PA?

Coal-fired Powerplants in Transport Rule Region Subject to Consent Decrees

Consent Decrees By State					
State	Company	Plant	Date of CD	Action Required	System-wide SO2 Limits
Florida	Tampa Electric Company	Big Bend	February 2000	Operate existing scrubbers to reduce SO2 emissions	
Illinois	Dynegy	Baldwin	March 2005	Install FGD to reduce SO2 emissions	2013: 29,000 tons per year
		Havana			
		Hennepin		Reduce SO2 emissions	
		Vermilion			
Indiana	Duke Energy	Gallagher	December 2009	Repower to natural gas or retire (Units 1 and 3), install DSI (Units 2 and 4)	Only prior to repower/retiring deadline (Jan. 1, 2012) for Units 1 and 3 – 20,447 combined tons
	Northern Indiana Public Service Company	Bailly	January 2011	Upgrade existing FGD	2019: 11,600 (Michigan City unit gets FGD) or 10,200 (Michigan City unit gets retired)
		Michigan City		Retire or install FGD	
		Schahfer		Install FGD (for 2 units) and upgrade FGD (for 2 units)	
	Southern Indiana Gas & Electric Company / Vectren Corp.	Culley Station	June 2003	Upgrade FGD	
Kentucky	Kentucky Utilities	Brown	February 2009	Install FGD	
	Tennessee Valley Authority	Paradise Fossil	April 2011	Upgrade FGD (Units 1 and 2) and Install Wet FGD (Unit 3)	2019: 110,000
		Shawnee Fossil		Install FGD, repower to renewable biomass, or retire	
New Jersey	PSEG Fossil LLC	Hudson	January 2006	Install FGD	
		Mercer			
Ohio	Ohio Edison / FirstEnergy Corporation	Burger	March 2005 and August 2009	Install FGD	
		Sammis		Install FGD, Flash Dry Absorber or ECO, Induct Scrubber at various units	2011: 29,900 tons (only for units in the Sammis Plant)
		Mansfield		Upgrade FGD	
South Carolina	South Carolina Public Service Authority (Santee Cooper)	Santee Cooper	March 2004	Upgrade FGD	2011: 65,000 tons

Consent Decrees By Company					
Company	State	Plant	Date of CD	Action Required	System-wide SO2 Limits
Duke Energy	Indiana	Gallagher	December 2009	Repower to natural gas or retire (Units 1 and 3), install DSI (Units 2 and 4)	Only prior to repower/retiring deadline (Jan. 1, 2012) for Units 1 and 3 – 20,447 combined tons
Dynegy	Illinois	Baldwin	March 2005	Install FGD to reduce SO2 emissions	2013: 29,000 tons per year
		Havana			
		Hennepin		Reduce SO2 emissions	
		Vermilion			
Kentucky Utilities	Kentucky	Brown	February 2009	Install FGD	
Northern Indiana Public Service Company	Indiana	Bailly	January 2011	Upgrade existing FGD	2019: 11,600 (Michigan City unit gets FGD) or 10,200 (Michigan City unit gets retired)
		Michigan City		Retire or install FGD	
		Schahfer		Install FGD (for 2 units) and upgrade FGD (for 2 units)	
Ohio Edison /FirstEnergy Corporation	Ohio	Burger	March 2005 and August 2009	Install FGD	2011: 29,900 tons (only for units in the Sammis Plant)
		Sammis		Install FGD, Flash Dry Absorber or ECO, Induct Scrubber at various units	
		Mansfield		Upgrade FGD	
PSEG Fossil Corp.	New Jersey	Hudson	January 2006	Install FGD	
		Mercer			
Southern Indiana Gas & Electric Company / Vectren Corp.	Indiana	Culley Station	June 2003	Upgrade FGD	
South Carolina Public Service Authority (Santee Cooper)	South Carolina	Santee Cooper	March 2004	Upgrade FGD	2011: 65,000 tons
Tampa Electric Company	Florida	Big Bend	February 2000	Operate existing scrubbers to reduce SO2 emissions	
Tennessee Valley Authority	Kentucky	Paradise Fossil	April 2011	Upgrade FGD (Units 1 and 2) and Install Wet FGD (Unit 3)	2019: 110,000
		Shawnee Fossil		Install FGD, repower to renewable biomass, or retire	

