

Table 3-31 New Source Review (NSR) Settlements in EPA Platform v6 2022 Reference Case

Company and Plant	State	Unit	Settlement Actions														Notes	Reference
			Retire/Repower		SO ₂ control			NO _x Control			PM or Mercury Control			Allowance Retirement	Allowance Restriction			
			Action	Effective Date	Equipment	Percent Removal or Rate	Effective Date	Equipment	Rate	Effective Date	Equipment	Rate	Effective Date	Retirement	Restriction	Effective Date		
Alabama Power																		
James H. Miller	Alabama	Unit 3			Install and operate FGD continuously	95%	12/31/11	Operate existing SCR continuously	0.1	05/01/08		0.03	12/31/06	Within 45 days of settlement entry, APC must retire 7,538 SO ₂ emission allowances.	APC shall not sell, trade, or otherwise exchange any Plant Miller excess SO ₂ emission allowances outside of the APC system	1/1/21	1) Settlement requires 95% removal efficiency for SO ₂ or 90% in the event that the unit combust coal with sulfur content greater than 1% by weight. 2) The settlements require APC to retire \$4,900,000 of SO ₂ emission allowances within 45 days of consent decree entry. 3) EPA assumed a retirement of 7,538 SO ₂ allowances based on a current allowance price of \$650.	http://www2.epa.gov/enforcement/alabama-power-clean-air-act-settlement
	Alabama	Unit 4			Install and operate FGD continuously	95%	12/31/11	Operate existing SCR continuously	0.1	05/01/08		0.03	12/31/06			1/1/21		
Minnkota Power Cooperative																		
			Beginning 1/01/2006, Minnkota shall not emit more than 31,000 tons of SO ₂ /year, no more than 26,000 tons beginning 2011, no more than 11,500 tons beginning 1/01/2012. If Unit 3 is not operational by 12/31/2015, then beginning 1/01/2014, the plant wide emission shall not exceed 8,500.															
Milton R. Young	North Dakota	Unit 1			Install and continuously operate FGD	95% if wet FGD, 90% if dry	12/31/11	Install and continuously operate Over-fire AIR, or equivalent technology with emission rate < 0.36	0.36	12/31/09		0.03 if wet FGD, .015 if dry FGD		Plant will surrender 4,346 allowances for each year 2012 – 2015, 8,693 allowances for years 2016 – 2018, 12,170 allowances for year 2019, and 14,886 allowances/year thereafter if Units 1 – 3 are operational by 12/31/2015. If only Units 1 and 2 are operational by 12/31/2015, the plant shall retire 17,886 units in 2020 and thereafter.	Minnkota shall not sell or trade NO _x allowances allocated to Units 1, 2, or 3 that would otherwise be available for sale or trade as a result of the actions taken by the settling defendants to comply with the requirements		1) Settlement requires 95% removal efficiency for SO ₂ at Unit 1 if a wet FGD is installed, or 90% if a dry FGD is installed. The FGD for Units 1 and 2 and the NO _x control for Unit 1 are modeled as emission constraints in EPA Platform v6, the NO _x control for Unit 2 is hardwired into EPA Platform v6. 2) Beginning 12/31/2010, Unit 2 will achieve a phase II average NO _x emission rate established through its NO _x BACT determination. Beginning 12/31/2011, Unit 1 will achieve a phase II NO _x emission rate established by its BACT determination.	http://www2.epa.gov/enforcement/minnkota-power-cooperative-and-square-butte-electric-cooperative-settlement
	North Dakota	Unit 2			Design, upgrade, and continuously operate FGD	90%	12/31/10	Install and continuously operate over-fire AIR, or equivalent technology with emission rate < 0.36	0.36	12/31/07		0.03	Before 2008					
SIGECO																		
FB Culley	Indiana	Unit 1	Repower to natural gas (or retire)	12/31/06										The provision did not specify an amount of SO ₂ allowances to be surrendered. It only provided that excess allowances resulting from compliance with NSR settlement provisions must be retired.			http://www2.epa.gov/enforcement/southern-indiana-gas-and-electric-company-sigeco-fb-culley-plant-clean-air-act-caa	
	Indiana	Unit 2			Improve and continuously operate existing FGD (shared by Units 2 and 3)	95%	06/30/04											
	Indiana	Unit 3			Improve and continuously operate existing FGD (shared by Units 2 and 3)	95%	06/30/04	Operate Existing SCR Continuously	0.1	09/01/03	Install and continuously operate a Baghouse	0.015	06/30/07					
PSEG FOSSIL																		
Bergen	New Jersey	Unit 2	Repower to combined cycle	12/31/02										The provision did not specify an amount of SO ₂ allowances to		Bergen unit 2 is a CC with DLN and SCR	http://www2.epa.gov/enforcement/pseg	

Company and Plant	State	Unit	Settlement Actions														Notes	Reference
			Retire/Repower		SO ₂ control			NO _x Control			PM or Mercury Control			Allowance Retirement	Allowance Restriction			
			Action	Effective Date	Equipment	Percent Removal or Rate	Effective Date	Equipment	Rate	Effective Date	Equipment	Rate	Effective Date	Retirement	Restriction	Effective Date		
Hudson	New Jersey	Unit 2			Install Dry FGD (or approved alt. technology) and continually operate	0.15	12/31/10	Install SCR (or approved tech) and continually operate	0.1	12/31/10	Install Baghouse (or approved technology)	0.015	12/31/10	be surrendered. It only provided that excess allowances resulting from compliance with NSR settlement provisions must be retired.			The settlement requires coal with monthly average sulfur content no greater than 2% at units operating FGD – this limit is modeled as a coal choice exception in EPA Platform v6. Hudson has retired	fossil-lic-settlement
Mercer	New Jersey	Unit 1			Install Dry FGD (or approved alt. technology) and continually operate	0.15	12/31/10	Install SCR (or approved tech) and continually operate	0.1	01/01/07	Install Baghouse (or approved technology) w/activated carbon injection for Hg control	0.015	12/31/10	The settlement requires coal with monthly average sulfur content no greater than 2% at units operating FGD – this limit is modeled as a coal choice exception in EPA Platform v6. Limits are consistent with recent Title V permits. Mercer has retired			The settlement requires coal with monthly average sulfur content no greater than 2% at units operating FGD – this limit is modeled as a coal choice exception in EPA Platform v6. Mercer has retired	http://www2.epa.gov/enforcement/psq
	New Jersey	Unit 2			Install Dry FGD (or approved alt. technology) and continually operate	0.15	12/31/10	Install SCR (or approved tech) and continually operate	0.1	01/31/07	Install Baghouse (or approved technology) w/activated carbon injection for Hg control	0.015	12/31/10		fossil-lic-settlement			
TECO																		
Big Bend	Florida	Unit 1			Existing Scrubber (shared by Units 1 & 2)	95% (95% or .25)	09/1/00 (01/01/13)	Install SCR	0.12	06/01/08				The provision did not specify an amount of SO ₂ allowances to be surrendered. It only provided that excess allowances resulting from compliance with NSR settlement provisions must be retired.				http://www2.epa.gov/enforcement/tampa-electric-company-teco-clean-air-act-caa-settlement
	Florida	Unit 2			Existing Scrubber (shared by Units 1 & 2)	95% (95% or .25)	09/1/00 (01/01/13)	Install SCR	0.12	06/01/09								
	Florida	Unit 3			Existing Scrubber (shared by Units 3 & 4)	93% if Units 3 & 4 are operating	2000 (01/01/10)	Install SCR	0.12	06/01/10								
	Florida	Unit 4			Existing Scrubber (shared by Units 3 & 4)	93% if Units 3 & 4 are operating	06/22/05	Install SCR	0.1	07/01/07								
Gannon	Florida	Six units	Retire all six coal units and repower at least 550 MW of coal capacity to natural gas	12/31/04														
WEPCO																		
			WEPCO shall comply with the following system wide average NO _x emission rates and total NO _x tonnage permissible: by 1/1/2005 an emission rate of 0.27 and 31,500 tons, by 1/1/2007 an emission rate of 0.19 and 23,400 tons, and by 1/1/2013 an emission rate of 0.17 and 17,400 tons. For SO ₂ emissions, WEPCO will comply with: by 1/1/2005 an emission rate of 0.76 and 86,900 tons, by 1/1/2007 an emission rate of 0.61 and 74,400 tons, by 1/1/2008 an emission rate of 0.45 and 55,400 tons, and by 1/1/2013 an emission rate of 0.32 and 33,300 tons.															http://www2.epa.gov/enforcement/wisconsin-electric-power-company-wepco-clean-air-act-civil-settlement
Presque Isle	Michigan	Units 1 – 4	Retire or install SO ₂ and NO _x controls	12/31/12	Install and continuously operate FGD (or approved equiv. tech)	95% or 0.1	12/31/12	Install SCR (or approved tech) and continually operate	0.1	12/31/12				The provision did not specify an amount of SO ₂ allowances to be surrendered. It only provided that excess allowances resulting from compliance with NSR settlement provisions must be retired.				http://www2.epa.gov/enforcement/wisconsin-electric-power-company-wepco-clean-air-act-civil-settlement
	Michigan	Units 5, 6					Install and operate low NO _x burners		12/31/03									
	Michigan	Units 7, 8					Operate existing low NO _x burners		12/31/05	Install Baghouse								
	Michigan	Unit 9					Operate existing low NO _x burners		12/31/06	Install Baghouse								

