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The Impact of EPA's Green Power Purchases

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Foreword

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Abstract

All federal agencies, including EPA, are required under Executive Order (EO) 13123 to reduce life-cycle greenhouse gas emissions attributed to facility energy use by 30% below 1990 levels by 2010. A key approach to reducing facility greenhouse gas emissions, employed by EPA's Office of Administration and Resources Management (OARM), involves the purchase of "green power". Green power generally includes renewables (wind, solar, biomass) and other clean energy technologies (municipal solid waste and landfill gas) that generate electricity. Green tags, which represent the positive environmental attributes associated with electricity production from green power sources, are sold through markets to electricity consumers.

The analysis presented in this report meets the following three objectives: (1) establish the 1990 EPA emissions baseline in order to assess progress towards fulfillment of EO 13123, (2) examine the impact of EPA's green power purchasing on facility-related greenhouse gas emissions and air pollution, and (3) develop a strategy for future green power purchases. In order to achieve these objectives, this report describes a new method to estimate net emissions of CO_2, SO_2, NO_X, and Hg. The estimation of net facility emissions is complicated by the purchase of green tags because it requires detailed knowledge of which conventional power plants are being offset by purchased green power. Different offset scenarios are analyzed in order to quantify the uncertainty inherent in estimating emissions offsets without hour-by-hour system dispatch data.

Keywords: green power, green tags, renewables, greenhouse gas, air quality

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Executive Summary

All federal agencies, including EPA, are required under Executive Order (EO) 13123 to reduce life-cycle greenhouse gas emissions attributed to facility energy use by 30 percent below 1990 levels by 2010. A key approach to reducing facility greenhouse gas emissions, employed by EPA's Office of Administration and Resources Management (OARM), involves the purchase of "green power." Green power generally includes renewables (wind, solar, biomass) and other clean energy technologies (municipal solid waste and landfill gas) that generate electricity. Green tags, which represent the positive environmental attributes associated with electricity production from green power sources, are sold through markets to electricity consumers. By paying a small premium for green tagged electricity, consumers are given exclusive ownership of the environmental benefits of the purchased green power, including the greenhouse gas and air pollutant emissions reductions associated with their use.

The analysis presented in this report meets the following three objectives: (1) establish the 1990 EPA emissions baseline in order to assess progress towards fulfillment of EO 13123, (2) examine the impact of EPA's green power purchasing on facility-related greenhouse gas emissions and air pollution, and (3) develop a strategy for future green power purchases. In order to achieve these objectives, this report describes a new method to estimate net emissions of CO_2, SO_2, NO_X, and Hg. The estimation of net facility emissions is complicated by the purchase of green tags because it requires detailed knowledge of which conventional power plants are being offset by purchased green power. Different offset scenarios are analyzed in order to quantify the uncertainty inherent in estimating emissions offsets without hour-by-hour system dispatch data.

In 2005, among the OARM-managed EPA facilities existing prior to 1990, one-third have already met the 30 percent greenhouse reduction specified in EO13123, one-third have reduced greenhouse gas emissions less than 30 percent below 1990 levels, and one-third have increased greenhouse gas emissions above 1990 levels. As a whole, OARM-managed EPA facilities have likely reduced greenhouse gas emissions below 1990 levels, but have not reached the 30 percent reduction target. Results for SO_2, NO_X, and Hg emissions are harder to categorize, owing to the larger ranges of uncertainty in emissions offsets.

To maximize the emissions benefits of future purchases, two key criteria should be used: life-cycle emissions and location of the green power source. Green power should be purchased from sources that have minimal emissions, such as wind power and municipal solid waste combustion. In addition, green power sources should be targeted in regions with the highest levels of coal use in order to maximize the air quality benefit.

1. Introduction

All federal agencies, including EPA, are required under Executive Order (EO) 13123 to reduce life-cycle greenhouse gas emissions attributed to facility energy use by 30 percent below 1990 levels by 2010. This target is more stringent than the U.S. commitment to the Kyoto Protocol, which had it been ratified by Congress, would have required a 7 percent reduction below 1990 levels to be achieved on average during the commitment period of 2008 – 2012. Three noteworthy points drawn from the EO shaped this analysis:

- *Part 2, Sec.201.* "Through life-cycle cost-effective energy measures, each agency shall reduce its greenhouse gas emissions attributed to facility energy use by 30 percent by 2010 compared to such emissions levels in 1990…"
- *Part 2, Sec.204.* "Each agency shall strive to expand the use of renewable energy within its facilities and in its activities by implementing renewable energy projects and by purchasing electricity from renewable energy sources…"
- *Part 2, Sec.206.* "The Federal Government shall strive to reduce total energy use and associated greenhouse gas and other air emissions as measured at the source. To that end, agencies shall undertake life-cycle cost-effective projects in which source energy decreases, even if site energy use increases…"

In 2004, the federal government consumed roughly 1,200 trillion BTU, which represents slightly more than 1 percent of total U.S. energy consumption (EIA, 2004). Though government energy consumption is small on an absolute scale, compliance with EO 13123 presents a significant opportunity to develop strategies for decision-makers to maximize the benefit of renewable energy purchases. Insight generated here can be utilized by other federal agencies as well as local and regional decision makers.

A key approach to reducing facility greenhouse gas emissions, employed by several federal agencies, involves the purchase of green power. "Green power" generally includes renewables (wind, solar, biomass) and other clean, non-fossil energy technologies (municipal solid waste and landfill gas) that generate electricity. Green tags, which represent the positive environmental attributes associated with electricity production from green sources, are sold through markets to electricity consumers. By paying a small premium for green tagged electricity, consumers are given exclusive ownership of the environmental benefits of the purchased green power. As a result, many private and commercial customers buy green tags to offset the greenhouse gas and air pollutant emissions associated with their energy use.

EPA's Office of Administration and Resources Management (OARM) has successfully purchased green power, but as of yet has not been able to estimate total greenhouse gas reductions or evaluate their progress towards fulfilling the mandate. This report has four objectives: (1) establish the 1990 emissions baseline in order to assess progress towards fulfillment of EO 13123, (2) examine the impact of EPA's green power purchasing on facility-related greenhouse gas emissions and air pollution, (3) develop a strategy for future green power purchases, and (4) propose future work to enhance the analysis presented here.

2. EPA Facilities and Emissions Analyzed

Data on 1990 fuel and electricity consumption from the following facilities were available: Narragansett, Edison, Athens, Gulf Breeze, RTP, Ann Arbor, Duluth / Grosse Ile, Cincinnati, Ada, Las Vegas, Manchester, and Corvallis. In addition to these facilities, the 2005 analysis included Chelmsford, Fort Meade, Houston, Kansas City STC, Golden, Richmond, and Newport. The data were provided by the Sustainable Facilities Practices Branch of EPA's Office of Administration and Resource Management, which is responsible for the operation and maintenance of select EPA facilities (EPA, 2006a; EPA, 2006b).

Given the significant growth in EPA building space over the last 15 years, the net emissions in 1990 and 2005 are characterized in three ways: facility-by-facility, total emissions across all facilities, and total emissions across all facilities normalized by building space. Because EO13123 requires absolute emissions reductions, the 2005 emissions estimates were not controlled for growth in floor space, number of personnel, or variations in the heating and cooling degree days.

Facility emissions came from two sources: fuel combustion and electricity consumption. With respect to greenhouse gases, CO_2 emissions from both electricity and fuel consumption were tracked. In addition, CH_4 and N_2O, which are potent greenhouse gases, were estimated for fuel use and electricity generation in 1990[1]. The CH_4 and N_2O emissions were multiplied by their global warming potential (21 and 310, respectively) and added to the CO_2 emissions to obtain CO_2 equivalent (CO_2e) emissions. Recognizing Part 2, Sec. 206 of the EO (see Section 1 above), air pollutants (SO_2, NO_X, and Hg) were also tracked along with greenhouse gas emissions.

[1] EPA (2003), which was used to calculate emissions in 2005, provides only CO_2 estimates. Examination of the 1990 electricity data indicates that CH_4 and N_2O emissions only increase the 1990 CO_2e estimates by approximately 0.2 percent, indicating that their likely impact on the 2005 estimates is negligible.

3. Emissions Estimation from Fuel Consumption

The procedure to estimate emissions from facility fuel use in both 1990 and 2005 was identical. The four fuels consumed by EPA facilities were natural gas, fuel oil, propane, and biodiesel. Emissions factors, obtained from the EPA (2006c) and Krishna (2004), are shown below in Table 1.

	Natural Gas (lbs / 10^6 scf)	Fuel Oil (lbs / 10^3 gal)	Propane (lbs / 10^3 gal)	Biodiesel (lbs / MBTU)
SO_2	0.6	157	0.1	0.328
NO_X	190	47	14	0.0775
Hg	0	1.13×10^{-4}	0	2.4×10^{-6}
CO_2	120,000	25,000	12,500	159.3
CH_4	2.3	0.28	0.2	NA
N_2O	0.64	0.11	0.9	NA

Table 1. Emissions factors associated with fuel combustion, drawn from EPA (2006c). Emissions from natural gas assume uncontrolled emissions from a large wall-fired boiler (>100 MBTU/hr) subject to New Source Performance Standards (NSPS). Emissions from fuel oil are based on a large No. 6 oil boiler (>100 MBTU/hr) with normal firing. Biodiesel represents a blend of 80 percent No. 2 fuel oil and 20 percent biodiesel – see Appendix 1 for assumptions regarding the calculation of emissions factors.

The emissions factors in Table 1 were used to calculate facility emissions from fuel use:

$$M_{\mathrm{p,f}} = \left(\frac{r_{\mathrm{gas,p}}}{1\times10^4}\right)\times C_{\mathrm{f,gas}} + \left(\frac{r_{\mathrm{oil,p}}}{1\times10^3}\right)\times C_{\mathrm{f,oil}} + \left(\frac{r_{\mathrm{propane,p}}}{1\times10^3}\right)\times C_{\mathrm{f,propane}} + r_{\mathrm{biodiesel,p}}\times C_{\mathrm{f,biodiesel}} \quad \textbf{(Equation 1)}$$

Where *M* is the mass of a particular pollutant (p) at a given facility (f), *r* is the fuel-specific emissions rate from Table 1, and *C* is the amount of a particular fuel consumed in units of gallons (oil and propane), 100 ft^3 (natural gas), or MBTU (biodiesel).

