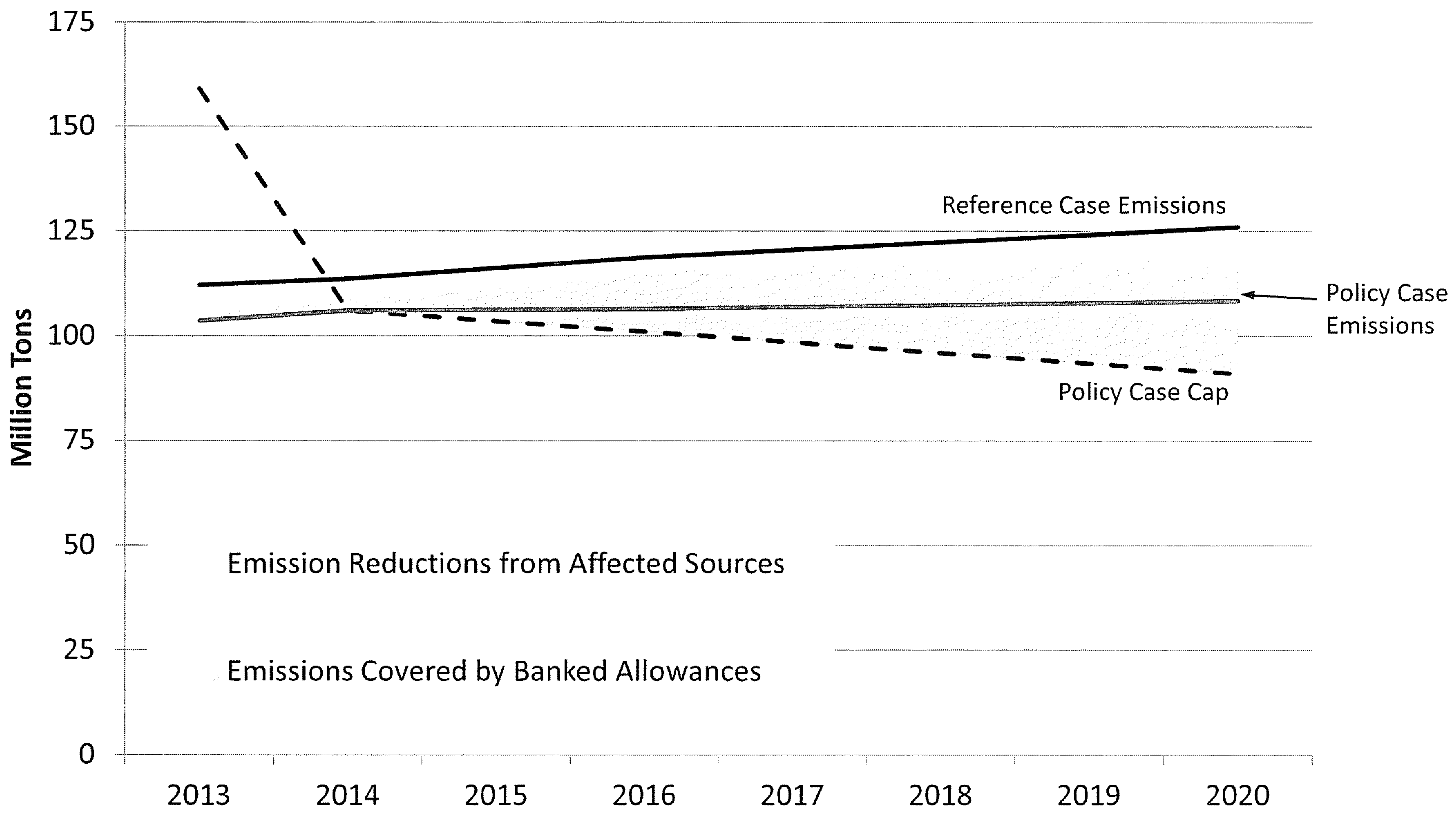
RGGI Allowance Price Projections

106 Cap CCR Cases (Reference, Low, High, Reference w/o Offsets)



Sources of Emission Reductions

106 Cap CCR Reference with No Offsets



January 26, 2012

Regional Cap-and-Trade Effort Seeks Greater Impact by Cutting Carbon Allowances

By MIREYA NAVARRO

Adjusting to shifts in the economy, states in the cap-and-trade system known as the Regional Greenhouse Gas Initiative have slashed the number of allowances that electric power companies can buy to offset their emissions.

