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Sources of Emission Reductions:

Evidence for US SO_2 Emissions 1985 – 2002

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ABSTRACT

An enduring issue in environmental regulation is whether to clean up existing "old" plants or in some manner to bring in new "clean" plants to replace the old. In this paper, a unit-level data base of emissions by nearly 2000 electric generating units from 1985 through 2002 is used to analyze the contribution of these two factors in accomplishing the significant reduction of sulfur dioxide emissions from these sources in the United States. The effect on SO_2 emissions of the new natural-gas-fired, combined-cycle capacity that has been introduced since 1998 is also examined. The results indicate that cleaning up the old plants has made by far the greater contribution to reducing SO_2 emissions, and that this contribution has been especially large since the introduction of the SO_2 cap-and-trade program in 1995. The new natural-gas-fired, combined cycle units have displaced conventional generation that would have emitted about 800,000 tons of SO_2; however, the effect has not been to reduce total SO_2 emissions since the 9.0 million ton cap is unchanged, but to reduce the quantity of abatement required of other units in meeting the cap and thereby the cost of doing so.

The Sources of Emission Reductions: Evidence from U.S. SO_2 Emissions from 1985 through 2002

A. Denny Ellerman

Florence Dubroeucq[1]

INTRODUCTION

Emissions can be reduced by emission rate reductions at existing plants or by displacing those plants by other plants, frequently new units, with lower emission rates. Accordingly, one of the enduring questions underlying policies aimed at reducing air emissions is the role of these two ways of reducing emissions. A good case study for analyzing their relative contributions is provided by the experience of the United States in reducing sulfur dioxide (SO_2) emissions from the combustion of fossil fuels for the generation of electricity. These emissions have been reduced by about 45%, from a peak of about 18.25 million tons in 1975 when the Clean Air Act Amendments of 1970 became effective to 10.1 million tons in 2002, the last year for which data is available.[2]

Since 1970, SO_2 emissions have been subject to two distinctly different regulatory regimes established respectively by the Clean Air Act Amendments of 1970 and 1990.

The Clean Air Act Amendments of 1970. These amendments instituted a coherent and effective regulatory system for reducing SO_2 emissions whereby

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[2] The decrease in SO_2 emissions from all sectors of the economy was slightly larger due to the disappearance of metals processing, mostly copper, within the United States. For the economy as a whole, peak SO_2 emissions were 31.8 million tons in 1973 and they had declined to 15.8 million tons in 2001, or by 50%. (US EPA, 2003).

a) *existing facilities* would be subject to emission rate limits imposed by State Implementation Plans that were to ensure attainment of the National Ambient Air Quality Standard for SO_2, and

b) *new plants* would be subject to stringent New Source Performance Standards that would require the adoption of best available control technology.

These provisions had become effective by the mid-1970s when national SO_2 emissions peaked and they have remained in effect to this day.

The Clean Air Act Amendments of 1990. Title IV of these amendments created a nationwide limit on aggregate SO_2 emissions of approximately 9 million tons to be achieved in two phases by an innovative cap-and-trade program that issued allowances in an amount equal to the cap and required all electric utility generating units to surrender allowances equal to the unit's emissions. Since no specific command concerning abatement is given at the unit level, the operators of affected units are free to decide whether they will reduce emissions by lowering the sulfur content of the fuel used to generate electricity (either by switching or retrofitting scrubbers) or by shifting generation to lower emitting units including new units. However, Title IV did not replace the source-specific limits and technology mandates of the earlier 1970 Amendments. The cap and the associated obligation to surrender allowances equal to the tons of SO_2 emitted is an additional requirement imposed on top of the pre-existing structure of prescriptive regulation.[3]

The reduction in electric utility SO_2 emissions has been the more remarkable in that the demand for fossil-fuel-fired generation of electricity has grown substantially since 1970 as shown in Figure 1.

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[3] The super-imposing of Title IV on the pre-existing prescriptive rate limits, which are aimed primarily at preventing adverse local health effects means that some plants are not free to increase emissions (and purchase allowances). In practice, these pre-existing constraints have not posed a serious impediment to trading under Title IV since the cap requires a significantly greater reduction of aggregate emissions than what is required to meet the National Ambient Air Quality Standard for SO_2. While generating units can trade only within the prescriptive limits imposed by the 1970 Amendments, these limits have become non-binding for most units.

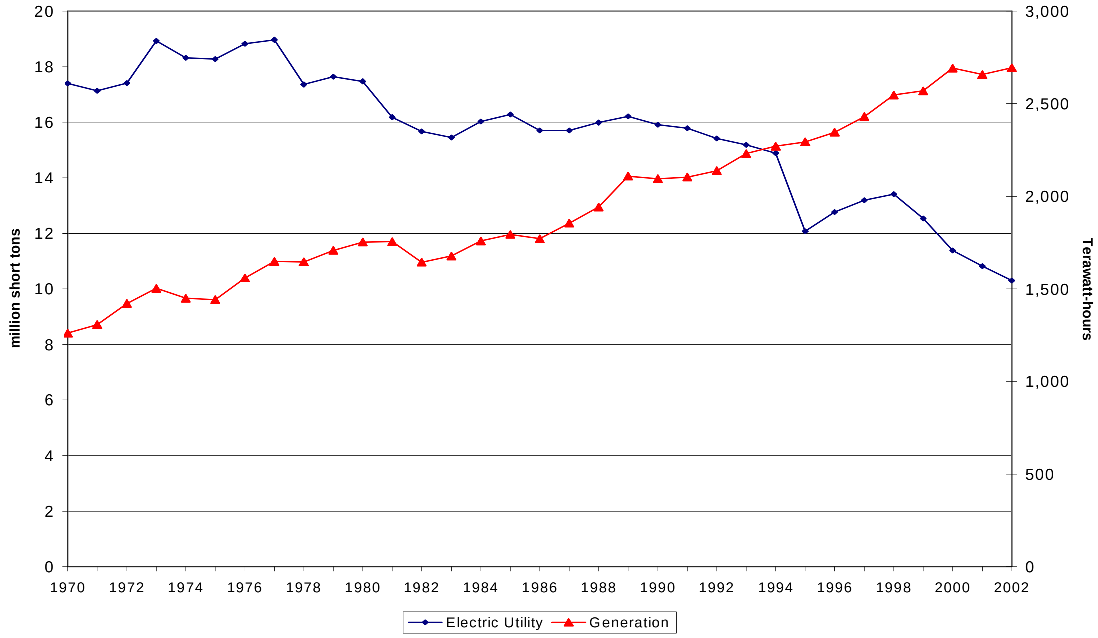

Figure 1. *U.S. Fossil-fuel-fired electricity generation and SO_2 emissions, 1970-2002*

In general, generation of electricity from fossil-fuel-fired power plants has increased steadily while SO_2 emissions have regularly declined. Since the year of peak emissions, 1977, fossil-fuel-fired generation has increased at an average annual rate of 2.0% while SO_2 emissions from these sources have decreased at an annual rate of 2.4%.[4] The implied annual rate of reduction in aggregate SO_2 intensity for fossil-fuel-fired generation is 4.3%, from 23 pounds of SO_2 per megawatt-hour in 1977 to 7.76 pounds in 2002. In broad terms, this reduction in aggregate intensity results from two effects: the reduction in emission intensity or rates at individual units and the displacement of higher emitting units by existing sources with lower emission rates or new sources with mandated lower emission rates.

While the trend in SO_2 emissions since the mid-1970s is instructive, the past five years offer an especially good opportunity to examine the effect on emissions of the introduction of low-emitting new generating units. Several factors—the need for new capacity to meet continually growing demand, the availability of more efficient,

[4] Over this same 25-year period, total electricity generation, including nuclear, hydro, and renewables, has increased at an annual rate of 2.4%.

combined-cycle generating technology, and the expectation of relatively low natural gas prices—coalesced in the late 1990's to create a boom in the construction of new natural-gas-fired generating capacity. Since natural gas emits only trace amounts of SO_2, the deployment of these new units could be expected to reduce SO_2 emissions considerably as pre-existing, higher emitting generating units are displaced in meeting the demand for electricity. As of the end of 2002, the new gas-fired capacity is estimated to be 133 GWe, an approximately 20% increase in generating capacity, and another 56 GWe is under construction and expected to be completed in the next few years, mostly in 2003 (EVA, 2003). About half of this capacity consists of single-cycle combustion turbines that are used mostly for meeting peak demand and offer few if any operating efficiencies compared to existing capacity. The remaining half of the new capacity utilizes combined cycle technology that offers marked operating efficiencies that would be expected to lead to greater utilization for these units and greater displacement of existing units.[5] Accordingly, we focus mostly on the combined-cycle units.