4. Emissions Estimation from Electricity Consumption

Estimating emissions from facility electricity use is more complicated than estimating fuel emissions, owing to the fact that electricity is drawn from a large regional grid of power plants. System operators direct power plant operation to ensure that electricity supply meets demand in real-time. Control areas are the fundamental entities responsible for performing system dispatch while maintaining bulk-power reliability, and there are roughly 150 in the U.S. Adjacent control areas often trade electricity with one another to minimize the amount of required electric generation capacity. The North American Electric Reliability Council (NERC) has pooled the control areas into 20 subregions that closely coordinate trading and reliability planning, and those subregions are also grouped into 10 NERC regions that coordinate activities across the broader regions. Therefore, each NERC region/subregion is often treated as an inclusive system in analyses of electric power systems. In this analysis, emissions from facility electricity use and the emissions offsets obtained through the purchase of renewable electricity are based on the mix of generators in the relevant NERC subregion. See Figure 1.

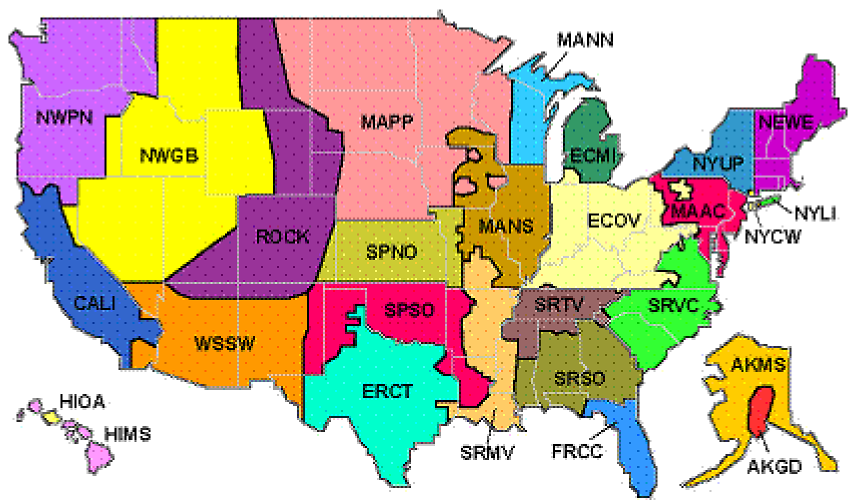

Figure 1. Map of NERC subregions. The mix of generators in each subregion was used to calculate EPA facility emissions. Map reproduced from EPA's eGRID.

4.1 Facility Emissions from Electricity Use in 1990

Comprehensive plant-level data on U.S. power plants emissions were virtually non-existent before the mid-1990s. The Energy Information Administration (EIA) tracks power plant emissions in Form-767, but the earliest dataset available is 1996. Likewise, EPA eGRID data exist from years 1996 to 2000, but not earlier. Boiler level emissions data are available from EPA's Clean Air Market Division (CAMD) in 1990, but only the boilers subject to the Acid Rain Program were tracked. As a result, average emissions by NERC subregion can not be estimated from CAMD data alone.

Lacking direct plant-level emissions data for 1990, emissions by NERC subregion were estimated directly. The NERC Electricity Supply & Demand (ES&D) database was used to sort plants by subregion and plant/fuel type[2] (NERC, 2004). Six plant types were tracked in each subregion:

[2] Although the NERC database contains all plants built through 2004, any plants built after 1990 were filtered out.

coal, oil, natural gas, hydro, nuclear, and wind. Other types present in the database made a negligible contribution to total regional capacity and were therefore not included. The filtered data were used to calculate the relative mix of units, expressed as a fraction of total subregional capacity. Two examples are shown in Figure 2.

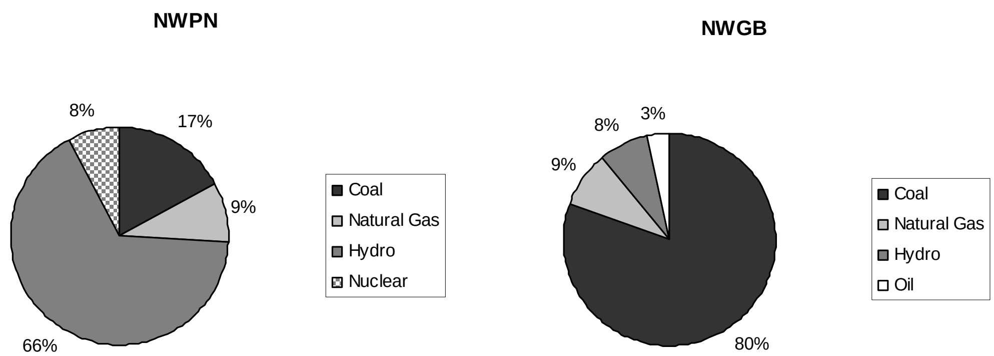

Figure 2. Relative mix of power plants in two adjacent northwestern NERC subregions: Pacific Northwest (NWPN) and Great Basin (NWGB). The dramatic difference in composition between these regions indicates that emissions will be much higher in NWGB than NWPN. Note that EPA Las Vegas facility is located in NWGB while EPA's Corvallis and Manchester facilities are located in NWPN.

To estimate facility emissions, it is also necessary to estimate the emissions rate for the three fossil-based plant types. The emissions rates were drawn from the EPA (2006c). See Table 2.

	Coal (lbs / ton)	Oil (lbs / 10^3 gal)	Natural Gas (lbs / MBTU)
SO_2	38	157	0.0034
NO_X	12	47	0.32
Hg	83×10^{-5}	1.13×10^{-4}	0
CO_2	6040	25,000	110
CH_4	0.04	0.28	0.0086
N_2O	0.03	0.11	0.003

Table 2. Emissions factors drawn from EPA (2006c) to approximate average power plant emissions in 1990. Coal emissions factors assume PC-fired, dry bottom, wall-fired boilers burning medium volatility bituminous coal under New Source Performance Standards. Oil emission factors assume No. 6 oil with 1 percent sulfur content is combusted in a boiler with normal firing. Natural gas emission rates assume combustion in a stationary turbine.

Using conversion factors, the emissions rates given in Table 2 are converted to units of lbs/MBTU[3]. Because these emissions rates are defined per unit of primary energy and purchased electricity represents end-use energy, one final transformation is required to account for the thermal efficiency of electricity production. The average thermal efficiencies for pulverized coal, oil, and natural gas-fired turbines were assumed to be 33 percent, 32 percent, and 33 percent, respectively (EIA, 2004). (See Appendix 2 for more details on the thermal efficiency calculations.) The resulting emissions rates per unit of purchased electricity are given below in Table 3.

[3] According to EPA AP 42, there are 26 MBTU / ton coal and 50 MBTU / 10^3 gal oil.

	Coal (lbs/MWh)	Petroleum (lbs/MWh)	Natural Gas (lbs/MWh)
SO2	15.1	11.2	0.04
NO_X	4.77	3.34	3.31
Hg	3.3×10^{-5}	8.03×10^{-6}	0
CO_2	2400	1780	1140
CH_4	0.02	0.02	0.09
N_2O	0.01	0.01	0.03

Table 3. Emissions factors per unit of electricity consumed. Data in Table 2 were transformed to lbs/MBTU and then divided by appropriate thermal efficiencies to account for heat lost during production.

Using this information, electricity-related facility emissions can be calculated:

$$M_{\mathrm{p,f}} = E_{\mathrm{f}} \times \left[\left(r_{\mathrm{p,coal}} \times NERC_{\mathrm{f,coal}} \right) + \left(r_{\mathrm{p,oil}} \times NERC_{\mathrm{f,oil}} \right) + \left(r_{\mathrm{p,gas}} \times NERC_{\mathrm{f,gas}} \right) \right], \qquad \textbf{(Equation 2)}$$

where $M_{\mathrm{p,f}}$ is the mass of pollutant emission attributed to electricity use at a particular facility, E_{f} is amount of electricity consumed by the facility, $r_{\mathrm{p,<fuel>}}$ is the emissions rate for a given pollutant and fuel, and $NERC_{\mathrm{f,<fuel>}}$ is the fraction of generating capacity using a given fuel in a particular region. Note that the NERC fractions only sum to 1 if coal, oil and natural gas are the only fuels used to produce electricity. The other main power sources – nuclear and hydro – do not explicitly appear in Equation 2 because they are assumed to have zero operating emissions. Note that Equation 2 assumes that power plants were utilized in rough proportion to their capacity, which given the paucity of data for 1990, is a necessary simplifying assumption.

4.2 Facility Emissions from Electricity Use in 2005

The latest available (year 2000) EPA eGRID data were used to estimate the facility emissions in 2005. Two developments over the last five years suggest that the eGRID data are likely overestimate emissions: the rapid construction of clean-burning natural gas turbines, and further compliance with federal air quality standards. Given that the 5-year gap between 2000 and 2005 is small compared to the average lifetime of power plants, major structural changes that would affect the conclusions of the analysis were not observed[4].

Estimating the emissions from facility electricity use in 2005 is complicated by the purchase of renewable energy (mostly green tags), which offset total emissions. It is important to note that green tags are simply an accounting mechanism to support the development of renewables and are not physically associated with the purchasing entity. The renewable electricity associated with the green tags can be produced anywhere in the U.S. as long as the energy production is credited to the purchaser. In most cases, purchased green tags did not come from the NERC subregion in which the EPA facility was located. In these cases, green tags are improving air quality in a region of the U.S. apart from the EPA facilities' local area. Unlike air pollutants, greenhouse gases are globally well-mixed, so the location where the greenhouse gas emissions offsets take place do not have regional implications for climate change.

