Output-Based Regulations: A Handbook for Air Regulators

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OUTPUT-BASED REGULATIONS:
A HANDBOOK FOR AIR REGULATORS

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CONTENTS

CONTENTS

Section **Page**

LIST OF TABLES

LIST OF TABLES (CONTINUED)

Table **Page**

LIST OF FIGURES

Figure **Page**

EXECUTIVE SUMMARY

The U.S. Environmental Protection Agency (EPA) developed this handbook to assist air regulators in developing emissions regulations that recognize the pollution prevention benefits of efficient energy generation and renewable energy technologies. These clean energy technologies prevent pollution by using less fuel and, thus, reducing associated emissions. Output-based regulations encourage energy efficiency and renewables by relating emissions to the productive output of the process, not to the amount of fuel burned. While *output-based* regulations have been used for regulating many industries, *input-based* regulations have been traditionally used for boilers and power generation sources. Recently, this trend has begun to change as regulators seek to promote pollution prevention and provide more compliance flexibility to combustion sources.

> *An electronic version of this handbook can be obtained at* http://www.epa.gov/cleanenergy.

The EPA Climate Protection Partnerships Division developed this handbook to assist state, local, and tribal regulators in developing output-based regulations. The handbook provides practical information to help regulators decide if they want to use output-based regulations and explains how to develop an output-based emission standard.

What is an output-based regulation?

Output-based *regulations* include output-based emission *standards* as well as output-based *allocations* of emission allowances within a cap and trade program. An output-based emission standard relates emissions to the productive output of the process. Output-based emission standards use units of measure such as lb emission/MWh generated or lb emissions/MMBtu of steam generated, rather than heat input (lb/MMBtu) or pollutant concentration (ppm). In a cap and trade program, emission allowances can be allocated to energy generation sources based on energy output (e.g., electricity or steam generated) rather than fuel burned (i.e., heat input).

Why adopt output-based regulations?

The primary benefit of output-based regulations is that they encourage efficiency and pollution prevention. More efficient combustion technologies and low-emitting renewable energy applications benefit from the use of output-based regulations. The use of these technologies reduces fossil fuel use and leads to multi-media reductions in the environmental impacts of the production, processing, transportation, and combustion of fossil fuels. In addition, reducing fossil fuel combustion is a pollution prevention measure that reduces emissions of all products of combustion, not just the target pollutant of a regulatory program.

Another benefit is that output-based standards allow sources to use energy efficiency as part of their emissions control strategy. Allowing energy efficiency as a control measure provides regulated sources with an additional compliance option that can lead to reduced compliance costs as well as lower emissions. Input- or concentration-based standards do not provide this option.

In a cap and trade program, states can design an output-based allowance allocation system to accomplish a number of environmental objectives. For example, a program that periodically updates output-based allocations encourages increased energy efficiency by sources vying for a larger share of the allocations. In addition, a program that allocates output-based allowances to non-emitting electricity generators on an updating basis provides a financial incentive for the introduction of renewable energy sources, such as wind power. EPA has developed guidance for states on how to develop output-based allocations under the NOx Budget Trading program.

How do I develop an output-based emission standard?

Several decisions must be made about the format of the rule. Making these decisions involves trade-offs between the degree to which the rule will account for the benefits of energy efficiency, the complexity of the rule, and the ease of measuring compliance.

The steps for developing an output-based emission standard are:

- *Develop the output-based emission limit.* The method that is used will depend on whether or not measured energy output data is available.

- *Specify a gross or net energy output format.* Net energy output more comprehensively accounts for energy efficiency, but can increase the complexity of compliance monitoring requirements.

- *Specify compliance measurement methods.* Output-based standards require designating methods for monitoring electrical, thermal, and mechanical outputs. Instruments to continuously monitor and record energy output are routinely used and are commercially available at a reasonable cost.

- *Specify how to calculate emission rates for combined heat and power (CHP) units.* For CHP units, the standard must account for multiple energy outputs. This handbook describes two general approaches that typically are used.

Who has developed output-based regulations?

A number of federal, regional, and state programs have recently adopted output-based emissions regulations, including emission standards for large and small generators, cap and trade allowance allocation systems, multi-pollutant regulations, and generation performance standards (Table ES-1).

To provide additional insight into the technical and policy considerations of setting output-based standards, this handbook describes three output-based emission reduction programs. These programs are:

- *The output-based approach that EPA used to revise the electric utility boiler NSPS.* This action reflected a major change in approach for the NSPS and provided an efficiency-based rationale for transitioning to output-based regulation.

- *A model rule for output-based standards for small electric generators.* The model rule is a good example of a straight-forward output-based emission limit program with recognition of the thermal output of CHP.

- *The EPA guidance on how to allocate emission allowances for the NO_x SIP call based on energy output.* The approach was developed by a stakeholder group of EPA, states, industry, and environmental groups. The guidance provides a thorough discussion of how output-based allocation can be applied.

In conclusion, output-based regulations are gaining greater attention as EPA, states, and regional planning organizations strive to find innovative ways to attain today's air quality goals. Emissions from energy production processes contribute to a number of air pollution problems, including fine particulates, ozone, acid rain, air toxics, visibility degradation, and climate change. An output-based regulation is a tool that can be used as part of a regulatory strategy that encourages pollution prevention and the use of innovative and efficient energy-generating technologies. Adopting output-based regulations, therefore, is a valuable tool for protecting air quality while fostering the development of efficient, reliable, and affordable supplies of energy.

Table ES-1
Current Output-based Regulations and Legislative Proposals

Type of Program	Regulatory Purview	Output-based Features
Emission Standards for Large Industrial and Utility Boilers	U.S. EPA NSPS for Utility boilers	Emission limit (lb/MWh)*
	New Jersey Mercury limit	Emission Limit (mg/MWh) **
	Ozone Transport Commission NOx Trading Program	Model rule with output-based emission limit (lb/MWh)
	U.S. EPA Mercury MACT	Emission limit (10^{-6} lb/MWh)**
	U.S.EPA Mercury Cap and Trade	Emission limit (10^{-6} lb/MWh)**
Emission Standards for Distributed Generation	New Hampshire	Emission tax (lb/MWh)
	California	Emission limit (lb/MWh) *
	Texas	Emission limit (lb/MWh) *
	Regulatory Assistance Program	Model rule with output-based emission limit (lb/MWh)*
	Connecticut	Emission limit (lb/MWh) *, **
	Massachusetts	Emission limit (lb/MWh)**
	New York	Emission limit (lb/MWh)**
NOx Budget Trading Program	Connecticut	Allocation of allowances
	Massachusetts	Allocation of allowances*
	New Hampshire	Allocation of allowances
	New Jersey	Allocation of allowances
State Multi-Pollutant Programs	Massachusetts	Emission limit (lb/MWh)
	New Hampshire	Allocation of allowances
State Generation Performance Standards	Connecticut	Portfolio standard (lb/MWh)
	Massachusetts	Portfolio standard (lb/MWh)
	New Jersey	Portfolio standard (lb/MWh)
Federal Greenhouse Gas Registry	U.S. DOE Section 1605(b)	Emission reporting
New Source Review	Connecticut	LAER option
Multi-Pollutant Legislative Proposals	Carper Bill – S843 & H.R. 3093	Allocation of allowances**
	Jeffords Bill – S366	Allocation of allowances**
	Clear Skies Act – S485 & H.R. 999	Emission limit (lb/MWh) **

* These programs recognize the multiple useful outputs of CHP.
** Currently under development.

1.0 INTRODUCTION

1.1 Purpose of the Handbook

The U.S. Environmental Protection Agency (EPA) developed this handbook to assist air regulators in developing emissions regulations that recognize the pollution prevention benefits of efficient energy generation and renewable energy technologies. Output-based *regulation*s include output-based emissions *standards* as well as output-based *allocations* of allowances within cap and trade programs. Use of output-based regulations can advance the adoption of highly efficient combustion technologies and renewable energy technologies, leading to emissions reductions.

> *An output-based standard relates emissions to the energy output of a process (e.g., electricity or thermal output) rather than the material inputs (e.g., fuel burned). An example would be lb/MWh_{output}, rather than $lb/MMBtu_{heat\ input}$.*

Output-based regulations do not provide a special benefit to any particular technology and do not increase emissions. Output-based regulations simply level the playing field by allowing energy efficiency and renewable energy to compete on an equal footing economically with any other method of reducing emissions (e.g., combustion controls and add-on controls). For this reason, environmental groups, associations of air regulators, and proponents of clean energy technologies have endorsed the use of output-based regulations (see Appendix C).

While *output-based* regulations have been used for regulating many industries, *input-based* regulations have been traditionally used for boilers and power generation sources. Recently, this has begun to change as regulators have sought to promote pollution prevention and provide compliance flexibility to combustion sources, which face ever-increasing requirements for emissions reductions. This handbook is a resource for air regulators who wish to consider applying output-based regulations to boilers or power generation sources. Specifically, the handbook:

- Describes output-based regulations,
- Explains the benefits of output-based regulations,
- Explains how to develop an output-based emission standard, and
- Provides a catalogue of the current use of output-based regulations for combustion sources.

> *Output-based regulations encourage pollution prevention, leading to reduced fuel consumption and the associated reductions in emissions.*

Now is an important time to examine output-based regulations because of the increasingly competitive energy markets and the improving economics of efficient power-generating technologies. Highly efficient generation systems, such as combined heat and power (CHP), and renewable energy technologies offer the potential to cost-effectively reduce fuel consumption and associated emissions. Output-based regulations recognize the environmental benefits of these technologies.

1.2 Trends Supporting Increased Use of Output-Based Regulation

Increased interest in output-based regulations began in the 1990s. During this period, air regulators faced persistent challenges in achieving progressively more stringent air quality standards, while the demand for energy continued to grow. Emissions from fuel combustion were determined to contribute to a variety of air quality problems, including ground level ozone, fine particulates, acid rain, urban toxics, visibility degradation, and climate change. To achieve air quality goals, state and federal regulators increasingly searched for more cost-effective approaches to achieve greater emission reductions from energy production sources. Against this backdrop, output-based regulations presented a way to provide flexibility to regulators and sources in achieving multi-pollutant emission reductions at the lowest cost.

A number of factors supported the growing interest in output-based regulations:

- *Growing difficulty in meeting increasingly stringent air quality standards*. To meet increasingly stringent air quality standards, regulators and the regulated community constantly look for new, cost-effective tools to reduce emissions. Policymakers realize that more efficient energy conversion and renewable energy technologies can have a substantial effect on reducing emissions. Most importantly, the investment in these technologies creates environmental benefits across all air quality programs.

- *Increasing recognition of pollution prevention as a preferred means of emissions control*. The growing interest in pollution prevention has focused more attention on energy efficiency and renewable energy as means of emission control. Improving efficiency is one of the best forms of pollution prevention. Avoiding pollution through energy efficiency can have long-term cost benefits through less reliance on emission control equipment and reduced fuel use. Gains in efficiency produce multiple pollutant benefits without creating adverse secondary environmental impacts that are common among end-of-pipe approaches. Similarly, renewable energy facilities achieve the same result through low or zero-emission technologies.

- *Need to assess and compare different generating technologies.* The widespread deployment of new gas combined cycle generating technology whose emissions are measured as flue gas concentration (ppm) rather than lb/MMBtu common for conventional plants, has made environmental comparisons between technologies difficult. As reducing emissions from electricity generation became a focus, regulators became increasingly interested in clear comparisons between alternative technologies. Output-based regulations place all generators on the same regulatory basis and promote comparisons of environmental performance.

- *Increased interest in CHP.* The high efficiency of CHP reduces both energy consumption and emissions and many regulators were looking for ways to encourage its application. However, CHP replaces two conventional emission sources with one source.

Comparing CHP to conventional systems requires an assessment of the energy production capacity that is displaced. Output-based measures facilitate this comparison.

- *Increased interest in renewable energy technologies.* Wind turbine technology, in particular, has become significantly less expensive and more competitive in electricity markets. Growth in wind generation has been dramatic, yet small cost improvements can still make a significant difference. By allocating emissions allowances on an output-basis, these facilities can be financially rewarded for the contribution they make to meeting an emissions cap.

- *The development of emission trading programs*. The current "cap and trade" programs limit the total tonnage of emissions from one or more fuel combustion sectors. Because of the cap on total emissions, generators strive to maximize the productive output that they can generate within their cap. This directly links the cost of allowances to electricity generation and causes generators to think in terms of lb emissions/MWh.

These trends led to growing interest in the development of output-based regulations.

1.3 EPA's Green Power and Combined Heat and Power Partnerships

The Green Power and the Combined Heat and Power (CHP) Partnerships, within the U.S. EPA's Climate Protection Partnerships Division (CPPD), developed this handbook. CPPD designs and implements voluntary partnerships to reduce U.S. greenhouse gas emissions by improving end-use energy efficiency and lowering the greenhouse gas intensity of energy conversion. CPPD's partnerships work to increase the understanding of the full range of benefits provided by energy efficiency and clean energy production. Output-based regulations can help air regulators incorporate these benefits into their programs.

The CHP Partnership is a voluntary program that reduces the environmental impact of power generation by fostering the use of CHP. CHP, also known as cogeneration, produces both heat and electricity from a single heat input. CHP is a more efficient, cleaner, and reliable alternative to conventional generation. The partnership works closely with the CHP industry, state and local governments, and other stakeholders to develop tools and services to support the development of new CHP projects and recognize their energy, environmental, and economic benefits. The use of output-based regulations is a tool that can foster the introduction of CHP.

> ***CHP is the sequential generation of electricity and heat from a single fuel combustion source.***

The Green Power Partnership is a voluntary program that reduces the environmental impact of power generation by facilitating corporate commitments to purchases of renewable energy. The Green Power Partnership expands awareness of renewable energy by providing objective information and public recognition for companies choosing green power for their energy supply. By stimulating a network among green power providers and potential purchasers, the Partnership helps to lower transaction costs for companies, state and local governments, and other organizations interested in switching to green power. The use of updating output-based allowance allocations in a cap and trade program is a tool that encourages the use of renewable energy.

1.4 Using the Handbook

This document provides practical information for an air regulator to consider in developing an output-based regulation.

- **Section 2** defines output-based regulations and explains the output-based units of measure typically used for different combustion technologies.
- **Section 3** explains how output-based regulations encourage pollution prevention, reduce fuel use and multiple associated pollutants, and can reduce compliance costs.
- **Section 4** describes the mechanics of developing output-based standards, and discusses the decisions involved and the compliance implications.
- **Section 5** catalogues recent output-based air regulations at the state, regional, and federal levels; and discusses three regulations in detail.
- **Appendix A** contains energy conversion factors.
- **Appendix B** lists existing output-based regulations.
- **Appendix C** provides examples of environmental organizations that support output-based regulations.

2.0 WHAT IS AN OUTPUT-BASED REGULATION?

An output-based regulation relates emissions to the productive output of the process. Outputs from combustion sources include electrical, thermal and mechanical energy. Output-based regulation can be used to develop traditional emission standards or to allocate emission allowances in a cap and trade program. In both cases, output-based regulations account for the pollution prevention benefits of efficient energy generation and renewable energy technologies.

- **Output basis for emission standards.** Output-based *standards* account for the emissions benefit of efficiency measures, such as increasing combustion efficiency, increasing turbine efficiency, recovering useful heat, and reducing parasitic losses associated with operating the affected unit (e.g., operation of fans, pumps, motors). Therefore, control strategies for meeting output-based emissions standards can include both emission controls *and* efficiency measures.

- **Output basis for allowance allocations.** An output basis can also be used in determining *allowance allocation*s in a cap and trade program. An output-based allocation provides a greater number of allowances to more efficient plants. Traditionally, allowances (the right to emit one ton per year of a pollutant) have been allocated based on the operating history (usually annual fuel input) of the regulated sources. Allowances also can be updated in the future (referred to as an “updating” allocation system). Adopting an updating allocation system on an output basis and including renewable energy facilities provides an incentive for both energy efficiency and renewable energy.