Our purpose in this paper is to analyze the sources of the reduction in SO_2 emissions and, in particular, to distinguish between the effects of lower emission rates at existing units and the displacement of higher emitting generating units by lower emitting ones, regardless of whether these are new units or existing units with lower emissions. In doing so, we give particular attention to the reduction in SO_2 emissions attributable to the large increase in new natural-gas-fired capacity in the United States since 1998. The methodology we employ in this paper does not discriminate between emission rate reductions and displacements that respond to policy measures and those that would have occurred anyway because of other non-policy-related factors affecting the electric utility generating sector of the economy. Accordingly, the results we report should not be interpreted as being entirely due to regulatory measures, although a large fraction surely is. Where appropriate, mention will be made of the non-regulatory factors.

[5] For instance, in the third quarter of 2002, combined cycle units constituted 52% of the new capacity and 79% of the generation from the new gas-fired units.

The next section of the paper explains the data base and methodology that is used to identify the source of observed SO_2 emission reductions. Results are then reported in the next section, and a final section concludes. A technical explanation of the decomposition methodology and the full data results are provided in appendices.

DATA AND METHODOLOGY

Adoption of the 1990 Clean Air Act Amendments, and specifically the decision to allocate allowances to generating units according to average 1985-87 heat input and the 1985 SO_2 emission rate, required the U.S. Environmental Protection Agency (US EPA) to develop a more detailed and accurate data base than had existed previously. This data base lists annual SO_2 emissions and heat input at the unit level for over 3000 generating units from 1985 on. The availability of data at the unit level is particularly important since any given power plant will typically consist of several generating units, usually three to four but sometimes as many as a dozen, usually built in different years and typically subject to differing regulatory requirements. Absent unit-level data, it would be impossible to tell whether an observed change in emissions at a power plant is due to changes in emission rates at all or several units or to the changing utilization of the constituent units with differing emission rates because of different regulatory requirements.

Our analysis is based on this data base from which some 1,000 rarely utilized, old, and small units are excluded. The remaining 1,890 units account for 99% of total SO_2 emissions from the electric utility sector during the years 1985-2002 (US EPA, 2003).[6] Given this concentration of SO_2 emissions in two-thirds of the total generating units (and about 95% of total heat input), any perceptible change in total SO_2 emissions from the

[6] A unit is included in the data base if it meets one of several criteria developed to determine units that are significant in generating electricity. These criteria are: 1) more than 5 trillion Btu heat input in any year from 1995 through 2001, 2) more than 1 trillion Btu in any two years out of four consecutive years between 1995 and 2001. A 100 MWe unit consuming 1 trillion Btu in a year with a heat rate of 10,000 Btu/kwh would generate 100 GWh of electricity in the year, or 1,000 hours (about 11% of the hours in a year) at full capacity.

electric utility sector as a whole will be determined almost entirely by changes at these 1,890 significant units.

Since annual SO_2 emissions are the product of heat input, measured in million Btus (mmBtu) and the emission rate measured in pounds of SO_2 per mmBtu (#/mmBtu), changes in observed emissions from one year to the next at any given unit can be decomposed into two components: a change in the annual emission rate, which would reflect the use of a higher or lower SO_2-emitting fuel or the installation of emission control equipment, and 2) a change in annual heat input at the unit, which may reflect a change in aggregate demand for electricity or the effect of displacement of one unit by another in meeting any given level of demand. In nearly all cases, both effects operate, often in off-setting directions; however, the relative contributions of each can be identified using analytic techniques explained briefly below and more fully in the appendix.

While the causes of changes in emissions at any individual unit can be decomposed into two effects, changes in observed emissions from any aggregate of generating units must take account of the interaction of all the units in the aggregate. For instance, if one unit is utilized less, as measured by heat input or generation, and the utilization of another unit is increased by the same amount, the effect on total emissions depends on the emission rates at the two units. If the emission rate is lower at the unit increasing utilization than at the other unit, total emissions will decrease without any change in the emission rates at the two units. Thus, for any aggregate, changes in total emissions can be broken down into three components—emission rate reductions at individual units, changes in aggregate demand, and changes in the utilization of units with differing emission rates—as represented in the following equation.

(1) $dE = dEr + dEh_{agg} + dEh_{Disp}$

where

dEr = the sum of the changes in emissions due to changes in emission rates at individual units,

dEh_{agg} = the change of emissions that can be attributed to changes in aggregate demand without any change in emission rates at individual units, dEh_{Disp} = the change of emissions that can be attributed to the displacement of some units by others in meeting aggregate demand.

The left-hand-side variable of equation (1) is observed and the first two right-hand-side terms can be easily calculated. The term dEr is the sum of the change in emissions due to changes in the emission rate at all constituent units and the term dEh_{agg} can be found by multiplying the prior year's emissions by the percentage change in heat input for the aggregate. Any difference between the sum of dEr and dEh_{agg} and the observed change in emissions, dE, is due, by definition, to displacement, or the emission effects of the changing shares in heat input of the units composing the aggregate.

The availability of data indicating whether the fuel burned in a generating unit is coal or oil/gas allows us to decompose the displacement effect into a shift between fuels and displacements among the units composing each fuel aggregate, as follows:

(2) $dEh_{Disp} = dEh_{bet} + dEh_{w/i,Coal} + dEh_{w/i,Oil/Gas}$

where

dEh_{bet} = the change of emissions that can be attributed to changing shares of generation between coal and oil/gas units,

dE$h_{w/i\ Coal}$ = the change in emissions due to a redistribution of heat input among units using coal, and

dE$h_{w/i\ Oil/Gas}$ = the change in emissions due to a redistribution of heat input among units using oil or natural gas.

One easy way to visualize this decomposition is to recall that the change in emissions due to changing heat input at any individual unit results from the change in aggregate demand for generation, any change in fuel shares, and individual displacements within the two fuel categories. Imagine a situation in which there is no change in the emission rates at individual units so that all changes in emissions are due to these three demand effects. If a coal-fired unit has increased emissions by 3% while aggregate demand has increased 1% and the demand for aggregate coal-fired generation has increased by 1%, one percentage point of the observed three-percent increase in emissions at this individual unit can be attributed to each of the three effects: dEh_{agg}, dEh_{bet}, and dEh_{w/i_Coal}. If observed emissions had not increased at all at this unit while the other conditions applied, then it could be said that this unit experienced a 2% reduction in utilization due to displacement by other coal-fired units. Once these differences are calculated for all units constituting some aggregate, they can then be summed to determine all of the components in equations (1) and (2).

Choosing the appropriate level of aggregation for determining growth in aggregate demand and changes in fuel shares in the United States is not obvious. Fuel shares differ markedly by region, as do the growth rates in the generation of fossil-fuel-fired electricity. Using the national aggregate would not provide an accurate estimate since it would assume that generating units are part of one large integrated national market, which they are not. At the other extreme, a state-level aggregation would be similarly misleading since electricity control areas often encompass several states and electricity flows frequently cross state boundaries even when control areas follow state lines. As a middle ground we have used the nine census regions, the composition of which is given in Table 1 below and for which regional aggregate data is given in Table A1 of the appendix. Accordingly, we calculate dEh_{agg} and the components of dEh_{Disp} on a regional basis and then sum across the nine census regions to obtain national figures.

Region	States
New England	CT, MA, ME, NH, RI, VT
Middle Atlantic	NJ, NY, PA
East North Central	IL, IN, MI, OH, WI
West North Central	IA, KS, MN, MO, ND, NE, SD
South Atlantic	DC, DE, FL, GA, MD, NC, SC, VA, WV
East South Central	AL, KY, MS, TN
West South Central	AR, LA, OK, TX
Mountain	AZ, CO, ID, MT, NM, NV, UT, WY
Pacific	CA, OR, WA

***Table 1**. U.S. census regions and constituent states*

The greater efficiency of the new combined cycle units presents a problem in estimating the SO_2 emission reductions attributable to this new capacity. The heat input used by these new units is fully incorporated into the components of equations (1) and (2), but these units generate more electricity per unit of input than conventional units. Since electricity is the final output, some accounting must be made for this additional displacement and emission reduction, which shows up otherwise erroneously as a reduction in aggregate demand.

This adjustment is made through a three-step process as explained in more detail in the appendix on methodology. First, the heat input savings attributable to the use of combined cycle generating plants is determined. We observe an average heat rate (Btus per kwh) of 7,400 for the combined cycle units and we assume an average heat rate of 10,000 Btus/kwh for the generation being displaced. These figures imply that the heat input displaced by these new combined cycle units is 35% greater than the heat input use observed at these new units. The second step is to determine whether the increased generation is displacing coal-fired or oil/gas fired generation, which we do on a regional basis. The last step is to calculate the emission reduction by multiplying the displaced heat input for each type of generation by the respective average regional emission rates.