Several steps were required to estimate the net emissions from facility electricity use in 2005, which includes the effect of purchased green power. The steps are enumerated below:

[4] To verify this assumption, electricity generation by state and fuel type was compared for the years 2000 and 2005 using EIA (2005). In most cases, there were only single-digit percentage changes in the amount of electricity coming from coal, petroleum or natural gas. Nationwide, there was roughly a 2 percent decrease in coal generation and a 3 percent increase in natural gas generation.

1. Identify the NERC subregion in which each EPA facility is located.
2. Calculate facility emissions assuming no green power was purchased.
3. Identify the NERC subregion in which green power purchases are made.
4. Calculate emissions offsets in NERC subregion where the green power is physically located.
5. Calculate emissions associated with the operation of the green power sources.
6. Calculate net emissions, taking into account conventional electricity consumption, green power offsets, and direct emissions from green power sources.

4.2.1 Steps 1-2: Calculating Emissions Assuming No Green Power Purchased

Step 1 is accomplished by associating the location of each facility with the regions shown in Figure 1. Estimated facility emissions in Step 2 are the product of total facility electricity consumption (conventional + green MWh) and the eGRID output emissions rates (lbs/MWh) for the NERC subregion in which the facility is located.

4.2.2 Steps 3-4: Estimating Offsets from Purchased Green Power

Step 3 requires identification of the NERC subregions in which the green power is physically generated. The physical location of EPA's purchased green power was drawn from ERG (2006). [5] Step 4 is difficult because there is no precise method to determine the emissions reductions from the purchase of electricity generated from renewable sources. Assuming that renewables are built to supplant existing generators rather than meet growing demand, it is necessary to make assumptions about which generators are displaced by the purchased renewable energy. Because renewables represent a small fraction of overall electricity supply and often produce electricity intermittently, they tend to displace load-following units, which can ramp output quickly to compensate for changes in supply or demand. Accurate identification of the conventional generators displaced by renewable energy sources requires substantial data regarding the hourly dispatch of all generators within a NERC subregion. For example, Connors et al. (2003) estimate the emissions offsets from solar photovoltaics by performing statistical analysis on hourly time series data of PV, fossil generation, and electricity demand. Their analysis identifies the load-following units by identifying the units that adjust their output hour-to-hour in the same direction as total system demand. Then they calculate the hourly emissions offsets from PV assuming the load-following units are being displaced. While such hour-by-hour analysis is beyond the scope of this study, the average annual emissions rate for load-following units by NERC subregion–as calculated by Connors et al. (2003)–is used to estimate the emissions offsets from EPA facilities.

In addition to the emissions offset estimates using Connors et al. (2003) data, three alternative scenarios are developed to form a wide but plausible range of emissions offsets. The advantage of this approach is that it uses highly aggregated data from EPA's eGRID, which greatly simplifies the analysis while providing a characterization of the uncertainty inherent in such an approach. In the first scenario, purchased renewables displace only the fossil-based generation. Renewables displacing fossil fuels exclusively can be considered the "environmental option" because it minimizes air pollution and greenhouse gas emissions. This scenario forms the upper bound on the emissions offset from renewables, since the plants with highest emissions are being displaced. In the second scenario, purchased renewables displace only natural gas turbine capacity. All

[5] Eastern Research Group (ERG) was contracted by EPA OARM to perform analysis of EPA's green power purchases.

NERC subregions have natural gas turbine capacity, which is often used to meet peak and shoulder load. Because gas turbines operate with high marginal costs, it would be cost-effective in most cases for the system operators to ramp down their output when renewable output ramps up. Renewables displacing natural gas can be considered the "economic option" and forms the lower bound on the emissions offset estimates since natural gas is clean-burning. In the third scenario, purchased renewables displace generators in proportion to the total amount of grid electricity they produce. This scenario forms a middle estimate between the economic and environmental options and can be considered the "proportional option" because it assumes the proportional displacement of all generators. This scenario approach has the advantage of quantifying the uncertainty inherent in estimating emissions offsets without detailed knowledge of system dispatch[6]. For comparison, an additional offset estimate was generated by using estimates from Connors et al. (2003).

A more detailed accounting of system dispatch is likely to result in offset estimates that fall between the proportional and economic scenarios. In general, low levels of green power are most likely to displace conventional generating units with high marginal costs that can ramp output quickly to follow load, which in many regions is dominated by gas turbine capacity. The Connors et al. estimates–which are based on higher resolution hourly power plant data–confirm this reasoning. The environmental scenario, in which only fossil-burning plants are displaced by green power, should be interpreted as a hypothetical scenario meant to minimize emissions. In reality, many boiler-based fossil plants such as coal do not have the ability to ramp output on the intra- or inter-hour timescale in order to compensate time-varying green power sources such as wind or solar. As such, the lower bound net emissions estimates based on the environmental scenario should be given less weight in the following section.

4.2.3 Step 5: Estimating Direct Emissions from Green Power

Step 5 requires the estimation of operating emissions from the renewables directly[7]. In 2005, there were only three green power sources purchased by EPA: wind, biomass, and land-fill gas (LFG). Wind was assumed to have zero emissions during operation and non-CO_2 emissions factors for LFG and biomass were drawn from the EPA (2006c). CO_2 emissions from landfill gas and pulp and paper mills were estimated at zero, since the ancillary production of electricity at such facilities does not result in additional CO_2 emissions beyond what would be produced by normal facility operation. See Table 4.

	SO_2 (lbs/MWh)	NO_X (lbs/MWh)	Hg (lbs/MWh)	CO_2 (lbs/MWh)
Wind	0	0	0	0
Landfill Gas	0.20	1.8	3.6×10^{-6}	0
Biomass (Pulp and paper)	0.86	2.4	0	0

Table 4. Operating emissions rates from renewable sources drawn from the EPA AP 42 (EPA, 2006c). Landfill gas emissions estimates are based on Burklin (2003). Because 37 percent of LFG electricity is generated by engines and 63 percent by turbines, a weighted average emissions rate was calculated based on estimates in Appendix 1. The emission rates for biomass pulp and paper are drawn from EPA (2003) and represent the specific estimates associated with the plant from which green tags were purchased for the EPA RTP facility.

[6] Emissions rate data for all three offset scenarios are available in eGRID (EPA, 2003). The emissions rates for the "proportional" scenario were obtained with the eGRID software by clicking on the appropriate subregion, clicking the "Emissions Profile" tab, and using the values in the middle column ("Output Rate (lbs/MWh)"). Likewise, the emissions rates for the "economic" and "environmental" scenarios were obtained by clicking the "Display emissions rates for fossil, coal/oil/gas" button on the "Emissions Profile" tab.
[7] Operating emissions were used because life-cycle emissions estimates for landfill gas and pulp and paper were unavailable.

4.2.4 Step 6: Calculating Net Emissions from Electricity

Step 6 incorporates all of the calculations in the previous steps to estimate the net emissions:

$$M_{\mathrm{p,f}} = \underbrace{(E_{\mathrm{f,c}} + E_{\mathrm{f,g}}) \times r_{\mathrm{p,c}}}_{\text{emissions assuming no green power}} - \underbrace{E_{\mathrm{f,g}} \times r_{\mathrm{p,o}}}_{\text{emissions offset from green power}} + \underbrace{E_{\mathrm{f,g}} \times r_{\mathrm{p,g}}}_{\text{emissions from green power}} \qquad \textbf{(Equation 3)}$$

Where, as in Equation 2, *M* represents pollutant mass, *E* represents electricity consumption, and *r* represents the emissions rate. The subscripts are defined as follows: 'f' denotes facility, 'c' denotes conventional electricity, 'g' denotes purchased green electricity, and 'o' denotes offset (of which there are three scenarios – economic, environmental, and proportional). The first term in Equation 3 is an estimate of emissions assuming no green power is purchased, the second term is an estimate of the emissions from conventional capacity that are being offset by the purchased green power, and the third term is an estimate of direct emissions from the green power source. To see the relative importance of various factors in determining net emissions, it is illustrative to rearrange Equation 3 by factoring out the amount of green power purchased ($E_{\mathrm{f,g}}$):

$$M_{\mathrm{p,f}} = E_{\mathrm{f,g}} \times \left[\left(\frac{E_{\mathrm{f,c}}}{E_{\mathrm{f,g}}} + 1 \right) \times r_{\mathrm{p,c}} - r_{\mathrm{p,o}} + r_{\mathrm{p,g}} \right] \qquad \textbf{(Equation 4)}$$

In addition to the amount of green power purchased ($E_{\mathrm{f,g}}$), Equation 4 demonstrates that a key determinant of net emissions is the relative magnitude of the emissions rates associated with the conventional electricity used by the EPA facility ($r_{\mathrm{p,c}}$), the offset of grid electricity by green power generation ($r_{\mathrm{p,o}}$), and the green power technology itself ($r_{\mathrm{p,g}}$).

5. Analysis

In this section, the method described above will be utilized to estimate EPA's emissions of greenhouse gases and air pollutants. These estimates will indicate EPA's progress towards fulfillment of EO 13123. Net emissions, including green power purchases, will be provided on a facility-by-facility basis, total across all facilities, and total across all facilities normalized by building space.

5.1 Facility Energy Consumption in 1990 and 2005

A sharp increase of 85 percent in building space between 1990 and 2005 led to a significant rise in energy consumption. See Table 5, where fuel and electricity consumption are presented separately for simplicity[8]. During this period, electricity consumption increased by 166 percent and fuel consumption by 6 percent. Interestingly, electricity consumption grew faster than building space while fuel consumption remained nearly constant.

	1990	**2005**
Building Space (10^6 Gross ft^2)	2.0	3.7
Electricity (GWh)	106	282
Fuel (10^6 BTU)	375	396

Table 5. Total building space and electricity and fuel consumption at select EPA facilities, 1990 and 2005.

For facilities that existed pre-1990, it is instructive to examine the facility-level changes in energy consumption that took place between 1990 and 2005. See Figure 3.

