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Office of Air Quality Planning and Standards

Rulemaking for Greenhouse Gas Emissions from Electric Utility Steam Generating Units

E.O. 13132 “Federalism” Consultation Meeting

April 12, 2011
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Room 1332
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Agenda

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Background

- On December 15, 2009 (74 FR 66496), EPA published a notice indicating that the EPA Administrator found that the current and projected atmospheric concentrations of GHGs are reasonably anticipated to endanger the public health and welfare of current and future generations (Endangerment Finding).

- On December 23, 2010, EPA announced that it entered into a proposed settlement agreement to issue rules that will address GHG emissions from certain fossil fuel-fired EGUs.

- Rules would establish new source performance standards (NSPS) for new and modified natural gas-, oil-, and coal-fired EGUs and emission guidelines for existing natural gas-, oil-, and coal-fired EGUs.

- Under the agreement, EPA commits to issuing proposed regulations by July 26, 2011 and final regulations by May 26, 2012.

- Agreement addresses, in part, EPA's September 2007 remand of its February 2006 final decision not to set GHG standards for boilers.

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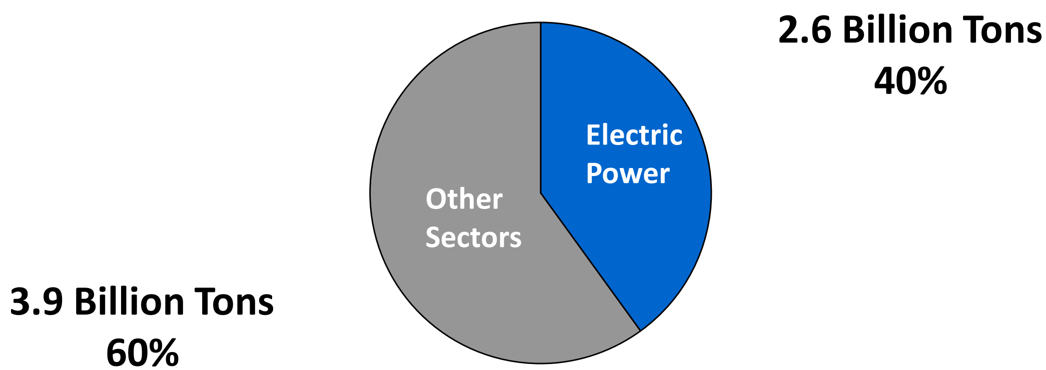
Power Sector:
A Major Share of U.S. GHG Emissions

Carbon Dioxide (CO_2), 2008
6.5 Billion Tons



- See Appendix A for additional details

Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2008 (2010) (CO_2)
"Other" sources include transportation, other mobile sources, and industrial sources

Summary of Listening Sessions

- Electric Power Industry
  - Allow for fleet wide averaging
  - Give credit for replacement of older less efficient generation
- Coalition Groups
  - Allow for State programs to be deemed equivalent
  - Provide market-based flexibility
  - Recognize early action
- State and Tribal Representatives
  - Allow for State programs to be deemed equivalent
  - Reward the very best possible systems available
  - Take a multi-pollutant approach
- Environmental and Environmental Justice
  - Allow for State programs to be deemed equivalent
  - Recognize environmental benefit of non-emitting technologies
  - No special considerations for biomass
  - Aggressive GHG approach will reduce other pollutants as well

Section 111 Overview

- NSPS implement CAA section 111(b) and are issued for categories of sources which cause, or contribute significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare.
  - NSPS affect new and modified sources.
    - New sources are those for which construction or modification is commenced after the publication of proposed regulations.
    - Modification is any physical change in, or change in the method of operation of, a source which increases the amount of any air pollutant emitted by the source or which results in the emission of any air pollutant not previously emitted.
      - Exempt: Routine maintenance, repair, and replacement and increased hours of operation
  - NSPS reflect the degree of emission limitation achievable through application of the best system of emission reduction which, taking into consideration the cost of achieving such reduction, any non-air quality health and environmental impact, and energy requirements, the Administrator determines has been adequately demonstrated.
  - Level of control is referred to as best demonstrated technology (BDT).
  - NSPS does not require installation and operation of any particular technological system of continuous emission reduction (except as authorized under CAA section 111(h)).

Section 111 Overview (cont.)

- Emission guidelines are established for existing sources under CAA section 111(d) for source categories that emit pollutants not regulated under other parts of the CAA and to which an NSPS would apply if such existing source were a new source.
  - Guidelines include targets based on demonstrated controls, emission reductions, costs and expected timeframes for installation and compliance.
  - Guidelines can be less stringent than the requirements for new sources.
  - States use the emission guidelines to develop plans for reducing emissions from existing sources.
  - EPA has the authorities to prescribe a plan for a State in cases where the State fails to submit a satisfactory plan and to enforce the provisions of a plan in cases where the State fails to enforce them.
  - In applying a standard of performance to any particular source under a State implementation plan or in promulgating a standard of performance under a plan prescribed by EPA, the remaining useful life of the existing source(s) can be considered.
- EPA may distinguish among classes, types, and sizes within categories of sources for the purpose of establishing standards.