Duke Energy

- EPA announced a settlement with Duke Energy for CAA violations at the company's Gallagher plant in Indiana on December 22, 2009.
- By no later than Jan. 1, 2012, Duke must elect whether to repower Units 1 and 3 to natural gas or retire them. If Duke elects to retire the units, it must do so by Feb. 1, 2012. If Duke elects to repower the units, it must do so by Dec. 31, 2012. (p. 16-17)
- Until Jan. 1, 2012, Duke may not exceed an annual SO2 tonnage limitation for Unit 1 of 11,062 tons, and for Unit 3, of 9,385 tons, to be reduced each year in accordance with equations in 40 C.F.R. Part 75, Appendix F. (p. 16)
- Beginning Jan. 30, 2011, Duke was required to operate Units 1 and 3 so that each achieves and maintains a 30-day rolling average emission rate for SO2 of no more than 1.70 lb/mmBTU.
- By Jan. 1, 2011, Duke must install and continuously operate Dry Sorbent Injection at Units 2 and 4 to achieve and maintain a 30-day rolling average emission rate for SO2 of no more than 0.800 lb/mmBTU. (p.17)
    - DSI is not required if Duke:
        - Permanently ceases to emit SO2 from Units 2 and/or 4, or
        - Makes physical/operational changes to the units that:
            - Achieve/maintain 30-day rolling average emission rate for SO2 of no more than 0.60 lb/mmBTU, AND
            - The changes are made federally enforceable in accordance with applicable regulatory requirements, including obtaining all necessary construction and operating permits.
- Duke must surrender tonnage equivalent in SO2 allowances for total tons of SO2 emitted from Units 1 and 3 from May 19, 2009 through the date that the units are repowered or retired. (p.18)
- Duke cannot use SO2 allowances to comply with the consent decree, and has to surrender any that it does not need to meet regulatory requirements, though Duke may purchase allowances from another source to comply with the consent decree surrender requirements (tonnage equivalents above) or regulatory requirements. (p.18)

Dynegy, Inc.

- EPA settled with Dynegy Midwest Generation, Inc., a wholly-owned subsidiary of Dynegy, Inc. over violations at its Baldwin and Havana plants in Illinois. The consent decree was lodged on March 7, 2005.
- All 3 Baldwin Units and Havana Unit 6 are required to install FGD (dry or wet) on a rolling basis, i.e. Dec. 31 of each year beginning in 2010 and commencing in 2012(Dec. 31, 2010 for Unit 1; Dec. 31, 2011 for Unit 2; Dec. 31, 2012 for Unit 3 and Havana Unit 6). After its effective date the unit may not operate unless the control technology has been installed and the unit achieves and maintains a 30-day rolling average emission rate of no more than 0.100 lb/mmBTU SO2. (p.19)
- With written permission, Dynegy may install a different control technology if it meets the same rolling average emission requirements.
- Dynegy was also required to reduce SO2 emissions for other Illinois plants:

- Hennepin Units 1 and 2, Wood River Units 4 and 5 (30-day rolling average emission rate of no more than 1.200 lb/mmBTU from the stack serving the unit) within 30 days of the entry of the Consent Decree;
- Vermilion Units 1 and 2 within 30 days of Jan. 1, 2007;
- Havana Unit 6 (30-day rolling average emission rate of no more than 1.200 lb/mmBTU from the stack serving the unit) within 30 days of the entry of the Consent Decree and until Dec. 31, 2012.

- The Consent Decree places system-wide limits, decreasing annually for a final limit in 2013 and years thereafter of 29,000 tons per year. (p.21)
- Dynegy may not use SO2 allowances to comply with the consent decree, and Dynegy must surrender allowances in an increasing amount each year (30,000 in 2011 and thereafter). (p.22).