DECOMPOSITION RESULTS

NATIONAL RESULTS FOR THE 1985-2002 PERIOD

Figure 2 below and Table A2 of the appendix show the national change in SO_2 emissions in tons by year for the 1985-2002 period and by the three components of equation (1), that is, changes in the emission rate, changes in aggregate demand, and changes in dispatch among units from one year to the next.

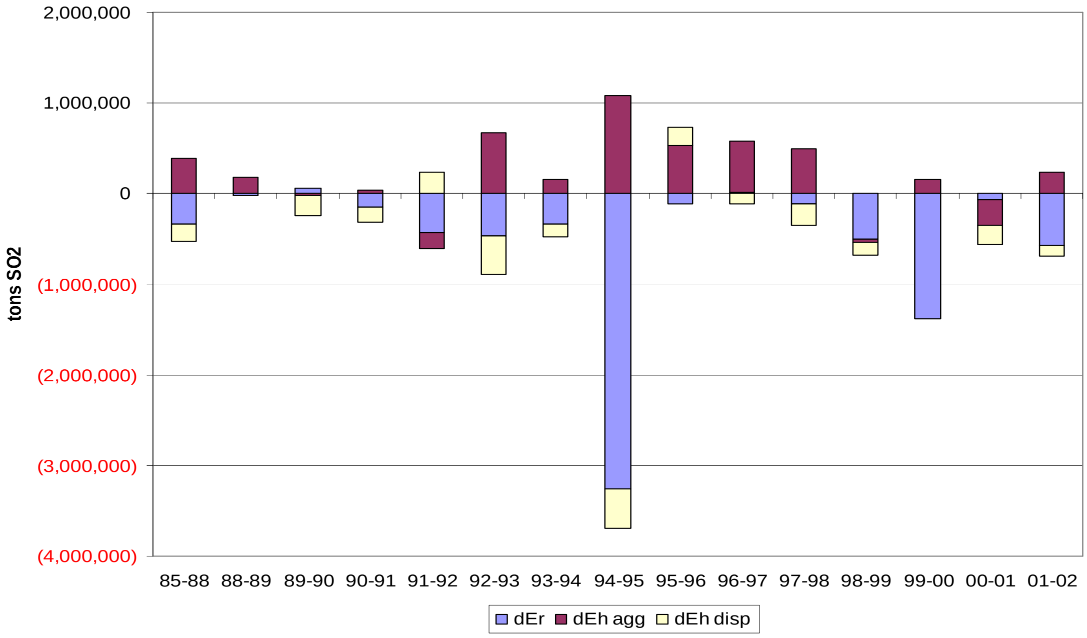

Figure 2*: National change in SO_2 emissions in tons by factor, from 1985 to 2001.*

The most salient feature of Figure 2 is the very large reduction in SO_2 emissions in 1995, the first year of Phase I of the Acid Rain Program. This reduction is especially remarkable in that 1) the cap applied only to a sub-set of units in that year (albeit the largest and most highly emitting units), 2) these units reduced emissions far more than was required to meet the cap in that year (or for any year of Phase I), and 3) the much larger set of generating units that did not become subject to the cap until 2000 increased emissions by some 439,000 tons in 1995 compared with 1994.

The second largest annual reduction is in 2000, when all of the other generating units were first subject to the Title IV cap and therefore required to pay the going price of allowances (about $150/short ton in this year) for all SO_2 emissions. The reduction in 2000 occurred despite the large accumulation of banked allowances from the Phase I units (11.6 million tons) that would have easily covered the abated emissions in 2000, had the owners been willing to pay the price of an allowance. That they did not do so suggests that the cost of reducing emissions at these units was less than $150/short ton. The broader point that emerges from the emission reductions observed in these two years is that, when a price must be paid for otherwise permitted emissions, further reductions of emissions can be achieved.

Setting these two years aside, SO_2 emissions typically declined each year (11 out of 15), but by much smaller amounts than were observed in 1995 and 2000. Table 2 summarizes the emission reductions shown on Figure 2 by component and period, pre- and post-Title IV.

(000 tons SO_2)	**1985-94**	**1994-2002**	**1985-2002**
dEr	- 2,343	- 6,001	- 8,345
dEh $_{agg}$	+ 2,009	+ 2,748	+ 4,757
dEh $_{disp}$	- 1,263	- 1,043	- 2,306
dE	- 1,598	- 4,296	- 5, 894

Table 2. *Emission reductions by component and period, 1985-2002*

As shown in the lower, right-hand cell, 2002 SO_2 emissions from electric utility generating units had fallen by 5.9 million tons from their level in 1985, and they will fall another million tons in order to meet the Phase 2 cap as the Phase I bank of allowances is drawn down. The decomposition of this change shows that emissions would have increased by 4.7 million tons over this period as a result of increasing generation from fossil-fuel-fired generating units[7], but this effect is more than offset by the combined effect of reductions in emission rates at existing units and the general displacement of generation to lower emitting units. Of these two emission-reducing effects, by far the greater is the effect of emission rate reductions. This effect is also notably larger after 1995 than before.

Moreover, not all of the emission reductions observed over the pre-Title IV period can be attributed to air emission regulations. Ellerman and Montero (1998) estimate that the effect of railroad deregulation in making low-sulfur western coals economically competitive at Midwestern generating units burning local, high-sulfur coals reduced SO_2 emissions by about two million tons between 1985 and 1993. This reduction occurred by switching units burning high sulfur mid-western coal partially or entirely to lower sulfur western coal and by the greater utilization of these units. Applying their estimate to this analysis suggests that about half of the 3.6 million ton reduction in SO_2 emissions resulting from emission rate reductions and displacement from 1985 through 1994 was due to reasons other than air emission regulation.[8] Accordingly, the contrast in the magnitude of the emission reductions associated with conventional prescriptive regulation and the cap-and-trade requirements instituted by Title IV is even greater than is suggested by the cumulative amounts in Table 2.

The displacement component in emission reductions observed since 1985 can be further decomposed to reflect the emission effects of shifts in the relative shares of coal and oil/gas and of greater or less use of lower emitting units within each of these fuel types, as shown below by year in Figure 3 and Table A2 of the appendix and cumulatively in Table 3.

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[7] This effect would be larger if it were calculated from some unchanging base year emission rate, such as in 1985, instead of from each succeeding year, which reduces the effect of increasing demand in each year by the emission rate reduction and displacement effects in prior years.
[8] Keohane (2003) shows that the reductions in the delivered price of low-sulfur western coal in the Midwest came to an end in the early 1990s so that the one-year difference in terminal years between the Ellerman-Montero analysis and the analysis in this paper is not likely to be great.

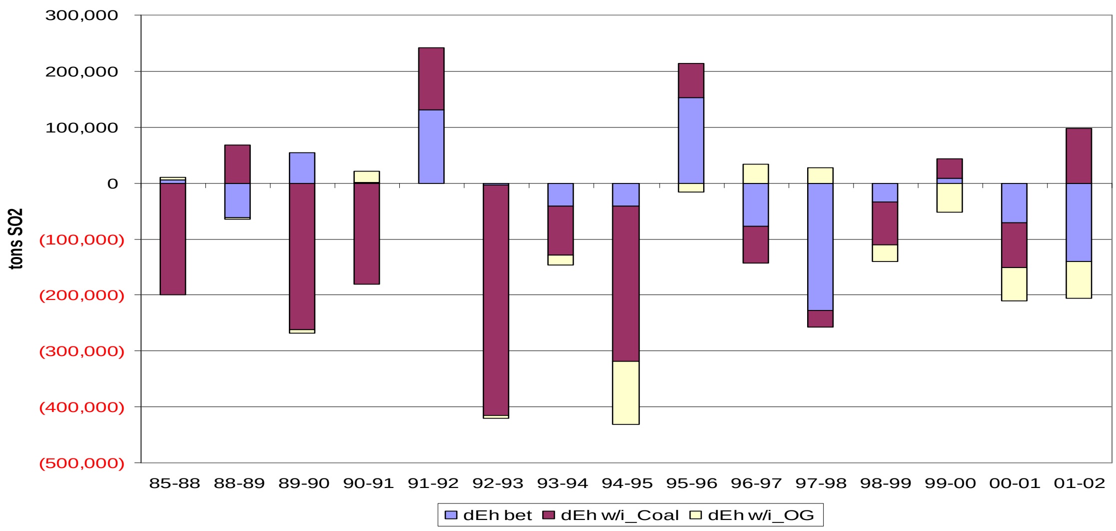

Figure 3. *Decomposition of the displacement effect by year, 1985-2002*

(000 tons SO_2)	**1985-94**	**1994-2002**	**1985-2002**
dEh $_{bet}$	+ 96	- 427	- 330
dEh $_{w/i\_coal}$	- 1,362	- 338	- 1,700
dEh $_{w/i\_OG}$	+ 2	- 278	- 276
dEh $_{disp}$	- 1,263	- 1,043	- 2,306

Table 3. *Cumulative decomposition of the displacement effect*

By far, the largest component of the 2.3 million ton reduction due to displacement of generation among fossil-fuel-fired generating units over the 1985-2002 period is that due to displacement among coal-fired units. This is not surprising since the potential for reduction is large given the range of sulfur content among coals, from as low as 0.5 lbs. SO_2/mmBtu to more than 5 lbs./mmBtu. Most of this reduction occurred in the years before Title IV became effective and it is largely due to the shift to low-sulfur western coal identified by Ellerman and Montero (1998).[9] Once Title IV became effective, the three components of the displacement effect are more balanced and the largest displacement component is a shift to more oil/gas fired generation. This shift is consistent with the abnormally low oil prices experienced in 1998 and the installation of over 150

[9] Since units are dispatched on the basis of variable costs, which are largely fuel costs, units switching to lower cost, lower sulfur western coal would tend to be dispatched more.