> *Output-based regulations are based on electrical, thermal, or mechanical output (MWh, MMBtu, or bhp-hr), rather than the heat input of fuel burned or pollutant concentration in the exhaust.*

2.1 Output-Based Units of Measure

The appropriate units of measure for an output-based emission standard depend on the type of energy output and the combustion source. For most applications, the units of measure are pounds of emissions per unit of energy output (Table 2-1). For reciprocating engines, output-based measure is either grams of emissions per brake horsepower-hour (g/bhp-hr) or pounds per megawatt hour (lb/MWh), depending on whether the engine is used to generate mechanical power or electricity.

Table 2-1
Output-based Units of Measure

For this type of energy production...	Using...	An output-based measure is...
Electricity generation	Boilers/steam turbines Reciprocating engines Combustion turbines	pounds per megawatt hour (lbs/MWh)
Steam or hot water generation	Industrial boilers Commercial boilers	pounds per million British Thermal Units (lbs/MMBtu $_{\text{heat output}}$)
Mechanical power	Reciprocating engines	grams/brake horsepower-hour (g/bhp-hr)

2.2 Output-based Standards Under the Clean Air Act

Traditionally, most *combustion sources* have been regulated based on heat input (lb/MMBtu $_{\text{heat input}}$) or the mass concentration of pollutants in the exhaust stream (parts per million or "ppm"). Input-based regulations were used during early Clean Air Act rulemaking efforts in part because at the time data on heat input were more readily available than data on energy output. Subsequently, compliance tests were based on heat input, and energy output data generally were not collected and reported as part of the required monitoring or source test requirements. Similarly, when cap and trade programs were initiated with the 1990 Clean Air Act Amendments (Title IV of which established the Acid Rain Program), emission allowances for individual power plants were allocated based on their historic annual heat input.

Nevertheless, output-based standards are not a new concept within the Clean Air Act. Output-based standards in the form of mass emitted per unit of production have been used for many new source performance standards (NSPS), national emission standards for hazardous Air pollutants (NESHAP), and other state and federal rules. Examples include the following:

- NSPS (40 CFR part 60) uses output-based standards for primary aluminum (subpart S), wool fiberglass (subpart PPP), asphalt roofing (subpart UU), glass manufacturing (subpart CC).

- NESHAP (40 CFR part 63) uses output-based standards for iron and steel (subpart FFFFF) and brick and structural clay (subpart JJJJJ), and other industries.

- States have used output-based standards for a variety of regulations. For example, Indiana sets NOx emissions limits for cement kilns in lbs/ton of clinker produced (326 IAC 10-1-4); and New Jersey sets NOx limits for glass melters in lbs/ton of glass removed (NJAC 7:27-19.10). Other states have similar requirements.

- The automotive emission standards are expressed in grams/mile, which is another example of an output-based standard.

3.0 WHY ADOPT OUTPUT-BASED REGULATIONS?

See what associations of air regulators, environmental groups, and energy conservation have said about output-based regulations in Appendix C.

Output-based regulations offer a variety of benefits for regulators and the regulated community. For regulators, output-based regulations encourage pollution prevention, leading to reductions in fossil fuel use and associated environmental impacts. For the regulated community, output-based regulations offer greater flexibility and the opportunity for lower compliance costs for individual facilities and society as a whole. Also, because output-based regulations encourage energy efficiency, these regulations can reduce the stress on today's energy systems.

This chapter demonstrates the benefits of output-based approaches by presenting case study examples of the differences between output- and input-based regulations at the facility level. Section 3.1 explains the emission reduction benefits of output-based regulations. Section 3.2 explains how costs can be reduced by the compliance flexibility that output-based regulations provide. Section 3.3 shows how an output-based format facilitates comparisons of environmental performance. Lastly, Section 3.4 describes combined heat and power technologies and how output-based regulations can be used to account for their unique efficiency benefits.

Benefits of output-based regulations:
- *Incentive for pollution prevention*
- *Multi-pollutant emission reductions*
- *Reduced fuel use*
- *Avoidance of upstream environmental impacts of fuel production and delivery*
- *Lower compliance costs*

3.1 Emission Reduction Benefits of Output-Based Regulation

Output-based regulations can reduce air pollution by encouraging energy efficiency and renewable energy technologies. The increased use of these technologies reduces fuel use and leads to multi-media reductions in the environmental impacts of fuel production, processing, transportation, and combustion. Reduced fuel use reduces emissions of all pollutants, not just the target pollutant of the regulatory program. In addition, energy efficiency and renewable energy create a permanent and consistent emission benefit that is not subject to short-term emissions increases that can result from startup, shutdown, or malfunction of add-on control devices (e.g., selective catalytic reduction for NO_x or scrubbers for SO_2). Pollution prevention also reduces the secondary pollutant releases (e.g., sludge and ash disposal) that are often associated with add-on control technologies. The sections that follow illustrate the effect of output-based regulations in a conventional emission standards program and in an emission trading program.

3.1.1 Output-Based Emission Standards

An output-based emission standard provides a clear indicator of emissions performance, because it accounts for the emission impact of efficiency in addition to fuel choice and emissions controls. A comparison of NO_x emissions at two 300 MW power plants can demonstrate this effect (Figures 3-1a and 3-1b). Assume that each plant operates at an 80 percent capacity factor and generates about 2.1 million megawatt hours (MWh) per year. Using the traditional input- or concentration-based units of measure, Plant 1 appears to have lower emissions (0.09 lb NO_x/MMBtu or 25 pmm versus 0.12 lb NO_x/MMBtu or 32 ppm for Plant 2). But input- or concentration-based measures do not account for differences in efficiency (34 percent for Plant 1 and 53 percent for Plant 2).

An output-based emission measure accounts for the effect of efficiency (Figure 3-1b). The difference in efficiency means that Plant 2 requires 35 percent less fuel to generate the same electrical output as Plant 1. Because of lower fuel consumption, Plant 2 emits fewer tons, even though it has a higher exhaust concentration. Plant 1 has a lower input-based emissions rate, but greater heat input, and emits more than 900 tons per year. Plant 2 has a higher emission rate, but lower heat input, and emits less than 800 tons per year. This example illustrates that emission limits based on heat input or concentration are not good indicators of the actual environmental impact. The output-based emission rate, however, reflects the true difference in emissions. Plant 1 has on output-based emission rate of 0.9 lb/MWh, while the rate for Plant 1 is 0.7 lb/MWh.

Because output-based standards account for the effect of energy efficiency, they allow for the use of efficiency as a control measure. This can result in multi-pollutant emission reductions. In addition to reducing NO_x emissions, the higher efficiency of Plant 2 means lower emissions of all other pollutants, including, SO_2, particulate matter, hazardous air pollutants, as well as unregulated emissions such as CO_2.

Moreover, an output-based standard ensures consistent long-term emission reductions. Under an output-based standard, a decrease in efficiency over time would cause an increase in the emissions per unit of output. This increased emissions rate would require the operator to reduce emissions or improve unit efficiency to stay in compliance. On the other hand, under an input-based standard, deterioration of unit efficiency is not be reflected in the emission rate, and total annual emissions can increase without affecting compliance.

Thus, an output-based standard offers several advantages:

- Allows sources to benefit from applying energy efficient measures, which lowers fuel use and achieves multi-pollutant emission reductions.

- Ensures consistent, long-term emission reductions.

- Allows regulators to more clearly compare emissions performance across different energy generating technologies and fuels.

- Provides sources with alternative compliance options that can lower costs (see Section 3.2).

Figure 3-1a. Benefits of Output-based Regulation

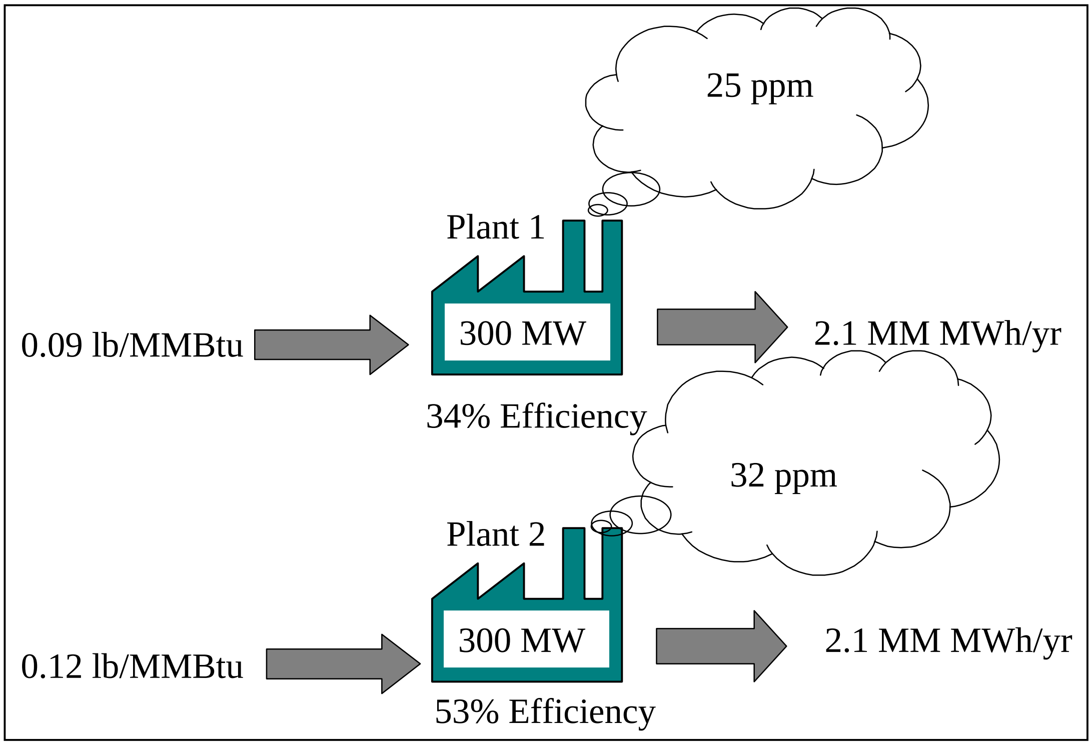
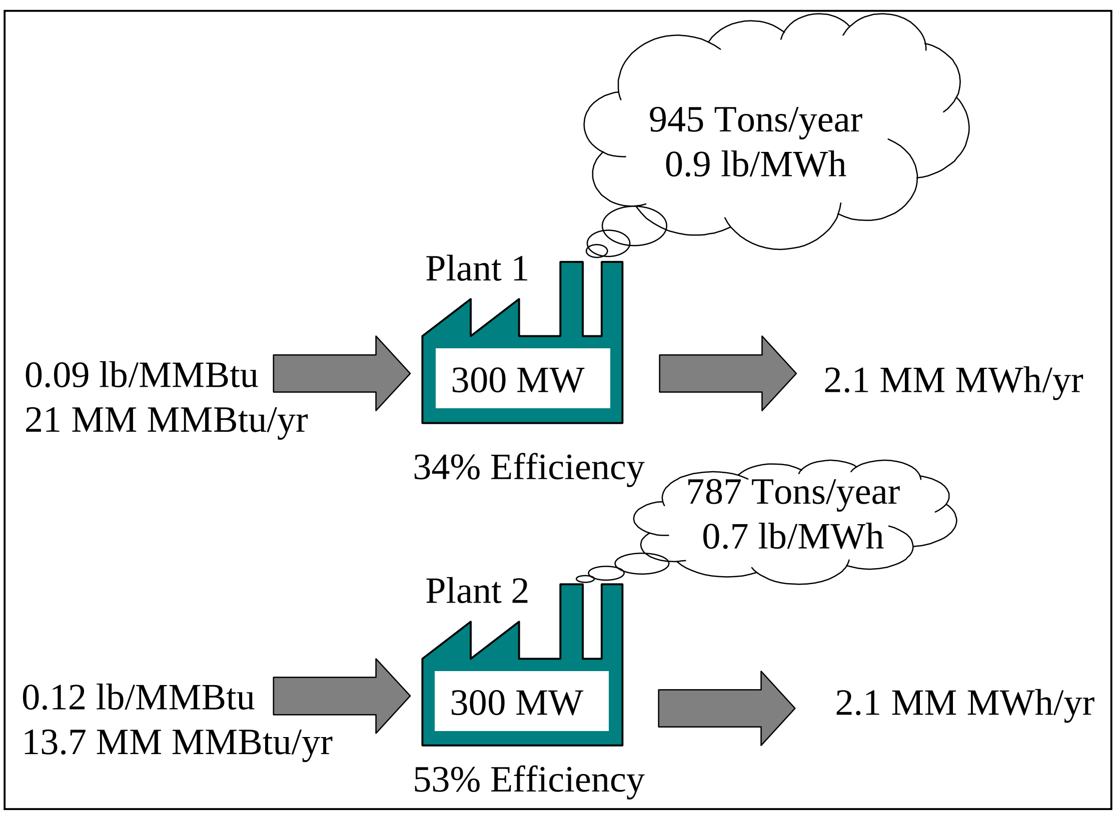


Figure 3-1b. Benefits of Output-based Regulation



3.1.2 Output-Based Allowance Allocations in Emission Trading Programs

In recent years, recognition of the regional nature of many air quality problems has led to the increasing use of cap and trade programs. In a cap and trade program, the total tons of emissions for a given industry sector are capped at the desired level of emission reduction. Emission allowances, which represent the right to emit one ton per specified time period (e.g., annually or during the ozone season), are allocated directly to industry participants or auctioned. At the end of each time period, every affected source is required to hold allowances equal to its emissions. Sources comply through a combination of reducing emissions and buying additional allowances.

Emission allowances are allocated at the beginning of a trading program on either a permanent basis or with a provision for updating allocations for future trading periods. For the national sulfur dioxide trading program, which was established under the Title IV acid rain program, SO_2 allowances were permanently allocated based upon historic annual heat input. More recently, the regional NOx Budget Trading Program left allocation decisions up to state governments and provided guidance to help states that might want to allocate on an output-basis (see Section 5.0 for further discussion). An output-based allocation provides relatively more allowances to efficient units than to inefficient ones. The example below illustrates this effect.

> *EPA guidance on developing output-based allocations:*
> *"Developing and Updating Output-Based NO_x allowance Allocations – Guidance for States Joining the NO_x Trading Program under the NO_x SIP Call." May 8, 2000*

How do input- and output-based allowance allocations differ?

Consider a state with emissions of 1,700 tons per year and an emissions cap of 1,500 tons per year. This cap represents a 12 percent reduction in emissions. Assume that the only emission sources are the two plants in Figure 3-1. The allocation of allowances under an input- and output-based approach is shown in the table.

Basis of Allocation	Plant 1	Plant 2
Heat Input		
Heat Input (million MMBtu/yr)	21.0	13.7
Percent of Total Heat Input	61%	39%
Initial Emissions (tons)	945	822
Allowances Allocated (tons)	909	591
Implied Emission Reduction	4%	28%
Energy Output		
Output (million MWh/yr)	2.10	2.10
Percent of Total Generation	50%	50%
Initial Emissions (tons)	945	822
Allowances Allocated	750	750
Implied Emission Reduction	21%	9%

In this example, Plant 1 uses 21 million MMBtu/yr, or 61 percent of the heat input, and Plant 2 uses 39 percent. Allocating the 1,500 allowances by these shares gives 909 allowances to Plant 1 and 591 allowances to Plant 2. If there were no trading, this allocation would impose a 4 percent emission reduction for Plant 1 (the higher emitting plant) and a 28 percent reduction for Plant 2 (the lower emitting plant). This allocation approach seems to reward the higher emitting plant by awarding it more allowances while penalizing the lower-emitting plant.

Alternatively, under an output-based allocation, both plants would receive 750 tons of allowances because they both produce the same output. Without trading, this implies a 21 percent emission reduction for Plant 1 and a 9 percent reduction for Plant 2. In this case, the trading program rewards the lower-emitting and more efficient plant. Several states participating in the NO_x SIP call trading program use output-based allocation, as do some existing and proposed multi-pollutant legislation (see descriptions of these programs in Appendix B).