<u>Kentucky Utilities</u> (LG&E and KU Energy LLC opposed GE's comments on the NODA)

- On February 3, 2009, EPA entered into a settlement agreement with Kentucky Utilities (KU).
- KU must install an FGD at Brown Unit 3 (in Mercer County, Kentucky) beginning no later than Dec. 31, 2010 and must operate it to achieve and maintain a 30-day rolling average SO2 emission rate of no more than 0.100 lb/mmBTU or a 30-day rolling average SO2 removal efficiency of no less than 97%. (p.15)
- During 2009 and 2010, the annual SO2 tonnage limitation at Brown Unit 3 was 31,998 tons per year. (p.15)
- Beginning in 2011 and continuing after, the annual SO2 tonnage limitation at Brown Unit 3 is 2,300 tons per year. (p.15)
- KU may not use SO2 allowances to comply with the Consent Decree (except as necessary to comply with the penalties section).
- KU was required to surrender 53,000 SO2 allowances of 2008 or earlier vintage by March 2009.

<u>Northern Indiana Public Service Company</u>

- EPA announced settlement with NIPSCO on Jan. 13, 2011 for violations at Indiana plants.
- The Consent Decree requires the following SO2 emission controls:

Unit	Control Technology	30-Day Rolling Average Emission Rate (lb/mmBTU) / Removal Efficiency & Monthly SO2 Removal Efficiency	Date required to meet emission rate/removal efficiency
Bailly Units 7 and 8	Upgrade existing FGD on Bailly 7 and 8 main stack	95.0% Monthly SO2 removal efficiency 97.0% 30-day rolling average SO2 removal efficiency or 95.0% 30-day rolling average	January 1, 2011 January 1, 2014

		SO2 removal efficiency if Bailly Units 7 and 8 burn only low sulfur coal for that entire 30-day period	
Michigan City Unit 12	SO2 Option 1: Retire	N/A	December 31, 2018 (Must notify EPA of decision by Dec. 31, 2014)
	SO2 Option 2: FGD	SO2 Option 2: 0.100 lb/mmBTU 30-day rolling average emission rate	
Schahfer Unit 14	FGD	0.080 lb/mmBTU 30-day rolling average emission rate	December 31, 2013
Schahfer Unit 15	FGD (equivalent control technology if satisfies same emission rate and provides written notice by Dec. 31, 2012)	0.080 lb/mmBTU 30-day rolling average emission rate	December 31, 2015
Schahfer Unit 17	Upgrade existing FGD	97.0% 30-day rolling average removal efficiency	January 31, 2011
Schahfer Unit 18	Upgrade existing FGD	97.0% 30-day rolling average removal efficiency	January 31, 2011

- The Consent Decree also includes specific provisions (at p.26-27) related to a bypass stack with an FGD that NIPSCO routes air emissions through for Bailly Units 7 and 8.
- The Consent Decree provides for surrendering of a set number of allowances (by formula) in the event that NIPSCO fails to satisfy the monthly SO2 removal efficiency requirements for Bailly Units 7 and 8. (p.28)
- All of these units together have annual system tonnage limitations for SO2 that reduce semi-annually, with the final date given as 2019. If NIPSCO selects SO2 Option 2 for Michigan City Unit 12 (FGD), then the total is 11,600 tons. If NIPSCO selects SO2 Option 1 (Retirement), then the total is 10,200 tons. (p.29-30)
- NIPSCO may not use allowances to comply with the Consent Decree.
- NIPSCO may still sell/trade allowances that are the result of installation/operation of pollution control technology not otherwise required by the Consent Decree or implemented prior to the dates required by the consent decree or meeting more stringent emissions controls than are required.
- Beginning in 2011, NIPSCO must surrender all allowances in excess of what is needed to meet regulatory requirements (subject to the sentence above).

<u>Ohio Edison/FirstEnergy Corporation</u>

- Ohio Edison entered into settlement agreements with EPA in 2005 and in 2009 to reduce SO2 emissions at plants in Ohio and Illinois.