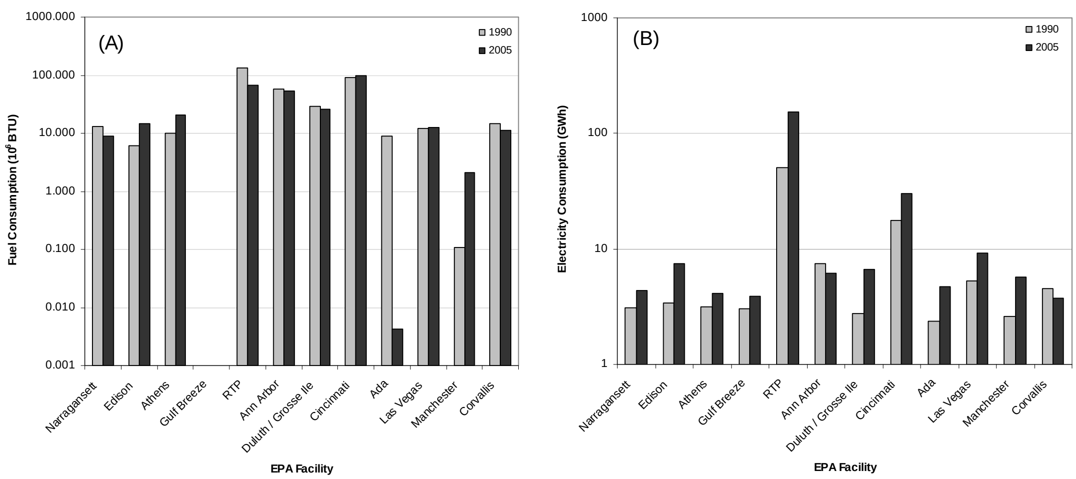

Figure 3. Semi-log plot of fuel (A) and electricity (B) consumption at select EPA facilities in 1990 and 2005. From 1990 to 2005, six facilities reduced fuel consumption while only two facilities decreased electricity use. Note that no heating fuel is consumed at the Gulf Breeze facility, and Ada dramatically reduced its fuel consumption by installing a ground source heat pump.

It is important to note that some EPA facilities, such as RTP, switched buildings between 1990 and 2005. Nonetheless, Figure 3 indicates that over the last 15 years, seven facilities reduced fuel consumption while only two facilities decreased electricity use. The two most likely reasons for the drop in fuel consumption is a milder winter in 2005 than 1990 and improved energy

[8] Estimated energy consumption due to fuel use represents primary energy since it is the heat content of the fuel consumed. Electricity is shown in end-use units of MWh.

efficiency measures[9]. However, only two facilities (Ann Arbor and Corvallis) decreased their electricity use. As is the case nationally, the increased use of electrical devices and air conditioning is likely responsible for the growing electricity consumption at EPA facilities.

5.2 Estimated CO_2 Emissions from Facility Electricity Use in 2005

The key question is how the energy consumption shown in Figure 3 translated into emissions of greenhouse gases and air pollutants. Estimated facility emissions are complicated by the purchase of renewable energy because there is no simple way to determine which conventional generators are displaced by the purchased renewable energy. Accurate estimates require detailed knowledge of system dispatch[10], which is beyond the scope of this analysis. In this analysis, the lack of system dispatch data creates uncertainty in the emissions offsets. This uncertainty is quantified by three scenarios, outlined in Section 4.2, which assume that renewables displace different types of power plants: fossil capacity (*environmental* scenario), gas turbines with high marginal cost (*economic* scenario), and all conventional units (*proportional* scenario).

Since EPA only began purchasing renewable energy after 1990, this uncertainty in emissions only applies to the year 2005 emissions. Before proceeding with the 1990/2005 comparative analysis, it is useful to quantify the uncertainty associated with the purchase of renewable energy credits in 2005. Figure 4 presents facility CO_2 emissions from electricity consumption. The three different offset scenarios result in three distinct emissions estimates for each facility, which are represented in Figure 4 by the filled circles and error bars.

In six different NERC subregions (NEWE, CALI, NWGB, MAAC, MAINS, SPNO), the proportional scenario produced higher CO_2 emissions than the economic scenario. Equation (3) implies that this can only happen if the average emissions rate from natural gas plants is higher than the total average emissions rate, which factors in all power plants. In five of these six subregions (not SPNO[11]), the power system was composed of at least 40 percent carbon-free power sources, mostly nuclear and hydro. As a result, the total average CO_2 emissions rate in these subregions was lower than the CO_2 emissions rate from natural gas alone.

[9] The influence of winter weather on fuel consumption can be tested by performing a degree day analysis on a regional basis for 1990 and 2005.
[10] System dispatch is the process by which power plants are called upon by the system operator to produce electricity; the objective is to minimize generation cost subject to operational limits.
[11] According to eGRID, the average natural gas rate in SPNO is very high. As a result, the CO_2 emissions rate from natural gas is higher than the total average rate. It could be due in part to the predominance of low efficiency natural gas steam boilers and simple-cycle turbines instead of the more efficient combined-cycle turbines.

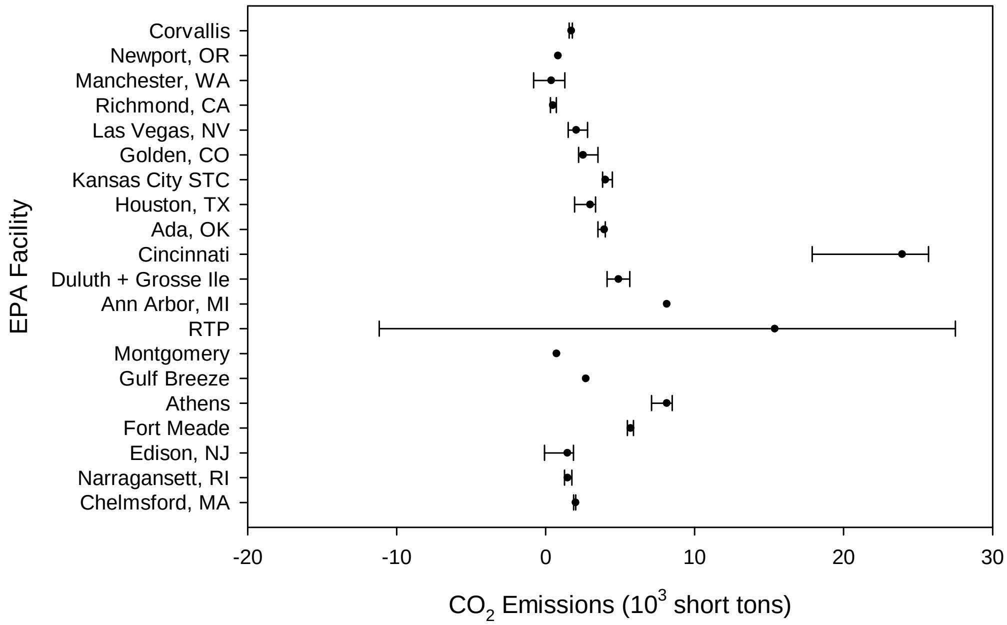

Figure 4. Short tons of CO_2 emissions resulting from EPA facility electricity consumption in 2005. The three scenarios that characterize the uncertainty associated with the emissions offsets are represented by the error bars and filled circles. No green tags were purchased for Newport, Ann Arbor, Montgomery, and Gulf Breeze.

The width of the error bars is explained by the amount of purchased green power. Table 6 ranks EPA facilities by the amount of green electricity purchased. Note the correspondence between the facility ranking in Table 6 and the width of the error bars in Figure 4.

Facility	Green Electricity (MWh)
RTP, NC	100,000
Cincinnati, OH	15,560
Edison, NJ	5,027
Las Vegas, NV	4,650
Athens, GA	4,150
Kansas City STC, MO	3,529
Houston, TX	3,394
Manchester, WA	3,333
Duluth, MN + Grosse Ile, MI	3,074
Golden, CO	2,100
Narragansett, RI	1,791
Richmond, CA	1,434
Ada, OK	1,250
Fort Meade, MD	800
Chelmsford, MA	375
Corvallis, OR	360

Table 6. EPA facilities ordered by the amount of green power purchased. Data drawn from EPA (2006b).

5.3 Total Emissions from Fuel and Electricity Consumption by Facility in 1990 and 2005

Adding together CO_2e emissions resulting from both fuel and electricity consumption in 1990 and 2005, it is possible to assess EPA's progress towards fulfilling Executive Order 13123[12]. In this section, emissions and progress towards the emissions target are presented on a facility-by-facility basis. Figure 5 shows total CO_2e emissions by facility, normalized by each facility's 1990 emissions level. The solid line represents the normalized 1990 CO_2e emissions level by facility and the dotted line represents the normalized emissions target under EO 13123 for 2010, which is 70 percent of 1990 emissions level. The emissions range for 2005 results from the variation in emissions among the three offset scenarios; the filled circles represent the emissions from the median scenario. The open circles represent the facility emissions that would have resulted had the green power purchases not been made. It is clear from inspection of Figure 5 that the purchased green tags resulted in substantial offsets of CO_2e emissions. Facilities can be grouped into three categories. First, facilities that are likely compliant with EO 13123: Manchester, Las Vegas, Ann Arbor, RTP, and Edison. Second, facilities that have reduced CO_2e emissions below 1990 levels but not the 30 percent reduction required by EO 13123: Corvallis, Cincinnati, Duluth+Grosse Ile, and Narragansett. Third, facilities that have increased CO_2e emissions since 1990: Ada, Gulf Breeze, and Athens.