Company and Plant	State	Unit	Settlement Actions													Notes	Reference	
			Retire/Repower		SO ₂ control			NO _x Control			PM or Mercury Control			Allowance Retirement	Allowance Restriction			
			Action	Effective Date	Equipment	Percent Removal or Rate	Effective Date	Equipment	Rate	Effective Date	Equipment	Rate	Effective Date	Retirement	Restriction			Effective Date
Pleasant Prairie	Wisconsin	Unit 1			Install and continuously operate FGD (or approved control tech)	95% or 0.1	12/31/06	Install and continuously operate SCR (or approved tech)	0.1	12/31/06							Both units are retired.	
	Wisconsin	Unit 2			Install and continuously operate FGD (or approved control tech)	95% or 0.1	12/31/07	Install and continuously operate SCR (or approved tech)	0.1	12/31/03								
Oak Creek	Wisconsin	Units 5, 6			Install and continuously operate FGD (or approved control tech)	95% or 0.1	12/31/12	Install and continuously operate SCR (or approved tech)	0.1	12/31/12								
	Wisconsin	Unit 7			Install and continuously operate FGD (or approved control tech)	95% or 0.1	12/31/12	Install and continuously operate SCR (or approved tech)	0.1	12/31/12								
	Wisconsin	Unit 8			Install and continuously operate FGD (or approved control tech)	95% or 0.1	12/31/12	Install and continuously operate SCR (or approved tech)	0.1	12/31/12								
Port Washington	Wisconsin	Units 1 – 4	Retire	12/31/04 for Units 1 – 3. Unit 4 by entry of consent decree														
Valley	Wisconsin	Boilers 1 – 4	converted to natural gas	2016				Operate existing low NO _x burner	0.08	12/31/15								
VEPCO																		
The Total Permissible NO _x Emissions (in tons) from VEPCO system are: 104,000 in 2003, 95,000 in 2004, 90,000 in 2005, 83,000 in 2006, 81,000 in 2007, 63,000 in 2008 – 2010, 54,000 in 2011, 50,000 in 2012, and 30,250 each year thereafter. Beginning 1/1/2013 they will have a system wide emission rate no greater than 0.15 lbs/MMBtu.																		
Mount Storm	West Virginia	Units 1 – 3			Construct or improve FGD	95% or 0.15	01/01/05	Install and continuously operate SCR	0.11	01/01/08								
Chesterfield	Virginia	Unit 4			Install and continuously operate FGD			Install and continuously operate SCR	0.1	01/01/13								
	Virginia	Unit 5			Construct or improve FGD	95% or 0.13	10/12/12	Install and continuously operate SCR	0.1	01/01/12								
	Virginia	Unit 6			Construct or improve FGD	95% or 0.13	01/01/10	Install and continuously operate SCR	0.1	01/01/11								
Chesapeake Energy	Virginia	Units 3, 4	Retire	12/1/2014			Install and continuously operate SCR	0.1	01/01/13									
Clover	Virginia	Units 1, 2			Improve FGD	95% or 0.13	09/01/03											
Possum Point	Virginia	Units 3, 4	Retire and repower to natural gas	05/02/03														
Santee Cooper																		
Santee Cooper shall comply with the following system wide averages for NO _x emission rates and combined tons for emission of: by 1/01/2005 facility shall comply with an emission rate of 0.3 and 30,000 tons, by 1/1/2007 an emission rate of 0.18 and 25,000 tons, by 1/1/2010 and emission rate of 0.15 and 20,000 tons. For SO ₂ emission the company shall comply with system wide averages of: by 1/1/2005 an emission rate of 0.92 and 95,000 tons, by 1/1/2007 and emission rate of 0.75 and 85,000 tons, by 1/1/2009 an emission rate of 0.53 and 70 tons, and by 1/1/2011 and emission rate of 0.5 and 65 tons.																		
http://www2.epa.gov/enforcement/virginia-electric-and-power-company-vepco-clean-air-act-caa-settlement http://www2.epa.gov/enforcement/south-carolina																		

Company and Plant	State	Unit	Settlement Actions														Notes	Reference	
			Retire/Repower		SO ₂ control			NO _x Control			PM or Mercury Control			Allowance Retirement	Allowance Restriction				
			Action	Effective Date	Equipment	Percent Removal or Rate	Effective Date	Equipment	Rate	Effective Date	Equipment	Rate	Effective Date	Retirement	Restriction	Effective Date			
Cross	South Carolina	Unit 1			Upgrade and continuously operate FGD	95%	06/30/06	Install and continuously operate SCR	0.1	05/31/04				The provision did not specify an amount of SO ₂ allowances to be surrendered. It only provided that excess allowances resulting from compliance with NSR settlement provisions must be retired.				http://www.epa.gov/eis/ohio-edison-company-w-h-sammis-power-station-clean-air-act-2005-settlement-and-2009	
	South Carolina	Unit 2			Upgrade and continuously operate FGD	87%	06/30/06	Install and continuously operate SCR	0.11/0.1	05/31/04 and 05/31/07									
Winyah	South Carolina	Unit 1			Install and continuously operate FGD	95%	12/31/08	Install and continuously operate SCR	0.11/0.1	11/30/04									
	South Carolina	Unit 2			Install and continuously operate FGD	95%	12/31/08	Install and continuously operate SCR	0.12	11/30/04									
	South Carolina	Unit 3			Upgrade and continuously operate existing FGD	90%	12/31/08	Install and continuously operate SCR	0.14/0.12	11/30/2005 and 11/30/08									
	South Carolina	Unit 4			Upgrade and continuously operate existing FGD	90%	12/31/07	Install and continuously operate SCR	0.13/0.12	11/30/05 and 11/30/08									
Grainger	South Carolina	Unit 1						Operate low NO _x burner or more stringent technology		06/25/04									
	South Carolina	Unit 2						Operate low NO _x burner or more stringent technology		05/01/04									
Jeffries	South Carolina	Units 3, 4	Retire	2012				Operate low NO _x burner or more stringent technology		06/25/04									
OHIO EDISON																			
			Ohio Edison shall achieve reductions of 2,483 tons NO _x between 7/1/2005 and 12/31/2010 using any combination of: 1) low sulfur coal at Burger Units 4 and 5, 2) operating SCRs currently installed at Mansfield Units 1 – 3 during the months of October through April, and/or 3) emitting fewer tons than the Plant-Wide Annual Cap for NO _x required for the Sammis Plant. Ohio Edison must reduce 24,600 tons system-wide of SO ₂ by 12/31/2010.																
			No later than 8/11/2005, Ohio Edison shall install and operate low NO _x burners on Sammis Units 1, 2, 4, 5, 6, and 7 and overfired air on Sammis Units 1, 2, 3, 6, and 7. No later than 12/1/2005, Ohio Edison shall install advanced combustion control optimization with software to minimize NO _x emissions from Sammis Units 1 – 5.																
W. H. Sammis Plant	Ohio	Unit 1			Install Induct Scrubber (or approved equiv. control tech)	50% removal or 1.1 lbs/MMBtu	12/31/08	Install SNCR (or approved alt. tech) & operate continuously	0.25	10/31/07				Beginning on 1/1/2006, Ohio Edison may use, sell or transfer any restricted SO ₂ only to satisfy the Operational Needs at the Sammis, Burger and Mansfield Plant, or new units within the FirstEnergy System that comply with a 96% removal for SO ₂ . For calendar year 2006 through 2017, Ohio Edison may accumulate SO ₂ allowances for use at the Sammis, Burger, and Mansfield plants, or FirstEnergy units equipped with SO ₂			Plant-wide NO _x Annual Caps: 11,371 tons 7/1/2005 – 12/31/2005; 21,251 tons 2006; 20,596 tons 2007; 18,903 tons 2008; 17,328 tons 2009 – 2010; 14,845 tons 2011; 11,863 2012 onward. Sammis Plant-Wide Annual SO ₂ Caps: 58,000 tons SO ₂ 7/1/2005-12/31/2005; 116,000 tons 1/1/2006 – 12/31/2007; 114,000 tons 1/1/2008-12/31/2008; 101,500 tons 1/1/2009 – 12/31/2010; 29,900 tons 1/1/2011 onward. Sammis Units 1 – 5 are also subject to the following SO ₂ Monthly Caps if Ohio Edison installs the improved SO ₂ control technology (Unit 5's option A): 3,242 tons May, July, and August 2010; 3,137 tons June and September 2010. Ohio Edison has installed the required SO ₂ technology (Unit 5's option B), so the Monthly Caps are: 2,533 tons		
	Ohio	Unit 2			Install Induct Scrubber (or approved equiv. control tech)	50% removal or 1.1 lbs/MMBtu	12/31/08	Operate existing SNCR continuously	0.25	02/15/06									
	Ohio	Unit 3			Install Induct Scrubber (or approved equiv. control tech)	50% removal or 1.1 lbs/MMBtu	12/31/08	Operate low NO _x burners and overfire air by 12/1/05; install SNCR (or approved alt. tech) & operate continuously by 12/31/07	0.25	12/01/05 and 10/31/07									