Section 111 Overview (cont.)

- If EPA determines that it is not feasible to prescribe or enforce a standard of performance, CAA section 111(h) authorizes promulgation of a design, equipment, work practice, or operational standard, or combination thereof, which reflects the best technological system of continuous emission reduction which (taking into consideration the cost of achieving such emission reduction, and any non-air quality health and environmental impact and energy requirements) EPA determines has been adequately demonstrated.
  - “Not feasible to prescribe or enforce a standard of performance” means any situation in which the Administrator determines that:
    - a pollutant or pollutants cannot be emitted through a conveyance designed and constructed to emit or capture such pollutant, or that any requirement for, or use of, such a conveyance would be inconsistent with any Federal, State, or local law, or
    - the application of measurement methodology to a particular class of sources is not practicable due to technological or economic limitations.
  - Believe there wouldn’t be a basis for using this authority in the proposed rulemaking for GHG emissions from EGUs

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Section 111 versus Section 112

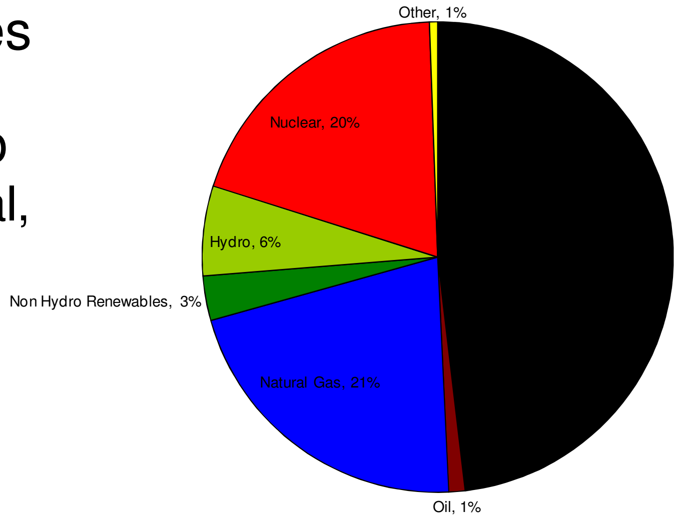
- Technology basis of standards
  - CAA section 111 standards are based on BDT
  - CAA section 112 standards are based on maximum achievable control technology (MACT) – very prescriptive
- Other considerations
  - Under CAA section 111, the cost of achieving reductions, any non-air quality health and environmental impacts, and energy requirements are considered in determining BDT
  - Under CAA section 112, costs and other impacts can only be considered when regulating beyond the minimum MACT level (the MACT floor)
- CAA section 111(d) standards developed by EPA do not directly impact existing sources. States use the standards as guidelines in establishing implementation plans with standards of performance that apply to those sources.

Definition of EGU

- The regulations would apply to each EGU capable of combusting more than 250 million British thermal units per hour (MMBtu/hr) heat input of fossil fuel.
- *Electric utility steam generating unit* means any steam electric generating unit that is constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 megawatts electric (MWe) output to any utility power distribution system for sale.
- *Fossil fuel* means natural gas, petroleum, coal, and any form of solid, liquid, or gaseous fuel derived from such material for the purpose of creating useful heat.

Affected Facilities

- Approximately 1,525 EGUs at 605 facilities
- Approximately 1,200 coal-fired boilers at 450 facilities in 44 States and Puerto Rico
  - Coal-fired EGUs include units that burn coal, coal refuse, or a synthetic gas derived from coal either exclusively, in any combination together, or in any combination with other supplemental fuels (e.g., petroleum coke, tire-derived fuels).
    - Bituminous coal ~ 50% of coal generation
    - Subbituminous ~45% of coal generation
    - Lignite ~ 5% of coal generation
  - Approximately 48 percent of nationwide net generation
- Approximately 150 oil-fired boilers at 75 facilities, mostly in Northeast, Midwest, California, Florida, and Hawaii
  - Approximately 1 percent of nationwide net generation



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Affected Facilities (cont.)