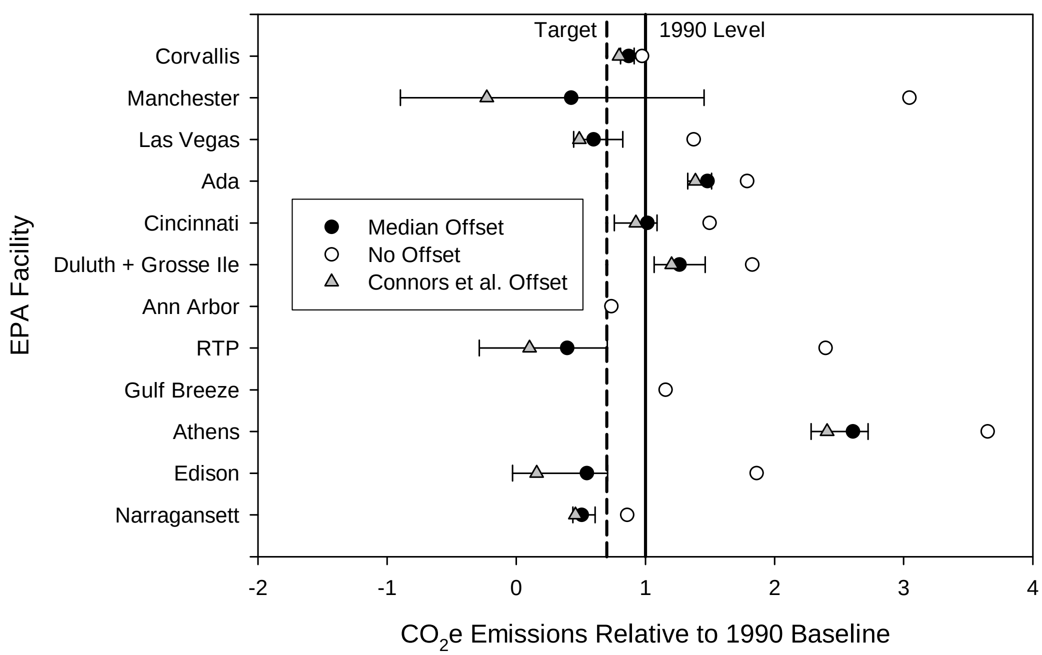

Figure 5. Total normalized CO_2e emissions by EPA facility, 1990 and 2005. Values are normalized by each facility's 1990 emissions. The solid line represents the 1990 emissions level and the dotted line represents the emissions target set by EO 13123. The filled circles and error bars are the estimated net emissions under the three different offset scenarios. The gray triangles represent the emissions offsets using estimates from Connors et al. (2003). The open circles represent 2005 CO_2e emissions if green tags not been purchased. Because no green tags were purchased in 1990, there is no uncertainty associated with emissions offsets.

[12] Note that the number of facilities being analyzed is less than in the previous section. Facilities analyzed in this section had available data for both 1990 and 2005.

Although the intent of EO 13123 is to reduce greenhouse gas emissions, it is also worthwhile to examine the change in air pollutant emissions, in particular SO_2, NO_X, and Hg (mercury). The purpose of examining these air pollutants in addition to greenhouse gases is to examine whether and to what degree EPA decreased air pollutant emissions through the purchase of green tags. The following analysis can also be used to help develop a strategy that maximizes the emissions offsets of both greenhouse gases and air pollutants.

Air pollutant emissions can be estimated with the same procedure used to calculate CO_2e emissions. The results are shown below in Figure 6. Although EO 13123 does not mandate reductions in air pollution, the same target of 30 percent below 1990 levels applied to CO_2e is provided for reference. Note that the change in air pollutant emissions from 1990 to 2005 is much more mixed than for CO_2e emissions. Because gas turbines produce negligible SO_2 and Hg emissions, assuming that purchased green power displaces natural gas capacity (economic scenario) results in little or no offset of those emissions. As a result, the theoretical case where no green power is purchased often results in the same SO_2 and Hg emissions as in the economic offset scenario. In most cases, there are moderate reductions in NO_X emissions, in part because even displacing clean natural gas capacity in the economic scenario results in less NO_X emissions.

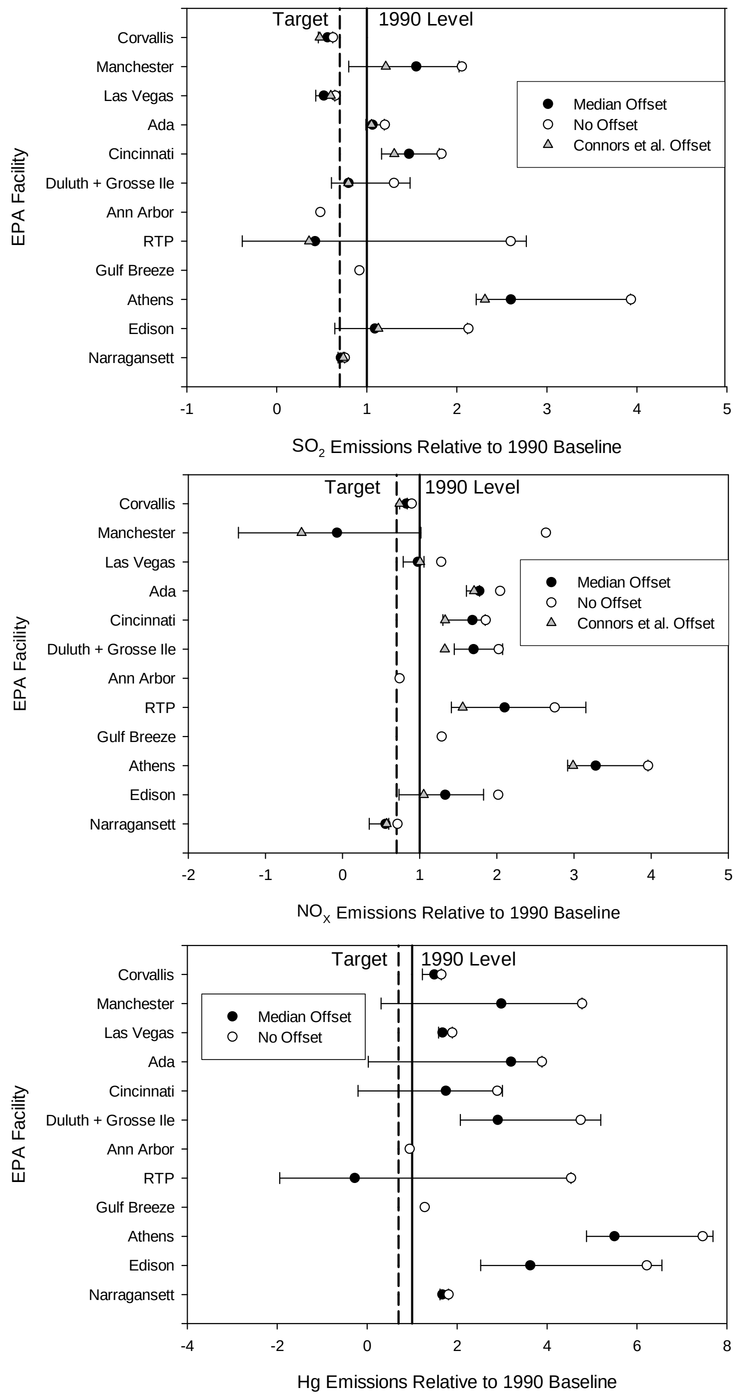

Figure 6. Total normalized SO2, NO_X and Hg emissions by EPA facility, 1990 and 2005. Values are normalized by each facility's 1990 emissions. The solid line represents the 1990 emissions level. Although EO 13123 does not target a reduction in air pollution emissions, the dotted line representing 30 percent below 1990 levels is provided for reference. The filled circles and error bars are the estimated emissions under the three different offset scenarios. The gray triangles represent net emissions using offset estimates from Connors et al. (2003). (Note that Connors et al. did not analyze Hg emissions.) The open circles represent 2005 emissions if green tags not been purchased. Note the mixed results compared with the reductions in CO_2e emissions.

5.4 Total Emissions from All Facilities, 1990 and 2005

The previous section presented net emissions on a facility-by-facility basis. To determine overall progress towards fulfillment of EO 13123, net emissions from all facilities were summed together. The central challenge of EO 13123 is achieving the mandated greenhouse gas reductions despite large increases in building space. The CO_2e target based on the 1990 emissions baseline is roughly 7.4×10^4 short tons of CO_2e emissions from 12 EPA facilities, which account for roughly 2×10^6 gross ft^2. By 2005, EPA had added eight new facilities, which increased the total building space by 85 percent to 3.7×10^6 gross ft^2. Without the purchase of green power, CO_2e emissions would have been nearly 2.2×10^5 short tons: an increase of 190 percent over the EO target and 100 percent over 1990 emissions levels. Figure 7 demonstrates how EPA's purchase of green power has affected net emissions of CO_2e, SO_2, NO_X, and Hg between 1990 and 2005.

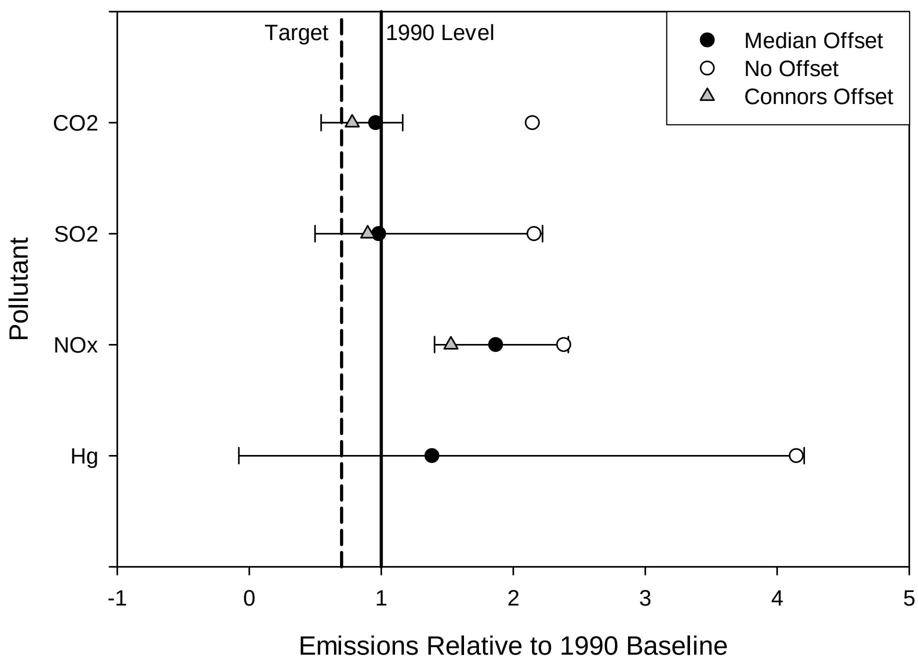

Figure 7. Total normalized CO_2e, SO_2, NO_X and Hg emissions, 1990 and 2005. The solid line represents the 1990 emissions level and the dotted line represents the EO target. The filled circles and error bars are the estimated emissions under the three different offset scenarios. The gray triangles represent net emissions using offset estimates from Connors et al. (2003). The open circles represent 2005 emissions if green tags not been purchased. Note that with uncertainty in emissions offsets, net CO_2e emissions in 2005 most likely fall somewhere between the 1990 level and the EO target.