Company and Plant	State	Unit	Settlement Actions													Notes	Reference			
			Retire/Repower		SO ₂ control			NO _x Control			PM or Mercury Control			Allowance Retirement	Allowance Restriction					
			Action	Effective Date	Equipment	Percent Removal or Rate	Effective Date	Equipment	Rate	Effective Date	Equipment	Rate	Effective Date	Retirement	Restriction			Effective Date		
	Ohio	Unit 4			Install Induct Scrubber (or approved equiv. control tech)	50% removal or 1.1 lbs/MMBtu	06/30/09	Install SNCR (or approved alt. tech) & operate continuously	0.25	10/31/07				Emission Control Standards. Beginning in 2018, Ohio Edison shall surrender unused restricted SO ₂ allowances.		May, July, and August 2010; 2,451 tons June and September 2010. Add'l Monthly Caps are: 2,533 tons May, July, and August 2011; 2,451 tons June and September 2011 thereafter.				
	Ohio	Unit 5			Install Flash Dryer Absorber or ECO ₂ (or approved equiv. control tech) & operate continuously	50% removal or 1.1 lbs/MMBtu	06/29/09	Install SNCR (or approved alt. tech) & Operate Continuously	0.29	03/31/08										
	Ohio	Unit 6			Install FGD ³ (or approved equiv. control tech) & operate continuously	95% removal or 0.13 lbs/MMBtu	06/30/11	Install SNCR (or approved alt. tech) & operate continuously	"Minimum Extent Practicable"	06/30/05	Operate Existing ESP Continuously	0.03	01/01/10						In addition to SNCR, settlement requires installation of first SCR (or approved alt tech) on either Unit 6 or 7 by 12/31/2010; second installation by 12/31/2011. Both SCRs must achieve 90% Design Removal Efficiency by 180 days after installation date. Each SCR must provide a 30-Day Rolling average. NO _x Emission Rate of 0.1 lbs/MMBtu starting 180 days after installation dates above.	
	Ohio	Unit 7			Install FGD (or approved equiv. control tech) & operate continuously	95% removal or 0.13 lbs/MMBtu	06/30/11	Operate existing SNCR Continuously	"Minimum Extent Practicable"	08/11/05	Operate Existing ESP Continuously	0.03	01/01/10							
Mansfield Plant	Pennsylvania	Unit 1			Upgrade existing FGD	95%	12/31/05									Additional Mansfield Plant-wide SO ₂ reductions are as follows: 4,000 tons in 2006, 8,000 tons in 2007, and 12,000 tons/yr for every year after. Settlement allows relinquishment of SO ₂ requirement upon shutdown of unit, after which the SO ₂ reductions must be made by another plant(s).				
	Pennsylvania	Unit 2			Upgrade existing FGD	95%	12/31/06													
	Pennsylvania	Unit 3			Upgrade existing FGD	95%	10/31/07													
Eastlake	Ohio	Unit 5						Install low NO _x burners, over-fired air and SNCR & operate continuously	"Minimize Emissions to the Extent Practicable"	12/31/06						Settlement requires Eastlake Plant to achieve additional reductions of 11,000 tons of NO _x per year commencing in calendar year 2007, and no less than 10,000 tons must come from this unit. The extra 1,000 tons may come from this unit or another unit in the region. Upon shutdown of Eastlake, another plant must achieve these reductions.				
Burger	Ohio	Unit 4	Repower with at least 80% biomass fuel, up to 20% low sulfur coal OR Retire by 12/31/2010	12/31/11																
Burger	Ohio	Unit 5		12/31/11																
MIRANT¹⁶																				
			System-wide NO _x Emission Annual Caps: 36,500 tons 2004; 33,840 tons 2005; 33,090 tons 2006; 28,920 tons 2007; 22,000 tons 2008; 19,650 tons 2009; 16,000 tons 2010 onward. System-wide NO _x Emission Ozone Season Caps: 14,700 tons 2004; 13,340 tons 2005; 12,590 tons 2006; 10,190 tons 2007; 6,150 tons 2008 – 2009; 5,200 tons 2010 thereafter. Beginning on 5/1/2008, and continuing for each and every Ozone Season thereafter, the Mirant System shall not exceed a System-wide Ozone Season Emission Rate of 0.150 lbs/MMBtu NO _x .														http://www2.epa.gov/enforcement/mirant-clean-air-settlement			
Potomac River Plant	Virginia	Unit 1																		
	Virginia	Unit 2	Retire	12/21/2012																

Company and Plant	State	Unit	Settlement Actions														Notes	Reference	
			Retire/Repower		SO ₂ control			NO _x Control			PM or Mercury Control			Allowance Retirement	Allowance Restriction				
			Action	Effective Date	Equipment	Percent Removal or Rate	Effective Date	Equipment	Rate	Effective Date	Equipment	Rate	Effective Date	Retirement	Restriction	Effective Date			
	Virginia	Unit 3						Install low NO _x burners (or more effective tech) & operate continuously		0.1	05/01/04							Settlement requires installation of Separated Overfire Air tech (or more effective technology) by 5/1/2005. Plant-wide Ozone Season NO _x Caps: 1,750 tons 2004; 1,625 tons 2005; 1,600 tons 2006 – 2009; 1,475 tons 2010 thereafter. Plant-wide annual NO _x Caps are 3,700 tons in 2005 and each year thereafter.	
	Virginia	Unit 4					Install low NO _x burners (or more effective tech) & operate continuously			0.1	05/01/04								
	Virginia	Unit 5					Install low NO _x burners (or more effective tech) & operate continuously			0.1	05/01/04								
Morgantown Plant	Maryland	Unit 1					Install SCR (or approved alt. tech) & operate continuously		0.1	05/01/07									
	Maryland	Unit 2					Install SCR (or approved alt. tech) & operate continuously		0.1	05/01/08									
Chalk Point	Maryland	Unit 1			Install and continuously operate FGD (or equiv. technology)	95%	06/01/10								For each year after Mirant commences FGD operation at Chalk Point, Mirant shall surrender the number of SO ₂			Mirant must install and operate FGD by 6/1/2010 if authorized by court to reject ownership interest in Morgantown Plant, or by no later than 36 months after they lose ownership interest of the Morgantown Plant. [Installed]	
	Maryland	Unit 2			Install and continuously operate FGD (or equiv. technology)	95%	06/01/10							Allowances equal to the amount by which the SO ₂ Allowances allocated to the Units at the Chalk Point Plant are greater than the total amount of SO ₂ emissions allowed under this Section XVIII.					
ILLINOIS POWER			System-wide NO _x Emission Annual Caps: 15,000 tons 2005; 14,000 tons 2006; 13,800 tons 2007 onward. System-wide SO ₂ Emission Annual Caps: 66,300 tons 2005 – 2006; 65,000 tons 2007; 62,000 tons 2008 – 2010; 57,000 tons 2011; 49,500 tons 2012; 29,000 tons 2013 onward.																
Baldwin	Illinois	Unit 1			Install wet or dry FGD (or approved equiv. alt. tech) & operate continuously	0.1	12/31/11	Operate OFA & existing SCR continuously	0.1	08/11/05	Install & continuously operate Baghouse	0.015	12/31/10	By year end 2008, Dynegy will surrender 12,000 SO ₂ emission allowances, by year end 2009 it will surrender 18,000, by year end 2010 it will surrender 24,000, any by year end 2011 and each year thereafter it will surrender 30,000 allowances. If the surrendered allowances result in insufficient remaining allowances allocated to the units comprising the DMG system, DMG can request to surrender			http://www2.eia.gov/enforcement/illinois-power-company-and-dynegy-midwest-generation-settlement		
	Illinois	Unit 2			Install wet or dry FGD (or approved equiv. alt. tech) & operate continuously	0.1	12/31/11	Operate OFA & existing SCR continuously	0.1	08/11/05	Install & continuously operate Baghouse	0.015	12/31/10						
	Illinois	Unit 3			Install wet or dry FGD (or approved equiv. alt. tech) & operate continuously	0.1	12/31/11	Operate OFA and/or low NO _x burners	0.12 until 12/30/12; 0.1 from 12/31/12	0.1	08/11/05 and 12/31/12	Install & continuously operate Baghouse	0.015	12/31/10					

Company and Plant	State	Unit	Settlement Actions														Notes	Reference
			Retire/Repower		SO ₂ control			NO _x Control			PM or Mercury Control			Allowance Retirement	Allowance Restriction			
			Action	Effective Date	Equipment	Percent Removal or Rate	Effective Date	Equipment	Rate	Effective Date	Equipment	Rate	Effective Date	Retirement	Restriction	Effective Date		
Havana	Illinois	Unit 6			Install wet or dry FGD (or approved equiv. alt. tech) & operate continuously	1.2 lbs/MMBtu until 12/30/2012; 0.1 lbs/MMBtu from 12/31/2012 onward	08/11/05 and 12/31/12	Operate OFA and/or low NO _x burners & operate existing SCR continuously	0.1	08/11/05	Install & continuously operate Baghouse, then install ESP or alt. PM equip	For Baghouse: .015 lbs/MMBtu; For ESP: .03 lbs/MMBtu	For Baghouse: 12/31/12; For ESP: 12/31/05	fewer SO ₂ allowances.				
Hennepin	Illinois	Unit 1				1.2	07/27/05	Operate OFA and/or low NO _x burners	*Minimum Extent Practicable	08/11/05	Install ESP (or equiv. alt. tech) & continuously operate ESPs	0.03	12/31/06				Settlement requires first installation of ESP at either Unit 1 or 2 on 12/31/2006; and on the other by 12/31/2010.	
	Illinois	Unit 2				1.2	07/27/05	Operate OFA and/or low NO _x burners	*Minimum Extent Practicable	08/11/05	Install ESP (or equiv. alt. tech) & continuously operate ESPs	0.03	12/31/06					
Vermilion	Illinois	Unit 1				1.2	01/31/07	Operate OFA and/or low NO _x burners	*Minimum Extent Practicable	08/11/05	Install ESP (or equiv. alt. tech) & continuously operate ESPs	0.03	12/31/10					
	Illinois	Unit 2				1.2	01/31/07	Operate OFA and/or low NO _x burners	*Minimum Extent Practicable	08/11/05	Install ESP (or equiv. alt. tech) & continuously operate ESPs	0.03	12/31/10					
Wood River	Illinois	Unit 4				1.2	07/27/05	Operate OFA and/or low NO _x burners	*Minimum Extent Practicable	08/11/05	Install ESP (or equiv. alt. tech) & continuously operate ESPs	0.03	12/31/05				Settlement requires first installation of ESP at either Unit 4 or 5 on 12/31/2005; and on the other by 12/31/2007.	