GWe of new natural gas fired generating capacity including nearly 100 GWe of new combined cycle capacity to which we now turn.

THE EFFECT OF COMBINED CYCLES ON SO_2 EMISSIONS

The critical issue in estimating the reduction in SO_2 emission due to the new combined cycle capacity is determining what generation is displaced. This question cannot be answered satisfactorily without a disaggregation to at least the regional level because of the significant differences in the regional distribution of the new combined cycle capacity, differing patterns of displacement by region, and different regional emission rates for coal and oil/gas fired generation. The regional distribution of the new combined cycle capacity is given in Table 4 and additional data used in calculating the effect of the new combined cycle capacity on SO_2 emissions is provided in Table A3 of the appendix.

Census Region	CC Capacity 2002 (MW^e)	Regional Share of CC Capacity 2002	Regional Share of US Oil/Gas Generation, 1997	Regional Share of Total Fossil Generation, 1997
New England	6,109	11%	10%	2%
Mid-Atlantic	3,248	6%	13%	8%
East North	3,827	7%	2%	20%
West South	918	2%	1%	10%
South Atlantic	6,489	11%	19%	20%
East South	5,537	10%	2%	11%
West South	22,448	39%	40%	16%
Mountain	4,318	8%	2%	10%
Pacific	4,395	8%	11%	2%
USA (lower 48)	57,289	100%	100%	100%

Table 4. *New combined cycle capacity and regional shares of generation*

The regional distribution of combined cycle capacity follows the pre-existing distribution of oil and gas generation far more closely than it does the pre-existing generation of fossil-fuel fired generation. Five regions constituting 93% of oil and gas generation in 1997 account for 75% of the combined cycle capacity but only 48% of total fossil generation. The largest share by far of new combined-cycle capacity is in the West South Central census region, encompassing Texas, Oklahoma, Arkansas, and Louisiana, which is also the region with the largest share (and absolute amount) of oil and gas generation. Conversely, regions in which there was little pre-existing oil and gas generation received a smaller share of the new combined cycle capacity.

A solid economic reason explains this pattern. When new, more efficient units compete with existing units using the same fuel, they can be assured of being dispatched first if all other factors are equal. However, when the competing units use a different fuel, displacement depends upon the price difference between natural gas and the other fuel. If the price of the fuel firing the more efficient generation is greater percentage-wise than percent savings in heat input, displacement will not occur. This has been the case for the new combined cycle units when they compete against existing coal-fired units in the U.S., especially since late 2002 when natural gas prices rose to levels that are two to three times the level of coal prices. There are, of course, other factors concerning location and network dynamics that influence dispatch, but building combined cycle units where reliance on less efficient natural gas generation is already high provides greater assurance of demand for generation from the new capacity, but also less reduction of emissions.

Two distinct patterns of displacement occur, as illustrated by the two charts in Figure 4.

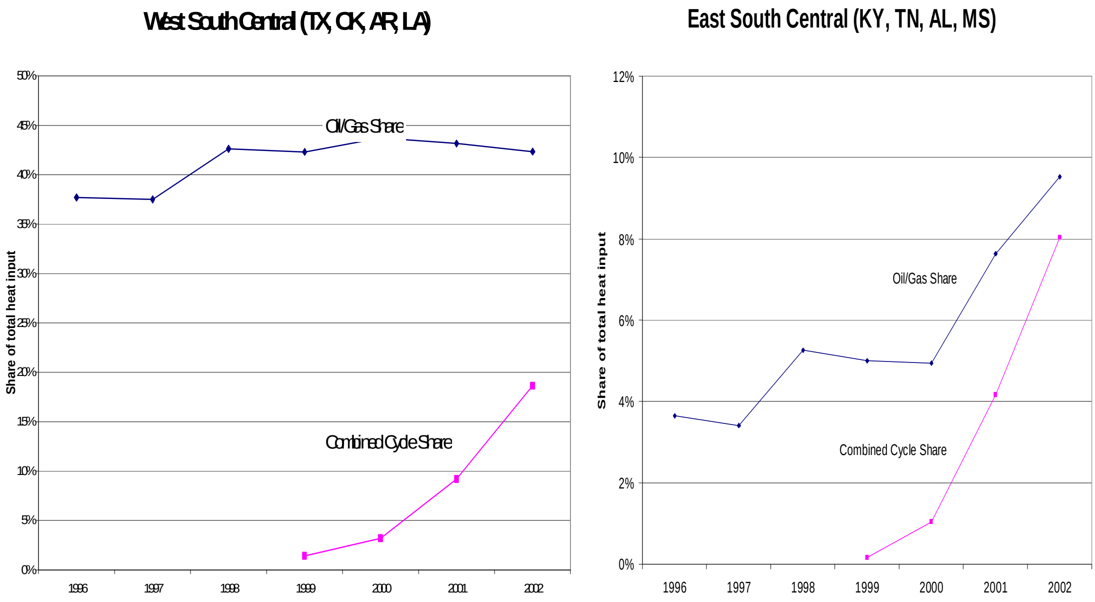

Figure 4*. Combined cycle and oil/gas shares in two census regions*

The uppermost line on each chart represents the share of heat input into oil/gas generating units in that region, while the bottom line shows the share of heat input going into combined cycle units. In all regions, the share of combined cycle capacity rises from nearly zero in 1998 to some noticeable positive share by 2002. In cases such as the West South Central census region, the share of combined cycle heat input rose from 1% in 1999 to 19% in 2002. Over the same period, the total oil and gas share of heat input remained relatively constant at 42%-44%. Obviously, the new combined cycle capacity in this region has been displacing existing oil and gas capacity, not coal capacity.

The East South Central region presents a different picture. The 2002 shares of oil/gas and combined cycle heat input are much smaller than in the West South Central region, but the increase in the combined cycle share from zero percent in 1999 to 8% in 2002 causes the oil/gas share of heat input to increase by five percentage points, from 5% in 1999 to 10% in 2002. Accordingly, it can be said that five percentage points of the 8% increase in combined cycle generation displaced coal generation and the remaining three percentage points displaced existing oil/gas generation, which is now 2% instead of 5%.

When displacement is calculated in this manner for all nine regions for each year, the amount of displacement depends not only on the amount of heat input displaced by the new combined cycle units, but also on the emission rate of the Btu's being displaced from coal or other oil and gas-fired units. Figure 5 and Table 5 below provide the year-by-year results for the nine census regions and the nation as a whole.

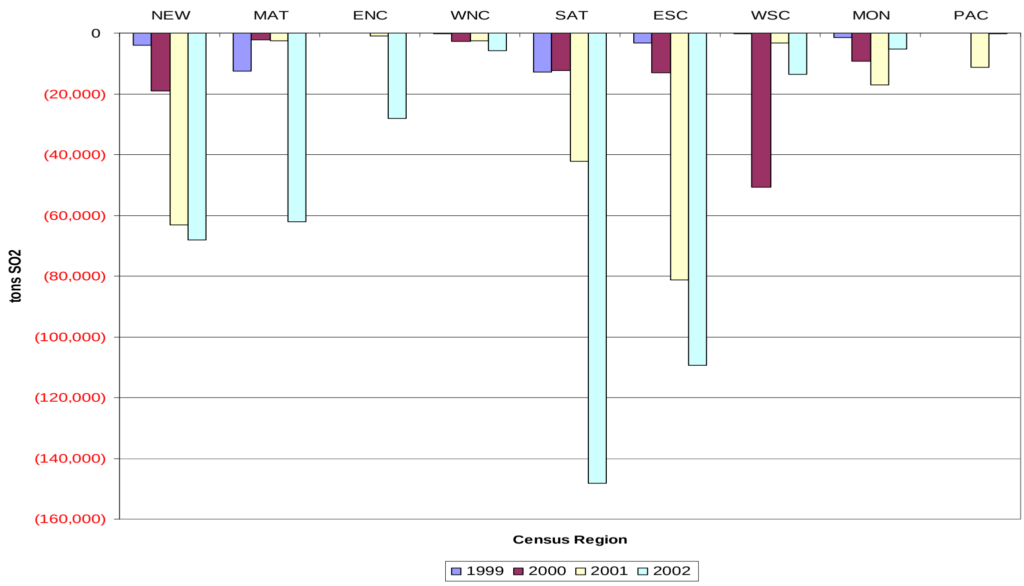

Figure 5. *SO_2 emission reductions due to new combined cycle capacity, by region and year*