- Approximately 175 gas-fired boilers at 80 facilities, mostly in Midwest, California, Louisiana, and Texas
  - Approximately 21 percent of nationwide net generation
  - Are not subject to the NESHAP for EGUs
- The regulations would apply to integrated gasification combined cycle (IGCC, i.e, “coal gasification”) EGUs.
  - Coal is “gasified” in a high-pressure, high-temperature gasifier with a limited supply of either oxygen or air to produce synthetic gas (syngas).
  - The syngas is cooled, cleaned, and fired in a gas (combustion) turbine.
  - The hot exhaust from the combustion turbine passes through a heat recovery steam generator (HRSG, i.e., boiler) where it produces steam that drives a steam turbine.
  - Electric power is produced from both the combustion and steam turbine-generators.
  - There are two IGCC plants currently operating in the U.S.
    - Duke Energy Wabash River Power Station in Indiana (operation began in 1995)
    - Tampa Electric Company Polk Power Station in Florida (operation began in 1996)

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Affected Facilities (cont.)

- The regulations would not apply to stationary combustion turbines (combined cycle gas turbines or simple cycle gas turbines).
  - In a combined cycle gas turbine plant, a gas turbine generates electricity and the waste heat is used to make steam to generate additional electricity via a steam turbine.
    - More efficient method of generating electricity
    - Used by most new gas power plants in North America and Europe
  - In a simple cycle gas turbine plant, there is no heat recovery.
    - Have the ability to be turned on and off within minutes
    - Usually used as peaking power plants because they are less efficient
- Industry includes investor- owned, publicly-owned and rural cooperative EGUs.
  - State/local jurisdictions identified as potentially impacted by the Toxics Rule would also be potentially impacted by the GHG rulemaking.
  - Jurisdictions with gas-fired EGUs also would be potentially impacted.
  - 123 State/local jurisdictions are estimated to own EGUs that may be affected by this action.
  - See Appendix B for list of potentially impacted State/local jurisdictions

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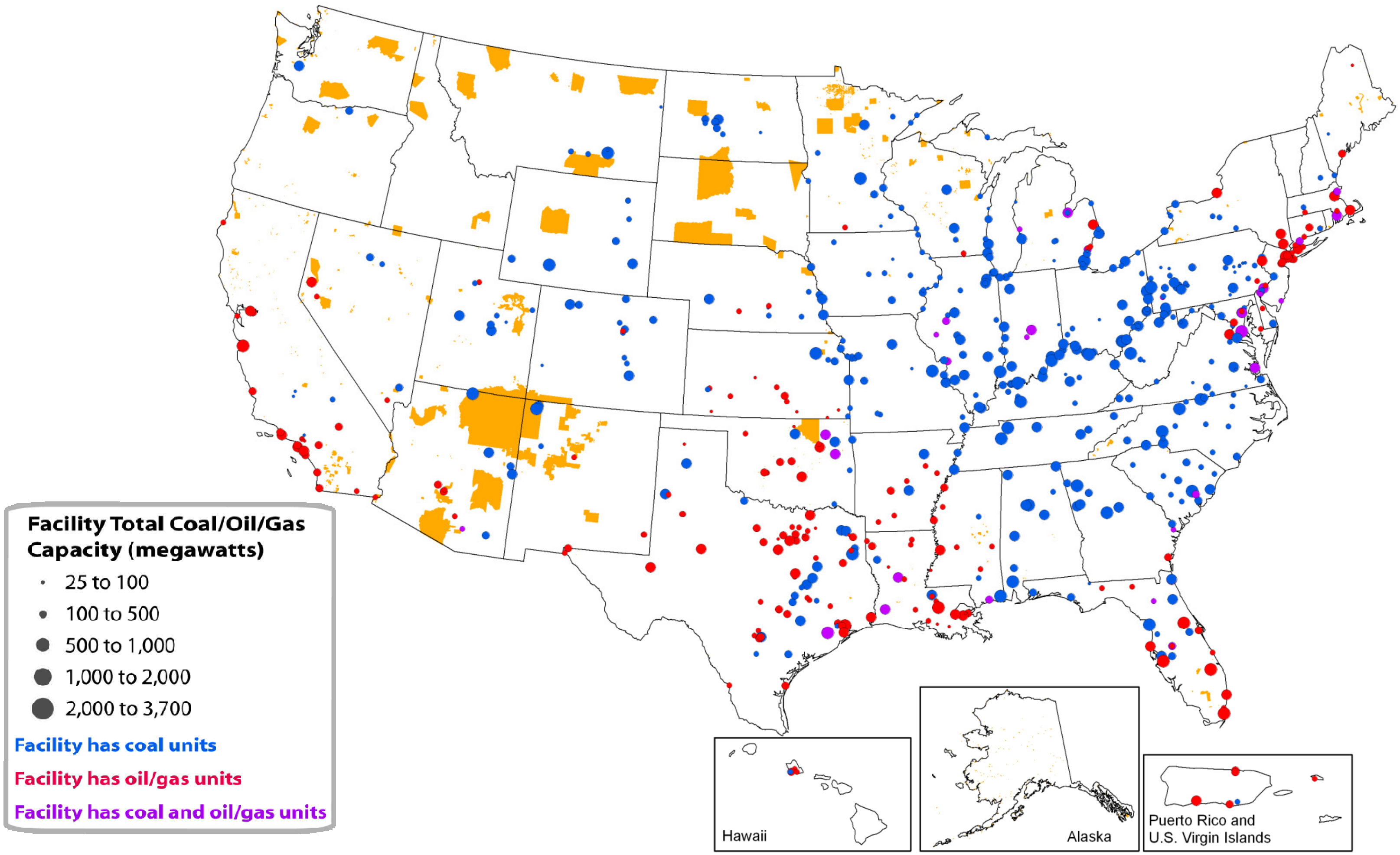
Power Plants Likely Covered by the EGU GHG Rule