Company and Plant	State	Unit	Settlement Actions														Notes	Reference	
			Retire/Repower		SO ₂ control			NO _x Control			PM or Mercury Control			Allowance Retirement	Allowance Restriction				
			Action	Effective Date	Equipment	Percent Removal or Rate	Effective Date	Equipment	Rate	Effective Date	Equipment	Rate	Effective Date	Retirement	Restriction	Effective Date			
	Illinois	Unit 5				1.2	07/27/05	Operate OFA and/or low NO _x burners	"Minimum Extent Practicable"	08/11/05	Install ESP (or equiv. alt. tech) & continuously operate ESPs	0.03	12/31/05						
Kentucky Utilities Company																			
EW Brown Generating Station	Kentucky	Unit 3			Install FGD	97% or 0.100	12/31/10	Install and continuously operate SCR by 12/31/2012, continuously operate low NO _x boiler and OFA.	0.07	12/31/12	Continuously operate ESP	0.03	12/31/10	KU must surrender 53,000 SO ₂ allowances of 2008 or earlier vintage by March 1, 2009. All surplus NO _x allowances must be surrendered through 2020.	SO ₂ and NO _x allowances may not be used for compliance, and emissions decreases for purposes of complying with the Consent Decree do not earn credits.		Annual SO ₂ cap is 31,998 tons through 2010, then 2,300 tons each year thereafter. Annual NO _x cap is 4,072 tons.	http://www2.epa.gov/enforcement/kentucky-utilities-company-clean-air-act-settlement	
Salt River Project Agricultural Improvement and Power District (SRP)																			
Coronado Generating Station	Arizona	Unit 1 or Unit 2			Immediately begin continuous operation of existing FGDs on both units, install new FGD.	95% or 0.08	New FGD installed by 1/1/2012	Install and continuously operate low NO _x burner and SCR	0.32 prior to SCR installation, 0.080 after	LNB by 06/01/2009, SCR by 06/01/2014	Optimization and continuous operation of existing ESPs.	0.03	Optimization begins immediately, rate limit begins 01/01/12 (date of new FGD installation)	Beginning in 2012, all surplus SO ₂ allowances for both Coronado and Springville Unit 4 must be surrendered through 2020. The allowances limited by this condition may, however, be used for compliance at a prospective future plant using BACT and otherwise specified in par. 54 of the consent decree.	SO ₂ and NO _x allowances may not be used for compliance, and emissions decreases for purposes of complying with the Consent Decree do not earn credits.		Annual plant-wide NO _x cap is 7,300 tons after 6/1/2014.	http://www2.epa.gov/enforcement/salt-river-project-agriculture-improvement-and-power-district-settlement	
	Arizona	Unit 1 or Unit 2			Install new FGD	95% or 0.08	01/01/13	Install and continuously operate low NO _x burner	0.32	06/01/11			Optimization begins immediately, rate limit begins 01/01/13 (date of new FGD installation)						
American Electric Power																			
Eastern System-Wide (Modified Limits)						Annual Cap (tons)	Year												
						145,000	2016-2018											72,000	2016-2017
						113,000	2019-2020											62,000	2018-2020
						94,000	2021-2028											52,000	2021-2028
						89,000	2029 and thereafter											44,000	2029 and thereafter
																	https://ipbs.org/projects/assets/AEP-FifthJointModification.pdf		

Company and Plant	State	Unit	Settlement Actions														Notes	Reference
			Retire/Repower		SO ₂ control			NO _x Control			PM or Mercury Control			Allowance Retirement	Allowance Restriction			
			Action	Effective Date	Equipment	Percent Removal or Rate	Effective Date	Equipment	Rate	Effective Date	Equipment	Rate	Effective Date	Retirement	Restriction	Effective Date		
Eastern System-Wide						Annual Cap (tons)	Year		Annual Cap (tons)	Year					NO _x and SO ₂ allowances that would have been made available by emission reductions pursuant to the Consent Decree must be surrendered.	NO _x and SO ₂ allowances may not be used to comply with any of the limits imposed by the Consent Decree. The Consent Decree includes a formula for calculating excess NO _x allowances relative to the CSAPR Allocations, and restricts the use of some. See par. 74-79 for details. Reducing emissions below the Eastern System-Wide Annual Tonnage Limitations for NO _x and SO ₂ earns super compliant allowances.		
				450,000	2010		96,000	2009										
				450,000	2011		92,500	2010										
				420,000	2012		92,500	2011										
				350,000	2013		85,000	2012										
				340,000	2014		85,000	2013										
				275,000	2015		85,000	2014										
				260,000	2016		75,000	2015										
				235,000	2017		72,000	2016 and thereafter										
				184,000	2018													
						174,000	2019 and thereafter											
At least 600MW from various units	West Virginia	Spom 1 – 4	Retire, retrofit, or re-power	12/31/18												Spom 1-4 have retired.		
	Virginia	Clinch River 1 – 3																
	Indiana	Tanners Creek 1 – 3																
	West Virginia	Kammer 1 – 3														Kammer 1-3 have retired.		
Amos	West Virginia	Unit 1			Install and continuously operate FGD		12/31/09	Install and continuously operate SCR		01/01/08								
	West Virginia	Unit 2			Install and continuously operate FGD		12/31/10	Install and continuously operate SCR		01/01/09								
	West Virginia	Unit 3			Install and continuously operate FGD		12/31/09	Install and continuously operate SCR		01/01/08								
Big Sandy	Kentucky	Unit 1			Burn only coal with no more than 1.75 lbs/MMBtu annual average		Date of entry	Continuously operate low NO _x burners		Date of entry								
	Kentucky	Unit 2			Install and continuously operate FGD		12/31/15	Install and continuously operate SCR		01/01/09								
Cardinal	Ohio	Unit 1			Install and continuously operate FGD		12/31/08	Install and continuously operate SCR		01/01/09	Continuously operate ESP	0.03	12/31/09					
	Ohio	Unit 2			Install and continuously operate FGD		12/31/08	Install and continuously operate SCR		01/01/09	Continuously operate ESP	0.03	12/31/09					

Company and Plant	State	Unit	Settlement Actions													Notes	Reference	
			Retire/Repower		SO ₂ control			NO _x Control			PM or Mercury Control			Allowance Retirement	Allowance Restriction			
			Action	Effective Date	Equipment	Percent Removal or Rate	Effective Date	Equipment	Rate	Effective Date	Equipment	Rate	Effective Date	Retirement	Restriction			Effective Date
	Ohio	Unit 3			Install and continuously operate FGD			12/31/12	Install and continuously operate SCR			01/01/09						
Clinch River	Virginia	Units 1 – 3	Units 1 & 2: switch fuels to natural gas Unit 3: Retire	2016 ----- 2015		Plant-wide annual cap: 21,700 tons from 2010 to 2014, then 16,300 after 1/1/2015	2010 – 2014, 2015 and thereafter	Continuously operate low NO _x burners			Date of entry							
Conesville	Ohio	Unit 1	Retire, retrofit, or re-power	Date of entry														
	Ohio	Unit 2	Retire, retrofit, or re-power	Date of entry														
	Ohio	Unit 3	Retire, retrofit, or re-power	12/31/12														
	Ohio	Unit 4			Install and continuously operate FGD			12/31/10	Install and continuously operate SCR			12/31/10						
	Ohio	Unit 5			Upgrade existing FGD	95%		12/31/09	Continuously operate low NO _x burners			Date of entry						
	Ohio	Unit 6			Upgrade existing FGD	95%		12/31/09	Continuously operate low NO _x burners			Date of entry						
Gavin	Ohio	Unit 1			Install and continuously operate FGD			Date of entry	Install and continuously operate SCR			01/01/09						
	Ohio	Unit 2			Install and continuously operate FGD			Date of entry	Install and continuously operate SCR			01/01/09						
Glen Lynn	Virginia	Units 1 – 3	Retire	6/1/15														
	Virginia	Units 5, 6	Retire	6/1/15	Burn only coal with no more than 1.75 lbs/MMBtu annual average			Date of entry	Continuously operate low NO _x burners			Date of entry						
Kammer	West Virginia	Units 1 – 3				Plant-wide annual cap: 35,000	01/01/10	Continuously operate over-fire air			Date of entry							
Kanawha River	West Virginia	Units 1, 2			Burn only coal with no more than 1.75 lbs/MMBtu annual average			Date of entry	Continuously operate low NO _x burners			Date of entry						
Mitchell	West Virginia	Unit 1			Install and continuously operate FGD			12/31/07	Install and continuously operate SCR			01/01/09						
	West Virginia	Unit 2			Install and continuously operate FGD			12/31/07	Install and continuously operate SCR			01/01/09						

Company and Plant	State	Unit	Settlement Actions													Notes	Reference	
			Retire/Repower		SO ₂ control			NO _x Control			PM or Mercury Control			Allowance Retirement	Allowance Restriction			
			Action	Effective Date	Equipment	Percent Removal or Rate	Effective Date	Equipment	Rate	Effective Date	Equipment	Rate	Effective Date	Retirement	Restriction			Effective Date
Mountaineer	West Virginia	Unit 1			Install and continuously operate FGD			12/31/07	Install and continuously operate SCR			01/01/08						
Muskingum River	Ohio	Units 1 - 4	Retire, retrofit, or re-power	12/31/15														
	Ohio	Unit 5			Install and continuously operate FGD			12/31/15	Install and continuously operate SCR			01/01/08	Continuously operate ESP	0.03	12/31/02			
Picway	Ohio	Unit 9							Continuously operate bw NO _x burners			Date of entry						
Rockport	Rockport Units 1 & 2 shall not exceed an Annual Tonnage Limit of 28 MTons of SO ₂ in 2016- 2017, 26 MTons in 2018-2019, 22 MTons in 2020, 10 MTons in 2021-2028 and 5 MTons in 2029 and each year thereafter.																	
	Indiana	Unit 1			Install DSI Install and continuously operate FGD			4/16/2015 12/31/2025	Install and continuously operate SCR			12/31/25						
	Indiana	Unit 2			Install DSI Install and continuously operate FGD			4/16/2015 12/31/2028	Install and continuously operate SCR			12/31/28						
Spom	West Virginia	Unit 5	Retire, retrofit, or re-power	12/31/13														
Tanners Creek	Indiana	Units 1 - 3			Burn only coal with no more than 1.2 lbs/MMBtu annual average			Date of entry	Continuously operate bw NO _x burners			Date of entry						
	Indiana	Unit 4			Burn only coal with no more than 1.2% sulfur content annual average			Date of entry	Continuously operate over-fire air			Date of entry						
East Kentucky Power Cooperative Inc.																		
Dale Plant	Kentucky	Unit 1	Retire	2012					Install and continuously operate bw NO _x burners by 10/31/2007	0.46		01/01/08						EKPC must surrender 1,000 NO _x allowances immediately under the ARP, and 3,107 under the NO _x SIP Call. EKPC must also surrender 15,311 SO ₂ allowances.
	Kentucky	Unit 2	Retire	2012					Install and continuously operate bw NO _x burners by 10/31/2007	0.46		01/01/08						Date of entry
System-wide	Kentucky	By 12/31/2009, EKPC shall choose whether to: 1) install and continuously operate NO _x controls at Cooper 2 by 12/31/2012 and SO ₂ controls by 6/30/2012 or 2) retire Dale 3 and Dale 4 by 12/31/2012.																
						12-month rolling limit (tons)	Start of 12-month cycle		12-month rolling limit (tons)	Start of 12-month cycle								
						57,000	10/01/08		11,500	01/01/08	PM control devices must be operated continuously system-wide, ESPs must be optimized	0.03	1 year from entry date	All surplus SO ₂ allowances must be surrendered each year, beginning in 2008.	SO ₂ and NO _x allowances may not be used to comply with the Consent Decree. NO _x allowances that would become available as a result of			
						40,000	07/01/11	All units must operate bw NO _x boilers	8,500	01/01/13								
				28,000	01/01/13	8,000	01/01/15											