000 tons SO_2	1999	2000	2001	2002	Cumulative
New England	-4	-19	-63	-68	-155
Mid Atlantic	-13	-2	-2	-62	-79
East North Central	0	0	-1	-28	-29
West North Central	0	-3	-3	-6	-12
South Atlantic	-13	-12	-42	-148	-215
East South Central	-3	-13	-81	-109	-207
West South Central	0	-51	-3	-14	-68
Mountain	-2	-9	-17	-5	-33
Pacific	0	0	-11	0	-11
Lower 48 States	-35	-110	-225	-441	-810

Table 5. *SO_2 emission reductions due to new combined cycle units, by year and region*

The two regions with the largest cumulative reduction (the sum of the annual amounts) are the East South Central and South Atlantic census regions. Even though they constitute only a quarter of national combined cycle generation, they account for 53% of the national SO_2 reduction attributable to the new combined cycle capacity. The reason is that the new combined cycle capacity in these regions displaced more coal generation and the emission rate associated with the displaced coal generation is relatively high. In contrast, the much larger displacement of existing generation in the West South Central region reduced SO_2 emissions by considerably less because no coal generation was displaced.

A final observation about the effect of the new combined cycle capacity on SO_2 emissions concerns the interaction between these new units and the Title IV cap. While the new combined cycle capacity clearly displaced generation that had higher SO_2 emissions, aggregate SO_2 emissions are no lower than they would otherwise be since the SO_2 emissions cap is fixed.[10] The effect of the new capacity is then to reduce the amount of abatement required from the other, mostly coal-fired units. Consequently, the effect of the new combined cycle capacity is not to reduce actual SO_2 emissions but the emission reduction required of other generators of electricity and therefore the cost of achieving the SO_2 cap.

The extent to which the cost of Title IV has been reduced can be estimated. As shown in Table 5, the cumulative reduction in SO_2 emissions attributable to the combined cycle units as of the end of 2002 is approximately 800,000 tons. The method for calculating the simple counterfactual for 2002 (cf. Ellerman *et al.*, 2000) yields counterfactual emissions that are 6.9 million tons greater than observed emissions of 10.2 million tons; however, this method does not take account of the assumed 35% efficiency gain and greater displacement per unit of heat input associated with the combined cycle units. When this correction is made, counterfactual emissions are 7.1 million tons higher than observed emissions. After subtracting the 800,000 ton emission reduction due to the new combined cycle units, the remaining units reduced SO_2 emissions by only 6.3 million

[10] This effect does not apply for any uncapped emissions, such as NO_x emissions in many states and CO_2 emissions.

tons or about 11% less than what would have been required to meet the same electricity demand without the new combined cycle units. .

Assuming a linear relation between quantity and price for incremental abatement at the current margin, the marginal cost of abatement and the price of allowances is 11% less than it would be absent the introduction of the new combined cycle capacity.[11] The average price of allowances in 2002 was about $150, which would imply marginal costs that would have been $16-$17 higher. Additional combined cycle capacity came on line in 2003, approximately equal in capacity to that added in 2002, so that the ultimate effect might be larger, but this would depend upon the amount of displacement by this new capacity and the data reported so far for 2003 indicates decreasing total oil/gas generation over the past year, probably because of the high natural gas prices that have been observed since the end of 2002. If a round number were to be used for the total effect of the new combined cycle capacity in reducing the marginal cost of abatement, say $20 per ton, the implied annual savings in electricity cost is $180 million when multiplied by the Phase 2 cap of 9 million tons of SO_2 emissions per year.

CONCLUSION

The major source of SO_2 emission reductions in the United States since 1985 has been the reduction of emission rates at existing units. Displacement of higher emitting units by lower emitting ones, whether newly constructed or existing units, has also contributed an important share of the total reduction; however, this factor alone has not been sufficient to offset the increase in emissions that would have occurred as a result of continuing growth in aggregate demand. Our analysis also indicates that Title IV has been more effective in reducing emissions during the eight years it has been in effect than the conventional, source-specific, prescriptive regulation had been in reducing emissions in the ten years preceding 1995.

[11] This is not to say that allowance prices have fallen as the new combined cycle capacity came on line since its effect of the allowance market would have been anticipated.

The effect of the new combined cycle capacity is not what might be expected at first sight. These units have clearly displaced more highly emitting generating units, although most often not coal-fired units, but the effect has been to reduce the cost of abatement, not total SO_2 emissions. When emissions are capped, exogenous factors such as the introduction of more efficient combined cycle generation results in less required abatement by other affected units, in this instance, mostly coal-fired units. From the standpoint of the competition among contending fuels, this effect is ironic but it is small and the ultimate beneficiary is the consumer who thereby pays slightly less for electricity without any change in this attribute of environmental quality.

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APPENDIX I: DECOMPOSITION METHODOLOGY

Decomposition of changes in emissions at the unit level

The SO_2 emissions produced by a generating unit in the *t*th year can be described as:

$$e_t = r_t * h_t$$

where h_t is the heat input (i.e. the energy contained in the fuel burnt during year t) and r_t is the emission rate (i.e. the amount of SO_2 emitted per unit of heat input). The change in SO_2 emission between year 0 and t can be described as a function of four observed values, h_0, h_t, r_0, and r_t, such that

$$de_{0,t} = r_t h_t - r_0 h_0 = (r_0 + dr_{0,t})(h_0 + dh_{0,t}) - r_0 h_0$$

$$de_{0,t} = r_0 dh_{0,t} + h_0 dr_{0,t} + dr_{0,t} dh_{0,t}$$

where the $d_{0,t}$'s denote the observed change in *e*, *r* or *h* between year *0* and *t*.

The change in emissions, $de_{0,t}$, can also be represented in a (h,r) diagram:

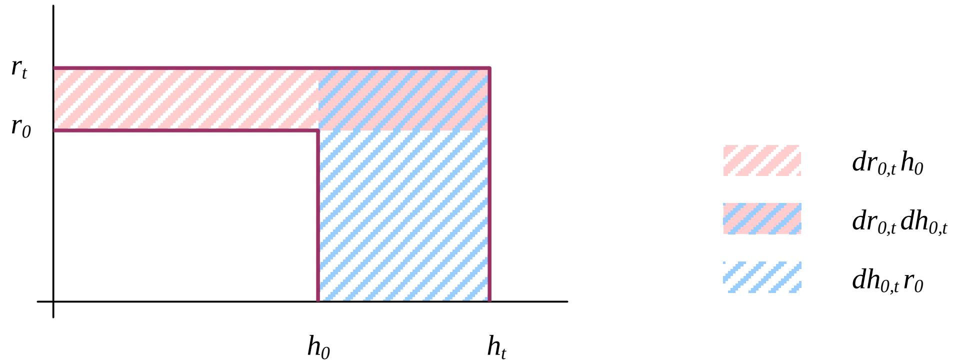

Figure 6. *Representation of the heat input, emission rate and emissions of a generating unit in a (h,r) diagram*

In this diagram the surface of the h_0 x r_0 rectangle is equal to the emissions e_0, and the surface of the h_t x r_t rectangle is equal to the emissions e_t. The difference $e_t - e_0$ is represented by the striped areas. The diagram clearly shows that $de_{0,t}$ can be separated into three components:

$\Delta_1 = (r_t - r_0)h_0$ which is created by a change of the unit's emission rate

$\Delta_2 = (h_t - h_0)r_0$ which is created by a change of the unit's heat input

$\Delta_3 = (r_t - r_0)(h_0 - h_t)$ which is created by both changes

We adopt the convention of splitting the third component evenly and attributing each half to the other two components so that we can attribute $\Delta_1 + \Delta_3 /2$ to a change of emission rate and $\Delta_2 + \Delta_3 /2$ to a change of heat input, which gives us:

- the change in emissions due to a change in heat input

$$de_h = r_0 dh_{0,t} + \frac{dr_{0,t} dh_{0,t}}{2}$$

- the change in emissions due to a change in the emission rate

$$de_r = dr_{0,t} h_0 + \frac{dr_{0,t} dh_{0,t}}{2}$$

When a unit is either shut down or put online (i.e. either h_o or h_t is equal to zero), we set $de_r = 0$ and attribute all the change in emissions to a change in heat input.