The environmental benefit of an output-based allocation system occurs only in programs where allowances are reallocated periodically for future periods (known as an updating allocation system). For the initial allocation, there is no difference in incentives between an input-based and output-based system of allocation, because the initial allocation in both cases is based on historical data. However, the opportunity to influence behavior comes when facility operators know that emission allowances will be reallocated in the future. An updating output-based allocation system would provide an incentive for increased energy efficiency because more efficient units would receive relatively more allowances in future allocations.

Alternatively, an input-based reallocation system would provide a relative disincentive for efficiency improvements because an efficient unit would burn less fuel and, therefore, receive fewer allowances.

The section 126 NO_x cap and trade program to reduce interstate ozone transport based the initial allowance allocations on heat input (because good quality energy output data were not available), but announced that allowances would be updated every 5 years based on energy output (65 FR 2698, January 18, 2002)

The primary *environmental* benefits of increased efficiency are the ancillary impacts. For example, if the cap and trade program controls NO_x emissions, total emissions of NO_x would be the same under either allocation method. However, the increased efficiency would reduce emissions of SO_2, CO, CO_2, hazardous air pollutants, and particulate matter, and would reduce fossil fuel demand and the environmental impacts associated with the fuel production and transportation systems.

States can design their output-based allocation system to pursue their own energy and environmental policy agenda. For example, output-based allocations under a cap and trade program provides the opportunity to allocate emission allowances to renewable energy sources. Output-based allowance allocation to renewable generators and efficiency programs treats these entities equally to conventional generators that provide the same function of providing electricity. When done on an updating basis, the allocation promotes the increased use and construction of these non-emitting sources by providing them with a market-based economic benefit. Output-based allocations also provide the opportunity to promote combined heat and power systems by including the thermal output of combined heat and power systems in the allocation calculation.

Another way to view the allowance allocation process is that it distributes the right to use a public resource–clean air. An output-based approach allocates that limited public resource on the basis of productive output rather than on the basis of raw materials used.

Thus, output-based allocation of allowances within a cap and trade program:

- Provides economic benefit to more efficient and non-emitting sources, thereby recognizing their contribution to meeting regional emission caps,
- Encourages increased construction and use of efficient energy sources including renewables (if done on an updating allocation basis), and
- Allocates public resources (the right to emit) in proportion to the public benefit (energy output).

3.2 Cost Reductions from Output-based Regulations

An output-based emission regulation can reduce compliance costs because it gives process designers greater flexibility in reducing emissions. A facility operator can comply by installing emission control equipment, using a more energy efficient process, or using a combination of the two. Regulating the emissions produced per unit of output has value for equipment designers and operators because it gives them additional opportunities to reduce emissions through more efficient fuel combustion, more efficient cooling towers, more efficient generators, and other process improvements that can increase plant efficiency.

This flexibility is particularly important for NO_x because NO_x formation is a function of combustion temperature and conditions. NO_x concentration and energy efficiency are often a trade-off in combustion design. In some cases, however, equipment designers can reduce emissions by increasing efficiency and allowing a slightly higher flue gas NO_x concentration. This control approach is not possible with input-based emission limits, but could be used under one that is output-based.

Example of cost flexibility allowed by an output-based emission standard: Consider a planned new or repowered coal-fired utility plant with an estimated uncontrolled NO_x emissions rate of 0.35 lb/ $MMBtu_{\text{heat input}}$. To comply with an input-based emission standard of 0.13 $lb/MMBtu_{\text{heat input}}$, the plant would have to install emission control technology to reduce NO_x emissions by more than 60 percent. On the other hand, if the plant were subject to an equivalent output-based emission standard of 1.3 lb/MWh, then the plant would have the option of considering alternative control strategies by varying both the operating efficiency of the plant and the efficiency of the emission control system (Table 3-1). This output-based format allows the plant operator to determine the most cost-effective way to reduce NO_x emissions and provides an incentive to reduce fuel combustion. The total annual emissions are the same in either case.

Table 3-1
Design Flexibility Offered by Output-based Standard

Plant efficiency (percent)	Emission Standard lb/MWh	Required Control device efficiency (percent)
34	1.3	60
40	1.3	55
44	1.3	48

From a broader economic perspective, achieving emission reductions through efficiency can be significantly more attractive than through add-on controls. Add-on controls require an investment of capital but do not increase productive output. In many cases, add-on controls reduce efficiency and/or output. The same capital, if used to increase efficiency, will reduce emissions *and increase* productive output. This contradicts the common assumption that a facility operator must choose between cost and emission reductions. Efficiency improvement reduces operating cost, increases production *and* reduces emissions.

3.3 Output-based Format as a Measure of Environmental Performance

An output-based format gives a clear measure of the emissions impact of producing an energy product, such as electricity or steam. As an example, the most common output-based measure for electricity generation is lb/MWh generated. When emissions are expressed in these units, all sources can be directly compared, and determining the actual tons of emissions for a given level of energy generation is straightforward. Table 3-2 shows conventional input-based units of measurement for electric utility emission limits and the comparable output-based units. The ranges shown in the table represent typical ranges of emission rates for each combustion technology.

Output-based standards make comparing emissions between technologies easier. By contrast, comparing 0.1 g NO_x/bhp-hr from an engine to 25 ppm NO_x from a gas turbine to 0.1 lb/MMBtu from a boiler is cumbersome. Using an output-based format, therefore, can simplify emissions comparisons and program design for an air quality planner.

Table 3-2
Conventional and Output-based Measurements for Electricity Generation

Steam Boiler[1]		Combustion Turbine[2]		Reciprocating Engine	
lb/MMBtu $_{\text{heat input}}$	lb/MWh	Ppm	lb/MWh	g/bhp-hr	lb/MWh
0.1	1.0	3	0.13	0.1	0.31
0.2	2.0	9	0.4	0.15	0.47
0.3	3.0	15	0.6	0.5	1.56
0.4	4.0	25	1.1	0.7	2.18
0.6	6.0	42	1.8	1.0	3.11

[1]At 10,000 Btu/kWh heat rate.
[2]At 12,000 Btu/kWh heat rate.

3.4 Output-Based Regulation and Combined Heat and Power Applications

CHP is one of the best examples of an energy efficiency technology that can reduce fuel consumption and emissions. Although CHP is not a new concept, it is unfamiliar to many regulators, investors, and potential users. This lack of familiarity can create obstacles to its widespread application. One way to promote the use of this environmentally beneficial technology is through output-based regulations.

3.4.1 What is Combined Heat and Power?

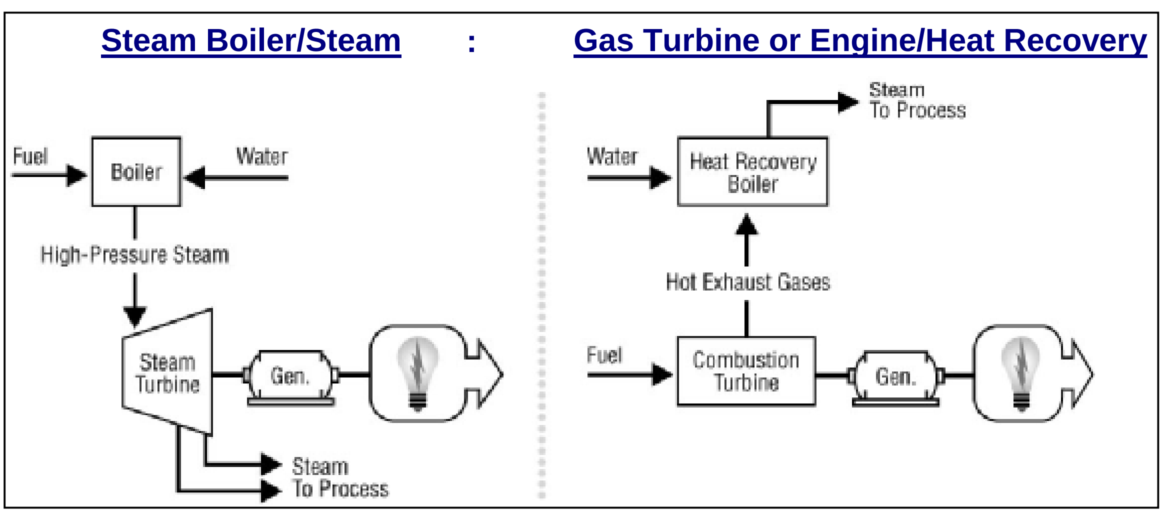
> *Typical CHP technologies are:*
> - *Combustion turbines*
> - *Reciprocating engines*
> - *Boiler/steam turbines*
> - *Combined cycle gas turbines*
> - *Microturbines*
> - *Fuel cells*

CHP is the sequential generation of power (electricity or shaft power) and thermal energy from a common fuel combustion source. CHP captures waste heat that ordinarily is discarded from conventional power generation, which typically discards two-thirds of the input energy as waste heat (typically up exhaust stacks and through cooling towers). CHP systems recover much of this otherwise wasted energy. This captured energy is used to provide process heat, space cooling or heating for commercial buildings or industrial facilities, and cooling or heating for district energy systems. By recovering waste heat, CHP systems achieve much higher efficiency than separate electric and thermal generators. Figure 3-2 shows two common configurations for CHP systems.

The steam boiler/turbine approach was the first application of CHP and the only CHP technology for many years. In this approach, a boiler makes high-pressure steam that is fed to a turbine to produce electricity. However, the turbine is designed so that sufficient steam is left over to feed an industrial process. This type of system typically generates about five times as much thermal energy as electric energy. Steam boiler/turbine CHP systems are widely used in the paper, chemical, and refining industries, especially when waste or byproduct fuel is available that can be used to fuel the boiler.

In the other common CHP system, a combustion turbine or reciprocating engine is used to generate electricity, and thermal energy is recovered from the exhaust stream to make steam or supply other thermal uses. These systems have been applied more in recent years, as the combustion technologies have developed. These types of CHP systems can use very large (hundreds of MW) gas turbines or very small (tens of kW) microturbine, engine, or fuel cell systems. In these systems, the electric energy produced is typically one to two times the thermal energy produced.

Figure 3-2. Two Typical CHP Configurations



The ratio of electrical to thermal energy generated by a CHP system is an important criterion in determining its applicability. This ratio is usually characterized as the power-to-heat ratio (P/H) - the ratio of electric output to thermal output in consistent units. The P/H ratio depends largely on the technology and configuration and can vary from 0.2 or less to more than 5. Table 3-3 shows typical P/H ratios for common CHP technologies.

Table 3-3
Typical Power-to-Heat Ratios (P/H)
for Common CHP Technologies

Technology	P/H
Combustion Turbine	0.6 - 0.8
Reciprocating Engine	0.7 - 1.0
Combined Cycle	1.0 - 3.0
Boiler/Steam Turbine	0.15 – 0.3

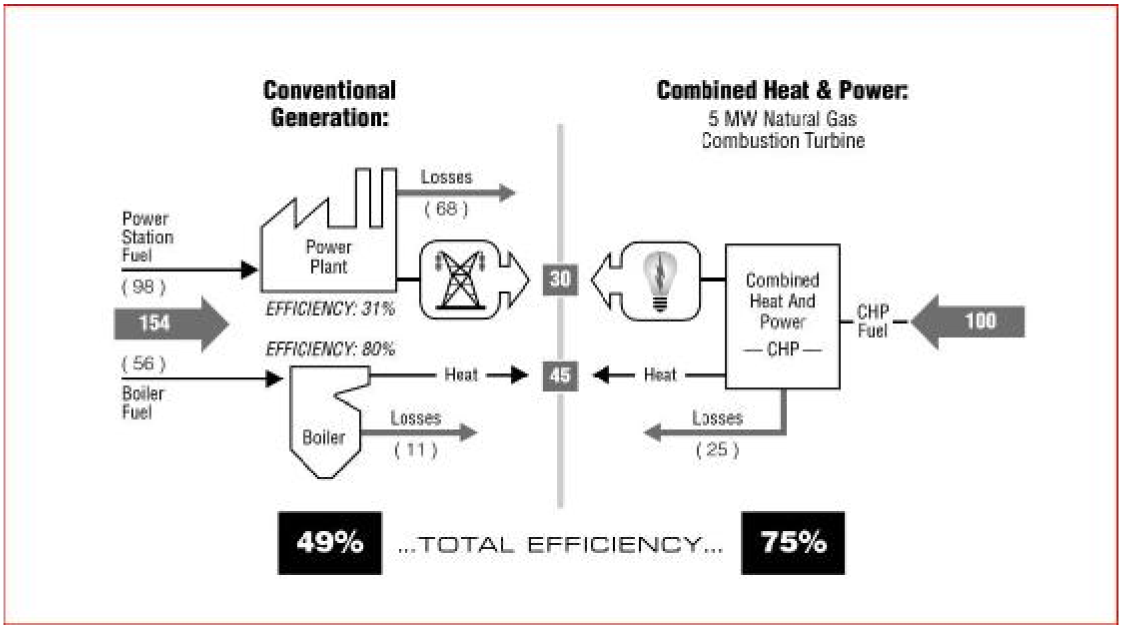
For example, a combustion turbine with a heat recovery system might typically have a P/H ratio of approximately 0.6 units of electricity per unit of thermal energy out, or, for every unit of electricity, there are 1.67 units of thermal energy out.

CHP is an especially attractive system because it can be applied with almost any combustion technology and fuel. This means that it can be applied in many different end uses and can use any fuels that are economically available. It is a well-known and well-demonstrated technology. The United States has approximately 77 gigawatts(GW) of CHP capacity in place as of 2003, yet the potential for substantial expansion is great. The U.S. Department of Energy (DOE) and EPA have set a goal to double the capacity of CHP between 2000 and 2010.

3.4.2 What are the Benefits of Combined Heat and Power?

By providing electrical and thermal energy from a common fuel input, CHP significantly reduces the associated fuel use and emissions. Figure 3-3 compares the efficiency and fuel use of a CHP facility to the efficiency and fuel use of conventional systems providing the same service. In this case, both systems provide 30 units of electric energy and 45 units of thermal energy to the facility.

Figure 3-3. Efficiency Benefits of CHP

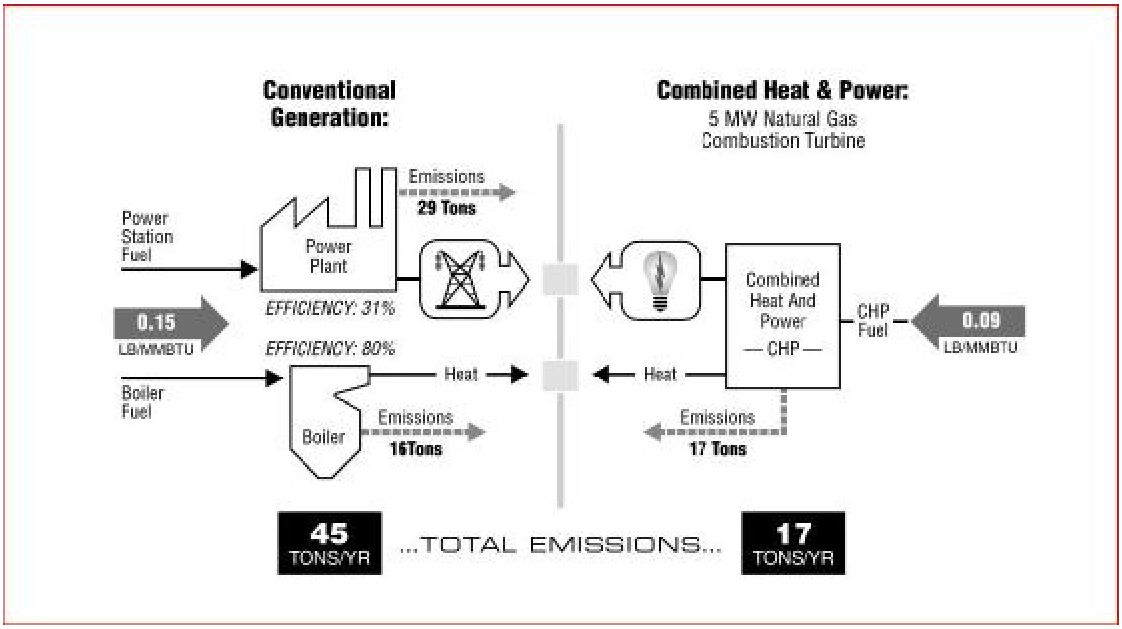


In the conventional system, the electricity required by the facility is purchased from the central grid. Power plants on average are about 31 percent efficient, considering both generating plant losses and the transmission and distribution losses. Thermal energy required by the facility is provided by an on-site boiler that might be 80 percent efficient. Combined, the two systems use 154 units of fuel to meet the combined electricity and steam demand. The combined efficiency to provide the thermal and electric service is 49 percent.