<http://www2.ecka.gov/enforcement/least-kentucky-power-cooperative-settlement>

Company and Plant	State	Unit	Settlement Actions														Notes	Reference
			Retire/Repower		SO ₂ control			NO _x Control			PM or Mercury Control			Allowance Retirement	Allowance Restriction			
			Action	Effective Date	Equipment	Percent Removal or Rate	Effective Date	Equipment	Rate	Effective Date	Equipment	Rate	Effective Date	Retirement	Restriction	Effective Date		
Spurlock	Kentucky	Unit 1			Install and continuously operate FGD	95% or 0.1	6/30/2011	Continuously operate SCR	0.12 for Unit 1 until 01/01/2013, at which point the unit limit drops to 0.1. Prior to 01/01/2013, the combined average when both units are operating must be no more than 0.1	60 days after entry						compliance with the Consent Decree may not be sold or traded. SO ₂ and NO _x allowances allocated to EKPC must be used within the EKPC system. Allowances made available due to super compliance may be sold or traded.		
	Kentucky	Unit 2			Install and continuously operate FGD by 10/1/2008	95% or 0.1	1/1/2009	Continuously operate SCR and OFA	0.1 for Unit 2, 0.1 combined average when both units are operating	60 days after entry								
Dale Plant	Kentucky	Unit 3	Retire	2014														
	Kentucky	Unit 4																
Cooper	Kentucky	Unit 1																
	Kentucky	Unit 2			If EKPC opts to install controls rather than retiring Dale, it must install and continuously operate FGD or equiv. technology	95% or 0.10		If EKPC elects to install controls, it must continuously operate SCR or install equiv. technology	0.08 (or 90% if non-SCR technology is used)	12/31/12							EKPC has installed a DFGD on this unit and Dale continues to operate.	
Nevada Power Company																		
Beginning 1/1/2010, combined NO _x emissions from Units 5, 6, 7, and 8 must be no more than 360 tons per year.																		
Clark Generating Station	Nevada	Unit 5	Units may only fire natural gas					Increase water injection immediately, then install and operate ultra-low NO _x burners (ULNBs) or equivalent technology. In 2009, Units 5 and 8 may not emit more than 180	5ppm 1-hour average	12/31/08 (ULNB installation), 01/30/09 (1-hour average)						Allowances may not be used to comply with the Consent Decree, and no allowances made available due to compliance with the Consent Decree may be traded or sold.	http://www2.epa.gov/enforcement/nvada-power-company-clean-air-act-cao-settlement	
	Nevada	Unit 6							5ppm 1-hour average	12/31/09 (ULNB installation),								

Company and Plant	State	Unit	Settlement Actions														Notes	Reference		
			Retire/Repower		SO ₂ control			NO _x Control			PM or Mercury Control			Allowance Retirement	Allowance Restriction					
			Action	Effective Date	Equipment	Percent Removal or Rate	Effective Date	Equipment	Rate	Effective Date	Equipment	Rate	Effective Date	Retirement	Restriction	Effective Date				
									tons combined		01/30/10 (1-hour average)									
	Nevada	Unit 7								5ppm 1-hour average	12/31/09 (ULNB installation), 01/30/10 (1-hour average)									
	Nevada	Unit 8								5ppm 1-hour average	12/31/08 (ULNB installation), 01/30/09 (1-hour average)									
Dayton Power & Light																				
Non-EPA Settlement of 10/23/2008																				
Stuart Generating Station	Ohio	Station-wide			Complete installation of FGDs on each unit.	96% or 0.10	07/31/09	Owners may not purchase any new catalyst with SO ₂ to SO ₂ conversion rate greater than 0.5%	0.17 station-wide	30 days after entry	0.030 lbs per unit	07/31/09						NO _x and SO ₂ allowances may not be used to comply with the monthly rates specified in the Consent Decree.		
									0.17 station-wide	60 days after entry date										
									0.15 station-wide	07/01/12										
									0.10 station-wide	12/31/14										
					82% including data from periods of malfunctions	7/31/09 through 7/30/11	Install control technology on one unit	0.10 on any single unit	12/31/12											
					82% including data from periods of malfunctions	after 7/31/11				Install rigid-type electro-des in each unit's ESP	12/31/15									
PSEG FOSSIL, Amended Consent Decree of November 2006																				
Keamy	New Jersey	Unit 7	Retire unit	01/01/07														Keamy has retired		
	New Jersey	Unit 8	Retire unit	01/01/07														Keamy has retired		
Hudson	New Jersey	Unit 2			Install Dry FGD (or approved alt. technology) and continually operate	0.15	12/31/10	Install SCR (or approved tech) and continually operate	0.1	12/31/10	Install Baghouse (or approved technology)	0.015	12/31/10					Allowances allocated to Keamy, Hudson, and Mercer may only be used for the operational needs of those units, and all surplus allowances must be surrendered. Within 90 days of amended Consent Decree, PSEG must surrender 1,230 NO _x Allowances and 8,568 SO ₂ Allowances not already allocated to or generated by the		
									Annual Cap (tons)	Year									Annual Cap (tons)	Year
									5,547	2007									3,486	2007
									5,270	2008									3,486	2008
									5,270	2009									3,486	2009
					5,270	2010			3,486	2010								Hudson has retired		

<http://www2.epa.gov/enforcement/pseg-fossil-lic-settlement>

Company and Plant	State	Unit	Settlement Actions														Notes	Reference	
			Retire/Repower		SO ₂ control			NO _x Control			PM or Mercury Control			Allowance Retirement	Allowance Restriction				
			Action	Effective Date	Equipment	Percent Removal or Rate	Effective Date	Equipment	Rate	Effective Date	Equipment	Rate	Effective Date	Retirement	Restriction	Effective Date			
Mercer	New Jersey	Unit 1			Install Dry FGD (or approved alt. technology) and continually operate	0.15	12/31/10	Install SCR (or approved tech) and continually operate	0.1	01/01/07	Install Baghouse (or approved technology)	0.015	12/31/10	units listed here. Kearny allowances must be surrendered with the shutdown of those units.			Mercer has retired		
	New Jersey	Unit 2			Install Dry FGD (or approved alt. technology) and continually operate	0.15	12/31/10	Install SCR (or approved tech) and continually operate	0.1	01/01/07	Install Baghouse (or approved technology)	0.015	12/31/10				Mercer has retired		
Westar Energy																			
Jeffrey Energy Center	Kansas	All units			Units 1, 2, and 3 have a total annual limit of 6,600 tons of SO ₂ starting 2011 Units 1, 2, and 3 must all install FGDs by 2011 and operate them continuously. FGDs must maintain a 30-Day Rolling Average Unit Removal Efficiency for SO ₂ of at least 97% or a 30-Day Rolling Average Unit Emission Rate for SO ₂ of no greater than 0.070 lbs/MMBtu.			Units 1-3 must continuously operate Low NO _x Combustion Systems by 2012 and achieve and maintain a 30-Day Rolling Average Unit Emission Rate for NO _x of no greater than 0.180 lbs/MMBtu. One of the three units must install an SCR by 2015 and operate it continuously to maintain a 30-Day Rolling Average Unit Emission Rate for NO _x of no greater than 0.080 lbs/MMBtu. By 2013 Westar shall elect to either (a) install a second SCR on one of the other JEC Units by 2017 or (b) meet a 0.100 lbs/MMBtu Plant-Wide 12-Month Rolling Average Emission Rate for NO _x by 2015			Units 1, 2, and 3 must operate each ESP and FGD system continuously by 2011 and maintain a 0.030 lbs/MMBtu PM Emissions Rate. Units 1 and 2's ESPs must be rebuilt by 2014 in order to meet a 0.030 lbs/MMBtu PM Emissions Rate								http://www2.epa.gov/enforcement/westar-energy-inc-settlement
Duke Energy																			
Gallagher	Indiana	Units 1 & 3	Retire or repower as natural gas	1/1/2012															http://www2.epa.gov/enforcement/duke-energy-gallagher-plant-clean-air-act-settlement
		Units 2 & 4			Install Dry sorbent injection technology	80%	1/1/2012												
American Municipal Power																			
Gorsuch Station	Ohio	Units 2 & 3 Units 1 & 4	Elected to Retire Dec 15, 2010 (must retire by Dec 31, 2012)																http://www2.epa.gov/enforcement/american-municipal-power-clean-air-act-settlement
Hoosier Energy Rural Electric Cooperative																			
Ratts	Indiana	Units 1 & 2					Install & continually operate SNCRS	0.25	12/31/2011		Continuously operate ESP			Annually surrender any NO _x and SO ₂ allowances that Hoosier does not need in order to meet its regulatory obligations					http://www2.epa.gov/enforcement/hoosier-energy-rural-electric-cooperative-inc-settlement
Merom	Indiana	Unit 1			Continuously run current FGD for 90% removal and update FGD for 98% removal by 2012	98%	2012	Continuously operate existing SCRs	0.12		Continuously operate ESP and achieve PM rate no greater than 0.007 by 6/1/12								