Figure 7 indicates that EPA has made substantial progress towards EO 13123. CO_2e emissions have roughly remained at the 1990 levels, despite an 85 percent increase in building space over the last 15 years. CO_2e emissions would have been 190 percent higher without any purchase of green power. Net emissions of SO_2 and NO_X show potentially modest benefits while uncertainty in Hg offsets is so large that no increase or decrease can be discerned.

Suppose that EO 13123 had been focused on decreasing CO_2e / ft^2 rather than absolute CO_2e. Such a standard would relax the target by factoring out the emissions associated with increased building space. Total emissions (shown in Figure 7) normalized by building space yields Figure 8. In this case, EPA has clearly met the CO_2e target already. More appreciable reductions in SO_2

and NO_X are also evident, although the reductions fall within the uncertainty associated with the emissions offsets. The results in Figures 7 and 8 indicate that EPA is close to meeting the EO target, but that further reductions are required to counter the rapid increase in building space.

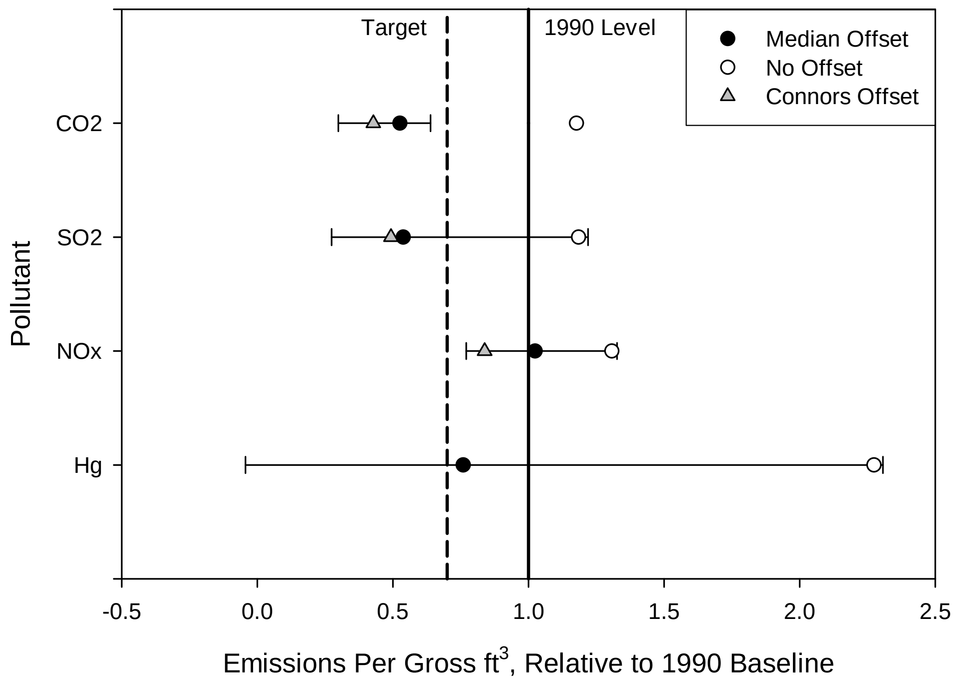

Figure 8. Total CO_2e, SO_2, NO_X and Hg emissions per gross ft^2 in 2005 normalized by 1990 emissions per gross ft^2. Note that when CO_2e emissions are normalized by building space, EPA has reduced emissions well below the target of 70 percent of 1990 levels.

6. Looking Ahead: Maximizing the Environmental Benefits of Green Power

In the future, EPA can maximize the emissions offsets provided by the purchase of renewable energy by carefully considering two factors: the direct emissions from different renewable sources and the total emissions level in each NERC subregion where green power is located. The following two subsections address these issues in more detail.

6.1 Emissions from Green Power Sources

As shown in Equation 4, the emissions rate from the green power source ($r_{p,g}$) is a key determinant of net emissions. Estimated emissions rates for green power sources should factor into purchasing decisions. In considering emissions from power plants, there is an important distinction between operating emissions and life-cycle emissions. Operating emissions only account for the emissions released during the production of electricity, while life-cycle emissions account for all emissions related to the construction, operation, and disposal of a technology as well as the emissions associated with extraction, transportation, and combustion of fuel. For reference, Table 7 below presents operating and life-cycle emissions rates for both renewable energy sources and conventional sources[13]. Table 7 is not meant to be comprehensive, but rather to provide a range of the estimated emissions produced by different electric generating technologies.

Among renewable sources, wind appears to be the most attractive from an emissions accounting perspective. It has zero operating emissions, and the life-cycle emissions associated with building and disposing of wind turbines is low. Solar photovoltaics (PV) also produce zero operating emissions, but the process to fabricate the crystalline silicon panels is energy intensive, resulting in higher life-cycle emissions than is the case for wind. However, thin film PV (in which photovoltaic material is applied to a low cost substrate) has the potential to reduce cost and life-cycle emissions in the future. Like solar PV, biomass also appears to be a relatively low emissions source of electricity, but there is currently limited availability in existing green power markets owing to higher generation costs.

The purchase of both municipal solid waste (MSW) and landfill gas (LFG)–widely available green power alternatives–has interesting implications for CO_2e emissions. The natural decomposition of trash in a landfill produces methane, a potent greenhouse gas. The direct combustion of MSW reduces greenhouse gas emissions by preventing the formation of methane. LFG combustion, on the other hand, allows methane to form in the landfill. The methane is then collected and combusted in either an engine or a turbine. However, the reported collection efficiencies of methane from landfills range from 60 to 85 percent, where an average efficiency of 75 percent is often assumed (EPA, 2006c). In a life-cycle analysis of different waste management options, Thorneloe et al. (2006) find that electricity from MSW produces considerably less CO_2e emissions than LFG. This result is due in large part to the high methane leakage rates associated with LFG. In addition, MSW combustion avoids the issue of leachate leakage from landfills, which can be difficult to track and can lead to groundwater contamination.

[13] It is important to note that different methods for estimating life-cycle analysis can affect emissions estimates. The estimates presented here were not reviewed in detail for consistency.

At first pass, it appears that green power from MSW is preferable to that from LFG. However, more detailed work is required to quantify the tradeoffs between the two generation alternatives. Life-cycle emission estimates for both MSW and LFG used in the emissions offset calculations are open to interpretation, since the estimated net emissions depend on assumptions about how the waste material would have been handled if not combusted. More accurate quantification of the life-cycle emissions from LFG and MSW incineration under a variety of scenarios is a high priority for future work.

Note that among the conventional alternatives, nuclear has very low emissions of both greenhouse gases and air pollutants, although the issue of nuclear waste disposal presents unique environmental considerations. Coal clearly has the highest CO_2 emissions compared with all other alternatives.

Technology	Source	Operating Emissions (lbs / MWh) CO_2e Low	CO_2e High	SO2 Low	SO2 High	NO_X Low	NO_X High	Hg Low	Hg High	Lifecycle Emissions (lbs / MWh) CO_2e Low	CO_2e High	SO2 Low	SO2 High	NO_X Low	NO_X High
Wind		0	0	0	0	0	0	0	0						
	Denholm (2005)									11	55	<0.04		<0.22	
	IEA (1998)									15	20	0.04	0.2	0.04	0.1
	Bergerson (2005)									0	60	0	0.03	0	0.05
Landfill Gas [a]	EPA AP 42 (2006)	N/A		0.2		1.8		3.6×10^{-6}		NA		NA		NA	
MSW Incineration [b]	EPA AP 42 (2006)	2130		0.2	3.7	3.9		0.002	0.006	NA		NA		NA	
Biomass (pulp and paper) [c]	EPA AP 42 (2003)	1900		0.26		2.3		3.5×10^{-6}		near zero		NA		NA	
Biomass (Varied) [d]	IEA (1998)	NA		NA		NA		NA		40	60	0.032	0.07	0.5	1.1
	Corti et al. (2004)	NA		NA		NA		NA		-1310	250				
	Bergerson (2005)	NA		NA		NA		NA		-80	400	0.013	0.35	0.25	1
Solar PV		0	0	0	0	0	0	0	0						
	IEA (1998)									220	370	0.4	0.8	0.4	0.7
	Bergerson (2005)									0	24	0	0.25	0	0.05
	Fthenakis et al. (2006)									30	110	NA		NA	
	Meier et al. (2005)									90		NA		NA	
Nuclear [e]		0	0	0	0	0	0	0	0						
	Denholm (2005)									20	60	<0.1		<0.25	
	Bergerson (2005)									7×10^{-5}	26	1.1×10^{-5}	0.15	8×10^{-2}	0.11
	Fthenakis et al. (2006)									30	120	NA		NA	
	Meier et al (2005)									40		NA		NA	
	Gagnon et al (2002)									30		0.007		NA	
Natural Gas (Combined Cycle)	EPA AP 42 (2006)	880		0.03		2.5				NA		NA		NA	
	Denholm (2005)	NA		NA		NA		NA		880	1100	0.2	0.9	0.4	1.3
	ORNL-RFF (1992)	NA		NA		NA		NA		1400		0		1.1	
Coal [f,g]	EPA AP 42 (2006)	2800		18		5.5		1.66×10^{-4}		NA		NA		NA	
	Denholm (2005)	NA		NA		NA		NA		2000	2400	4	20	4	9
	ORNL-RFF (1992)	NA		NA		NA		NA		2400		4		7	
	Sundqvist (2004)	NA		NA		NA		NA		2000	3100	1.8	34	2	13
	Bergerson (2005)	2200	2400	0.2	1.4	1.3	2.2	NA		2200	2600	0.3	1.5	1.8	2.6
	CUEcost (2006)	NA		15		7		NA		NA		NA		NA	

Table 7. Operating and life-cycle emissions estimates for renewable and conventional power sources. Note that the zeros in the operating emissions rows for wind, solar PV, and nuclear denote negligible operating emissions. NA = Not Available.