In the CHP system, an on-site system provides the same combined thermal and electric service. Electricity is generated in a combustion turbine and the waste heat is captured for process use. The CHP system satisfies the same energy demand using only 100 units of fuel. This system is 75 percent efficient.

Figure 3-4 shows the emissions benefits of the CHP system, in this case for NO_x emissions. The CHP system has much lower emissions because it uses 35 percent less fuel, even if the combustion process has the same input-based emission rates as the conventional equipment. In this example, as is often the case, the new CHP system displaces higher-emitting generators on the electric grid, and the emission rate for the new system is lower than the conventional alternative, thus, further reducing emissions. In the case shown, the CHP system emits less than half as much NO_x as the conventional system due to a combination of greater efficiency and lower emission rate.

Figure 3-4. Emissions Benefits of CHP



This example illustrates the significant energy and environmental benefits that are achievable through the application of CHP. In this case, a large portion of the avoided emissions is from the off-site power plant. The ***on-site*** emissions from the CHP system are ***slightly higher*** than in the conventional case because more fuel is burned on-site[1]. But the ***total regional emissions*** are ***lower*** (17 tons/yr vs. 45 tons/yr). Output-based regulations can be designed to recognize this benefit. Under conventional generation, the two combustion units have a combined output-based emission factor of 1.05 lb/MWh_{t+e}. The CHP system has output-based emissions of 0.75 lb/MWh_{t+e}[2]. Output-based regulations that account for this net regional emissions benefit will encourage the application of CHP.

Thus, an output-based regulation:

- Provides a compliance methodology to account for the emission reduction benefits of CHP. Some approaches for designing an output-based regulation to recognize the efficiency of CHP are discussed in Chapter 4.

- Reduces fuel use and net regional emissions by encouraging the adoption of CHP and other highly efficient energy technologies.

[1] Depending on the characteristics of the boiler and CHP combustion device, the on-site emissions could be higher or lower with CHP than with a conventional system.

[2] The output-based emission rate in this case was calculated by converting the thermal output to MWh and dividing the emissions by the total electric and thermal output. Other approaches to incorporating thermal output are addressed Chapter 4.

4.0 HOW DO I DEVELOP AN OUTPUT-BASED EMISSION STANDARD

This chapter explains how to develop an output-based emission standard. To begin, several decisions must be made about the format of the rule. Making these decisions will involve trade-offs between the degree to which the rule will account for the benefits of energy efficiency, the complexity of the rule, and the ease of measuring compliance. This chapter explains the technical approach, available options, and the implications of each option. The steps for developing an output-based emission standard are:

1. ***Develop the output-based emission limit.*** The method that you use will depend on whether or not you have measured energy output data available.

2. ***Specify a gross or net energy output format.*** Net energy output will more comprehensively account for energy efficiency, but can increase the complexity of compliance monitoring requirements.

3. ***Specify compliance measurement methods***. Output-based rules require designating methods for monitoring electrical, thermal, and mechanical outputs. These outputs are already monitored for commercial purposes at most facilities.

4. ***Specify how to calculate emission rates for CHP units.*** For CHP units, the rule must account for multiple energy outputs. Two commonly used approaches are explained.

4.1 Develop the Output-based Emission Limit

Ideally, to develop an output-based emission limit, you must obtain emissions data and simultaneously measured energy output. Unfortunately, energy output data are not always available. Most emission test data available today are based on energy input, consistent with current compliance measurement requirements. But output-based emission limits can still be developed by converting input-based emissions data or existing emission limits to an output-based equivalent using unit conversions and a benchmark energy efficiency. The following sections demonstrate the units of measure conversions from:

- Input-based emission limit in pounds per million Btu (lb/MMBtu$_{\text{heat input}}$)
- Flue gas concentration limit in parts per million by volume (ppmv)
- Emission limit based on mechanical power in grams per brake horsepower-hour (g/bhp-hr)

for the two primary types of energy outputs:

- electrical power generation (to lb/MWh)
- steam or hot water generation (to lb/MMBtu $_{\text{heat output}}$).

4.1.1 Conversion from Input-based Emission Limit (lb/MMBtu/$_{\text{heat input}}$)

Many emission standards for boilers are expressed in lb emissions/MMBtu$_{\text{heat input}}$. You convert to output-based standards using a benchmark efficiency factor and a units of measure conversion. The conversion is straightforward for electric generators and industrial boilers.

Electric Generators. For utility boilers, the output-based unit of measure is lb/MWh of electricity generated.

$$\text{Output standard} = (I \times H) \div 1{,}000 \qquad (1)$$

Where:

Output Standard	=	Output-based emission limit, lb/MWh
I	=	Input-based emission limit, lb/MMBtu heat input
H	=	Benchmark heat rate of steam generator set, Btu/kWh
1,000	=	Unit of measure conversion, $\frac{1{,}000\ \text{kWh}}{\text{MWh}} \times \frac{\text{MMBtu}}{1{,}000{,}000\ \text{Btu}}$

If the power plant efficiency is used as the benchmark rather than the heat rate, calculate the heat rate as shown below.

$$\text{Heat rate} = 3413/\text{efficiency}$$

For example

$$3413/34\%\ \text{efficiency} = 10{,}000\ \text{Btu/kWh}_{\text{electric output}}$$

Then, the output-based emission limit can be calculated using equation 1.

Example Calculation

Consider a State with an emission limit of 0.15 lb/MMBtu $_{\text{heat input.}}$ Assume that you select a benchmark heat rate of 10,000 Btu/kWh of electric output. Using this heat rate and Equation 1, the equivalent output-based limit would be:

$$\begin{aligned}\text{Output Standard} &= I \times H \div 1{,}000 \\ &= 0.15\ \text{lb/MMBtu} \times 10{,}000\ \text{Btu/kWh} \div 1000 \\ &= 1.5\ \text{lb/MWh}_{\text{electric output}}\end{aligned}$$

While this calculation is straightforward, you must determine a benchmark efficiency to use in the calculation. The choice of benchmark efficiency will affect the stringency of the output-based limit. Heat rates for conventional steam turbine power plants can vary from 9,000 to 11,000 Btu/kWh, depending on type of unit and load factor. Heat rates for older units can be higher (i.e., less efficient). Selecting a low heat rate will result in an aggressive limit for the less efficient units in the existing source population. Selecting an average or typical value from the population of affected sources will result in less control of newer, more efficient units. When selecting efficiency, you should consider the goals of the regulatory program (e.g., new source or existing source regulation) and the degree of emission reduction needed.

Heat rates can be calculated from heat input and generation data collected by the Energy Information Administration on Form 767. Heat rate data for individual power plants also are available in EPA's EGRID Database (http://www.epa.gov/cleanenergy/egrid/).

Both the heat rate and efficiency should be based on the higher heating value (HHV), not lower heating value (LHV) of the fuel. Heating values describe the amount of energy released when fuel is burned. HHVs and LHVs are determined differently, however. HHV is the heating value including the latent heat of the combustion products. HHV is usually used for systems using boilers. LHV is the heating value net of the latent heat in the combustion products. LHV is often used in calculating efficiencies for combustion turbines and reciprocating engines. EPA's practice is to base all regulatory limits on the HHV of the fuel. Fuel is typically sold based on HHV.

If you know only the LHV, then convert to HHV as follows:

$$HHV = LHV + 10.3\ (H_2 \times 8.94)$$

Where: H_2 = mass percent hydrogen in fuel, %.
LHV = lower heating value, Btu/lb

Factors for specific fuels are listed in Appendix A. For natural gas the HHV is 1,030 Btu/cf and the LHV is 937 Btu/cf or LHV/HHV=0.91

Commercial/Industrial Steam Boilers. For steam or hot water generators, the output-based unit of measure is lb emission/$MMBtu_{heat\ output}$. You can convert an input-based emission rate to an output-based format using the boiler efficiency, as follows:

$$\text{Output Standard} = I \div E \qquad \textbf{(2)}$$

Where:

Output Standard	=	Output-based emission limit, lb/MMBtu heat output
I	=	Input-based emission limit, lb/MMBtu heat input
E	=	Benchmark steam generator efficiency, **%**

Typical steam generator efficiencies are in the range of 75 to 80 percent.

Example Calculation

Consider a State with an emission limit of 0.15 lb/MMBtu for natural gas-fired industrial boilers. Assume that you select a benchmark efficiency of 80 percent. The output-based limit would be:

$$\begin{aligned}\text{Output Standard} &= I \div E\\ &= 0.15\ \text{lb/MMBtu} \div 0.80\\ &= 0.19\ \text{lb/MMBtu}_{\text{heat output}}\end{aligned}$$

4.1.2 Conversion from Flue Gas Concentration Limit (ppmv)

Emission limits for combustion turbines and sometimes for boilers and engines are expressed as concentration standards in ppm by volume on a dry basis. The conversion of concentration measurement (ppmv) to output-based measures is a two-step process.

Step 1. The first step is to convert ppm concentration to an input-based limit and correct for different levels of dilution air in the exhaust gas stream. The conversion is a function of the composition of the exhaust stream and thus varies for different fuels because their combustion products are different. The calculation procedure is:

$$\text{lb/MMBtu}_{\text{heat input}} = \text{ppm x k x F x } \left(\frac{20.9}{20.9 - \%0_2}\right)$$

The factor, k, accounts for unit conversions (i.e., from ppm to lbs/dry standard cubic foot), and F relates the dry flue gas concentration to the caloric value of the fuel combusted. The k and F factors have been tabulated for a variety of fuels and pollutants (See EPA Method 19 and Appendix A.). The last term in the equation adjusts the measured ppm value to a standard O_2 level to correct for any bias due to stack gas dilution. If CO_2 is measured rather than O_2, the method of correction is explained in EPA Method 19. For example, convert an emission limit of 25 ppmv (15 percent O_2) to an input-based limit as follows:

$$\begin{aligned}\text{lb/MMBtu}_{\text{heat input}} &= 25\ \text{ppm}\ NO_x\ @\ 15\%\ O_2 \text{ x k x F } \left(\frac{20.9}{20.9 - 15}\right)\\ &= 0.09\ \text{lb/MMBtu}_{\text{heat input}}\end{aligned}$$

For natural gas, the conversion is:

$$\text{lb/MMBtu}_{\text{heat input}} = \text{ppm @15\% } O_2 / 272$$

Step 2. The second step is to convert the input-based limit to an output-based limit. Use either Equation (1) for electricity generators or Equation (2) for steam or hot water generators.

4.1.3 Conversion from Emission Limit Based on Mechanical Power (g/bhp-hr)

Emissions from reciprocating engines are typically measured in grams per brake horsepower-hour (g/bhp-hr). This is an output-based measure of mechanical power that does not account for the efficiency of the electric generator. You can determine the output-based emission limit using generator efficiency and a units of measure conversion. The conversion is as follows:

$$\text{Output Standard} = (P \times 2.953) \div E \qquad (5)$$

Where:

Output Standard	=	Output-based emission limit, lb/MWh
P	=	Output-based mechanical power, g/bhp-hr
E	=	Benchmark electric generator efficiency, %
2.953	=	Units of measure conversion, $\frac{1\ \text{lb}}{454\ \text{g}} \times \frac{1\ \text{hp}}{0.746\ \text{kW}} \times \frac{1{,}000\ \text{kW}}{\text{MW}}$

Using a benchmark efficiency of 95 percent, which is a typical generator efficiency, the conversion can be simplified to:

$$\text{lb/MWh} = \text{g/bhp-hr} \times 3.11$$

4.2 Specify a Gross or Net Energy Output Format

Output-based regulations relate emissions to energy output. You must decide whether the emission limit you are preparing will be expressed as mass per *gross* energy output or mass per *net* energy output. These two approaches have different implications for compliance monitoring and the extent to which the rule accounts for energy efficiency.

Gross output is the total output of a process. Gross output from an electric generating unit would be the gross electric generation (MWh) that comes directly from the electric generator terminals before any electricity is used internally at the plant. Gross output from an industrial boiler would be the gross thermal output ($MMBtu_{heat\ output}$) that comes directly from the boiler header.

Net output is the gross output minus any of the energy output consumed to generate the output. Examples of output that would be subtracted from the gross output when calculating net output include:

- Auxiliary loads related to thermal or electric generation, such as fuel handling and preparation equipment, pumps, motors, and fans.

- Output diverted to operate pollution control devices.

- Thermal output used in heat recovery equipment such as preheaters or economizers.

- House loads (loads used inside the plant for lighting, heating, etc).

Using a *net* energy output basis provides the greatest incentive for energy efficiency because it accounts for all internal energy consumption at the plant. This method provides an incentive to use energy-efficient devices to lower internal power consumption and realize a net gain in efficiency. But measuring *net* output can be more difficult than measuring *gross* output, because net energy cannot always be directly measured at a single location. Rather, determining *net* output can involve accounting individually for each piece of equipment that uses steam or electricity. At complex industrial sites, it may be difficult to determine the energy associated with power generation or to isolate parasitic loses from energy used by production processes. At utilities, it can be difficult to determine net generation if individual units are subject to different emission limits, because metering net energy from the site would not allocate net energy for each boiler generator set. Thus, while a *net* output format will more completely account for efficiency measures within a process, the associated measurement and recordkeeping requirements can be burdensome.

The decision on which format to use in a particular application should balance the likely burden of greater complexity with the potential benefits of encouraging a greater range of efficiency improvement measures within a process. For small, distributed generation technologies (e.g., microturbines or engine generators) the difference between using a net versus gross output is not significant, because the technology is packaged as an integral unit. All losses are internal to the package, and net and gross output is essentially the same.

4.3 Specify Compliance Measurement Methods

Methods for measuring compliance with output-based standards are readily available. You must specify what to measure and the appropriate monitoring locations that correspond to the emission standard. Mass emissions are measured using the same emission monitors and reference methods used for input-based standards. The only variable that changes is the quantity to which the mass emissions will be related. Instruments to continuously monitor and record energy output are routinely used and commercially available at a reasonable cost. Most facilities already monitor their output for a variety of business purposes.

For *electric generation applications,* MWh must be measured. Measurement of MWh is straightforward and highly accurate. In most cases, the electric output of the generator is already being measured to record electricity sales. If it is not already being measured, the generation can easily be recorded by standard kWh meters. Mass emissions would be divided by MWh produced to calculate lb/MWh.

At large power plants, multiple boilers might serve multiple generators such that a one-to-one relationship does not exist between the emitting units and the generating units. In this case, two different approaches could be used for relating the measured emissions to the measured electric output:

- The simpler approach is to set the output-based emission limit for the overall plant (i.e., all boilers combined). Compliance can be then measured as the total emissions divided by the total generation. In this case, the output-based approach simplifies the compliance issue by focusing on the overall impact - that is, the total emissions per MWh independent of where in the plant the emissions come from. This approach creates an incentive for the plant operator to use the lowest-emitting, most efficient units available.

- If the regulation applies to each boiler, the output from the various generators can be allocated to the boilers according to the steam output of the boilers. In this case, the emissions for each boiler (lb/hr) are measured at each stack. The total electrical output (MW) is allocated to each boiler based on the percentage of steam output (MMBtu/hour) generated by each boiler. Allocating based on heat input to the boilers would not be as effective, however, because that procedure would ignore the efficiency of the boilers.