Company and Plant	State	Unit	Settlement Actions														Notes	Reference
			Retire/Repower		SO ₂ control			NO _x Control			PM or Mercury Control			Allowance Retirement	Allowance Restriction			
			Action	Effective Date	Equipment	Percent Removal or Rate	Effective Date	Equipment	Rate	Effective Date	Equipment	Rate	Effective Date	Retirement	Restriction	Effective Date		
		Unit 2			Continuously run current FGD for 90% removal and update FGD for 98% removal by 2014	98%	2014									Continuously operate ESP and achieve PM rate no greater than 0.007 by 6/1/13		
Northern Indiana Public Service Co.																		
Bailly	Indiana	Units 7 & 8			Upgrade existing FGD	95% by 01/01/11 97% by 01/01/14 (95% if low sulfur coal only is burned)		OFA & SCR	0.15 lbs/MMBtu by 12/31/10 0.13 lbs/MMBtu by 12/31/13 0.12 lbs/MMBtu by 12/31/15			0.3 lbs/MMBtu (0.015 if a Baghouse is installed)	12/31/2010					
Michigan City	Indiana	Unit 12			FGD	0.1 lbs/MMBtu	12/31/2018	OFA & SCR	0.14 lbs/MMBtu by 12/31/10 0.12 lbs/MMBtu by 12/31/11 0.10 lbs/MMBtu by 12/31/13			0.3 lbs/MMBtu (0.015 if a Baghouse is installed)	12/31/2018					
Schahfer	Indiana	Unit 14			FGD	0.08 lbs/MMBtu	12/31/2013	OFA & SCR	0.14 lbs/MMBtu by 12/31/10 0.12 lbs/MMBtu by 12/31/12 0.10 lbs/MMBtu by 12/31/14			0.3 lbs/MMBtu (0.015 if a baghouse is installed)	12/31/2013					
	Indiana	Unit 15			FGD	0.08 lbs/MMBtu	12/31/2015	LNB/OFA Either: SCR or SNCR	0.16 0.08 0.15	3/31/2011 12/31/2015 12/31/2012		0.3 lbs/MMBtu (0.015 if a baghouse is installed)	12/31/2015					
	Indiana	Units 17 & 18			Upgrade existing FGD	97%	1/31/2011	LNB/OFA	0.2	3/31/2011		0.3 lbs/MMBtu (0.015 if a baghouse is installed)	12/31/2010					
Dean H Mitchell	Indiana	Units 4, 5, 6, & 11	Retire	12/31/2010														
Tennessee Valley Authority																		
Colbert	Alabama	Units 1-4			FGD		6/30/2016	SCR		6/30/2016								
		Unit 5			FGD		12/31/15	SCR		Effective Date								
Widows Creek	Alabama	Units 1-6	Retire 2 units 7/31/13 Retire 2 units 7/31/14 Retire 2 units 7/31/15															
		Unit 7			Continuously operate FGD			SCR		Effective Date								
		Unit 8			Continuously operate FGD			SCR		Effective Date								
Paradise	Kentucky	Units 1 & 2			Upgrade FGD	93%	12/31/12	SCR		Effective Date								
		Unit 3			Wet FGD		Effective Date	SCR		Effective Date								
Shawnee	Kentucky	Units 1 & 4			FGD	1.2	12/31/17	SCR		12/31/17								
		Units 5-10				1.2	Effective Date											
Allen	Tennessee	Units 1-3			FGD		12/31/18	Continuously operate SCR				0.03 PM Emissions	12/31/18					
<p>Shall surrender all calendar year NO_x and SO₂ Allowances allocated to TVA that are not needed for compliance with its own CAA reqts. Allocated allowances may be used for TVA's own compliance with CAA reqts.</p> <p>Shall not use NO_x or SO₂ Allowances to comply with any requirement of the Consent Decree.</p> <p>Nothing prevents TVA from purchasing or otherwise obtaining NO_x and SO₂ allowances from other sources for its compliance with CAA reqts.</p> <p>TVA may sell, bank, use, trade, or transfer any NO_x and SO₂ Super-Compliance* Allowances resulting from meeting System-wide limits. Except that reductions used to support new CC/CT will not be Super</p>																		

Company and Plant	State	Unit	Settlement Actions													Notes	Reference	
			Retire/Repower		SO ₂ control			NO _x Control			PM or Mercury Control			Allowance Retirement	Allowance Restriction			
			Action	Effective Date	Equipment	Percent Removal or Rate	Effective Date	Equipment	Rate	Effective Date	Equipment	Rate	Effective Date	Equipment	Rate			Effective Date
Bull Run	Tennessee	Unit 1			Wet FGD		Effective Date	Continuously operate SCR					0.03 PM Emissions Rate	Effective Date		Allowances in that year and thereafter.		
Cumberland	Tennessee	Units 1 & 2			Wet FGD		Effective Date	Continuously operate SCR										
Gallatin	Tennessee	Units 1 - 4			FGD		12/31/17	SCR			12/31/17		0.03 PM Emissions Rate	12/31/17				
John Sevier	Tennessee	Units 1 & 2	Retire 2 Units 12/31/12 and 12/31/15															
		Units 3 & 4			FGD		12/31/15	SCR			12/31/15							
Johnsonville	Tennessee	Units 1 - 10	Retire 6 Units 12/31/15 Retire 4 Units 12/31/17															
Kingslon	Tennessee	Units 1 - 9			FGD		Effective Date	SCR			Effective Date		0.03 PM Emissions Rate	Effective Date				
Wisconsin Public Service																		
Pulliam	Wisconsin	Units 5-6	Retired	6/1/2015		0.750 lbs/MMBtu	1/1/2013 until retirement											
	Wisconsin	Units 7-8				0.750 lbs/MMBtu & plant-wide cap of 2100 tons starting 2016	1/1/2013		0.250 lbs/MMBtu & plant-wide cap of 1500 tons starting 2016	12/31/12							The modeled SO ₂ rate in IPM is lower; only tonnage limitation imposed through a constraint. These units have retired.	
Weston	Wisconsin	Unit 1	Retired			0.750 lbs/MMBtu	1/1/2013 until retirement		0.250 lbs/MMBtu	12/31/2012 until retirement								
	Wisconsin	Units 2	Repower as natural gas	6/1/2015		0.750 lbs/MMBtu	1/1/2013 until retirement		0.280 lbs/MMBtu	12/31/2012 until retirement								
	Wisconsin	Units 3			ReACT by 12/31/2016	0.750 lbs/MMBtu until 2016 0.080 lbs/MMBtu 2016 onwards	12/31/16	ReACT by 12/31/2016	0.130 lbs/MMBtu until 2016 0.100 lbs/MMBtu 2016 onwards	12/31/16								
	Wisconsin	Units 4			Continuously Operate the existing DFGD & burn only Powder River Basin Coal	0.080 lbs/MMBtu	2/31/2013	Continuously Operate the existing SCR	0.060 lbs/MMBtu	2/31/2013								
Louisiana Generating LLC																		
			Plant-Wide Annual Tonnage Limitations for SO ₂ is 18,950 tons in 2016 and thereafter					Plant-Wide Annual Tonnage Limitations for NO _x is 8,950 tons in 2015 and thereafter										

Company and Plant	State	Unit	Settlement Actions														Notes	Reference	
			Retire/Repower		SO ₂ control			NO _x Control			PM or Mercury Control			Allowance Retirement	Allowance Restriction	Effective Date			
			Action	Effective Date	Equipment	Percent Removal or Rate	Effective Date	Equipment	Rate	Effective Date	Equipment	Rate	Effective Date	Retirement	Restriction				
Big Cajun 2	Louisiana	Unit 1	Retirement, Refueling, Repowering, or Retrofit	04/01/25	install and Continuously Operate DSI — install and Continuously Operate Dry FGD	0.380 lbs/MMBtu [2015] — 0.070 lbs/MMBtu	4/15/2015 [DSI] — 4/1/2025 [DFGD]	install and Continuously Operate SNCR	0.150 lbs/MMBtu	05/01/14	Continuously Operate each ESP	0.030 lbs/MMBtu	04/15/15				May trade Super-Compliant Allowances, may buy external allowances to comply. "Commencing January 1, 2013, and continuing thereafter, Settling Defendant shall burn only coal with no greater sulfur content than 0.45 percent by weight on a dry basis at Big Cajun II Units 1 and 3. "	http://www2.epa.gov/enforcement/buisiana-generating-settlement	
		Unit 2	Refuel/convert to NG fired	04/15/15				install and Continuously Operate SNCR	0.150 lbs/MMBtu	05/01/14									
		Unit 3						install and Continuously Operate SNCR	0.135 lbs/MMBtu	05/01/14	Continuously Operate each ESP	0.030 lbs/MMBtu	04/15/15						
Dairyland Power Cooperative																			
Dairyland Power Cooperative shall not exceed an Annual Plant-wide Tonnage Limitation of 6800 tons of NO _x in calendar years 2016, 3700 tons 2017-2019, and 3200 tons in 2020 and thereafter; and an Annual Plant-wide Tonnage Limitation of 6070 tons of SO ₂ in 2016, 6060 tons 2017-2019 and 4580 tons in 2020 and thereafter.																			
Alma	Wisconsin	Unit 1	Cease Burning Coal	06/30/12													Dairyland was provided with two options for compliance. It chose Option 2 and it is the one modeled in IPM. Details on Option 1 can be found in the settlement document referenced in the adjoining column. Units 4 and 5 have retired.	http://www2.epa.gov/enforcement/dairyland-cooperative-settlement	
		Unit 2	Cease Burning Coal	06/30/12															
		Unit 3	Cease Burning Coal	06/30/12															
		Unit 4	Option 2: Retrofit and Regulate both units more stringently	12/31/14	Install and continuously operate DFGD or DSI at Alma 4	1.00 lbs/MMBtu at Alma 4 And a joint cap of 3,737 tons until 2019, and 2,242 tons thereafter. In the event that one retires, Tonnage Cap of 2,136 tons for the remaining unit until 2019 and 1,282 tons thereafter	12/31/2014	Continuously Operate the existing Low NO _x Combustion System (including OFA) and SNCR	0.350 lbs/MMBtu — Joint cap of 1308 tons for-unit 2019, and 785 tons thereafter. In the event that one retires, Tonnage Cap of 746 tons for remaining unit until 2019 and 449 tons thereafter	8/1/2012 — 12/31/2014	Continuously Operate an ESP or FF on Alma Unit 4	0.030 lbs/MMBtu [with ESP] 0.015 lbs/MMBtu [with FF] at Alma 4. Joint cap of 112 tons until 2019, and 67 tons thereafter. In the event that one retires, Tonnage Cap of 64 tons for the remaining unit until 2019 and 39 tons thereafter	12/31/14						
		Unit 5																	
J.P. Madgett	Wisconsin	Unit 1			Install and continuously operate DFGD	0.090 lbs/MMBtu	12/31/14	Continuously Operate existing Low NO _x Combustion System — Install an SCR	0.30 lbs/MMBtu — 0.080 lbs/MMBtu	8/1/2012 — 6/30/2016	Continuously Operate the existing Baghouse	0.0150 lbs/MMBtu	07/01/13						