- The 2005 Consent Decree required FGD installations at Sammis Units 6-7 (by Dec. 31, 2010 with a 95% design removal efficiency for SO2) and Burger Units 4-5 (wet FGD or ECO, by Dec. 31, 2010 with a 95% design removal efficiency for SO2). Ohio retained the option to install an alternative control technology with written notice and maintenance of the 95% removal efficiency required. (p.20)
- By Dec. 31, 2008, Ohio Edison had to elect to either satisfy the emission control requirements for Burger Units 4 and 5 or shut down the units by Dec. 31, 2010 or repower the units with circulating fluidized bed boilers or other clean coal technologies by Dec. 31, 2012. (p.21) Ohio Edison elected to repower the units to combust biomass fuel, and the parties modified the Consent Decree in 2009 to reflect the election.
    - For the first 180 days after biomass operation, Ohio Edison must use its reasonable best efforts to achieve/maintain a 30-day rolling average emission rate for SO2 of 0.100 lb/mmBTU at the Burger Units 4 and 5.
    - If the units achieve the emission rates specified in the 2005 Consent Decree within the 180 days, then Ohio Edison will continue to comply with those rates. If they do not, then Ohio Edison will have another 180 days to use its reasonable best efforts to comply. During this entire period, SO2 emissions may not exceed a 30-day rolling average emission rate greater than 0.150 lb/mmBTU. At the end of this period, Ohio Edison will submit a compliance plan with proposed 30-day rolling average SO2 emission rates that may be no greater than 0.150 lb/mmBTU or lower than 0.100 lb/mmBTU. (p.3-4)
- By Dec. 31, 2008, Ohio Edison had to install and operate a Flash Dryer Absorber or ECO (or equivalent approved technology) at Sammis Unit 5 to have at least a 50% design removal efficiency for SO2. (p.22)
- By Sept. 30, 2008, Ohio Edison had to install an Induct Scrubber (or equivalent approved technology) at Sammis Units 1-4, and by Dec. 31, 2008, Ohio Edison had to install a second Induct Scrubber at those locations. By Dec. 31, 2009, Ohio Edison had to install two more Induct Scrubbers at those units. Within 180 days of installation, each Induct Scrubber was to be operated to achieve a 30-day rolling average SO2 emission rate of 1.100 lb/mmBTU. (p.23-24)
- By October 31, 2007, Ohio Edison was required to upgrade its FGDs at Mansfield Units 1-3 to achieve 95% design removal efficiency. Additional SO2 reductions at the Mansfield plants were required, with the most recent ton/year reduction in 2008 of 12,000. (p.24-25)
- All units in the Sammis Plant were required to meet annual SO2 caps, decreasing each year after 2007, with a final reduction in 2011 of 29,900 tons. (p.26). The 2005 Consent Decree also includes monthly caps for some of the Sammis units during 2011. (p.27)
- The 2005 Consent Decree also required interim SO2 emission reductions between 2006 and 2010 in the amount of 7,000 tons per year by using low sulfur coal at Burger Units 4 and 5. (p.27)
- Ohio Edison was also required to create, and submit to Plaintiffs for approval, a plan to achieve a 24,600 ton reduction of SO2 emissions from the FirstEnergy System by Dec. 31, 2010. (p.28)
- After Jan. 1, 2006, Ohio Edison was only allowed to use, sell, or transfer restricted SO2 allowances to satisfy operational needs of the Sammis, Burger, and Mansfield Plants and/or the units within the FirstEnergy System that are equipped with SO2 control

technology and that meet an annual average removal efficiency of 96% or an annual average emission rate of 0.100 lb/mmBTU. (p.29)

- Ohio Edison may not use, sell, or transfer restricted SO2 allowances to meet operational needs of an existing unit equipped with SO2 emission control standards until after the unit first uses all the SO2 allowances allocated in that given year to the unit to meet the operational needs of that unit. Additional provisions on SO2 allowances are on pages 29-30 of the 2005 Consent Decree.