The decision, made last week, was intended to shore up the pioneering program as it undergoes its first comprehensive review this year. While the program has been judged a success by most of the participating states, in the Northeast and Mid-Atlantic, an oversupply of the allowances — in essence, permits to pollute — has limited the program's impact.

The program, the nation's first cap-and-trade system, sets a ceiling on carbon dioxide emissions from electric power providers and requires the companies to pay for their heat-trapping emissions by buying the allowances in online auctions held four times a year. Companies that pollute less can benefit by selling off allowances to other companies.

Because of a switch to natural gas from coal by many utilities and a limping economy, however, both the demand for electricity and the plants' emissions have been lower than expected since the program was first put into effect in 2009, with many of the allowances going unsold.

On Jan. 17, New York, Connecticut, Delaware, Massachusetts, Rhode Island and Vermont announced that they were permanently eliminating 72 percent of the unsold carbon allowances, or a total of 67 million. (Each allowance amounts to one ton of carbon dioxide emissions.) Maryland has also said it intends to retire some unsold allowances, raising the percentage of the unsold permits retired to 93 percent.

The reduction is widely viewed as a prelude to a major change expected by the end of the review period this summer: the potential tightening of emissions ceilings for electric power providers, which are currently set to reduce emissions by 10 percent by 2018. But emissions have already dropped by more than 30 percent below the cap.

"Lowering the number of allowances in the program sounds like the direction the states want to go in," said Ashley Lawson, a senior analyst with Thomson Reuters Point Carbon, a carbon-market research firm.

Ms. Lawson said that while the regional initiative had so far proved itself as a working cap-and-trade model, the oversupply of allowances led to a lower price for them, easing the pressure on electricity providers to emit even less.

Since they began, the sales of carbon allowances have nonetheless produced almost $1 billion in revenue for the 10 original participating states.

Still, as political winds shifted nationally, with many Republican candidates denouncing cap-and-trade in the 2010 midterm elections, the program came under fire from critics who argued that the initiative imposed additional costs on electric utilities that were then passed on to consumers. Among them was Gov. Chris Christie of New Jersey, who pulled his state out of the program last year, and also contended that it did not reduce emissions.

Officials from supporting states vehemently countered that the benefits of the program far outweighed any costs, and an independent study released last November backed them up. The study, commissioned by four nonprofit foundations and conducted by the Boston consulting firm Analysis Group, concluded that the regional initiative had saved consumers money over all and created jobs. States have often used proceeds from the program to improve energy efficiency in offices and homes and to promote renewable energy installations, the report pointed out.

Although there were differences in how individual states applied the money — New York and Massachusetts heavily invested in energy efficiency programs, while New Jersey used most of the money to offset a shortfall in the state budget — carbon dioxide emissions in the initiative's 10-state region were 6 percent lower than they would have been without the program, said Susan F. Tierney, one of the study's authors.

As the program goes forward with 9 states instead of 10, some power companies say that the sweet spot will be lowering emissions without imposing too great a financial burden.

"My hope is that it will be strengthened because we need to address greenhouse gas emissions, but we need to do it in a responsible way so it doesn't impact utility customers, especially in this economy," said Bob Teetz, vice president of environmental services for National Grid, an electrical and gas company.

Some environmental groups are advocating changes that would broaden the program to include other industrial and commercial sources of greenhouse gas emissions and link it to similar programs in the works, like the cap-and-trade system being planned by California and some Canadian provinces.

A boost may come from the Environmental Protection Agency's plans for new performance standards to limit greenhouse gas emissions from power plants. One way for states to comply with the new rules could be to join the initiative or a similar program authorized by the agency.

REQUEST NO. 8. Refer to page 26, lines 19-21, of Dr. Fisher's testimony. Dr. Fisher's testimony suggests that the fixed Operation and Maintenance ("O&M") costs of Big Sandy 2 drop significantly in 2030 to 2031. Provide a rationale for this significant drop in O&M costs.

RESPONSE NO. 8:

Dr. Fisher observes on page 26, lines 11-13 that:

> The stream of fixed O&M costs in Option 1 (the retrofit case) drops markedly from 2030 to 2031 by about $36 million per year (nominal, or $27 M 2010$) and maintains at this lower value through the remainder of the analysis period.

This statement is a description of the Company's inputs to Strategist. Dr. Fisher has no rationale for this "significant drop in O&M costs" other than the hypothesis he has put forward on page 27 of his testimony.