[a]Calculations by Clint Burklin of ERG's Morrisville Office, based on EPA's AP 42, See Appendix 3.
[b]High estimate based on uncontrolled emissions, low estimate assumes spray dryer + fabric filter, and an assumed thermal efficiency of 35 percent.
[c]Assumes a "wet wood-fired boiler" and a thermal efficiency of 35 percent.

[d]There is a wide range depending on whether the biomass is gasified before combustion and whether CO_2 emissions are sequestered afterwards (producing net negative emissions). CO_2e estimates from Corti et al. (2004) are for biomass integrated gasification combined cycle, with (low estimate) and without (high estimate) the chemical absorption of CO_2.
[e]The low end of the Bergerson estimate reflects a once-through fuel cycle, while high end includes fuel recycling.
[f]Coal emissions estimates from EPA's AP 42 are based on a pulverized coal boiler with the following characteristics: dry bottom, tangentially-fired, post-NSPS (New Source Performance Standard), and combustion of medium volatile bituminous coal.
[g]Coal emissions estimates from Bergerson assume low NO_X burners and selective catalytic reduction for NO_X control, and flue gas desulfurization for SO_2 control.

6.2 Best Regions in Which to Buy Green Power

Equation (4) indicates that an optimal green power purchasing strategy should also take into account the emissions rates of the NERC subregions in which the green power sources are located, since the higher the subregion's emissions rates, the higher the offset achieved. With respect to greenhouse gases, purchasing green power in the NERC subregions with the highest CO_2 emissions rates will maximize the CO_2 offset achieved by the purchaser. Because CO_2 is non-reactive and has a long residence time in the atmosphere, the location where the emissions takes place is irrelevant to global climate.

With criteria pollutants such as SO_2 and NO_X as well as Hg, the location where emissions take place is very important because atmospheric transport occurs mainly at local to regional scales. In this case, searching for NERC subregions with the highest rates of air pollution will provide the highest offset for the purchaser, but does not necessarily improve air quality the most. To target areas where green power would have the greatest benefit to air quality, a better metric than emissions rate is total tonnage of emissions by NERC subregion, which is simply the product of the emissions rate and total electricity generated in the region. Purchasing green power in regions with the highest levels of air pollution provides the greatest air quality benefit.

Put simply, green power purchasers should focus on the NERC subregions that have the highest rates of greenhouse gas emissions and the worst air quality. The process could be complicated by the tradeoff between greenhouse gas and air pollution emissions as well as tradeoffs among different air pollutants. Fortunately, targeting specific NERC subregions to achieve maximum emissions offsets is relatively easy for a simple reason: the energy source that creates the highest emissions of both greenhouse gases and air pollutants is coal. As a result, regions with the highest levels of electricity production from coal will also have the highest greenhouse gas and air pollutant emissions. Using emissions data from EPA (2003), CO_2, SO2, NO_X, and Hg emissions by NERC subregion were sorted by CO_2 emissions from greatest to least. See Table 8.

NERC Subregion	CO_2 (10^6 tons)	SO_2 (10^3 tons)	NO_X (10^3 tons)	Hg (tons)
ECAR Ohio Valley	488	3351	1229	11.33
ERCOT	221	464	351	4.27
SERC South	184	1085	397	4.38
SERC Virginia/Carolina	171	954	381	3.37
MAPP	165	496	356	3.87
MAIN South	146	612	320	4.49
MAAC	145	1013	327	5.18
FRCC	126	502	297	1.06
SPP South	124	274	220	2.07
SERC Mississippi Valley	113	276	243	1.13
SERC Tennessee Valley	111	721	288	1.85
WECC Southwest	97	143	206	1.84
WECC California	92	64	110	0.32
ECAR Michigan	77	346	159	1.45
WECC Rockies	59	105	99	0.34
SPP North	59	172	134	1.15
NPCC New England	52	219	87	0.52
MAIN North	52	202	114	1.09
WECC Great Basin	47	81	100	0.49
WECC Pacific Northwest	43	121	80	0.70
NPCC Upstate NY	41	245	66	0.65
NPCC NYC/Westchester	15	8	16	0.11
NPCC Long Island	12	34	19	0.04
HICC Oahu	7	12	11	0.05
ASCC Alaska Grid	3	4	10	0.01
HICC Miscellaneous	2	12	16	0.00
ASCC Miscellaneous	0	0	4	0.00
Correlation Coefficient		0.93	0.98	0.95

Table 8. EPA eGRID emissions by NERC subregion, ranked by the level of CO_2 emissions. Note that ECAR – Ohio Valley has the highest emissions; CO_2 and air pollutant levels are at least a factor of two higher than ERCOT, which is second on the list. The last row provides the correlation (0-1) between the CO_2 emissions and SO_2, NO_X, and Hg emissions. Data drawn from EPA's eGRID database (EPA, 2003).

Table 8 shows that ECAR Ohio Valley is by far the most polluted NERC subregion. It is also worth noting that 2-4 orders of magnitude separate the greatest and least polluted regions. In general, the order of air pollution levels by NERC subregion closely tracks the CO_2 ranking. Note the strong correlation between CO_2 and SO_2, NO_X, and Hg emissions, resulting in correlation coefficients close to 1.

Coal is the fuel that ties all of these emissions together. To prove this assertion, a simple linear regression of electricity production from coal (MWh) versus the level of emissions (by NERC subregion) was performed. The results are shown in Table 9.

	CO_2	SO2	NO_X	Hg
R^2 (Coal MWh)	0.92	0.93	0.98	0.93

Table 9. R^2 values resulting from a regression of coal usage (MWh) versus tons of emissions. The R^2 value estimates what fraction of the variation in emissions can be explained by coal usage.

Table 9 demonstrates that coal consumption explains more than 90 percent of the variation in emissions by NERC subregion. As a result, buying green power in areas with the heaviest coal usage for electricity production produces the greatest greenhouse gas and air pollution benefits.

7. Conclusions

The conclusions can be summarized as follows:

- Despite growing energy consumption at EPA facilities, the purchase of green power has offset much of the overall growth in emissions. In many cases, on a facility-by-facility basis, the purchased green power in 2005 (assuming extension of current contracts) has already met EPA's mandate under Executive Order 13123. Overall; however, total reductions of CO_2e fall between the 1990 levels and the EO target.
- There is uncertainty in determining the emissions offsets from green power because it depends on which generating units are being displaced by the green power. The scenario approach used in this analysis quantified the uncertainty in emissions offsets.
- Comparison of both operating and life-cycle emissions from various green power sources revealed that wind and MSW combustion appear to be the cleanest sources that also are widely available in existing markets.
- After comparing NERC subregion emissions of CO_2, SO_2, NO_X, and Hg, it became clear the best regions to make green power purchases were the ones with the highest levels of coal use. The three regions with highest emissions were ECAR – Ohio Valley, ERCOT, and SERC South.
- Bottom line: search for the cleanest green power sources in the dirtiest NERC subregions. A good starting point would be to search for wind power generators selling green tags in ECAR – Ohio Valley.

8. Future Work

There are three goals for further analysis. First, the spreadsheets developed for this analysis could be automated for use as a decision support tool. A decision-maker would be able to use the spreadsheet tool to estimate the emissions benefits of different purchasing options. The user would be able to select and test four key variables: the location of the facility for which green tags will be purchased, the green power technology, the amount of green energy to be purchased, and the location of the green power source. Using EPA eGRID data and emissions estimates for green power sources, the spreadsheet would estimate the net emissions as described in this report.

Second, a dispatch model could be used to identify with greater precision which generating units are being displaced by purchased green power, which would shrink the size of the error bars associated with net emissions (see Figures 4-6). The project could build upon work performed by Stephen Connors et al. (2003), which estimated the emissions offsets from photovoltaics. Their work utilized plant-level data from EPA's eGRID, hourly plant data from EPA's Clean Air Markets division, and hourly electricity demand data from the FERC. The data and methodology could be expanded to create an important decision support resource for green power purchasers. The resource would allow users to accurately estimate the emissions offsets in each NERC subregion based on the purchase of electricity from a particular type of generation technology. Examination of green power purchasing decisions using a tool based on a dispatch model to estimate emissions offsets would represent a significant improvement for EPA green power purchasing decisions.

Third, more work needs to be done to better characterize the life-cycle emissions from landfill gas and MSW combustion. In particular, it is critical to estimate the emissions from these sources with and without power generation. This analysis can be done by EPA-ORD using the Municipal Solid Waste Decision Support Tool developed by EPA and RTI (Research Triangle Institute). This work has already been discussed with the lead developers, and further analysis is planned.

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Appendix 1: Derivation of Biodiesel Emissions Rates

Two EPA facilities, Narragansett, RI and Manchester, WA, use a biodiesel blend in their boilers. At both facilities, 80 percent No. 2 fuel oil is blended with 20 percent biodiesel, referred to as B20. The emissions rates for B20 are estimated from EPA (2006c) and Krishna (2004). Details on the estimated emissions of CO_2, SO_2, Hg, and NO_X are provided below.