For ***steam generators***, thermal output ($MMBtu_{heat\ output}$) must be measured. Most large boiler facilities measure boiler thermal output as part of system operation. In many CHP facilities, the thermal output is sold to a separate customer and is therefore measured for commercial billing purposes. Meters are available that can be installed to measure and record the thermal output of the steam or hot water produced. Alternatively, the thermal output can be calculated using measurements of the steam or water flow and temperature rise of the thermal fluid. Mass emissions then would be divided by the thermal output to calculate lb/ $MMBtu_{heat\ output}$..

4.4 Specify How to Calculate Emission Rates for Combined Heat and Power Units

CHP has been shown to be beneficial from both an energy and environmental perspective and many regulators would like to provide recognition for these benefits in their regulations by recognizing the increased output of a CHP facility. CHP units produce both electrical and thermal output (e.g., process steam). Therefore, the rule must specify the method to account for the two different types of energy in the compliance computation. Several approaches have been used in current regulations and guidance documents. The different methods can result in different calculated levels of efficiency (i.e., more or less energy output in the denominator of the emission rate) and different compliance measurement requirements.

Two ways to account for the efficiency benefits of the thermal output of a CHP system are:

1. Add the thermal output of the steam to the electric output (in consistent units) when calculating compliance. This method maximizes the total output recorded and reduces the lb/output emission rate. Its actual impact on the output-based emission rate can vary substantially based on the power-to-heat ratio.
2. Determine the amount of avoided emissions that a conventional boiler system would otherwise emit had it provided the same thermal output (i.e., purchasing electricity from the grid and generating steam onsite). This approach relates the value of the thermal output of the CHP system more directly to the emissions actually avoided by the CHP system.

The two approaches are illustrated in the examples below. Consider a simple 1 MW gas turbine that has emissions of 0.7 lb/hr. Its emission rate is 0.7 lb/MWh electric. In a CHP configuration, the turbine also could produce a thermal output of about 5.7 MMBtu/hr (or about 5700 lb steam/hr of thermal output) in addition to its electric output. Assure that the output-based emission limit is 0.5 lb/MWh.

Approach 1: Convert thermal output to an equivalent MWh and add to the electric output

This approach focuses on including the full output in the calculation. It converts all of the energy output to units of MWh and compares the total emission rate to the emission limit. First, convert the thermal output of steam to units of MW by a unit conversion factor (1 MWh=3.413 MMBtu). This results in a thermal output of 1.67 MW output. Then, add the thermal and electric output to yield a total output of 1 MW + 1.67 MW = 2.67 MW. Dividing the measured stack emissions by this total output results in a combined emission rate of 0.7 lb/hr ÷ 2.67 MW = 0.26 lb/MWh_{th+e}.

This regulatory method recognizes 100 percent of the thermal output of steam in the compliance calculation, and the greater overall efficiency of a CHP facility results in a lower emission rate. It is a simple approach. The rule language simply must state that the output will be calculated as the electric output plus the thermal output in MW based on the conversion of 1 MWh = 3.413 MMBtu of heat output.

Several states have used this approach. The Texas distributed generation rule and California distributed generation certification program use this method. The U.S. EPA's 1998 NSPS for utility boilers used the same approach but includes only half of the thermal output in the calculation. All of the states that recognize CHP's thermal output (including Texas, California, Massachusetts and Connecticut) have included the full thermal value in order to benefit CHP.

The amount of energy output calculated by this method varies greatly depending on the power-to-heat ratio of the CHP unit. For low P/H ratios (i.e., proportionally high steam generation compared to power), this approach will result in a relatively high total energy output. This is because at low P/H ratios the unit operates more like a steam boiler than a utility boiler. Output-based emission limits for steam boilers are very different (lower) than those for utility boilers because of the significant energy losses introduced by the turbine generators.

Approach 2: Avoided emissions approach

This approach recognizes the thermal output by calculating the displaced emissions associated with the thermal output and subtracting them from the measured emission rate. The displaced emissions are the emissions that would otherwise have been generated to provide the same thermal output from a conventional system (applying a new source emission rate). The approach is a three-step process, as explained below.

First, compute the emission rate (lb/MWh) of the CHP unit based on the total measured emissions and the amount of electricity generated (ignoring process steam use for now). Second, for the steam output, compute the emissions avoided (in lb/MWh) from a conventional boiler system that otherwise would have provided the same steam output. Then subtract the avoided emissions rate from the initial lb/MWh rate that was computed based only on electrical output. The regulation would specify a five-step process to determine the emission rate for compliance purposes:

Step 1. Determine a gross emission rate based on electrical output only. To do this, divide the measured stack emissions by the metered electricity generated:

$$\text{Gross emission rate } (\text{lb/MWh}_{\text{electric}}) = \text{emissions (lb) / electrical output (MWh)}$$

Step 2. Determine the new source emission rate of the thermal generator that the CHP unit displaces. Where a CHP system directly replaces an existing thermal generator, the calculation recognizes the actual displaced emissions up to a maximum rate. The maximum rate would be established to prevent the CHP system from receiving "excessive" recognition for displacing very old, very high emitting boilers that might be scheduled for replacement anyway. For new CHP systems or where the emissions from the existing steam generation cannot be documented, the calculation for steam generation would be based on the emission limits for a new gas boiler in the particular state. This approach would provide a conservatively low estimate of displaced emissions.

Step 3. Convert the emission rate of the displaced steam boiler from an input to a heat output-based rate ($\mathbf{lb/MMBtu_{out}}$). The avoided emission rate is:

$$\text{lb/MMBtu}_{\text{heat output}} = \text{lb/MMBtu}_{\text{heat input}} \text{ / boiler efficiency}$$

Step 4. Convert the displaced emissions to lb/MWh. To do so, relate the emission rate of the displaced unit to the electricity produced by the CHP unit. First, convert the Btu's of heat output to MWh of heat output. (1 MWh is equivalent to 3.413 MMBtu). The power-to-heat ratio expresses how much thermal output is produced per unit of electric output, so then divide the thermal emission factor by the power-to-heat ratio to get the electric equivalent:

$$\text{Displaced emissions } (\text{lb/MWh}_{\text{electric}}) = \text{lb/MMBtu}_{\text{heat output}} \times 3.413 \, \frac{\text{MMBtu}}{\text{MWh}} \div (\text{P/H})$$

Step 5. Subtract the displaced emission rate from the initial output-based emission rate, which was based only on electrical energy, to obtain the net emission rate. The resulting CHP emission rate is then compared to the emission limit:

$$\text{CHP emission rate } (\text{lb/MWh}_{\text{electric}}) = \text{Gross emissions } (\text{lb/MWh}_{\text{electric}}) - \text{Displaced emissions } (\text{lb/MWh}_{\text{electric}})$$

Example Calculations for the Avoided Emissions Approach

Consider the same CHP project as in the previous example - a new 1 MW_e combustion turbine CHP system with a power to heat ratio of 0.6 that must meet an emission standard of 0.5 lb/MWh or less.

<u>Step 1</u>: The measured gross emission rate based only on electrical output is 0.7 $\text{lb/MWh}_{\text{electric}}$

<u>Step 2</u>: For this calculation, assume that the CHP unit displaces a typical small industrial boiler with an efficiency of 80 percent. Because the avoided emissions are not known, assume the avoided emissions for a new gas-fired boiler. The state regulation for new gas boilers is 0.05 $\text{lbs/MMBtu}_{\text{heat input}}$.

<u>Step 3</u>: Compute the output-based new source emission rate for the thermal output as follows (Equation 2). This is the avoided emission rate for an equivalent industrial boiler:

$$0.05\ \text{lb/MMBtu}_{\text{heat input}} / 80\%\ \text{efficiency} = 0.06\ \text{lb/MMBtu}_{\text{heat output}}$$

<u>Step 4</u>: Convert the displaced emissions by relating the thermal output emission rate to the electricity produced by this CHP system. This calculation estimates the avoided emissions as a ratio of the lb/MW_e produced by the CHP. Based on the power-to-heat ratio of 0.6, the emission displacement on an electric basis would be:

$$0.06\ \text{lb/MMBtu} \times 3.413\ \text{MMBtu/MWh} / 0.6 = 0.36\ \text{lb/MWh}$$

<u>Step 5</u>: Adjust the gross emission factor. The gross emission rate is 0.7 lb/MWh. Subtract the displaced emissions of 0.36 lb/MWh from the initial emission limit. The emission rate for compliance purposes, therefore, is:

$$0.70\ \text{lb/MWh} - 0.36\ \text{lb/MWh} = 0.34\ \text{lb/MWh}$$

The unit, therefore, is in compliance with the emission limit of 0.5 lb/MWh. The avoided emissions approach yields a emission rate that is higher than Approach 1, which resulted in an emission rate of 0.26 lb/MWh. This is a function of the P/H.

Table 4-1 computes the displaced boiler emissions rate (Steps 3 and 4) for a range of avoided emission rates (Step 2).

Table 4-1
Displaced Boiler Emissions Rate (lb/MWh$_{electric}$) for CHP Units

	Displaced Thermal Emissions* Rate (lb/MMBtu $_{heat\ input}$)						
P/H	**0.01**	**0.04**	**0.05**	**0.1**	**0.2**	**0.3**	**0.4**
0.5	0.09	0.30	0.40	0.85	1.71	2.56	3.41
0.7	0.07	0.22	0.29	0.61	1.22	1.83	2.44
1.0	0.05	0.15	0.20	0.43	0.85	1.28	1.71

*Assuming 80 percent boiler efficiency.

Many states set a typical emission limit for new gas boilers at 40 ppm (equal to approximately 0.05 lb/MMBtu). So, for example, a combustion turbine-based CHP system with a power-to-heat ratio of 0.7 would have a displaced emissions rate of 0.29 lb/MWh$_{electric}$ to apply against the applicable limit. A reciprocating engine with a power-to-heat ratio of 1.0 would have a displaced emissions rate of 0.20 lb/MWh$_{electric}$.

4.5 Summary of Steps to Develop an Output-based Standard

Table 4-2 briefly summarizes the information that is provided in this section.

Table 4-2
Summary of Rule Development Steps

1. Develop the output-based emission limit.	Two methods are provided: a. An emission limit can be based on measured emissions and energy output data. b. An input-based emission limit can be converted to an output-based format using the procedures in this section: Ÿ Conversion from lb/MMBtu heat input for electric generators or steam boilers. Ÿ Conversion from flue gas concentration for combustion turbines. Ÿ Conversion from g/bhp-hr for engine generators.
2. Specify a gross or net energy output format.	Net energy output will more comprehensively account for energy efficiency, but can increase the complexity of compliance monitoring requirements.
3. Specify compliance measurement methods.	The energy forms that must be measured are electricity generated (MWh) thermal output (MWh or Btu), and shaft power (bhp-hr). These outputs are monitored at most facilities for commercial purposes.
4. Specify how to calculate emission rates for CHP units.	Two methods are described: a. Equivalent MWh output approach b. Avoided boiler emissions approach These two methods provide different results and, thus, different levels of recognition of the efficiency benefits of a given CHP application. Neither is more "correct" than the other, however, the equivalent MWh output approach is simpler to calculate and can result in significantly lower calculated emission rates in certain cases.

5.0 EXAMPLES OF OUTPUT-BASED REGULATIONS

A number of federal, regional, and state programs have recently adopted output-based regulations. These regulations include emissions standards for large and small generators, cap and trade allowance allocation systems, multi-pollutant regulations, and generation performance standards. Table 5-1 lists existing output-based regulatory programs that apply to electric and thermal generation. Each of these programs is described more fully in Appendix B. Appendix B briefly describes the rule, jurisdiction, applicability (type and size of units covered), specific emission limits or provisions, timing, treatment of CHP units, references to rule language, and other relevant information.

To provide additional insight into the technical and policy considerations of setting output-based standards, three of these programs are described in more detail below:

- Section 5.1 describes the output-based approach that EPA used in the revision of the electric utility boiler NSPS. This action reflected a major change in approach for the NSPS and provided an efficiency-based rationale for transitioning to output-based regulation.

- Section 5.2 describes a model rule for output-based standards for small electric generators. The model rule is a good example of a straight-forward output-based emission limit program with recognition of the thermal output of CHP.

- Section 5.3 describes the EPA guidance on how to allocate emission allowances for the NO_x SIP call based on output. The approach was developed by a stakeholder group of EPA, states, industry, and environmental groups. The guidance provides a thorough discussion of how output-based allocation can be applied.

5.1 Utility Boiler New Source Performance Standard (40 CFR 60 Subpart Da)

In 1998, EPA promulgated revisions to the New Source Performance Standards (NSPS) for NO_x from Electric Utility Steam Generating Units. The revised NSPS reflected advances in NO_x control technology and a change to a uniform output-based NO_x regulation. This action was the first NSPS for boilers that incorporated output-based emission limits. In the rationale for revisions, EPA stated that it had "established pollution prevention as one of it highest priorities" and that "one of the opportunities for pollution prevention lies in simply using energy efficient technologies to minimize the generation of emissions" (62 FR 36954). Up to this point, the basis for boiler emission standards had been boiler input energy (i.e., pounds of pollutant per million Btu of heat input).

> *To learn more about the output-based NSPS emission limits for utility boilers, read the September 16, 1998 Federal Register (63 FR 49442)*

Table 5-1
List of Current Output-based Programs

Type of Program	Regulatory Purview	Output-based Features
Emission Standards for Large Industrial and Utility Boilers	U.S. EPA NSPS for Utility boilers	Emission limit (lb/MWh)*
	New Jersey Mercury limit	Emission Limit (mg/MWh) **
	Ozone Transport Commission NOx Trading Program	Model rule with output-based emission limit (lb/MWh)
	U.S. EPA Mercury MACT	Emission limit (10^{-6} lb/MWh)**
	U.S.EPA Mercury Cap and Trade	Emission limit (10^{-6} lb/MWh)**
Emission Standards for Distributed Generation	New Hampshire	Emission tax (lb/MWh)
	California	Emission limit (lb/MWh) *
	Texas	Emission limit (lb/MWh) *
	Regulatory Assistance Program	Model rule with output-based emission limit (lb/MWh)*
	Connecticut	Emission limit (lb/MWh) *, **
	Massachusetts	Emission limit (lb/MWh)**
	New York	Emission limit (lb/MWh)**
NOx Budget Trading Program	Connecticut	Allocation of allowances
	Massachusetts	Allocation of allowances*
	New Hampshire	Allocation of allowances
	New Jersey	Allocation of allowances
State Multi-Pollutant Programs	Massachusetts	Emission limit (lb/MWh)
	New Hampshire	Allocation of allowances
State Generation Performance Standards	Connecticut	Portfolio standard (lb/MWh)
	Massachusetts	Portfolio standard (lb/MWh)
	New Jersey	Portfolio standard (lb/MWh)
Federal Greenhouse Gas Registry	U.S. DOE Section 1605(b)	Emission reporting
New Source Review	Connecticut	LAER option
Multi-Pollutant Legislative Proposals	Carper Bill – S843 & H.R. 3093	Allocation of allowances**
	Jeffords Bill – S366	Allocation of allowances**
	Clear Skies Act – S485 & H.R. 999	Emission limit (lb/MWh) **

* These programs recognize the multiple useful outputs of CHP.
** Currently under development.

The revised NO_x emission limit is 1.6 lb/MWh gross energy output, regardless of boiler or fuel type. This emission limit applies to new utility boilers that commence construction after July 7, 1997. For modified and reconstructed units that commenced construction after July 7, 1997, the revised emission limit is 0.15 lb/MMBtu $_{\text{heat input}}$, regardless of fuel type. All past NSPS's specified separate emission limits by fuel type.

EPA considered several different output-based formats. The final structure of the rule was based on meeting the following goals:

1. Provide flexibility in promoting energy efficiency.
2. Permit measurement of parameters related to stack NO_x emissions and plant efficiency on a continuing basis.
3. Be suitable for equitable application on a variety of power plant configurations.

The basis of EPA's decisions on the format of the rule is explained below.