PSEG Fossil LLC

- EPA and PSEG settled in January 2006 after PSEG failed to comply with the terms of a 2002 Consent Decree.
- The original 2002 Consent Decree required PSEG to install and continuously operate FGD (or alternative approved technology) on Hudson Unit 2 and Mercer Units 1 and 2 by the following dates:
    - Hudson Unit 2: By Dec. 31, 2004, PSEG was required to submit proposed design parameters for an FGD to achieve a 30-day rolling average emission rate for SO2 of no greater than 0.150 lbs/mmBTU. (p.14) And by Dec. 31, 2006, PSEG was to have installed and begun to continuously operate an FGD in accordance with those designs achieving and maintaining the emission rate above as well as 0.250 lb/mmBTU based on a 24-hour emission rate.
    - Mercer Unit 1: By Dec. 31, 2008, PSEG was required to submit proposed design parameters for an FGD for the same emission rates as above and then install and commence operation by Dec. 31, 2010 achieving and maintaining the same emission rates as above.
        - The 2006 Consent Decree added FGD milestones, including dates for award of major equipment orders (Feb. 5, 2007), delivery of OEM design package (June 9, 2008), commencement of construction (July 6, 2009), commencement of tie-in outage (Sept. 15, 2010), and commencement of FGD operation (14 days after unit is synchronized with any utility electric distribution system following the tie-in outage).
    - Mercer Unit 2: By Dec. 31, 2010 PSEG was required to submit proposed design parameters for an FGD for the same emission rates as above and then install and commence operation by Dec. 31, 2012 achieving and maintaining the same emission rates as above.
        - The 2006 Consent Decree advanced the compliance dates for Mercer Unit 2 to Dec. 31, 2008 and Dec. 31, 2010, respectively. It also added FGD milestones as for Mercer Unit 1.
- The original Consent Decree also required that upon beginning operation of an FGD at any unit in compliance with the Consent Decree, PSEG may burn only coal with a monthly average sulfur content no greater than 2.00%.

South Carolina Public Service Authority (Santee Cooper)

- EPA signed a settlement agreement with Santee Cooper in March 2004.

- Santee Cooper was required to install and continuously operate FGD (or equivalent approved control technology) on Cross Units 3 and 4 (within 180 days of 1st start-up) and Winyah Units 1 and 2 (by June 30, 2008). Both sets of units were also required to maintain a 30-day rolling average removal efficiency for SO2 of at least 95% (within 180 days of 1st start-up for the Cross Units and by December 31, 2008 for the Winyah Units). (p.20)
- Santee Cooper was required to upgrade FGD on Cross Units 1 and 2 (by Dec. 31, 2005), Winyah Unit 3 (by June 30, 2012), and Unit 4 (by June 30, 2007). All units were also required to maintain 30-day rolling average removal efficiency for SO2 measures as follows:
  - Cross Unit 1: 95% removal efficiency through upgrades of existing FGD modules by June 30, 2006
  - Cross Unit 2: Design to 91% but achieve and maintain at least 87% removal efficiency through upgrades of existing FGD modules by June 30, 2006
  - Winyah Unit 3: 90% removal efficiency by Dec. 31, 2012
  - Winyah Unit 4: 90% removal efficiency by Dec. 31, 2007 (p.21)
- Winyah Unit 3 also has an interim 30-day rolling average emission rate for SO2 of no greater than 1.20 lb/mmBTU during the construction phase of the FGD upgrade to extend no later than Dec. 31, 2012. (p.21)
- The Consent Decree placed system-wide annual emission limits for SO2, decreasing each year with a final limit in 2011 of 0.50 lb/mmBTU (p.23), and system-wide annual rolling tonnage limitations for SO2, decreasing each year with a final limit in 2011 of 65,000 tons. (p.23) Santee Cooper may not use SO2 allowances to comply with these limitations.
- Santee Cooper must surrender SO2 allowances surplus to its regulatory requirements for that year until 2013, at which point, Santee cooper may use surplus SO2 allowances to meet its allowance-holding requirements for the Santee Cooper System Units until 2018. In 2018 and annually thereafter, Santee Cooper must surrender any allowances that have not been used in the prior five-year rolling period. (p.25)
- Santee Cooper may bank, sell, or transfer allowances that are available as a result of activities above and beyond the consent decree. (p.27)
- Santee Cooper may not burn petroleum coke at any unit unless the unit has FGD and has achieved its 30-day rolling average removal efficiency for SO2 requirement and Santee Cooper has obtained the necessary permits (or if Santee Cooper receives permit authorization under the CAA). (p.29)