Source: National Electric Energy Data System (NEEDS 4.10) (EPA, December 2010)

Note: This map displays facilities that are included in the NEEDS 4.10 data base and that contain at least one coal, oil or gas-fired steam generating unit that generates more than 25 megawatts of power. This includes coal-fired units that burn petroleum coke and that turn coal into gas before burning (using integrated gasification combined cycle or IGCC). NEEDS reflects available capacity on-line by the end of 2011; this includes committed new builds and committed retirements of old units. Only steam boilers are covered by this rule. In areas with a dense concentration of facilities, the facilities on the map may overlap and some may be impossible to see. American Indian Reservations / Federally Recognized Tribal Entities shown were provided by the US DOI, BIA, and GDSC; they are not a legal representation of reservation boundaries.

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CO_2 Emissions Control Technologies

- General types of control measures for CO_2 emissions:
  - Energy efficiency
    - Reduce the amount of fuel used by improving the efficiency of the electrical generation process
  - Post-combustion
    - Separate the CO_2 for long-term storage using carbon capture technology
  - Other measures
    - Co-firing
    - Fuel switching
    - Combined heat and power

Efficiency Improvements for Existing EGUs

Efficiency Improvements for Existing EGUs

Efficiency Improvement Technology	Description	Efficiency Increase
Replace/Upgrade Burners	Replacement or upgrade of older, incorrectly sized, or mechanically deteriorated burners and inoperable dampers, broken registers, or clogged nozzles	Up to ~5%
Improved combustion	Tuning of combustion system to optimum settings and use/adjustment of instrumentation (e.g., temperature sensor, oxygen monitor, excess air setting, CO monitor)	~0.5 to 3%
Heat recovery	Use of heat from boiler exhaust to preheat incoming combustion air or to preheat boiler feedwater	Up to ~6%
Reduce air leakages	Maintenance of boiler system to minimize air leakage through routine maintenance procedures and monitoring of indicators of air leakage (e.g., oxygen level, fuel consumption, gas temperature)	~1.5 to 3%
Capture energy from boiler blowdown	Recovery of waste heat (low-pressure steam) from blowdown	~1 to 2%
Reduce slagging & fouling of heat transfer surfaces	Operation within boiler's design parameters (including fuel quality), use of cleaning system (soot blower - air or steam is used to periodically remove deposition on boiler walls and tubes), and/or fuel treatment (modifies ash characteristics)	1% to 3%

Source: EPA White Paper - Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Industrial, Commercial, and Institutional Boilers, October 2010

Efficiency Improvements for Existing EGUs (cont.)

Efficiency Improvements for Existing Coal-Fired EGUs

Efficiency Improvement Technology	Description	Reported Efficiency Increase
Combustion Control Optimization	Adjustment of coal and air flow to optimize steam production for the generator	0.15 to 0.84%
Cooling System Heat Loss Recovery	Recovery of a portion of the heat loss from cooling water exiting the steam condenser	0.2 to 1%
Flue Gas Heat Recovery	Recovery of the heat lost when flue gas is sprayed with flue gas desulfurization (FGD) reagent slurry and cools	0.3 to 1.5%
Low-rank Coal Drying	Drying of subbituminous and lignite coals using waste heat from flue gas and/or cooling water systems	0.1 to 1.7%
Sootblower Optimization	Intermittent injection of high velocity gets of steam or air to clean coal ash deposits from boiler tube surfaces to maintain adequate heat transfer	0.1 to 0.65%
Steam Turbine Design	Maintain mechanical and physical condition of steam turbine through use of efficiently designed turbine blades and steam seals	0.84 to 2.6%

Source: EPA White Paper - Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Coal-Fired Electric Generating Units, October 2010