5.1.1 Units of Measure

The format of the revised NO_x emission limit is in units of lb/MWh. The EPA considered basing the emission limit on lb per gross boiler steam output (lb/MMBtu $_{\text{heat output}}$). EPA determined that the drawback with using a gross steam output basis was that it accounted for the boiler efficiency only and ignored turbine cycle efficiency. Since this did not meet one of EPA's goals of providing maximum flexibility in an output-based format, EPA decided that it would not be an acceptable basis. Therefore, EPA selected the lb/MWh format.

5.1.2 Net Versus Gross Energy Output

EPA also decided to define energy output in terms of gross energy output. Initially, EPA proposed the emission limit based on net energy output because the Agency wanted to account for both turbine cycle efficiency and internal plant energy efficiency. Several commenters on the rule claimed that monitoring net electrical output was not practical because it:

- Would require significant and costly changes to the existing monitoring systems.
- Could not be measured directly due to the amount of auxiliary electrical equipment at a plant.
- Did not account for the power drain associated with many types of pollution control equipment.
- Would be difficult at plants where both NSPS and non-NSPS units existed.
- Was not well understood because EPA did not provide a specific methodology for determining net output in the proposal.

Given the potential monitoring difficulties associated with measuring net output, EPA concluded that the use of gross energy output would be more appropriate for broad national application. However, EPA stated that it might revisit this issue should a cost effective methodology be developed to determine net energy output in all circumstances.

5.1.3 Selection of the Emission Limit for New Units

The emission limit for new sources is 1.6 lb NO_x/MWh gross energy output. EPA initially proposed an emission limit of 1.35 lb/MWh net energy output but decided to change the emission limit in response to comments received after proposal and further analysis of utility units.

The proposed emission limit was based on the use of selective catalytic reduction to reduce NO_x emissions to 0.15 lb/MMBtu $_{\text{heat input}}$. EPA applied an efficiency factor to convert the format to an output-based limit. Based on EPA's review of power plant efficiency, most plants fell into the range of 24 to 38 percent efficiency. EPA concluded, however, that newer units (both coal and gas) operate at about 38 percent efficiency, which corresponds to a heat rate of 9,000 Btu per kilowatt hour. This figure was the baseline chosen at proposal, and it resulted in an equivalent output-based emission limit of 1.35 lb/MWh.

0.15 lb/MMBtu x 9,000 Btu/kWh x 1,000 kWh/MWh /1,000,000 Btu/MMBtu = 1.35 lb/MWh

After proposal, a majority of commenters opposed the selection of an assumed 9,000 Btu/kWh heat rate for use in converting the input-based emission limit to an output-based emission factor. Several commenters provided examples of state-of-the art units that could not achieve the 9,000 Btu/kWh heat rate that EPA used to set the output-based emission limit. The EPA conducted statistical analyses of the data submitted by the commenters and collected additional data to assess the long-term NO_x emission levels that were achievable on an output-basis by new units. Considering these new data, EPA promulgated an emission standard based on actual measured output data rather than converted heat input data. This analysis resulted in an output-based emission limit of 1.6 lb/MWh.

5.1.4 Modified and Reconstructed Units

The revised NSPS retained an input-based format for existing sources that become subject to the NSPS by modification or reconstruction. In response to the proposed rule, a number of commenters objected to the fact that the proposed output-based limit was not achievable at a reasonable cost by all existing sources. Commenters claimed that EPA's assumed heat rate of 9,000 Btu/kWh (equivalent to 38 percent efficiency) was appropriate for new units only and that existing units should not be required to meet the same output-based standard as new sources. The higher heat rates associated with older, less efficient plants would cause those plants to have a more difficult time complying with the standard. To compensate for the higher heat rates, these existing units might have to use more expensive control devices with higher NO_x removal performance. In justifying the final rule, EPA noted that while most utility plants have efficiencies ranging from 24 to 38 percent, existing plants are likely to operate in the lower end of this efficiency range, which would make meeting an output-based standard more costly. Therefore, to minimize this potential burden, EPA decided to require modified and reconstructed units that become subject to the NSPS to meet a standard of 0.15 lb NOx/MMBtu $_{\text{heat input}}$.

5.1.5 Treatment of Combined Heat and Power Plants

Applying the regulation to a utility boiler that incorporates CHP must account for both the electrical energy output and the thermal output (typically steam). For CHP, the revised NSPS defines gross energy output as the gross electrical output plus 50 percent of the gross thermal output of the process steam (converted to units of MWh). The 50 percent steam conversion policy was based on a Federal Energy Regulatory Commission regulation that defines the efficiency of CHP units as “the useful power output plus one half the useful thermal output” (18 CFR 292, section 205).

EPA rejected two other approaches for determining how to account for process steam at CHP plants: (1) consider valuing steam assuming it will be used to generate electricity; and (2) consider valuing steam at greater than 50 percent of its heat value, up to 100 percent. Valuing steam as if it were being converted to electricity would cap the energy value at 38 percent of the heat value of the steam (based on the maximum reported efficiency for electrical production with a steam turbine). Because EPA wanted to encourage CHP, the Agency did not choose this option. The Agency did not choose the option of allowing for greater than 50 percent of the heat value of steam because it concluded that including all of the thermal output created a potential for calculating an “artificially high” output rate, especially if a large amount of steam is exported. As a sub-option, EPA also considered allowing 100 percent of the heat value, but limiting the amount of thermal energy to a specified percentage of total output. Ultimately, EPA determined that this approach was too complex from a monitoring standpoint. Therefore, EPA adopted the policy of 50 percent thermal energy for steam from CHP plants because the policy will encourage energy efficiency, will not result in artificially high output rates, and will not require complex monitoring.

5.2 <u>RAP National Model Emission Rule for Distributed Generation</u>

The Regulatory Assistance Project (RAP) is a non-profit organization formed in 1992 that provides workshops and education assistance to state public utility regulators on electric utility regulation. In 2000, the National Renewable Energy Laboratory engaged RAP to facilitate the development of a uniform, national model emission rule for small distributed generation (DG) equipment. The interest in regulating emissions from DG had been building in recent years due to the increased development of small generators, including microturbines, fuel cells, and small engines. More importantly, there had been increasing concern over the use of high-emitting diesel engines for load response or peaking applications. The development of DG emission regulations in Texas and California had sparked concern that many individual states would develop emission standards for DG and create an overly complex, conflicting set of permitting requirements that would limit the development of DG. The goal of the model rule project was to

> *To learn more about the Regulation Assistance Project Model Rule, see <u>www.raponline.org</u>.*

develop a model rule that could be uniformly applied throughout the United States and provide appropriate environmental protections and technology drivers for DG.

The stakeholder group involved with the process consisted primarily of state energy and environmental regulators with a few participants from the DG industry and representatives from EPA, U.S. DOE, and environmental groups. The model rule was completed in February of 2003. The emission limits for the Model Rule are presented in Appendix B.

5.2.1 Format of the Rule

The stakeholder group established from the beginning that the rule would be expressed in an output-based format. Several of the participants had been involved in the development of the output-based Texas and California DG rules, and agreed that reflecting efficiency in the regulation was important - especially for very small DG units that do not typically use add-on controls. For these units, pollution prevention and efficiency are the primary emission control alternatives and must be recognized by regulation. In addition, the rule sets one standard for all technologies, so the standard must be in units that can be applied to all technologies. An output-based limit in lb/MWh meets this requirement. Finally, the participants wanted the rule to account for the efficiency of CHP and potentially recognize renewable technologies. An output-based approach allowed the flexibility to achieve both of these goals.

5.2.2 Treatment of Combined Heat and Power

RAP made providing recognition for CHP an important priority in the rule development process. The group evaluated several possible methods. Several prior rules had recognized CHP by including the thermal output converted to electric equivalent as part of the output calculation. Although this method does recognize the thermal output, the effect is largely a function of the relative amounts of thermal and electric energy created and is not tied to the actual environmental benefit of the CHP created by displacing conventional emitting units.

The RAP group decided to take an approach based on calculation of the displaced emissions from the thermal output (see section 4.4). The emissions standards apply to the electrical output of the system and the measured emissions are reduced based on the emissions avoided by the displacement of thermal generator (steam boiler) providing the same thermal output as the CHP system. For a greenfield CHP facility, the avoided emissions are based on the emissions limits applicable to a new natural gas boiler. For a retrofit system, the avoided emissions are based on the emission rate of the boiler actually displaced by the system. There is a cap on this avoided emission rate, however, to avoid basing the displacement on old, very high emitting boilers.

5.3 EPA Guidance on Output-based NO_x Allowance Allocations

> *To learn more about output-based allowance allocations, read "Developing and Updating Output-Based NO_x Allowance Allocations, Guidance for States Joining the NOx Budget Trading Program Under the NO_x SIP Call" May 8, 2000. (http://www.epa.gov/airmarkets/fednox/april00/finaloutputguidanc.pdf)*

In October 1998, EPA issued the NO_x SIP call to reduce regional transport of ozone in the 22 northeastern states. To meet the requirements of the SIP call, states have the option of adopting further emission regulations or participating in a regional cap and trade program. In this cap and trade program, the EPA allocated NO_x allowances for an ozone season cap and trade program to the states, but it allowed each state to allocate the allowances to individual emission sources in the state. Although the most prominent model for this allocation was the input-based allocation approach of the acid rain SO_2 trading program, there was increasing interest in an output-based allocation system that would account for the benefits of new, more efficient generators. Despite this interest, stakeholders had a lot of questions about the actual mechanics of output-based allocation system and whether such a system could be efficiently implemented.

The EPA convened a stakeholder working group to investigate and analyze these questions and assist in developing guidance for states interested in applying output-based allocation in their NO_x trading programs. The group was composed of EPA staff, industry representatives, state regulators, and environmental groups. The group worked for most of 1999 and produced a guidance document that addresses issues including:

- The types of facilities to which the guidance applies.
- The assignment of allowances to units, plants, or generators.
- Technical and policy concerns in selecting the location for measuring or calculating output data to be used in allocations.
- Requirements for sources, such as monitoring, recording, and reporting output data.
- Potential sources of output data.
- Regulatory provisions to include in state rules and actual regulatory language specifying the allocation procedures.

Some of these issues are summarized in the following sections.

5.3.1 Allocation of Allowances

Perhaps the most basic issue considered by the stakeholder group was the actual mechanism for allocating allowances on an output basis, including industrial boilers and CHP facilities. The basic concept is that each unit receives allowances in proportion to its share of the total energy output in the state. In most states, a separate pool of allowances was established for electric generators and for industrial boilers. Under an output-based allocation program, an electric generating unit that generates 5 percent of the total electricity generated in the state would receive 5 percent of the allowances available for electric generators. An industrial boiler that generates 5 percent of the total thermal output generated in the state would receive 5 percent of the allowances available for industrial boilers. A CHP facility would receive a share of each pool based on its generation of electricity and steam. If a CHP facility generated 2 percent of the electricity and 3 percent of the steam in the state inventory of affected units, it would receive 2 percent of the electricity allowances and 3 percent of the boiler allowances. The guidance document presents a variety of examples of these allocation procedures and some variations for states whose emission pools are organized differently. Overall, however, the guidance illustrates that the procedure is straightforward and relatively simple.

One related issue was that a one-to-one relationship does not always exist between emission units and electric generating units. Compliance is based on emission units but an output-based allocation would relate to generating units. Some stakeholders questioned whether this situation creates a problem for compliance or enforcement. The stakeholder group determined that enforcement would remain the same, regardless of how the allowances are allocated. It is up to the sources to ensure that they have adequate allowances in their compliance account at the facility level, regardless of how many emission units are onsite. The allocation basis does not change the approach for the source either, as long as the plant operators can transfer allowances as needed to cover the actual emissions from their emission units. In fact, some industry representatives suggested that to allocate allowances at the plant level rather than at the unit level - whether based on emissions or output - would be just as easy from a compliance perspective.

5.3.2 Availability, Measurement, and Reporting of Output Data

One of the biggest obstacles to output-based regulations is concern about the collection of data on output. Environmental regulators are familiar with collecting data on heat input and emissions, but not output. The stakeholder group determined that collecting these data is new for many regulators but does not present any fundamental technical barriers.

One of the key insights is that the productive output of a process is a commercial product and is therefore accurately measured for commercial purposes. In other words, utilities must measure their generation in order to get paid. Measurement of the electric output of a generating unit is straightforward and highly accurate and is a normal order of business for most generators. Similarly, many CHP facilities are in the business of selling steam and must measure thermal output for contractual purposes. While this is less true for thermal output of industrial boilers, most operators of large boilers measure their steam output for plant management purposes. The group found that accurate measurement technology is available “off-the-shelf” for electric and thermal output streams, so that in the end these data are likely to be more accurate than the heat input data used in input-based allocation systems.

A more complex question is how to measure the output. This issue is also referred to as the “net versus gross” issue. In a large facility, some of the electricity and/or steam is used internally to operate plant systems, including pollution control devices. The electric output could be measured at the generator terminals (gross) or after the internal loads as it leaves the plant (net). From the policy perspective, the net output is the preferable concept because it indicates the actual energy available from the plant. Some stakeholders suggested that in a net energy approach, energy used for pollution control devices should not be subtracted from the gross output, because it benefits the environment. Others pointed out, however, that there are different ways to reduce emissions, and subtracting energy used for pollution control would be an incentive for more efficient pollution prevention techniques.

Actually determining how to measure net output can be difficult for a complex power generation or industrial facility. The energy flows are complicated and sometimes the plant uses grid electricity (i.e., not generated onsite) for some of its parasitic loads. The plant may have co-located facilities (administrative offices not directly related to the plant operation) that use some of the power generated onsite that should not be subtracted for allocation purposes. The guidance document produced by the stakeholder group provides a number diagrams illustrating how and where net and gross output should be measured. In the end, the final guidance allows regulators to choose either net or gross output, whichever method is most expedient. For very small generators, the net versus gross decision might not be relevant because parasitic loads are internal to the prime mover.

Overall, the guidance document provides a highly effective "cookbook" for the implementation of output-based allocation. Since its release, several states have implemented these approaches and are currently operating emission trading programs with output-based allocation.

APPENDIX A

ENERGY CONVERSION FACTORS

APPENDIX A. ENERGY CONVERSION FACTORS

Energy Conversions

Conversion from Btu Higher Heating Value (HHV) to Btu Lower Heating Value (LHV)

multiply by 0.91 for natural gas
multiply by 0.94 for diesel

Conversion from lb/MMBtu HHV to lb/MMBtu LHV

multiply by 1.099 for natural gas
multiply by 1.064 for diesel

	HHV	LHV
Natural Gas (Btu/cf)	1,030	937
Natural Gas (Btu/lb)	21,980	20,000
Diesel (Btu/gallon)	137,000	128,780
Diesel (Btu/lb)	19,490	18,320

1 horsepower hour (hp-hr) = 2,545 Btu
1 kW = 3,413 Btu per hour (Btu/hr)
1 kWh = 3,413 Btu
0.7457 kW = 1 hp

1,000,000 Btu = 1 MMBtu = 392.9 hp-hr
1 MMBtu/hr = 293 kW
1 MMBtu = 293 kWh
1 kW = 1.341 hp

Turbines

NO_x emissions for turbines are typically presented as parts per million (ppm) reported at 15 percent O_2 in the exhaust stack. Other means of reporting emission use heat input (lb per MMBtu), output (lb per MWh) and time (tons per year).