Witness: Jeremy Fisher

REQUEST NO. 9. Refer to page 67, lines 10-12, of Dr. Fisher's testimony. Dr. Fisher indicates that the allocation of off-system sales to shareholders rather than ratepayers diminishes the advantage of the DFDG option. Please provide a further explanation.

RESPONSE NO. 9:

According to the Company's analysis, if the Big Sandy 2 unit is retrofit and continues to operate, it will achieve significantly more revenues from off-system sales (OSS) than under Options 2-4B. The Company's analysis allocates 100% of the OSS revenue to ratepayer benefit, but the Company's tariff allocates only 60% of that revenue to ratepayer benefit with the remaining 40% going to shareholders (see response to KPSC 1-1). Adjusting the Company's analysis for the OSS revenue distribution established in the tariff reduces the relative benefit of OSS for the retrofit option in comparison to Options 2-4B.

In the Company's analysis, there is a significant financial benefit from achieving total revenues from OSS. It estimated that, under the Company's assumptions, <u>total</u> revenues from OSS reduce the overall cost (CPW) of Option 1 by about $700 million.[2] Option 2, which generates less total revenue from OSS, sees a reduction of only $460 million in CPW.

If these OSS revenues were not counted in the analysis at all, clearly that would have a significant impact on the overall outcome of the analysis. For example, Option 2 would improve on a relative scale by $240 million CPW ($700-$460=$240), bringing it to about parity with Option 1.

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[2] Where total revenues are considered equivalent to the metric "Market Purch /(Sales)" as used by the Company in the Company Strategist Compilation Workbook.

Thus, if less than 100 percent of OSS revenues are allocated to ratepayers, and thus do not reduce the CPW the Company collects from ratepayers, there will be a similar, although muted, effect as the example above.

Allocating less than 100 percent of off-system sales revenues to ratepayers makes OSS a less important factor in mitigating the cost of each Option. The apparent benefit of Option 1 is reduced by allocating OSS away from ratepayers because the Option 1 retrofit results in a larger OSS than the other Options.

Witness: Jeremy Fisher

VERIFICATION

The undersigned, JEREMY FISHER, being duly sworn deposes and says that he has personal knowledge of the matters set forth in the foregoing responses for which he is the identified witness and that the information contained therein is true and correct to the best of his information, knowledge, and belief.

____
Jeremy Fisher

STATE OF MASSACHUSETTS)
) Case No. 2011-00401
COUNTY OF MIDDLESEX)

Subscribed and sworn to before me, a Notary Public in and before said County and State by Jeremy Fisher, this the 2 day of April 2012.

____
Notary Public

My Commission Expires: 7/27/18

JANICE CONYERS
Notary Public
Commonwealth of Massachusetts
My Commission Expires
July 27, 2018

VERIFICATION

The undersigned, J. RICHARD HORNBY, being duly sworn deposes and says that he has personal knowledge of the matters set forth in the foregoing responses for which he is the identified witness and that the information contained therein is true and correct to the best of his information, knowledge, and belief.

J. Richard Hornby

STATE OF MASSACHUSETTS)
) Case No. 2011-00401
COUNTY OF MIDDLESEX)

Subscribed and sworn to before me, a Notary Public in and before said County and State by J. Richard Hornby, this the 2 day of April 2012.

Notary Public

My Commission Expires: 7/27/18

JANICE CONYERS
Notary Public
Commonwealth of Massachusetts
My Commission Expires
July 27, 2018

VERIFICATION

The undersigned, RACHEL WILSON, being duly sworn deposes and says that she has personal knowledge of the matters set forth in the foregoing responses for which she is the identified witness and that the information contained therein is true and correct to the best of her information, knowledge, and belief.

Rachel Wilson

STATE OF MASSACHUSETTS	)	
	)	Case No. 2011-00401
COUNTY OF MIDDLESEX	)	

Subscribed and sworn to before me, a Notary Public in and before said County and State by Rachel Wilson, this the 2 day of April 2012.

Notary Public

My Commission Expires: 7/27/18

JANICE CONYERS
Notary Public
Commonwealth of Massachusetts
My Commission Expires
July 27, 2018

CERTIFICATE OF SERVICE

I certify that I mailed a copy of Environmental Intervenors Tom Vierheller, Beverly May, and Sierra Club's Responses to Commission Staff's First Request for Information by first class mail on April 2, 2012 to the following:

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