Efficiency Improvements for New EGUs

- Efficiency improvements for new coal-fired EGUs
  - Use of supercritical boilers
    - Operate at higher pressures and temperatures
    - Start-up times are quicker
    - National Energy Technology Laboratory (NETL) analysis shows that supercritical boilers are approximately 2.3% more efficient than subcritical boilers
    - Application currently limited to facilities of approximately 200 MWe gross output or more due to the availability of steam turbines that are designed for supercritical steam conditions
  - Use of ultra-supercritical boilers
    - Operate at even higher pressures and temperatures
    - Can potentially operate at efficiencies approaching 50%
    - Material degradation can be an issue when firing high-sulfur coal
    - Use is prevalent in Denmark, Germany, and Japan
    - First ultra-supercritical EGU in U.S. – Southwest Electric Power Company's John W. Turk, Jr. Power Station near Texarkana, AR
      - 600 MWe pulverized coal-fired EGU
      - Will burn Powder River Basin subbituminous coal
      - Scheduled to begin operation in late 2012

Source: EPA White Paper - Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Coal-Fired Electric Generating Units, October 2010

Efficiency Improvements for New EGUs (cont.)

- Use of IGCC technology
  - Electric output is generated by both the combustion turbine and the steam turbine
  - NETL analysis of three coal gasification processes shows net efficiencies of 38.2% to 41.1%
- Coal drying
  - Several advanced pre-combustion coal drying technologies are or nearly are commercially available
  - Reported net gains in overall efficiency of 2% to 4%
- Boiler feedwater heating
  - Use of heat sources other than the steam turbine to heat feedwater
  - Increases the output of the steam cycle and potentially lowers GHG emissions

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Source: EPA White Paper - Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Coal-Fired Electric Generating Units, October 2010

Technology assessment

Carbon Capture & Storage

- There are no insurmountable technological, legal, institutional, or other barriers that prevent carbon capture and storage (CCS) from playing a role in reducing GHG emissions.
  - Current technologies could be used to capture CO_2 from new and existing fossil energy power plants; however they are not ready for widespread implementation primarily because they have not been demonstrated at the scale necessary to establish confidence for power plant application.
  - CCS retrofits could face challenges at some existing plants due to space and configurational limitations or proximity to a CO_2 pipeline or geologic storage.
- Existing Federal programs are being used to deploy at least five to ten large-scale integrated CCS projects expected to be online by 2016.
- Federal research, development and demonstration efforts are focused on reducing costs of CCS to facilitate widespread cost-effective deployment after 2020.
  - Approximately 70–90% of CCS cost is associated with capture and compression.
  - The cost and performance of CCS technologies will evolve with longer-term testing.

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Source: Report of the Interagency Task Force on Carbon Capture and Storage, August 2010

Key Questions

- What should emission limits for new sources be based on?
- What should emission limits for modified sources be based on?
- What should emission limits for existing sources be based on?
- What regulatory mechanisms should be used to get reductions?
- How should State equivalency with guidelines be addressed?

State/Local Implementation

- Envision implementation of the guidelines as similar to what State/local jurisdictions are already used to under the SIP process

- This includes:
  - Development of a State plan consistent with the emissions guidelines
  - Implementation of that plan, including permitting and enforcement

Questions?

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Appendix A

What are Greenhouse Gases?

- GHGs are chemical compounds found in the Earth's atmosphere
  - They allow sunlight to enter the atmosphere freely.
  - When sunlight strikes the Earth's surface, some of it is re-radiated back towards space as heat (infrared radiation).
  - GHGs absorb the infrared radiation and trap the heat in the atmosphere.
  - Over time, if atmospheric concentrations of GHGs remain relatively stable, the amount of energy sent from the sun to the Earth's surface should be about the same as the amount of energy radiated back into space, leaving the temperature of the Earth's surface roughly constant.
  - Some GHGs occur naturally and are emitted to the atmosphere through natural processes and human activities (e.g., carbon dioxide, methane, and nitrous oxide).
  - Other GHGs are created and emitted solely through human activities (e.g., fluorinated gases).

What are Greenhouse Gases? (cont.)

- Principal GHGs that enter the atmosphere due to human activities:
  - Carbon Dioxide (CO_2)
    - Burning of fossil fuels (oil, natural gas, and coal), solid waste, trees and wood products
    - Chemical reactions (e.g., manufacture of cement, steel, aluminum)
  - Methane (CH_4)
    - Production and transport of coal, natural gas, and oil
    - Livestock and other agricultural practices
    - Decay of organic waste in municipal solid waste landfills
  - Nitrous Oxide (N_2O)
    - Combustion of fossil fuels and solid waste
    - Agricultural and industrial activities
  - Fluorinated Gases
    - Hydrofluorocarbon (HFC), perfluorocarbon (PFC), and sulfur hexafluoride (SF_6)
    - Typically emitted in smaller quantities, but are potent GHGs
    - Synthetic GHGs emitted from a variety of industrial processes
    - Sometimes used as substitutes for ozone-depleting substances
      - Chlorofluorocarbons (CFCs) - used as refrigerants, solvents, and foam blowing agents
      - Hydrochlorofluorocarbons **(**HCFCs) - used to replace CFCs due to lower ozone depleting potential
      - Halons - used as fire extinguishing agent

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GHG Emissions Across Sectors

GHG Emissions in U.S.