Conversion from lb/MMBtu to ppm

From lb/MMBtu HHV to ppm @15% O_2

For	Natural Gas	Diesel
NO_x	272	258
CO	446	423
SO_2	196	185

From lb/MMBtu LHV to ppm @15% O_2

For	Natural Gas	Diesel
NO_x	248	235
CO	406	385
SO_2	178	169

Conversion from ppm to lb/MWh using heat rate

$$\text{lb/MWh} = \frac{(\text{ppm @15\% } O_2) \times (\text{Btu HHV/kWh heat rate})}{(272 \times 1000)}$$

or

$$\text{lb/MWh} = \frac{(\text{ppm @15\% } O_2) \times (\text{Btu LHV/kWh heat rate})}{(248 \times 1000)}$$

Example

$$\text{lb/MWh} = \frac{(25 \text{ ppm}) \times (10{,}500 \text{ Btu HHV/kWh})}{(272 \times 1000)} = 0.97 \text{ lb/MWh}$$

Conversion from ppm to lb/MWh using efficiency

$$\text{lb/MWh} = \frac{(\text{ppm @15\% } O_2) \times (3.413)}{(272) \times (\text{\% efficiency HHV})} \quad \text{or} = \quad \frac{(\text{ppm @15\% } O_2) \times (3.413)}{(248) \times (\text{\% efficiency LHV})}$$

Example:

$$\text{lb/MWh} = \frac{(25 \text{ ppm}) \times (3.413)}{(272) \times (0.325)} = 0.97 \text{ lb/MWh}$$

Conversion from lb/MWh to tons/year

tons/year = (lb/MWh emission rate) x (MW capacity) x (% utilization) x (8760/2000)

Example:
tons/year = (0.951 lb/MWh) x (5 MW) x (0.30 utilization) x (8760/2000) = 6.25 tons/year

Engines
NO_x emissions for engines typically are reported as g/hp-hr. Other means of reporting emission use heat input (lb/MMBtu), concentration (ppm) and time (tons per year).
The efficiency of engines is described in terms of percent efficiency or brake specific fuel consumption (BSFC) in Btu/hp-hr.

Conversion from BSFC to % efficiency

% efficiency = 2545 / (BSFC Btu/hp-hr)
Example:
% efficiency = 2545 / (7,276 Btu/hp-hr) = 35% efficiency

Conversion from g/hp-hr to lb/MWh

lb/MWh = (g/hp-hr) x (3.11) (Including 95% generator efficiency)
Example:
lb/MWh = (5 g/hp-hr) x (3.11) = 15.55 lb/MWh

Conversion from g/hp-hr to lb/MMBtu

lb/MMBtu HHV = (g/hp-hr) x (efficiency of engine HHV) x (0.866)
Example:
lb/MMBtu HHV = (5 g/hp-hr) x (0.35) x (0.866) = 1.52 lb/MMBtu HHV

Conversion from g/hp-hr to ppm

ppm @15% O_2 = (g/hp-hr) x (efficiency of engine HHV) x (235) for natural gas-fired engines
ppm @15% O_2 = (g/hp-hr) x (efficiency of engine HHV) x (223) for diesel-fired engines

Example:
ppm @15% O_2 = (5 g/hp-hr) x (0.35) x (235) = 411 ppm @15% O_2

Conversion from g/hp-hr to tons/year

$$\text{tons/year} = \frac{(\text{g/hp-hr}) \times (\text{hp capacity}) \times (\%\ \text{utilization})}{(103.6)}$$

Example:

$$\text{tons/year} = \frac{(5\ \text{g/hp-hr}) \times (3000\ \text{hp}) \times (0.30\ \text{utilization})}{(103.6)} = 43.4\ \text{tons/year}$$

Conversion between different O_2 corrections for ppm reporting

$$\text{ppm @actual}\ \%\ O_2 = \frac{(\text{ppm @15\% } O_2) \times (20.9 - \text{actual}\ \%\ O_2)}{(20.9 - 15)}$$

Example:
ppm @1% O_2 = (346 ppm @15% O_2) x (20.9 - 1) x (1/(20.9 - 15)) = 1,167 ppm @ 1% O_2

Generalized conversion from ppm to lb/MMBtu

$$\text{lb/MMBtu} = \frac{(\text{ppm } NO_x \text{ @actual}\ \%\ O_2) \times (20.9) \times (F_d) \times (K)}{(20.9 - \text{actual}\ \%\ O_2)}$$

F_d HHV = 8,710 dscf/MMBtu HHV for natural gas
F_d HHV = 9,190 dscf/MMBtu HHV for diesel

Example: natural gas turbine at 15% O_2
lb/MMBtu = (25 ppm) x (20.9) x (8,710) x (1.194×10^{-7})/(20.9-15) = 0.092 lb/MMBtu HHV

F_d Factors from EPA Method 19

Fuel	F_d dcf/10^6 Btu
Coal:	
Anthracite	10,100
Bituminous	9,780
Lignite	9,860
Oil[1]	9,190
Gas:	
Natural	8,710
Propane	8,710
Butane	8,710
Wood	9,240
Wood Bark	9,600
MSW	9,570

[1] Crude, residual or distillate

K Factors

Pollutant	K (lb/scf)/ppm
NO_x	1.194 E-07
SO_2	1.660 E-07
CO	7.264 E-08

APPENDIX B

EXISTING OUTPUT-BASED REGULATIONS

APPENDIX B. EXISTING OUTPUT-BASED REGULATIONS

This appendix lists and describes output-based regulations currently in effect or under development.

B.1 Conventional Emission Rate Limit Programs

Conventional emission rate regulations, such as New Source Performance Standards (NSPS), reasonably available control technology (RACT), or maximum achievable control technology (MACT), can be made output-based simply by changing the format of the standards. These types of regulations can allow energy efficiency to act as a pollution control measure and enable more direct comparisons among regulated entities. They can also include provisions to which account for the energy efficiency and pollution reduction benefits of combined heat and power (CHP) projects.

B.1.1 New Source Performance Standards (NSPS) for Utility Boilers

NSPS are technology-based emissions standards that are set for specific processes and pollutants under the 1970 Clean Air Act. The NSPS limits apply to new, modified, or reconstructed facilities that meet the applicability criteria in the rule. The U.S. Environmental Protection Agency (EPA) periodically reviews the limits set in the NSPS.

In 1998, EPA revised the NO_X limits for electric utility steam generating units and industrial-commercial-institutional steam generating units (40 CFR Part 60 Subparts Da and Db). These revisions changed the format of the NO_X emission limit for new electric utility boilers from an input basis (lb/MMBtu) to an output basis (lb/MWh) and thereby provided a means for improved efficiency to contribute to meeting the new standards. The regulation was changed from a fuel-specific limit (i.e., different limits for different fuels) to a single limit of 1.6 lb NO_X/MWh gross energy output, regardless of fuel type. Compliance with the proposed NO_X emission limit is determined on a 30-day rolling average basis. EPA added compliance and monitoring provisions explaining how sources must demonstrate compliance with the output-based standards. The regulation allows CHP facilities to take a credit for the process steam generated that is equal to 50 percent of the thermal output of process steam converted to MWh. The change in format for a major emission standard was an important precedent in the diffusion and acceptance of output-based standards. The NSPS is discussed in more detail in section 5.2 of this report.

Additional information:
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Research Triangle Park, NC 27711
(919) 541-5426
http://www.epa.gov/ttn/atw/combust/boiler/boilnsps.html#RULE

B.1.2 Ozone Transport Commission Model Rule for Additional NO_X Reductions

In 2001, the Ozone Transport Commission (OTC) developed a model rule for additional NO_X reductions as part of a regional effort to:

- Attain and maintain the one-hour ozone standard.
- Address emission reduction shortfalls that were identified by EPA in specific states' plans to attain the one-hour ozone standard.
- Reduce eight-hour ozone levels.

The rule addresses additional NO_X reductions from existing boilers, gas turbines, and reciprocating engines that are not affected by the OTC NO_X budget cap and trade program. The rule is essentially an extension of the RACT rules applied in the OTR in 1995 and is a conventional emission limit regulation. The limits set by the model rule must be voluntarily adopted by individual states for the rule to take effect, and several states in the OTR are in the process of adopting the limits set forth in the rule.

The model rule limits for reciprocating engines are in conventional output-based units of g/bhp-hr. The limits for combustion turbines are presented in output-based (lb/MWh) format, as well as the standard ppm basis. This allows turbine manufacturers to trade-off emission rate versus efficiency to achieve the lowest actual emissions. The combustion turbine limits are shown in Table B-1.

Table B-1
OTC Model Rule
Additional NO_X Reductions for Combustion Turbines

	Simple Cycle lb/MWh (ppm)	Combined or Regenerative Cycle lb/MWh (ppm)
Gas-Fired Unit*	2.2 (55)	1 1.3 (42)
Oil-Fired Unit	3.0 (75)	2.0 (65)

* Must meet the oil-fired limits whenever oil is fired as a back-up fuel.

Additional information:
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Ozone Transport Commission
Hall of the States
444 North Capitol Street, Suite 638
Washington, DC 20001
(202) 508-3840
http://www.sso.org/otc/Publications/2001/modelrule_Add'lNOx_010306_final.PDF

B.1.3 New Jersey Proposed Mercury Emissions Limitations

The state of New Jersey is proposing output-based emission limits for mercury from coal-fired boilers. The proposed rule specifies that as of December 15, 2007, the mercury emissions from any coal-fired boiler shall not exceed 3 milligrams per megawatt hour (mg/MWh), based on the annual weighted average of all tests performed during four consecutive quarters; or, in the alternative, the owner or operator of a coal-fired boiler must achieve 90 percent reduction in mercury emissions as measured at the exit of the air pollution control apparatus. Compliance is to be determined by averaging three stack emission test runs per quarter for four consecutive quarters, measuring the net megawatt hours for each quarter, and then calculating annual weighted averages using the quarterly averages and the net megawatt hours generated. The DEP will allow averaging amongst units at the same site.

The DEP is proposing an extension of the December 15, 2007 compliance deadline to December 15, 2012, for any facility that by December 15, 2007, installs and operates air pollution control systems to control: (1) NO_x emissions to less than 0.100 lb/MMBtu for dry bottom boilers and 0.130 lb/MMBtu for wet bottom boilers; (2) SO_2 emissions to less than 0.150 lbs/MMBtu; and (3) PM emissions to less than 0.030 lb/MMBtu. This extension of the compliance deadline is only available for half of the New Jersey coal fired capacity of a company. The other half of the coal-fired capacity must achieve the mercury emission limits by December 15, 2007. The DEP believes that compliance with these emission limits by December 15, 2007 is readily achievable with currently available air pollution control technology. PSE&G has already entered into a multi-pollutant consent agreement with the DEP to attain these emission limits at all three coal-fired units. This provision is available to other electric generating companies in New Jersey, as well.

If a unit plans to shut down by December 15, 2012 the DEP will allow the unit to be exempt from the proposed regulations.

Additional information:
NJ Department of Environmental Protection
Alice Previte, Esq.
Attn: DEP Docket # 30-03-12/340
Office of Legal Affairs
P.O. Box 402
Trenton, New Jersey 08625-0402
http://www.nj.gov/dep/aqm/hgprop.pdf

B.1.4 Mercury MACT

The EPA published a proposal for mercury (and nickel) MACT for utility coal and oil boilers in the *Federal Register* on January 30, 2004. This was based on an EPA announcement in December 2000 that it would regulate emissions of mercury and other air toxics from coal and oil-fired electric utilities under section 112 of the Clean Air Act. In the January 30, 2004 notice, EPA also released an alternative regulatory approach that is their preferred approach (section B.1.5).

The MACT proposal is a conventional rule under the air toxics provisions of CAA section 112. This rule sets mercury emission limits for new and existing coal-fired utility boilers and nickel emission limits for new and existing oil-fired utility boilers. The limits would be effective 3 years after publication of the final rule. The limits are differentiated by coal type (bituminous, subbituminous, lignite, coal refuse) and by combustor type – conventional and IGCC. For new sources, the emission limits are output-based (lb/MWh). A new source is each individual unit that is constructed or reconstructed after January 20, 2004. The limits for existing sources are expressed in both input and output-based format. Existing units can choose to comply with either the input- or output-based limit and can average emissions across existing coal-or oil-fired units, respectively, within a facility. Emission averaging is not allowed for new sources. The limits for existing and new sources are shown in Tables B-2 through and B-5).

Table B-2
Proposed Mercury MACT Emissions Limits
For Existing Coal-fired Electric Utility Steam Generating Units

Unit Type	Hg	
	(lb/TBtu)	(10^{-6} lb/MWh)[1]
Bituminous-fired[2]	2.0	21
Subbituminous-fired	5.8	61
Lignite-fired	9.2	98
IGCC unit	19	200
Coal refuse-fired	0.38	4.1

[1] Based on 12-month rolling average
[2] Anthracite units are included with bituminous units

Table B-3
Proposed MACT Nickel Emissions Limits
for Existing Oil-fired Electric Utility Steam Generating Units

Unit Type	Ni	
	(lb/TBtu)	(10^{-6} lb/MWh)[1]
Oil-fired	210	0.002

[1] Based on do-not-exceed limit

Table B-4
Proposed MACT Mercury Emissions Limits
for New Coal-fired Electric Utility Steam Generating Units

Unit Type	**Hg (10^{-6} lb/MWh)[1]**
Bituminous-fired[2]	6.0
Subbituminous-fired	20
Lignite-fired	62
IGCC unit	20[3]
Coal refuse-fired	1.1

[1] Based on 12-month rolling average.
[2] Anthracite units are included with bituminous units.
[3] Based on 90 percent reduction for beyond-the-floor control.

Table B-5
Proposed MACT Nickel Emissions Limits
for New Oil-fired Electric Utility Steam Generating Units

Unit Type	**Ni (10^{-6} lb/MWh)[1]**
Oil-fired	0.0008

[1] Based on do-not-exceed limit

B.1.5 Mercury Cap and Trade Proposal

Along with the mercury MACT proposal (section B.1.3), the EPA proposed an alternative approach that includes an emission cap and trade program for mercury from utility boilers. The alternative rule was proposed under section 111 and section 111(d) of the Act (NSPS and Emission Guidelines). To justify this alternative rule, EPA proposed to rescind its earlier finding that regulation of utility boilers under section 112 is necessary. The proposed cap and trade approach has two components. First, new plants are subject to an output-based NSPS that is identical to the proposed MACT standard for new coal plants. The limits are summarized in Table B-6.

Table B-6
NSPS for Coal-fired Electric Utility Steam Generating Units

Unit Type	Hg (10^{-6} lb/MWh)[1]
Bituminous-fired[1]	6.0
Subbituminous-fired	20
Lignite-fired	62
IGCC unit	20[2]
Coal refuse-fired	1.1

[1] Anthracite units are included with bituminous units.
[2] Based on 90 percent reduction for beyond-the-floor control.

Second, EPA will issue Emission Guidelines for mercury emissions from existing utility boilers. The Emission Guidelines will trigger a SIP call-like program that will create a national emissions cap for mercury from all coal units. EPA will create state mercury caps based on baseline plant heat input with adjustment factors by coal rank.

There will be a Phase 1 cap in 2010 and a 15-ton Phase 2 cap in 2018. The level of the Phase 1 cap is not yet determined. EPA is estimating a cap at 34 tons, based on the co-control of mercury achieved by NO_x and SO_2 control technologies that will be installed to comply with the ozone and fine particulate air quality standards. States have the option of meeting their cap by publishing emission standards or by participating in the trading program. The emission caps will apply to existing and new sources. Allowances to individual plants will be allocated by the states.

On March 16, 2004, EPA published a supplemental proposal, which contained guidance for approving the state cap and trade programs and a model cap and trade rule (proposed emission guideline) for mercury. States will be allowed to design their own program, but the EPA model program has two output-based elements. Mercury allowances for new sources are allocated using a modified output approach (i.e., gross electrical output times 8,000 Btu/kWh). For new CHP units, one-half of the gross process steam output is multiplied by 8,000Btu/kWh and added to the modified electrical output to determine allocations.

Additional information:
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http://www.epa.gov/ttn/atw/utility/utiltoxpg.html

B.2 Regulations for Distributed Generation

Distributed generation (DG) refers to the use of technologies such as microturbines, diesel generator sets, fuel cells, solar panels, and reciprocating engines to satisfy small-scale electrical power needs closer to the point of use. There is increasing interest in DG because of a desire for improved reliability, energy efficiency, and lower costs. With innovations in DG technology, there has been increased interest in how one consistently and appropriately regulates small distributed electric generators. This activity has coincided with the interest in output-based regulation and several new regulatory programs have incorporated output-based measures as a means of recognizing efficiency as a pollution control measure. Several of these regulations also include provisions to account for the efficiency advantages of CHP. Most of these programs are conventional emission rate limit programs in many respects, but they include some innovative features.