CO_2 Emissions Rate

On a lifecycle basis, the emissions of CO_2 from the pure biodiesel are asummed to be negligible. Based on Table 1.3-12 of the EPA AP 42, the CO_2 emissions rate for No. 2 fuel oil is 22,300 lbs / 10^3 gal. Based on Krishna (2004), the energy content of B20 is roughly 136,600 BTU per gallon. Since No. 2 fuel oil represents 80 percent of the B20 mixture,

$$\text{B20 CO}_2 \text{ emissions rate} = 0.8 \times \left(\frac{22{,}300 \text{ lbs CO}_2}{10^3 \text{ gal}} \times \frac{103 \text{ gal}}{136.6 \text{ MBTU}} \right) = 130.6 \text{ lbs/MBTU}$$

SO_2 Emissions Rate

According to Krishna (2004), the sulfur content of the B20 blend used for testing was 0.293 percent. Also, according to Table 1.3-1 of EPA (2006c), the SO_2 emissions rate for a No. 2 oil-fired boiler (>100 MBTU/hr) is 157*S* lbs/10^3 gal, where *S* is the sulfur content percentage of the fuel:

$$\text{B20 SO}_2 \text{ emissions rate} = 157 \times 0.293 = \frac{46 \text{ lbs}}{10^3 \text{ gal}} \times \frac{10^3 \text{ gal}}{136.6 \text{ MBTU}} = 0.337 \text{ lbs/MBTU.}$$

Hg Emissions Rate

The biodiesel component of B2O is assumed to have zero Hg content. The Hg content of No. 2 fuel oil was drawn from Table 1.3-10 of EPA (2006c):

$$\text{B20 Hg emissions rate} = 0.8 \times \left(\frac{3 \text{ lbs}}{10^{12} \text{ BTU}} \times \frac{10^6 \text{ BTU}}{1 \text{ MBTU}} \right) = 2.4 \times 10^{-6} \text{ lbs/MBTU.}$$

NO_X Emissions Rate

According to Figure 18 of Krishna (2004), the concentration of NO_X in the commercial boiler is roughly 42 ppm at 8 percent O_2. First, the NO_X concentration must be adjusted to a 3 percent O_2 level, according to a formula provided by Preferred Instruments (see: http://www.preferredinstruments.com/engineering_data.html#emissions):

$$\text{NO}_X \text{ ppm (at 3\% O}_2) = \left(\frac{21 - 3}{21 - \text{O}_2 \text{(actual)}} \right) \times \text{ppm(actual)} .$$

Plugging in the B20 data,

$$\text{NO}_X \text{ ppm (at 3\% O}_2) = \left(\frac{21 - 3}{21 - 8} \right) \times 42 \text{ ppm} = 58.1 \text{ ppm NO}_X .$$

Then, according to the Preferred Instruments reference above, the NO_X concentration is converted to lbs/MBTU through a simple linear transformation:

$$\text{B20 NO}_X \text{ emissions rate} = \frac{58.1\,\text{ppm}}{750} = 0.0775\,\text{lbs/MBTU}\ .$$

Appendix 2: Estimation of Power Plant Thermal Efficiencies By Fuel Type in 1990

Source: (EIA/DOE, 2004). Annual *Energy Review 2003*

Electricity Generation by Fuel Type, 1990
Table 8.2a: Electricity Net Generation: Total (All Sectors), 1949-2002

- Coal = 1594 billion kWh
- Petroleum = 126.6 billion kWh
- Natural Gas = 372.8 billion kWh

Fuel Consumed for Electricity Generation, 1990

Table 8.3c: Consumption of Combustible Fuels for Electricity Generation: Total (All Sectors), 1949-2002

- Coal = $792{,}457\times10^3$ short tons
- Petroleum = $218{,}997\times10^3$ barrels
- Natural Gas = $3{,}692\times10^9$ ft^3

Conversion Factors, 1990

Table A5: Approximate Heat Content of Coal and Coal Coke, 1949-2002

- Electric Power Sector Coal = 20.779 MBTU / short ton

Table A3: Approximate Heat Content of Petroleum Product Weighted Averages, 1949-2002

- Electric Power Sector Petroleum = 6.244 MBTU / barrel

Table A4: Approximate Heat Content of Natural Gas, 1949-2002

- Electric Power Sector Natural Gas = 1,027 BTU / ft^3

Thermal Efficiencies

First, convert primary fuel consumption to MBTU using the conversion factors above. Next, convert billion kWh of electricity production to MBTU (3.415×10^3 MBTU/billion kWh). Divide MBTUs of energy use electricity by MBTUs of primary energy in the fuel.

$$\text{Coal} = \frac{5.444\times10^9}{1.647\times10^{10}} = 33\%$$

$$\text{Petroleum} = \frac{4.323\times10^8}{1.367\times10^9} = 32\%$$

$$\text{Natural Gas} = \frac{1.273\times10^9}{3.792\times10^9} = 33\%$$

Appendix 3: Data for Landfill Gas Emissions Rate Estimates

Table 4. 1998 AP-42 Data

Electricity Generation Technology	AP-42 Emission Rates (lbs/MWh, except LFG flares)					
	NO_X	SO_2[a]	VOC[b]	PM	Mercury[c]	CO_2
LFG IC Engines	2.98	0.186	(0.035 - 0.265)	0.572	3.62E-06	N/A
LFG Turbines from MSW LF Chapter (2.4)	1.21	0.218	(0.082 - 0.311)	0.307	4.24E-06	N/A
LFG Turbines from Gas Turbine Chapter (3.1)[d]	1.98	0.636	0.184	0.325	N/A	N/A

[a] Assumes all sulfur compounds in LFG are converted to SO_2 during combustion. Uses the AP-42 default sulfur content for raw LFG rather than using landfill-specific data.
[b] Lower bounds of ranges were calculated by multiplying the default VOC concentration (as hexane) for LFG by typical NMOC control efficiencies for each technology. Upper bounds of ranges were determined based on the fact that some flares, engines, and turbines are known to comply with the NSPS limit of 20 ppmv NMOC, which converts to 0.022 lbs/MMBTU, 0.244 lbs/MWh, and 0.286 lbs/MWh VOC, respectively. Per AP-42, VOC is 39% by weight of NMOC for landfills with no or unknown co-disposal of hazardous waste.

[c] Uses the default concentration for total mercury in LFG (Table 2.4-1) to estimate mercury released from IC engines & turbines.

[d] This value of NO_X was not used since it was based on less landfill data.

Constants:

Default LFG IC engine heat rate (BTU/kWh) =	11,100	(HHV)
Default LFG turbine heat rate (BTU/kWh) =	13,000	(HHV)
parasitic loss =	0.92	
Methane heating value (BTU/scf) =	1,012	(HHV)
Percent methane in LFG =	50%	
Molecular weight of sulfur dioxide (lb/lb-mol) =	64.1	
Molecular weight of hexane (lb/lb-mol) =	86.2	
Molecular weight of mercury (lb/lb-mol) =	200.6	
Scf LFG at standard conditions (scf/lb-mol) =	385.5	
% of electricity generated by engines	37	

Appendix 4: Description of Spreadsheets Containing Data Analysis

These spreadsheets contain the data analysis presented in this report and are available upon request from the author: decarolis.joseph@epa.gov.

"EPA FY1990 only.xls" contains the following worksheets:

- "OARM data" contains original energy data for 1990 obtained from Justin Spenillo.
- "NERC pre-1990 generators" provides a comprehensive list of all U.S. power plants installed in the U.S. before 1990 and still in operation. Data obtained from NERC (2004).
- "NERC_frac" provides a summary of power plant capacity by plant type and NERC subregion. Obtained by filtering data in previous sheet.
- "1990 EPA ELC Emissions" performs calculations to estimate EPA facility emissions from electricity use in 1990.
- "1990 EPA Fuel Emissions" performs calculations to estimate EPA facility emissions from fuel consumption in 1990 using emissions factors from EPA's AP 42.
- "Total Emissions" sums the emissions from electricity and fuel consumption.

"EPA FY1990 and FY2005.xls" contains the following worksheets:

- "FY05 Totals" contains original energy data for 2005 obtained from Justin Spenillo.
- "ELC Emissions 2005" calculates the net emissions by facility, taking into account emissions offsets from the purchase of green power. For each green power contract, the net emissions are estimated under 3 different offset scenarios. Tables beginning with cell B52 summarize the net emissions (absolute and relative) under each scenario.
- "Fuel Emissions 2005" performs calculations to estimate EPA facility emissions from fuel consumption in 2005 using emissions factors from EPA's AP 42.
- "Total Energy 1990 – 2005" summarizes both energy associated with electricity and fuel consumption at EPA facilities in both 1990 and 2005.
- "Total Emissions 1990 – 2005" summarizes total CO_2e, SO2, NO_X and Hg emissions by EPA facility for 1990 and 2005. The number of facilities used in 1990 to 2005 comparisons is only a subset of the 2005 dataset since less facility data was available for 1990.

Appendix 5: Data Quality Disclaimer

This study utilizes several data sources, which can be categorized as follows:

- Federal organizations and laboratories
- Academic studies
- Journal articles

For cases where metadata exist that describe precision, accuracy, completeness, or other uncertainty measures with respect to the data, the data collector can use this information to assess data quality. In cases where no quality assurance descriptions are available, the data collector must accept the data on an as-is basis. The primary sources of the information are ultimately responsible for the quality of their data. However, the author recognizes that each source organization may have different levels of resources available to accomplish their mission, or may have differing commitments to quality assurance within their organization, and consequently data quality may vary from place to place in ways that cannot be quantified.

Widely cited data from authoritative sources was used wherever possible. The core 1990/2005 comparative analysis was based on several key data sources: EPA (2003, 2006c) for emissions data, NERC (2004) for 1990 electric generating capacity by NERC subregion, and EIA (2004) for data used to calculate power plant thermal efficiencies by fuel type in Appendix 2. EPA facility energy consumption data was drawn from EPA (2006a, 2006b) and details on purchased green power were drawn from ERG (2006).

Emissions data came from the EPA, which has already been subjected to rigorous internal review. Electric generating capacity in 1990 came from the North American Electric Reliability Council (NERC), which is an organization that pools information from all U.S. electric utilities, and is therefore considered to be a primary source of high quality power system data. Thermal power plant efficiencies in 1990 were based on estimates from EIA (2004), which is an authoritative source for U.S. energy data. Finally, the energy consumption data by EPA facility was provided by EPA's Office of Administration and Resource Management (OARM), which is responsible for the operation and maintenance of EPA facilities. EPA-OARM also contracted Eastern Research Group (ERG) to perform analysis of green power purchases, and this report utilizes the reported physical location of purchased green power from the ERG spreadsheet (ERG, 2006).

Other data from reputable government and academic sources were used to characterize operating and life-cycle emissions from alternative energy sources.

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