Accounting for the interaction of individual units with others in some aggregate

The two components accounting for changes in emissions at the unit level, de_r and de_h, have differing characteristics when the unit is considered as part of some aggregate, such as an electricity grid.[12] A change in emission rate, de_r, such as that resulting from the installation of a scrubber, is a unit specific action that does not imply a change in the emission rate at other units in the aggregate. In contrast, a change in heat input at an individual unit, de_h , will always reflect some change in the aggregate that is shared by other units or is the result of the interaction among the constituent units. For instance, a change in aggregate demand would be expected to affect all units in some measure. Similarly, changes in fuel prices or in conditions on the electricity network, would be expected to change the contribution of constituent units to meeting aggregate demand.

While the observed change in heat input at any single unit results from changes in conditions affecting the aggregate, the contributing factors can be analytically separated into three components: the change in aggregate demand, any change in the contribution of coal and oil/gas units viewed as sub-sets, and any change in the utilization of individual units within each fuel share.

More formally, heat input at the *i*th unit can be decomposed into three components.

$h_t^i - h_0^i = dh_{agg}^i + dh_{bet}^i + d\,h_{w/i}^i$.

where

dh_{agg}^i is the *i*th unit's share of the change of heat input for the aggregate:

$$dh_{agg}^i = \frac{h_0^i}{H_0}\left(H_t - H_0\right)$$

with H_0, H_t being the aggregate heat input for years $0, t$

dh_{bet}^i reflects what would be the change in the *i*th unit's heat input due to a change in the share of the subset of units constituting "fuel X" in year t assuming no change in the shares of the constituent units in that fuel subset:

$$dh_{bet}^i = \frac{h_0^i}{H_{0,\,fuelX}}\left(H_{t,\,fuelX} - H_{0,\,fuelX} * \frac{H_t}{H_0}\right) = h_0^i\left(\frac{H_{t,\,fuelX}}{H_{0,\,fuelX}} - \frac{H_t}{H_0}\right)$$

with $H_{0,fuelX}$, $H_{t,fuelX}$ the aggregate heat input for 'fuel X' units for years $0, t$.

$dh_{w/i}^i$ is the remaining part of $h_t - h_0$ which will be equal after substitution and cancellation to:

$$dh_{w/i}^i = h_t^i - h_0^i \frac{H_{t,\,fuelX}}{H_{0,\,fuelX}}$$

$dh_{w/i}^i$ reflects the effect of any change in the role of the *i*th unit within the fuel X subset after allowing for changes in aggregate demand and for any change in fuel share.

[12] We use regional aggregates defined along the lines of the U.S. census regions, but the

With these definitions, the new decomposition of $de_{0,t}$ in the (h,r) diagram for a unit experiencing an increase in heat input due to all three factors is:

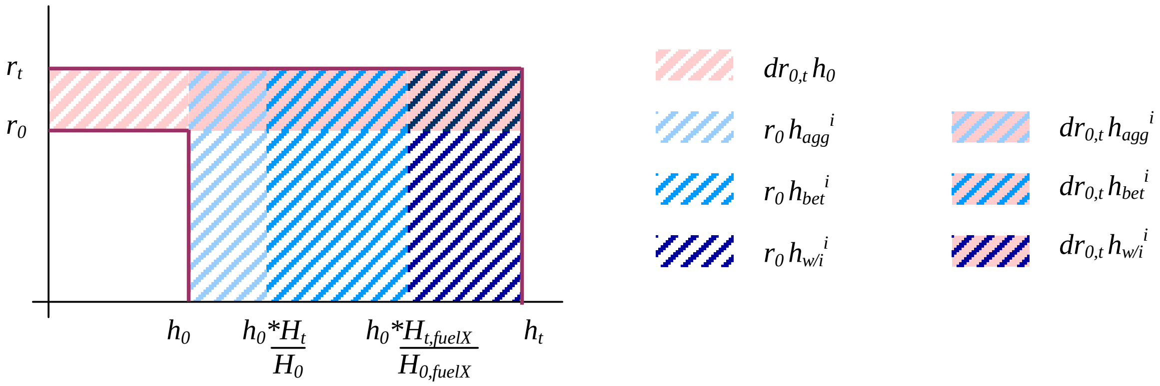

Figure 7. *Representation of the decomposition of the heat input and associated emissions of a generating unit in a (h,r) diagram*

Returning now to the formulae for changes in emissions, we can decompose $de_{0,t}$ into four components:

$$de_r^i = dr_{0,t}^i\left(h_0^i + \frac{dh_{0,t}^i}{2}\right)$$

$$de_{h,agg}^i = \left(r_0^i + \frac{dr_{0,t}^i}{2}\right)dh_{agg}{}^i = \left(r_0^i + \frac{dr_{0,t}^i}{2}\right)\frac{h_0{}^i}{H_0}(H_t - H_0)$$

$$de_{h,bet}^i = \left(r_0^i + \frac{dr_{0,t}^i}{2}\right)dh_{bet}{}^i = \left(r_0^i + \frac{dr_{0,t}^i}{2}\right)\frac{h_0{}^i}{H_{0,\,fuel}}\left(H_{t,\,fuel} - H_{0,\,fuel}\frac{H_t}{H_0}\right)$$

$$de_{h,w/i}^i = \left(r_0^i + \frac{dr_{0,t}^i}{2}\right)dh_{w/i}{}^i = \left(r_0^i + \frac{dr_{0,t}^i}{2}\right)\left(h_t{}^i - \frac{H_{t,\,fuel}}{H_{0,\,fuel}}h_0^i\right)$$

All the above equations are unit-level equations. Aggregate numbers can be obtained by adding up the $de^i{}_x$ of all the units of the database: $dE_X = \sum_{i\in database} de_X^i$.

methodology applies for any aggregate.

Special considerations for combined cycle units

Combined cycle units present a problem in accounting for their effect on emissions because they are markedly more efficient in generating electricity than conventional coal and oil/gas generating units. The decomposition methodology presented above is based upon heat input, not electricity, which is the final product. So long as the heat rate, the number of Btu's used to produce a kilowatt-hour of electricity remains relatively constant from year to year and among units that would substitute for one another on the electricity grid, no great distortion results from using heat input as the proxy for electricity output. However, with the recent introduction of a significant amount of combined cycle capacity, this assumption no longer holds and some allowance must be made to recognize that the emission reduction resulting from the displacement of conventional generation by new combined cycle units is greater than would be indicated by a similar displacement among conventional units.

More formally, so long as combined cycles did not play a large role in generation, such as was the case until 1999, it was reasonable to assume that $dEh_{agg} \approx dEh_{elec}$ where the left-hand-side of the equation is defined as the change in emissions due to the observed change in heat input and the right-hand-side, as the change due to the assumed change in demand for electricity from fossil-fuel-fired generating units. With the introduction of a significant amount of combined cycle generation, a new term is required, dEh_{cc}, defined as the change in emissions due to the unobserved heat input savings resulting from the zero-fuel (thus zero-emission) electricity generation by the heat recovery unit of combined cycle facility. Conceptually, this new term can be defined in the following manner:

$$dEh_{cc} \approx dEh_{agg} - dEh_{elec}$$

If the share of combined cycle generation in the aggregate is increasing, then $dEh_{elec} > dEh_{agg}$ and dEh_{cc} will be negative, and vice versa if the share of combined cycle generation is decreasing.

Estimating dEh_{cc} required two analytical tasks to be performed. First, combined cycle units were identified within the subset of oil/gas units. Second, the heat input savings associated with combined cycles was estimated. At first appearance, all of the information required to perform both tasks appeared to be in the quarterly reports whereby emissions are reported to the U.S. Environmental Protection Agency, hereafter called the CEMS (for Continuous Emissions Monitoring System) database, which record not only emissions but also heat input and electricity generation at the unit level, as well as identifiers for the fuel burned and the type of unit. In fact, cross checks with other sources revealed that labels identified as combined cycle in the CEMS database were not always such and that some not so labeled were combined cycle units. Comparison with data reported to the Energy Information Agency and data obtained by web search and direct calls enabled us to identify 276 out of the 948 oil/gas units that could be considered combined cycle units in that these Btu-using generating units had an associated heat recovery unit.

A more serious problem was that the generation reported for combined cycle units in the CEMS database was often only the generation from the gas turbine and not the additional power from the associated heat recovery unit. For instance in 2001, out of the 276 combined cycles, 52 units had an average heat rate above 10,000 Btu/kWh. From discussions with the owners of some of these units, we found that the data reported to the EPA on the CEMS forms sometimes contains only the generation for the turbine (which is the Btu-using and emitting unit) and not the generation from the (non-emitting) recovery unit. Consequently, there is no reliable method within the CEMS data to determine which combined cycle units had complete generation data and which were incomplete. To remedy this problem, we used another database from the Energy Information Administration, EIA Form 906, which reports electricity generation and heat input for all units for the year 2001. We took all the units from the EIA database that were also present in the 276 combined cycles list of the CEMS data and selected a group of 41 units that had been in operation for more than two quarters (thereby avoiding heat-rate-diminishing start-up problems) and showed steady generation and generally high utilization. This subset of fully operational combined cycles experienced an average heat rate of 7,400 Btu/kWh.