(million metric tons of CO_2 equivalent)

Gas/Source Type	1990	2000	2009
CO_2	**5100.2**	**5976.2**	**5508.1**
Fossil Fuel Combustion	4741.2	5597.7	5212.0
Non-Energy Use of Fuels	116.2	142.5	122.1
Iron and Steel Production & Metallurgical Coke Production	99.5	85.9	42.6
Natural Gas Systems	37.6	29.9	32.2
Cement Production	33.3	41.2	29.4
Incineration of Waste	8	11.1	12.3
Amonia Production and Urea Consumption	16.8	16.4	11.8
Lime Production	11.5	14.1	11.2
Cropland remaining Cropland	7.1	7.5	7.8
Limestone and Dolomite Use	5.1	5.1	7.6
Soda Ash Production and Consumption	4.1	4.2	4.3
Aluminum Production	6.8	6.1	3.0
Petrochemical Production	3.3	4.5	2.7
Carbon Dioxide Consumption	1.4	1.4	1.8
Ferroalloy Production	2.2	1.9	1.6
Titanium Dioxide Production	1.2	1.8	1.5
Wetlands remaining Wetlands	1	1.2	1.1
Phosphoric Acid Production	1.5	1.4	1

Source: Table ES-2 of EPA's Draft Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2009, February 15, 2011

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GHG Emissions Across Sectors (cont.)

GHG Emissions in U.S. (cont.)

(million metric tons of CO_2 equivalent)

Gas/Source Type	1990	2000	2009
CH_4	**674.9**	**659.9**	**686.5**
Natural Gas Systems	189.8	209.3	221.2
Enteric Fermentation	132.1	136.5	139.8
Landfills	147.4	111.7	117.5
Coal Mining	84.1	60.4	71.0
Manure Management	31.7	42.4	49.5
Petroleum Systems	35.4	31.5	30.9
Wastewater Treatment	23.5	25.2	24.5
Forest Land remaining Forest Land	3.2	14.3	7.8
Rice Cultivation	7.1	7.5	7.3
Stationary Combustion	7.4	6.6	6.2
Abandoned Underground Coal Mines	6.0	7.4	5.5
Mobile Combustion	4.7	3.4	2.2
Iron and Steel Production & Metallurgical Coke Production	1.0	0.9	0.4

Source: Table ES-2 of EPA's Draft Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2009, February 15, 2011

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GHG Emissions Across Sectors (cont.)

GHG Emissions in U.S. (cont.)

(million metric tons of CO_2 equivalent)

Gas/Source Type	1990	2000	2009
N_2O	**315.2**	**341.0**	**299.5**
Agricultural Soil Management	197.8	206.8	204.6
Mobile Combustion	43.9	53.2	27.8
Manure Management	14.5	17.1	17.9
Nitric Acid Production	17.7	19.4	14.6
Stationary Combustion	12.8	14.6	12.8
Forest Land remaining Forest Land	2.7	12.1	6.7
Wastewater Treatment	3.7	4.5	5.0
N2O from Product Uses	4.4	4.9	4.4
Adipic Acid Production	15.8	5.5	1.9
HFCs	**36.9**	**103.2**	**125.0**
Substitution of Ozone Depleting Substances	0.3	74.3	119.3
HCFC-22 Production	36.4	28.6	5.4
Semiconductor Manufacture	0.2	0.3	0.3
PFCs	**20.8**	**13.5**	**5.6**
Semiconductor Manufacture	18.5	8.6	1.6
Aluminum Production			
SF_6	**34.4**	**20.1**	**14.8**
Electrical Transmission and Distribution	28.4	16	12.8
Magnesium Production and Processing	5.4	3.0	1.1
Semiconductor Manufacture	0.5	1.1	1.0

Source: Table ES-2 of EPA's Draft Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2009, February 15, 2011

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GHG Emissions - Energy Sector

Energy Sector GHG Emissions

(million metric tons of CO_2 equivalent)

Gas/Source Type	1990	2000	2009
CO_2	**4903.6**	**5781.7**	**5379.0**
Fossil Fuel Combustion	4741.2	5597.7	5212.0
Electricity Generation	1820.8	2296.9	2154.0
Transportation	1485.9	1809.5	1718.9
Industrial	849.3	853.9	738.4
Residential	338.3	370.7	340.2
Commercial	219.0	230.8	218.8
U.S. Territories	27.9	35.9	41.7
Non-Energy Use of Fuels	116.2	142.5	122.1
Natural Gas Systems	37.6	29.9	32.2
Incineration of Waste	8.0	11.1	12.3
Petroleum Systems	0.6	0.5	0.5

Source: Table 2-4 of EPA's Draft Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2009, February 15, 2011

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GHG Emissions - Energy Sector (cont.)