Southern Indiana Gas & Electric Company (predecessor to Vectren Corporation)

- EPA and SIGECO entered into a Consent Decree in June 2003 regarding its Culley Station Plant in Indiana.
- SIGECO was required to improve FGD already serving Culley Station Units 2 and 3 and to continually operate it to achieve and maintain a 30-day rolling average SO2 removal efficiency of at least 95% by June 30, 2004. (p.10-11)
- The Consent Decree provides for the use of compliance coal (2.0 lb/mmBTU) during scheduled FGD outages. (p.11)

- SIGECO may not sell or trade in SO2 emissions allowances that result from compliance with the Consent Decree. (p.11)
- SIGECO must surrender any allowances that are not needed to meet Culley Station's operational needs and may not purchase or otherwise obtain SO2 allowances to comply with the Consent Decree. (p.12)

Tampa Electric Company

- EPA signed a Consent Decree with Tampa Electric Company (TEC) in February 2000 that covered two of its Florida plants, Big Bend and Gannon. Shut-down and re-powering of Gannon units covered only NOx emissions. (p.10-12)
- Big Bend:
  - Beginning in September 2000 (or the entry of the Consent Decree, if that was later), TEC was required to operate an existing scrubber on Big Bend Units 1 and 2 at all times so that at least 95% of the SO2 contained in the flue gas entering the scrubber is removed. (p.13)
  - Certain provisions provided for operating Units 1 and 2 during scrubber outages, setting requirements such as that TEC combust only alternative coal during those times (and between 2010 and 2012, only coal with a sulphur content of 1.2 lb/mmBTU or less). (p.13-14)
  - At entry of the consent decree, TEC was required to operate the existing scrubber treating SO2 emissions from Units 3 and 4 at all times that Unit 3 was in operation. With both units operating, TEC is required to operate the scrubber so that at least 93 % of all SO2 contained in the flue gas entering the scrubber is removed or the SO2 emission rate for Unit 3 does not exceed 0.35 lb/mmBTU. When only Unit 3 is running (between May 2002 and January 2010), TEC was required to operate the scrubber so that at least 95% of the SO2 in the flue gas entering the scrubber was removed or the SO2 emission rate did not exceed 0.30 lb/mmBTU. (p.15)
  - Again, the Consent Decree includes certain provisions to provide for operating the units during scrubber outages.
    - A 2001 amended consent decree provided additional days for operating without treatment by a scrubber because of necessary maintenance. (p.2-3)
  - TEC was required to submit a plan to EPA addressing all operation and maintenance changes to maximize the availability of existing scrubbers to treat SO2 emissions from Units 1-3.

Tennessee Valley Authority

- The settlement between TVA and EPA was announced on April 14, 2011.
- The compliance Agreement with EPA covers 2 plants in Kentucky (p.32)
  - Paradise Fossil Plant in Drakesboro
    - Unit 1 – FGD Upgrade to 93% removal efficiency by Dec. 31, 2012
    - Unit 2 – FGD Upgrade to 93% removal efficiency by Dec. 31, 2012
    - Unit 3 – Wet FGD by effective date

- Shawnee Fossil Plant near Paducah
  - Unit 1 – FGD, Repower to Renewable Biomass, or Retire by Dec. 31, 2017
  - Unit 4 – FGD, Repower to Renewable Biomass, or Retire by Dec. 31, 2017
- The Compliance Agreement also places annual system-wide SO2 tonnage limits, requiring an emission reduction to 110,000 by 2019. (p.28-29)
- Upon the effective date of the Compliance Agreement, SO2 emissions at Shawnee Units 1-10 must not exceed 1.2 lb/mmBTU. (p.33)
- TVA is not permitted to use SO2 allowances to comply with the requirements of the Compliance Agreement.
- The same limitations and implementation requirements exist under a settlement between TVA and states and citizen groups.