Company and Plant	State	Unit	Settlement Actions													Notes	Reference		
			Retire/Repower		SO ₂ control			NO _x Control			PM or Mercury Control			Allowance Retirement	Allowance Restriction				
			Action	Effective Date	Equipment	Percent Removal or Rate	Effective Date	Equipment	Rate	Effective Date	Equipment	Rate	Effective Date	Retirement	Restriction			Effective Date	
Genoa	Wisconsin	Unit 1			Continuously Operate the FGD	0.090 lbs/MMBtu	12/31/12	Continuously Operate existing Low NO _x Combustion System including OFA — Install an SNCR	0.14 lbs/MMBtu — Annual Tonnage Cap of 1,140 tons	12/31/2014 — 6/1/2015	Continuously Operate the existing Baghouse	0.0150 lbs/MMBtu	07/01/13						
Dominion Energy, Inc.																			
			In calendar year 2014, and in each calendar year thereafter, Kincaid shall not exceed a Plant-Wide Annual Tonnage Limitation of 3,500 tons of NO _x & 4,400 tons of SO ₂ , and Brayton Point shall not exceed a Plant-Wide Annual Tonnage Limitation of 4,600 tons of NO _x & 4,100 tons of SO ₂ .																
Brayton Point	Massachusetts	Unit 1			Continuously Operate the existing dry FGD	0.150 lbs/MMBtu	06/01/13	Continuously Operate the SCR, OFA, and LNB	0.080 lbs/MMBtu	05/01/13	Install/Continuously Operate a Baghouse	0.015 lbs/MMBtu [PM by 2013] 0.01 lbs/MMBtu [PM post-2013]	06/01/13					Brayton Point retired in June 2017 and surrendered its permits to operate. http://www2.epa.gov/enforcement/dominion-energy-inc	
		Unit 2					Continuously Operate the LNB and OFA	0.280 lbs/MMBtu	05/02/13										
		Unit 3			Continuously Operate dry FGD	0.080 lbs/MMBtu	07/01/13	Continuously Operate the SCR, OFA, and LNB	0.080 lbs/MMBtu	05/01/13	Install/Continuously Operate a Baghouse	0.015 lbs/MMBtu [PM by 2013] 0.01 lbs/MMBtu [PM post-2013]	07/01/13						
Kincaid Power Station	Illinois	Unit 1			Continuously Operate DSI	0.100 lbs/MMBtu	01/01/14	Continuously Operate each SCR and OFA	0.080 lbs/MMBtu	05/01/13	Continuously Operate the ESP	0.030 lbs/MMBtu [PM by 2013] 0.015 lbs/MMBtu [PM by post-2013]	06/01/13						
		Unit 2																	
State Line Power Station	Indiana	Unit 3																	
		Unit 4	Retire	06/01/12															
Wisconsin Power and Light																			
					Edgewater 3-5- shall not exceed an Annual Tonnage Limitation of 2,500 tons of NO _x in calendar years 2016-2018, and 1100 tons 2019 onwards & an Annual Tonnage Limitation of 12,500 tons of SO ₂ in 2016, 6000 tons 2017-2018 and 1100 tons 2019 onwards. Columbia 1 & 2 shall not exceed an Annual Tonnage Limitation of 5,600 tons of NO _x in calendar years 2016-2018, and 4300 tons 2019 onwards & an Annual Tonnage Limitation of 3290 tons of SO ₂ in 2016 and thereafter.														
Edgewater Generating Station	Wisconsin	Unit 3	Retired	12/31/15		Unit-Specific Annual Tonnage Cap of 700 Tons of SO ₂	05/21/13		Unit-Specific Annual Tonnage Cap of 250 tons of NO _x	05/21/13								http://www2.epa.gov/enforcement/wisconsin-power-and-light-et-al-settlement	
		Unit 4	Retire, Refuel, or Repower	12/31/18		0.700 lbs/MMBtu	05/21/13	Operate SNCR and LNB	0.150 lbs/MMBtu	01/01/14	Continuous Operation of the existing ESP	0.030 lbs/MMBtu	12/31/13				Unit has retired.		
		Unit 5			Install and continuously operate DFGD	0.075 lbs/MMBtu	12/31/16	Install and continuously operate SCR	0.070 lbs/MMBtu	05/01/13	Install and continuously operate Fabric Filter	0.015 lbs/MMBtu	12/31/16						

Company and Plant	State	Unit	Settlement Actions													Notes	Reference							
			Retire/Repower		SO ₂ control			NO _x Control			PM or Mercury Control			Allowance Retirement	Allowance Restriction									
			Action	Effective Date	Equipment	Percent Removal or Rate	Effective Date	Equipment	Rate	Effective Date	Equipment	Rate	Effective Date	Retirement	Restriction			Effective Date						
Columbia Generating Station	Wisconsin	Unit 1			Install and continuously operate DFGD	0.075 lbs/MMBtu	01/01/15	Operation of the Low NO _x Combustion System	0.150 lbs/MMBtu	07/21/13	Install and continuously operate Fabric Filter	0.015 lbs/MMBtu	12/31/14											
		Unit 2				0.075 lbs/MMBtu			Operation of the Low NO _x Combustion System — Install and continuously operate SCR	0.150 lbs/MMBtu — 0.070 lbs/MMBtu		7/21/2013 — 12/31/2018	0.015 lbs/MMBtu	12/31/14										
Nelson Dewey Generating Station	Wisconsin	Unit 1	Retire, Refuel, or Repower	12/31/15	commence burning 100% Powder River Basin or equivalent fuel containing ≤ 1.00 lbs/MMBtu of SO ₂	0.800 lbs/MMBtu	05/22/13		0.300 lbs/MMBtu	04/22/13		0.100 lbs/MMBtu	04/22/13				Cease burning pet coke and commence burning 100% PRB coal or equivalent at Nelson Dewey Units 1 and 2.							
		Unit 2	Retire, Refuel, or Repower	12/31/15																				
Minnesota Power																								
Boswell	Minnesota	Unit 1	Retire/Repower	12/31/18	FGD	0.70 lbs/MMBtu and 0.03 lb/MMBtu after 12/31/18	07/16/14	Continuously Operate the ROFA and SNCR	0.20 lbs/MMBtu	6/30/2014	Continuously Operate Baghouses	0.015 lb/MMBtu	07/16/14				http://www2.epa.gov/enforcement/minnesota-power-settlement							
	Minnesota	Unit 2	Retire/Repower	12/31/18	FGD	0.70 lbs/MMBtu and 0.03 lb/MMBtu after 12/31/18	07/16/14	Continuously Operate the ROFA and SNCR	0.20 lbs/MMBtu	6/30/2014	Continuously Operate Baghouses	0.015 lb/MMBtu	07/16/14											
	Minnesota	Unit 3			FGD	0.030 lbs/MMBtu	12/31/18	Continuously Operate the Low NO _x Burners, OFA system and SCR control	0.060 lbs/MMBtu	07/16/14	Continuously Operate Baghouses	0.015 lb/MMBtu	07/17/14											
	Minnesota	Unit 4			FGD	0.03	05/31/16	Continuously Operate the Low NO _x Burners, OFA system and SCR	0.120 lbs/MMBtu	07/16/14	Continuously Operate Baghouses	0.015 lb/MMBtu	05/31/16											
Taconite Harbor	Minnesota	Unit 1				0.30 lbs/MMBtu	12/31/2015	Continuously Operate the ROFA systems and SNCR	0.160 lbs/MMBtu	7/16/2014	Continuously Operate ESP	.03 lb/MMBtu	07/16/14											
	Minnesota	Unit 2																						
	Minnesota	Unit 3	Retire/Repower/Refueling	12/31/2015																				
Laskin	Minnesota	Unit 1				0.200 lb/MMBtu	07/16/14	Continuously Operate the Low NO _x Burners, and OFA systems	0.190 lbs/MMBtu	07/16/14		0.050 lb/MMBtu	07/16/14											
	Minnesota	Unit 2																						
Rapids	Minnesota	Unit 5				0.150 lb/MMBtu	07/16/14		0.37 lbs/MMBtu	07/16/14	Continuously Operate ESP	0.03 lb/MMBtu	07/16/14											
	Minnesota	Unit 6																						