Energy Sector GHG Emissions (cont.)

(million metric tons of CO_2 equivalent)

Gas/Source Type	1990	2000	2009
CH_4	**327.4**	**318.6**	**337.0**
Natural Gas Systems	189.8	209.3	221.2
Coal Mining	84.1	60.4	71.0
Petroleum Systems	35.4	31.5	30.9
Stationary Combustion	7.4	6.6	6.2
Abandoned Underground Coal Mines	6.0	7.4	5.5
Mobile Combustion	4.7	3.4	2.2
Incineration of Waste	<0.05	<0.05	<0.05
N_2O	**57.2**	**68.1**	**41.0**
Mobile Combustion	43.9	53.2	27.8
Stationary Combustion	12.8	14.6	12.8
Incineration of Waste	0.5	0.4	0.4

Source: Table 2-4 of EPA's Draft Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2009, February 15, 2011

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GHG Emissions – Electricity Generation

Electricity Generation-Related GHG Emissions

(million metric tons of CO_2 equivalent)

Gas/Source Type	1990	2000	2009
CO_2			
Fossil Fuel Combustion	1820.8	2296.9	2154
Coal	1547.6	1927.4	1747.6
Natural Gas	175.3	280.8	373.1
Petroleum	97.5	88.4	32.9
CH_4			
Stationary Combustion	0.6	0.7	0.7
N_2O			
Stationary Combustion	8.1	10.0	9.0

Source: Table 2-13 of EPA's Draft Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2009, February 15, 2011

- CO_2 emissions from fossil fuel combustion are ~99.5% of total GHG emissions from fossil fuel combustion (2009)
- CO_2 emissions from coal-fired combustion are ~81% of total CO_2 emissions from fossil fuel combustion (2009)

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Appendix B

State & Local Governments Potentially Subject to Regulation

Alexandria, LA (City of)	Conway Corp	Hastings Utilities (NE)
Algona Municipal Utilities	Coon Rapids, IA (City of)	Heartland Consumers Power District
Alta, IA (City of)	CPS Energy	Henderson Municipal Power & Light
American Municipal Power Inc	Dalton, GA (City of)	Holland Board of Public Works
Ames Municipal Electric System	Detroit Public Lighting	Holyoke Gas & Electric Dept
Anaheim, CA (City of)	Dover, DE (City of)	Illinois Municipal Electric Agency
Atlantic Municipal Utilities	Eldridge, IA (City of)	Imperial Irrigation District
Austin Energy	Farmington, NM (City of)	Indiana Municipal Power Agency
Austin Utilities	Florida Municipal Power Agency	Intermountain Power Agency
Azusa, CA (City of)	Fremont Dept of Public Utilities	JEA
Bancroft Municipal Utilities	Gainesville Regional Utilities	Jonesboro Water & Light
Banning Electric Division	Garland Power & Light	Kansas City Board Public Utilities
Brownsville Public Utility Board	Geneseo Municipal Utilities	Kissimmee Utility Authority
Bryan Texas Utilities	Glendale Water & Power	Lafayette Public Power Authority
Burbank Water & Power	Graettinger Municipal Light Plant	Lafayette Utilities System
California Dept Water Resources	Grand Haven Light & Power	Lakeland Dept of Electric Water Utilities
Cedar Falls (IA) Utilities	Grand Island Utilities	Lansing Board of Water & Light
Coffeyville Municipal Light & Power	Grand River Dam Authority	Laurens, IA (City of)
Colorado Springs Utilities	Greenville Electric Utility System	Lincoln Electric System
Colton Electric Utility Dept	Harlan Municipal Utilities	Littleton, MA (Town of)