The heat input savings from combined cycle units was then easily calculated using an assumed average heat rate of 10,000 Btu/kwh for conventional generating units. Dividing 10,000 by 7,400 provides the assumed heat input savings of 35% that we use for estimating the emission reductions from the conventional generation displaced by the new combined cycle units.

More formally, it is possible to calculate the total heat input displaced by combined cycles as the sum of the observed heat input of CCs and an estimate of the heat input saved by the recovery unit:

$h^{i}_{cc,disp} = h^{i}_{cc,obs} + h^{i}_{cc,sav}$ for any CC unit I

Since the combined cycle units are present in the database we use, the change in emissions associated with changes in $h^{i}_{cc,obs}$ are already included in dEh_{bet} and $dEh_{w/i,OG}$. dEh_{cc} is an adjustment, required to account for the emissions savings due to the greater efficiency of combined cycle units, that depends on $h^{i}_{cc,sav}$, which is related in turn to $h^{i}_{cc,obs}$ as follows: $h^{i}_{cc,sav} = 0.35*h^{i}_{cc,obs}$.

Finally, the savings for the Yth region can be summed across units as: $H^{Y}_{cc,sav} = \sum_{i \in cc,regionY} h^{i}_{cc,sav}$

Furthermore, if we assume that the displacement due to the heat input savings, $H_{t,cc,sav}$, is proportional in all respects to the displacement occasioned by the observed heat input at combined cycle units, $H_{t,cc,obs}$, then the heat input savings can be similarly broken down into a component displacing coal generation and another displacing other oil/gas units. Thus:

$$H_{t,cc,sav} = H_{t,cc,sav}^{coal} + H_{t,cc,sav}^{O/G} = H_{t,cc,sav} * (\%_{coal} + \%_{O/G})$$

The calculation of $\%_{coal}$ and $\%_{O/G}$ can be illustrated taking New England between 1999 and 2001 as an example. Figure 8 represents the heat input shares of coal units, conventional oil/gas units, and combined cycle units.

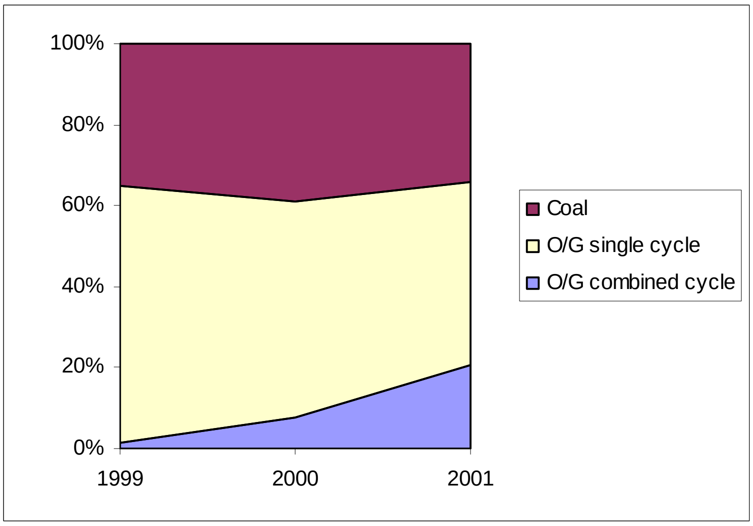

Figure 8. *Shares of Heat Input from coal, oil/gas single cycles and oil/gas combined cycle units in New England between 1999 and 2001.*

Three patterns of heat input displacement by combined cycles are possible.

i) If the share of coal heat input either increases or stays equal from one year to the next, then there is no coal displacement and combined cycles exclusively displaced oil/gas units. We then simply calculate the emissions savings by using the average oil/gas emission rate. Accordingly, $\%_{coal} = 0$ and $\%_{O/G} = 1$.

ii) If the share of heat input from coal decreases more than the share of combined cycles increases, then we assume that the combined cycle units have displaced coal units only (and that conventional oil/gas single cycles have displaced coal as well). Thus $\%_{coal} = 1$ and $\%_{O/G} = 0$.

iii) Finally, if there is a decrease in the share of heat input from coal smaller than the increase in the share of combined cycles, then we assume that the combined cycle units have displaced both coal and oil/gas units as follows: $\%_{coal} = -\frac{(H_{t,coal} - H_{0,coal})}{(H_{t,cc,obs} - H_{0,cc,obs})}$ and $\%_{O/G} = \%_{coal} - 1$.

Once $\%_{coal}$ and $\%_{O/G}$ have been calculated for each region and each year between 1999 and 2002, the corresponding emissions savings can then be calculated using the average regional (or other aggregate) emission rates of coal r_{coal} and oil/gas $r_{O/G}$, which are observed. Thus,

$$E_{t,cc,sav} = E_{t,cc,sav}^{coal} + E_{t,cc,sav}^{O/G} = H_{t,cc,sav} * (\%_{coal} * r_{coal} + \%_{O/G} * r_{O/G})$$

Table 6 shows the values obtained for dEh_{cc}, as well as the SO_2 savings due to the displacement of generation by the entire combined cycle unit, which is related to the savings by a factor of 1.35/0.35 or about 4)

	SO_2 savings due to CCs' heat recovery unit (dEh_{cc})				SO_2 savings due to CCs as a whole			
	1999	2000	2001	2002	1999	2000	2001	2002
NEW	-1,051	-4,974	-16,397	-17,703	-4,052	-19,185	-63,246	-68,283
MAT	-3,253	-610	-632	-16,096	-12,547	-2,353	-2,438	-62,083
ENC	0	-9	-260	-7,315	0	-35	-1,004	-28,213
WNC	-36	-711	-657	-1,480	-138	-2,744	-2,532	-5,709
SAT	-3,343	-3,228	-10,989	-38,397	-12,893	-12,452	-42,386	-148,102
ESC	-852	-3,385	-21,074	-28,342	-3,287	-13,056	-81,286	-109,319
WSC	-56	-13,154	-833	-3,503	-216	-50,738	-3,212	-13,511
MON	-402	-2,402	-4,436	-1,343	-1,552	-9,264	-17,110	-5,179
PAC	0	0	-2,951	-74	0	0	-11,382	-285
USA	-8,992	-28,473	-58,229	-114,252	-34,685	-109,825	-224,596	-440,685
USA Cumul.		-37,466	-95,694	**-209,946**		-144,510	-369,106	**-809,792**

Table 6. *SO_2 emissions savings due to the electricity generation displaced by combined cycles between 1999 and 2002*

APPENDIX II: DATA TABLES

Table A1. Heat input, SO_2 emissions, and average emission rates by region

	1985	1988	1989	1990	1991	1992	1993	1994
New England								
Heat input	484	527	556	485	461	413	327	331
SO_2 emissions	380	406	409	354	337	306	234	212
Emission rate	1.568	1.540	1.470	1.461	1.459	1.483	1.430	1.283
Middle Atlantic								
Heat input	1,818	1,962	2,031	1,923	1,843	1,737	1,657	1,627
SO_2 emissions	1,645	1,694	1,696	1,670	1,623	1,557	1,465	1,429
Emission rate	1.809	1.727	1.670	1.737	1.762	1.793	1.767	1.756
East North Central								
Heat input	3,456	3,601	3,662	3,741	3,808	3,713	3,906	4,069
SO_2 emissions	5,435	5,149	5,232	5,167	5,091	4,784	4,673	4,686
Emission rate	3.145	2.860	2.857	2.762	2.673	2.577	2.393	2.303
West North Central								
Heat input	1,518	1,756	1,754	1,800	1,825	1,754	1,829	1,933
SO_2 emissions	1,582	1,355	1,317	1,311	1,306	1,169	974	1,088
Emission rate	2.085	1.543	1.502	1.457	1.431	1.334	1.065	1.126
South Atlantic								
Heat input	3,341	3,661	3,817	3,640	3,634	3,678	3,873	3,867
SO_2 emissions	3,372	3,559	3,527	3,469	3,420	3,457	3,444	3,306
Emission rate	2.018	1.944	1.848	1.906	1.882	1.880	1.778	1.710
East South Central								
Heat input	1,795	1,919	1,797	1,910	1,932	1,969	2,235	2,157
SO_2 emissions	2,234	2,245	2,310	2,354	2,267	2,342	2,556	2,354
Emission rate	2.489	2.340	2.571	2.464	2.347	2.379	2.287	2.182
West South Central								
Heat input	3,340	3,331	3,324	3,335	3,344	3,311	3,503	3,456
SO_2 emissions	802	677	715	732	750	774	838	763
Emission rate	0.480	0.406	0.431	0.439	0.448	0.468	0.478	0.442
Mountain								
Heat input	1,643	1,974	2,038	2,043	2,009	2,138	2,097	2,201
SO_2 emissions	480	428	466	454	442	466	457	484
Emission rate	0.585	0.434	0.457	0.444	0.440	0.436	0.436	0.440
Pacific Contiguous								
Heat input	707	646	639	569	543	681	590	728
SO_2 emissions	75	76	78	71	71	84	87	86
Emission rate	0.212	0.235	0.245	0.248	0.263	0.248	0.295	0.235
National								
Heat input	18,102	19,378	19,619	19,446	19,398	19,394	20,018	20,369
SO_2 emissions	16,006	15,591	15,751	15,581	15,306	14,939	14,727	14,408
Emission rate	1.768	1.609	1.606	1.602	1.578	1.541	1.471	1.415

Note. Heat input in trillion Btus, emissions in thousand short tons, emission rate in lb. SO_2/mmBtus.