Company and Plant	State	Unit	Settlement Actions														Notes	Reference
			Retire/Repower		SO ₂ control			NO _x Control			PM or Mercury Control			Allowance Retirement	Allowance Restriction			
			Action	Effective Date	Equipment	Percent Removal or Rate	Effective Date	Equipment	Rate	Effective Date	Equipment	Rate	Effective Date	Retirement	Restriction	Effective Date		
Consumer Energy																		
Campbell	Michigan	Unit 1			install and continuously operate DSI	0.350 lb/MMBtu 30-Day Rolling Average ----- 0.290 lb/MMBtu 90-Day Rolling Average	6/30/2016 12/27/2016	Continuously Operate the Low NO _x Combustion System (including OFA)	0.220 lb/MMBtu 90-Day Rolling Average	11/4/2014	Install and continuously operate Baghouse	.015 lb/MMBtu	04/01/16					
	Michigan	Unit 2			install and continuously operate DSI	0.32 lb/MMBtu	6/30/2017	Continuously Operate an SCR	0.080 lb/MMBtu 90-Day Rolling Average	5/3/2015	Install and continuously operate Baghouse	0.015 lb/MMBtu	2/6/2015					
	Michigan	Unit 3			install and continuously operate FGD	0.085 lb/MMBtu 30-Day Rolling Average ----- 0.07 lb/MMBtu 365-Day Rolling Average	3/1/2017 ----- 12/31/2017	Continuously Operate an SCR	0.080 lb/MMBtu 90-Day Rolling Average	2/6/2015	Install and continuously operate Baghouse	0.015 lb/MMBtu	12/31/16					
Cobb	Michigan	Unit 7	Retire	04/15/16														Unit will retire by 04/15/16
	Michigan	Unit 8	Retire	04/15/16														Unit will retire by 04/15/16
Kam	Michigan	Unit 1			Install and continuously operate FGD	0.075 lb/MMBtu	12/31/2015	Continuously Operate the existing SCR	0.080 lb/MMBtu	60 Operating Days after the Date of Entry	Continuously Operate the existing Baghouse	0.015 lb/MMBtu						
	Michigan	Unit 2			Install and continuously operate FGD	0.075 lb/MMBtu	4/15/2016	Continuously Operate the existing SCR	0.080 lb/MMBtu	60 Operating Days after the Date of Entry	Continuously Operate the existing Baghouse	0.015 lb/MMBtu						
Weadock	Michigan	Unit 7	Retire	04/15/16														Unit has retired
	Michigan	Unit 8	Retire	04/15/16														Unit has retired
Whiting	Michigan	Unit 1	Retire	04/15/16														Unit has retired
	Michigan	Unit 2	Retire	04/15/16														Unit has retired
	Michigan	Unit 3	Retire	04/15/16														Unit has retired
Interstate Power and Light																		
<p>For each calendar year as specified below, Defendant shall not exceed the corresponding Prairie Creek Annual Tonnage Limitation for SO₂ specified below: Each calendar year from 2016 through 2018: 5,500 tons per year Each calendar year from 2019 to 2020: 3,500 tons per year Each calendar year from 2021 through 2025: 3,000 tons per year 2026 and continuing each calendar year thereafter: 100 tons per year</p>																		
<p>For each calendar year as specified below, Defendant's System shall not exceed the corresponding System-Wide Annual Tonnage Limitation for SO₂ specified below: 2015: 39,000 tons per year 2016: 23,500 tons per year Each calendar year from 2017 through 2018: 14,100 tons per year Each calendar year from 2019 through 2020: 12,000 tons per year 2021: 11,000 tons per year</p>																		

<https://www.epa.gov/enforcement/consumers-energy-clean-air-act-settlement>

Company and Plant	State	Unit	Settlement Actions														Notes	Reference
			Retire/Repower		SO ₂ control			NO _x Control			PM or Mercury Control			Allowance Retirement	Allowance Restriction			
			Action	Effective Date	Equipment	Percent Removal or Rate	Effective Date	Equipment	Rate	Effective Date	Equipment	Rate	Effective Date	Equipment	Rate	Effective Date		
<p>Each calendar year from 2022 through 2025: 6,000 tons per year 2026 and continuing each calendar year thereafter: 3,250 tons per year</p> <p>For each calendar year as specified below, Defendant shall not exceed the corresponding Prairie Creek Annual Tonnage Limitation for NO_x, specified below: Each calendar year from 2015 through 2018: 3,250 tons per year Each calendar year from 2019 through 2025: 2,650 tons per year 2026 and continuing each calendar year thereafter: 1,500 tons per year</p> <p>For each calendar year as specified below, Defendant's System shall not exceed the corresponding System-Wide Annual Tonnage Limitation for NO_x, specified below: Each calendar year from 2015 through 2017: 11,500 tons per year Each calendar year from 2018 through 2019: 10,500 tons per year 2020: 7,500 tons per year 2021: 7,250 tons per year 2022 and continuing each calendar year thereafter: 6,800 tons per year</p>																		
Lansing	Iowa	Unit 1	Retire	2016														
	Iowa	Unit 2	Retire	2016														
	Iowa	Unit 3	Retire	2016														
			Unit 4			Continuous Operation of a DFGD	0.075 lb/MMBtu	12/31/2016	Continuously Operate the existing SCR	0.090 lb/MMBtu — 0.080 lb/MMBtu	01/31/2015 — 12/30/2015	Continuous Operation of a Baghouse	0.015 lb/MMBtu	12/31/2016				https://www.epa.gov/sites/production/files/2015-07/documents/interstatepowerandlight-cd.pdf
Ottumwa	Iowa	Unit 1			Continuous Operation of a DFGD	0.075 lb/MMBtu	12/31/2015	Install an SCR	0.160 lb/MMBtu — 0.080 lb/MMBtu	09/15/2015 — 12/31/2019	Continuous Operation of a Baghouse	0.015 lb/MMBtu	12/31/2015					
Milton L Kapp	Iowa	Unit 1	Retire	2016														
	Iowa	Unit 2	Retire or Refuel	08/31/2015		0.750 lb/MMBtu	09/15/2015		0.150 lb/MMBtu	09/15/2015								
Sutherland	Iowa	Unit 1	Retire or Repower	06/01/2019														
	Iowa	Unit 2	Retire	2016														
	Iowa	Unit 3	Retire or Repower	06/01/2019														
Sixth Street	Iowa	Unit 1-5	Retire	2016														
Dubuque	Iowa	Unit 1	Retire or Repower	06/01/2019														
	Iowa	Unit 5	Refuel	07/15/2015														
	Iowa	Unit 6	Retire or Repower	06/01/2019														
Burlington	Iowa	Unit 1	Retire or Refuel	12/31/2021		0.750 lb/MMBtu	09/15/2015		0.180 lb/MMBtu	09/15/2015	Continuously Operate the ESP	0.030 lb/MMBtu	01/15/2016					
Prairie Creek	Iowa	Unit 1	Retire or Refuel	12/31/2025		0.900 lb/MMBtu (Unit 1 and Unit 2 combined)	09/15/2015		0.600 lb/MMBtu	09/15/2015	Continuously Operate the ESP	0.030 lb/MMBtu (Unit 1 and Unit 2 combined)	10/15/2015					
	Iowa	Unit 2	Retire or Refuel	12/31/2025					0.600 lb/MMBtu	09/15/2015	Continuously Operate the ESP							
	Iowa	Unit 3	Retire or Refuel	12/31/2025		0.700 lb/MMBtu	09/15/2015		0.400 lb/MMBtu	09/15/2015	Continuously Operate the ESP	0.030 lb/MMBtu	10/15/2015					
	Iowa	Unit 4	Retire or Refuel	06/01/2018		0.700 lb/MMBtu	09/15/2015		0.400 lb/MMBtu	09/15/2015	Continuously Operate the ESP	0.030 lb/MMBtu	10/15/2015					

Company and Plant	State	Unit	Settlement Actions														Notes	Reference	
			Retire/Repower		SO ₂ control			NO _x Control			PM or Mercury Control			Allowance Retirement	Allowance Restriction				
			Action	Effective Date	Equipment	Percent Removal or Rate	Effective Date	Equipment	Rate	Effective Date	Equipment	Rate	Effective Date	Retirement	Restriction	Effective Date			
Duke Energy																			
Buck	North Carolina	Unit 3	Retire	09/2015													<p>Except as provided in this Consent Decree, beginning in calendar year 2016 and continuing each calendar year thereafter, Defendant shall not sell, bank, trade, or transfer its interest in any NO_x or SO Allowances allocated to Allen Unit 1, Allen Unit 2, Buck Unit 3, Buck Unit 4, Buck Unit 5, Cliffside Unit 1, Cliffside Unit 2, Cliffside Unit 3, Cliffside Unit 4, Dan River Unit 3, Riverbend Unit 4, Riverbend Unit 6, and Riverbend Unit 7.</p> <p>Beginning in calendar year 2016, and continuing each calendar year thereafter, Defendant shall Surrender all NO_x and SO₂ Allowances allocated to Allen Unit 1, Allen Unit 2, Buck Unit 3, Buck Unit 4, Buck Unit 5, Cliffside Unit 1, Cliffside Unit 2, Cliffside Unit 3, Cliffside Unit 4, Dan River Unit 3, Riverbend Unit 4, Riverbend Unit 6, and Riverbend Unit 7 for that calendar year that Defendant does not need to meet federal and/or state CAA regulatory requirements for those Units.</p>	https://www.epa.gov/sites/production/files/2015-09/documents/duke-energy-consent-decree-civil-action-1cv1262_0.pdf	
	North Carolina	Unit 4	Retire	09/2015															
	North Carolina	Unit 5	Retire	09/2015															
Cliffside	North Carolina	Unit 1	Retire	09/2015															
	North Carolina	Unit 2	Retire	09/2015															
	North Carolina	Unit 3	Retire	09/2015															
Dan River	North Carolina	Unit 3	Retire	09/2015															
	North Carolina	Unit 4	Retire	09/2015															
Riverbend	North Carolina	Unit 6	Retire	09/2015															
	North Carolina	Unit 7	Retire	09/2015															
Allen	North Carolina	Unit 1	Retire	12/31/2024	Continuously Operate the existing FGD	0.120 lb/MMBtu	01/2017	Continuously Operate the existing SNCR	0.250 lb/MMBtu ----- 600 tons per year	01/2017 ----- 2016									
	North Carolina	Unit 2	Retire	12/31/2024	Continuously Operate the existing FGD	0.120 lb/MMBtu	01/2017	Continuously Operate the existing SNCR	0.250 lb/MMBtu ----- 600 tons per year	01/2017 ----- 2016									
	North Carolina	Unit 3	Retire	12/31/2024															
Arizona Public Service Company																			
Four Corners	New Mexico	4				6800 tons per year	2019	Continuously Operate the SCR	0.080 lb/MMBtu ----- 4968 tpy	2019								https://www.epa.gov/sites/production/files/2015-06/documents/fourcorners-cd.pdf	