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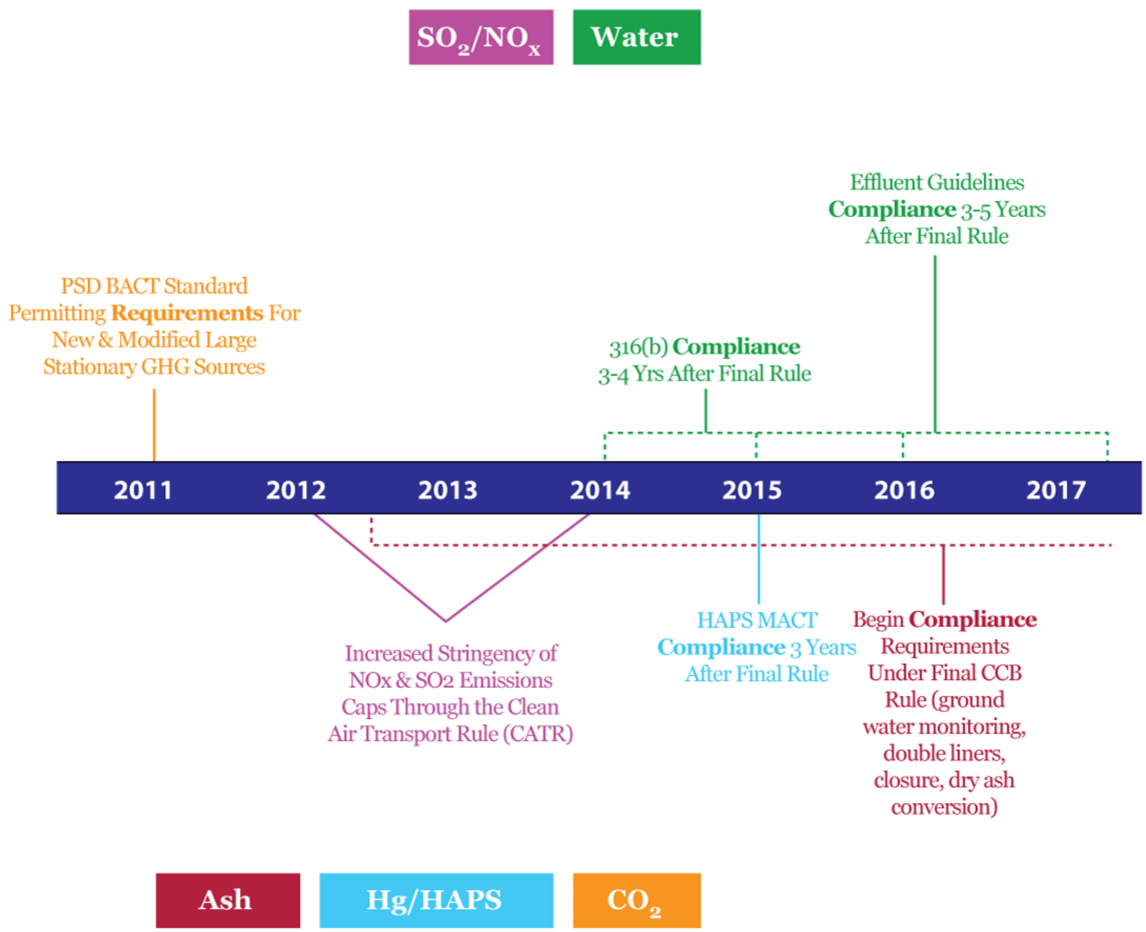
State & Local Governments Potentially Subject to Regulation (cont.)

Los Alamos County	New York Power Authority	Southern Minnesota Municipal Power Agency
Los Angeles Dept of Water & Power	North Attleborough Electric Dept	Spencer Municipal Utilities
Louisiana Energy & Power Authority	North Carolina Eastern Municipal Power Agency	Springfield, MO (City of)
Lower Colorado River Authority	Northern Municipal Power Agency	Springfield (IL) Water Light & Power Dept
Lubbock Power & Light Dept	Oklahoma Municipal Power Authority	Sumner Municipal Light Plant
Lyndonville Electric Dept	Omaha Public Power District	Tallahassee, FL (City of)
Manitowoc Public Utilities	Orlando Utilities Commission	Taunton Municipal Lighting Plant
Marquette Board of Light & Power	Osceola AR (City of)	Terrebonne Parish Consolidated
Massachusetts Municipal Wholesale Electric	Owensboro Municipal Utilities	Texas Municipal Power Agency
Michigan Public Power Agency	Pasadena Water & Power Dept	Tipton, IA (City of)
Michigan South Central Power Agency	Pella Municipal Light & Power	Utah Associated Municipal Power System
Milford Municipal Utilities	Platte River Power Authority	Utah Municipal Power Agency
Missouri River Energy Services	Ponca City, OK (City of)	Vero Beach Municipal Utilities
Modesto Irrigation District	Provo City Corp	Waverly Light & Power
Montezuma Municipal Utilities	Redding Electric Utility	Webster City, IA (City of)
Morgan City, LA (City of)	Richmond Power & Light	West Bend, IA (City of)
Municipal Electric Authority of Georgia	Rochester Dept Public Utilities	West Memphis Utility Dept
Municipal Energy Agency of Nebraska	Salt River Project	Winfield, KS (City of)
Muscatine Power & Water	Santa Clara, CA (City of)	WPPI Energy
Nebraska Public Power District	Santee Cooper	Wyandotte Dept of Municipal Service
New Hampton Municipal Light Plant	Sikeston Utilities	Wyoming Municipal Power Agency

Regulatory Compliance Obligations for the Utility Industry



Sources: WRI Analysis based on Edison Electric Institute 2010, Wegman, EPA 2003.

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