Table A1 (con't). Heat input, SO_2 emissions, and average emission rates by region

	1995	1996	1997	1998	1999	2000	2001	2002
New England								
Heat input	369	413	558	550	505	470	511	512
SO2 emissions	204	195	265	274	243	211	192	128
Emission rate	1.105	0.943	0.950	0.996	0.961	0.897	0.750	0.500
Middle Atlantic								
Heat input	1,695	1,699	1,839	1,961	1,858	1,870	1,827	1,917
SO2 emissions	1,324	1,292	1,369	1,420	1,283	1,270	1,241	1,170
Emission rate	1.562	1.521	1.490	1.448	1.381	1.359	1.359	1.220
East North Central								
Heat input	4,250	4,579	4,707	4,875	4,791	4,832	4,619	5,450
SO2 emissions	3,258	3,667	3,804	3,762	3,489	3,015	2,761	2,730
Emission rate	1.533	1.602	1.616	1.543	1.457	1.248	1.195	1.002
West North Central								
Heat input	2,211	2,259	2,320	2,417	2,422	2,472	2,484	2,190
SO2 emissions	996	959	918	939	896	790	813	974
Emission rate	0.901	0.849	0.791	0.777	0.740	0.639	0.655	0.890
South Atlantic								
Heat input	4,253	4,579	4,792	5,056	5,073	5,059	4,870	4,888
SO2 emissions	2,750	2,954	3,086	3,269	3,148	2,840	2,713	2,746
Emission rate	1.293	1.290	1.288	1.293	1.241	1.123	1.114	1.124
East South Central								
Heat input	2,534	2,513	2,620	2,570	2,676	2,762	2,724	2,406
SO2 emissions	1,781	1,807	1,866	1,823	1,767	1,651	1,496	1,099
Emission rate	1.406	1.438	1.424	1.418	1.320	1.195	1.098	0.914
West South Central								
Heat input	3,775	3,830	3,880	4,142	4,266	4,361	4,142	4,205
SO2 emissions	924	96	994	971	984	836	834	841
Emission rate	0.490	0.506	0.513	0.469	0.461	0.384	0.403	0.400
Mountain								
Heat input	2,200	2,302	2,378	2,499	2,507	2,601	2,650	2,587
SO2 emissions	503	489	507	484	434	408	418	391
Emission rate	0.457	0.425	0.426	0.388	0.347	0.314	0.315	0.302
Pacific Contiguous								
Heat input	467	454	504	594	643	866	1,003	708
SO2 emissions	60	83	70	88	104	98	87	32
Emission rate	0.255	0.367	0.278	0.297	0.325	0.227	0.173	0.089
National								
Heat input	21,753	22,629	23,598	24,663	24,740	25,292	24,829	24,863
SO2 emissions	11,799	12,415	12,880	13,030	12,349	11,119	10,554	10,112
Emission rate	1.085	1.097	1.092	1.057	0.998	0.879	0.850	0.813

Note. Heat input in trillion Btus, emissions in thousand short tons, emission rate in lb. SO_2/mmBtus.

Table A2. Decomposition of US SO_2 emission changes from 1985 to 2002 (tons SO_2)

	85-88	88-89	89-90	90-91	91-92	92-93	93-94	94-95
dEr	(1,006,068)	(21,095)	68,099	(151,580)	(431,379)	(467,854)	(333,388)	(3,262,739)
dEh agg	1,158,880	177,574	(24,002)	36,217	(176,880)	676,632	160,129	1,085,564
dEh disp	(567,998)	4,032	(214,656)	(159,150)	241,372	(420,647)	(146,430)	(431,280)
dEh bet	*17,003*	*(61,896)*	*54,290*	*972*	*131,061*	*(4,149)*	*(40,983)*	*(40,992)*
dEh w/i_Coal	*(585,000)*	*65,927*	*(268,946)*	*(160,123)*	*110,311*	*(416,498)*	*(105,447)*	*(390,288)*
dEh w/i_OG	*14,837*	*(2,671)*	*(7,520)*	*21,081*	*(885)*	*(4,928)*	*(17,920)*	*(112,684)*
dE	(415,185)	160,511	(170,559)	(274,513)	(366,887)	(211,869)	(319,689)	(2,608,455)

	95-96	96-97	97-98	98-99	99-00	00-01	01-02
dEr	(116,650)	18,020	(118,570)	(504,606)	(1,375,826)	(64,047)	(576,993)
dEh agg	535,560	556,647	499,392	(35,830)	154,141	(289,325)	242,235
dEh disp	196,802	(109,935)	(230,446)	(140,263)	(8,622)	(211,068)	(107,741)
dEh bet	*152,300*	*(76,646)*	*(227,473)*	*(33,027)*	*9,076*	*(70,293)*	*(139,518)*
dEh w/i_Coal	*44,502*	*(33,289)*	*(2,973)*	*(107,236)*	*(17,699)*	*(140,775)*	*31,777*
dEh w/i_OG	*(16,480)*	*33,494*	*27,133*	*(30,322)*	*(52,333)*	*(60,269)*	*(66,537)*
dE	615,712	464,732	150,376	(680,698)	(1,230,307)	(564,440)	(442,498)

Table A3. Data for calculating combined cycle SO_2 emission reductions, 1998-2002

	1998	1999	2000	2001	2002
Heat input into combined cycle units (trillion Btu)					
New England	-	7	37	105	191
Middle Atlantic	-	10	11	10	58
East North Central	-	0	0	7	41
West North Central	-	1	6	15	19
South Atlantic	-	14	24	52	253
East South Central	-	4	29	113	193
West South Central	-	61	139	381	783
Mountain	-	6	41	74	162
Pacific Contiguous	-	0	0	21	95
National	-	104	287	778	1,796
Combined cycle share of fossil-fuel heat input					
New England	-	1.4 %	7.9 %	20.6 %	37.4 %
Middle Atlantic	-	0.5 %	0.6 %	0.5 %	3.0 %
East North Central	-	0.0 %	0.0 %	0.1 %	0.8 %
West North Central	-	0.0 %	0.3 %	0.6 %	0.9 %
South Atlantic	-	0.3 %	0.5 %	1.1 %	5.2 %
East South Central	-	0.2 %	1.0 %	4.2 %	8.0 %
West South Central	-	1.4 %	3.2 %	9.2 %	18.6 %
Mountain	-	0.3 %	0.5 %	1.1 %	5.2 %
Pacific Contiguous	-	0.0 %	0.0 %	2.1 %	13.5 %
National	-	0.4 %	1.1 %	3.1 %	7.2 %
Oil/gas share of fossil-fuel heat input					
New England	68 %	65 %	61 %	66 %	68 %
Middle Atlantic	29 %	31 %	28 %	29 %	32 %
East North Central	2 %	2 %	2 %	2 %	6 %
West North Central	2 %	2 %	2 %	2 %	2 %
South Atlantic	18 %	18 %	16 %	18 %	20 %
East South Central	5 %	5 %	5 %	8 %	10 %
West South Central	43 %	42 %	44 %	43 %	42 %
Mountain	4 %	5 %	7 %	9 %	9 %
Pacific Contiguous	75 %	77 %	84 %	85 %	80 %
National	18 %	18 %	19 %	20 %	20 %
Average emission rate for coal units (lbs. SO_2 per million Btu)					
New England	1.31	1.32	1.32	1.32	1.00
Middle Atlantic	1.88	1.86	1.75	1.77	1.60
East North Central	1.58	1.49	1.27	1.21	1.02
West North Central	0.79	0.75	0.65	0.66	0.90
South Atlantic	1.39	1.35	1.22	1.21	1.29
East South Central	1.44	1.35	1.23	1.13	1.01
West South Central	0.81	0.79	0.67	0.69	0.69
Mountain	0.41	0.36	0.34	0.34	0.33
Pacific Contiguous	1.18	1.43	1.40	1.15	0.44
National	1.22	1.16	1.03	1.00	0.97