B.2.1 New Hampshire Emission Fee

New Hampshire has an output-based emission fee program for DG. The program requires affected generators to report NO_X emissions and power production and either: (1) offset their emissions through the purchase of NO_X emissions allowances within the Ozone Transport Region; or (2) pay an emissions fee. The new regulation affects any internal combustion engine or combustion turbine that generates electricity for use or sale and emits more than 5 tons of NO_x per year. However, back-up, start-up, and emergency generators are exempted, as are generators used in areas where electrical power is not reasonably and reliably available. The amount of the fee per ton of NO_X emitted is $100 from October 1 to April 30 and $200 from May 1 to September 30. The fee increases over time but is capped at $500 per ton from October 1 to April 30 and $1,000 from May 1 to September 30. A NO_X emissions reductions fund will be established with these fees and used to reduce NO_X emissions from generation sources. No fee or allowance is required for the first 7 lb/MWh of NO_X. The original intent of the 7 lb/MWh threshold was to focus the fee on higher emitting engines, including diesels. However, this limit provides the additional benefit of encouraging efficiency by rewarding units that emit at a lower output-based rate.

Additional information:
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Concord, NH 03302-0095
(603) 271-6798
http://www.des.state.nh.us/ard/permit.htm

B.2.2 California Senate Bill 1298 Regulations for Distributed Generation

In 2000, California passed Senate Bill 1298 (SB 1298), which required the California Air Resources Board (CARB) to set new emissions standards and provide guidance for permitting new DG projects. In California, generators larger than 50 MW require air permits from the

California Energy Commission, while the 35 local air quality districts issue permits for units smaller than 50 MW. Very small projects have been exempted from permitting by the individual districts. The size threshold for the permitting exemption varies from district to district. The threshold is as low as 37 kW in some districts but includes all gas-fired reciprocating engines in other districts. This variation makes it difficult to implement the regulation. SB 1298 calls for CARB to:

- Establish an emission certification program for the small projects that are exempt from permitting.

- Develop a best available control technology (BACT) guidance document for DG projects less than 50 MW but large enough to require local district permits (BACT in California is equivalent to lowest achievable emission rate in other states).

Certification Program

The final certification regulations became effective in October 2002[1]. The certification program sets emission standards that must be achieved by all affected DG units that are manufactured for sale, lease, use, or operation in California. The program is implemented in two phases. Phase I took effect on January 1, 2003 and sets the standards summarized in Table B-7.

Table B-7
2003 California Distributed Generation Certification Standards
(lb/MWh)

Pollutant	Not Integrated with CHP	Integrated with CHP
Oxides of Nitrogen	0.5	0.7
Carbon Monoxide	6.0	6.0
Volatile Organic Compounds	1.0	1.0
Particulate Matter	Corresponding to natural gas with sulfur content not more than 1 grain/100 scf	

The standards include a separate limit for DG units that include CHP as part of a standardized package. In addition, DG units that are sold with a zero emission technology integrated into a standardized package can have the electric power output of the zero emission technology added to the electrical power output of the DG unit to meet the emission standards.

Phase II will take effect January 1, 2007 and is based on the emissions level that CARB determines to be BACT for permitted central station power plants. Table B-8 summarizes the 2007 certification standards. The 2007 standards will be reviewed in 2005 to determine if they are appropriate as BACT.

[1] The final regulation and additional documentation are available at: www.arb.ca.gov/energy/dg/dg/htm.

Table B-8
2007 California Distributed Generation Certification Standards
(lb/MWh)

Pollutant	**lb/MWh**
Oxides of Nitrogen	0.07
Carbon Monoxide	0.10
Volatile Organic Compound	0.02
Particulate Matter	Corresponding to natural gas with sulfur content not more than 1 grain/100 scf

In Phase II, DG units that use CHP can take a increase the output calculation by 1 MWh for every 3.4 MMBtu of heat recovered in the CHP system if the system is an integrated package with the DG system and if the overall system has an efficiency of at least 60 percent. This recognizes 100 percent the thermal output generated.

Certified Technologies

The regulation also specifies appropriate testing, testing parameters, labeling and record keeping requirements along with information about the equipment to be submitted by the manufacturer for certification. The Executive officer or an authorized representative will periodically inspect manufacturer, distributors, and retailers selling or leasing DG in California to ensure compliance with the regulations. Failure of the inspection may lead to denial, suspension, or revocation of certification. The equipment must be guaranteed to meet the certification for 15,000 hours of operation. As of early 2004, four technologies have been certified. Two microturbine systems have been certified to the 2003 standards and two fuel cell systems have been certified to the 2007 standards (Table B-9).

BACT Guidelines

CARB released its “Guidance for Permitting of Electrical Generating Technologies” in July 2002[1]. The document provides guidance to assist air control districts in making air permitting decisions for new electrical generators that are smaller than 50 MW but larger than the local exemption level. It expresses currently achievable emissions on an output basis.

[1] The final document is available at: www.arb.ca.gov/energy/dg/documents/guidelines.pdf.

Table B-9
DG Technologies Certified Under SB 1298

Company Name	Technology	Standards Certified to	Executive Order Number	Expiration Date
United Technologies Corporation Fuel Cells	200 kW phosphoric acid fuel cell	2007	DG-001	01/29/2007
Capstone Turbine Corporation	C60 MicroTurbine	2003	DG-002	12/31/2006
Fuel Cell Energy, Inc.	250 kw, DFC300A fuel cell	2007	DG-003	05/07/2007
Ingersoll-Rand Energy Systems	70 kw, 70LM PowerWorks Microturbine	2003	DG-004	12/31/2006

Most BACT definitions in California are consistent with the federal LAER definition and are often referred to as "California BACT." "California BACT" should not be confused with the less restrictive federal BACT.

The CARB BACT guidance document summarizes CARB's evaluation of the status of California BACT for electrical generators smaller than 50 MW. SB 1298 calls for the guidance to approach the emission levels of the cleanest central station power plants. The CARB guidance suggests that the central station levels will only be achievable by DG technologies through the application of a CHP credit.

Table B-10 summarizes the 2002 guidance for combustion turbines. Table B-11 summarizes the 2002 guidance for reciprocating engines. All of the standards are expressed in lb/MWh. There is no recognition for thermal energy produced by CHP.

Table B-10
CARB BACT Guidance for Small Combustion Turbines*

Equipment Category	NO_X** lb/MWh	VOC** lb/MWh	CO** lb/MWh	PM Lb/MWh
< 3MW	0.5 (9 ppmvd)	0.1 (5 ppmvd)	0.4 (10 ppmvd)	An emission limit corresponding to natural gas with fuel sulfur content of no more than 1 grain/100 standard cubic foot
3 - 12 MW Combined Cycle	0.12 (2.5 ppmvd)	0.04 (2 ppmvd)	0.2 (6 ppmvd)	
Simple Cycle	0.25 (5 ppmvd)	0.04 (2 ppmvd)	0.2 (6 ppmvd)	
>12 AND <50 MW Combined Cycle	0.1 (2.5 ppmvd)	0.03 (2 ppmvd)	0.15 (6 ppmvd)	An emission limit corresponding to natural gas with fuel sulfur content of no more than 1 grain/100 standard cubic foot
Simple Cycle	0.2 (5 ppmvd)	0.03 (2 ppmvd)	0.15 (6 ppmvd)	
Waste Gas Fired	1.25 (25 ppmvd)	---	---	---

* All standards based upon three-hour rolling average and in lb/MWh.
** Equivalent limit is presented in ppmdv, expressed at 15 percent O_2.

Table B-11
CARB BACT Guidance for Reciprocating Engine Generators*

Equipment Category	NO_X lb/MWh	VOC lb/MWh	CO lb/MWh	PM lb/MWh
Fossil Fuel Fired	0.5 (0.15 g/bhp-hr or 9 ppmvd**)	0.5 (0.15 g/bhp-hr or 25ppmvd**)	1.9 (0.6 g/bhp-hr or 56 ppmvd**)	0.06 (0.02 g/bhp-hr)
Waste Gas-Fired	1.9 (0.6 g/bhp-hr or 50 ppmvd**)	1.9 (0.6 g/bhp-hr or 130 ppmvd**)	7.8 (2.5 g/bhp-hr or 300 ppmvd**)	NA

* All standards based upon 3-hour rolling average and in lb/MWh.
** Equivalent limit is presented in ppmdv, expressed at 15 percent O_2.

Additional information:
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Sacramento, CA 95812
(916) 322-2990
http://www.arb.ca.gov/energy/dg/dg.htm

B.2.3 Texas Standard NO_X Permit for Distributed Generation

In May 2001, the Texas Commission on Environmental Quality (TCEQ) approved a new standard permit for emissions from small electric generating units[1]. This new standard:

- Applies to electric generating units that were new or modified after June 2001.
- Exempts non-emitting generators from permitting.
- Does not apply to DG used to power an individual’s home.
- Provides separate standards for east and west Texas.
- Differentiates by system size and capacity factor.
- Provides full credit for heat recovery in CHP projects.

The permit sets output-based limits for units in 2001 with a more stringent limit in 2005 for 10 MW or less in Eastern Texas (Table B-12).

Table B-12
TCEQ Standard Permit for NO_X from Distributed Generation

Region	10 MW or less	>10 MW
East	Installed prior to 2005: Operating >300 hrs/yr =0.47 lb/MWh Operating ≤300 hrs/yr=1.65 lb/MWh Installed starting 2005: Operating >300 hrs/yr =0.14 lb/MWh Operating ≤300 hrs/yr=0.47 lb/MWh	Operating >300 hrs/yr =0.14 lb/MWh Operating ≤300 hrs/yr =0.38 lb/MWh
West	Operating >300 hrs/yr =3.11 lb/MWh Operating ≤300 hrs/yr =21 lb/MWh	Operating >300 hrs/yr =0.14 lb/MWh Operating ≤300 hrs/yr =0.38 lb/MWh

The rule also sets a NO_X limit of 1.7 lb/MWh for generators burning waste gases, including landfill gas, digester gas, and oil field gas. In addition, the gas is limited to less than 1.5 grains of hydrogen sulfide or 30 grains of sulfur compounds. CHP units can add 1 MWh to the output calculation for each 3.413 MMBtu of thermal output produced.

[1] The final permitting regulation is available at: www.tnrcc.state.tx.us/permitting/airperm/nsr_permits/files/segu_permitonly.pdf.

Additional information:
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Texas Natural Resource Conservation Commission
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Austin, TX 78711-3087
(512) 239-1250
http://www.tnrcc.state.tx.us/permitting/airperm/index.html#gen

B.2.4 Regulatory Assistance Project Model Rule for Distributed Generation

A collaborative group of state utility regulators, state air regulators, environmental organizations, and DG industry representatives, with participation from the U.S. Department of Energy (DOE) and EPA, is developing a model emissions rule for small DG units. Supported by the DOE's Office of Distributed Energy Resources, the Regulatory Assistance Project facilitated the formation of the collaborative group as well as its deliberations. The purpose of the model rule is to facilitate the permitting of DG projects by providing a framework of underlying principles that can be uniformly adopted across the United States. The model rule was completed in February 2003.

The model rule recommends output-based emission limits for NO_X (separate standards for ozone attainment and nonattainment areas), CO, and PM. The rule also requires diesel-fueled generators to use low-sulfur highway diesel fuel. The limits are established in three phases, taking effect in 2004, 2008, and 2012. The third phase is subject to a technology review to determine whether the limits are feasible and appropriate. The limits are summarized in Table B-13.

Table B-13
RAP Model Rule Emission Limits
(lb/MWh)

	NO_X Attainment	NO_X Nonattainment	CO	PM*
Phase I – 2004	4	0.6	10	0.7
Phase II – 2008	1.5	0.3	2	0.07
Phase III – 2012**	0.15	0.15	1	0.03

*Diesel engines only **Subject to technology review

Limits on CO_2 were endorsed by the collaborative group but are not part of the final recommendations. The model rule provides compliance credit for CHP facilities based on the avoided emissions from an equivalent thermal generator. It also allows credit for avoided combustion of waste and byproduct gases. There is also a section on credit for combined conventional/renewable projects, though the approach is not described in detail.

Additional information:
Rick Weston
The Regulatory Assistance Project
50 State Street, Suite 3
Montpelier, VT 05602
(802) 223-8199
http://www.raponline.org/ProjDocs/DREmsRul/Collfile/ReviewDraftModelEmissionsRule.pdf

B.2.5 Connecticut Air Pollution Regulations 22a-174-42

The state of Connecticut is currently working on a draft rule setting output-based emissions standards based on the RAP rule for distributed generation. The draft rule regulates oxides of nitrogen, particulate matter, carbon monoxide, ammonia and carbon dioxide. Additionally, the rule incorporates a fuel sulfur content requirement to control SO_2 emissions. The rule is based on the RAP model rule for new generators (Table B-14). The rule also sets less stringent limits for existing generators. The rule is applicable to generators with a nameplate capacity less than 15 MW that generates electricity for other than emergency use and have potential emissions less than 15 tons per year.

Table B-14
Proposed Connecticut Emissions Standards for New Distributed Generators

Date of Installation	Oxides of Nitrogen (lbs/MWh)	Particulate Matter (lbs/MWh)	Ammonia (ppm)	Carbon Monoxide (lbs/MWh)	Carbon Dioxide (lbs/MWh)
On or after May 1, 2004	0.6	0.7	2.0	10	1,900
On or after May 1, 2008	0.3	0.07	2.0	2	1,900
On or after May 1, 2012	0.15	0.03	2.0	1	1,650

Table B-15
Proposed Connecticut Emissions Standards for Existing Distributed Generators

Oxides of Nitrogen (lbs/MWh)	Particulate Matter (lbs/MWh)	Carbon Monoxide (lbs/MWh)	Carbon Dioxide (lbs/MWh)
4.0	0.7	10	1,900

An owner or operator of any new or existing distributed generator subject to this section may satisfy compliance with the applicable emissions standards of this section by obtaining one of the following certifications:

(A) Certification by the California Air Resources Board pursuant to Title 13, sections 94200 through 94214 of the California Code of Regulations;

(B) Certification from the generator supplier that satisfies the requirements of this subsection; or

(C) For an existing generator, certification by the owner or operator that satisfies the requirements of this subsection.

The proposed regulation does recognize the thermal output of CHP systems based on displaced emissions as long as:

(A) At least 20% of the fuel's total recovered energy shall be thermal and at least 13% shall be electric, with a resulting power-to-heat ratio between 4.0 and 0.15,

(B) The design system efficiency shall be at least 55%.

Additional information:
Merrily Gere
Department of Environmental Protection at Bureau of Air Management
79 Elm Street, 5th Floor
Hartford, CT 06106-5127
(860) 424-3416
http://www.dep.state.ct.us/air2/siprac/2003/maincomm.htm

B.2.6 Massachusetts Draft 310 CMR 7.20 Engines and Combustion Turbines

The state of Massachusetts has released a draft output-based regulation on emissions from commercial/industrial size engines and combustion turbines. The proposed rule applies to engines and combustion turbines that are not subject to Prevention of Significant Deterioration or Non-Attainment Review. It includes separate standards for emergency and non-emergency units. "Emergency" is defined as not only when there is an equipment failure, but also when the imminent threat of a power outage is likely due to failure of the electrical supply or when capacity deficiencies result in a deviation of voltage from the electrical supplier to the premises of three percent (3%) above or five percent (5%) below standard voltage. The limits for emergency engines and turbines are summarized in Tables B-16 and B-17.

Table B-16
Proposed Massachusetts Emission Limits for Emergency Engines

Rated Power Output	Oxides of Nitrogen	Carbon Monoxide	Particulate Matter
≥ 1 MW to < 2 MW	18.3 lbs/MW-hr	5.0 lbs/MW-hr	0.45 lbs/MW-hr
≥ 2 MW	16.3 lbs/MW-hr	1.5 lbs/MW-hr	0.45 lbs/MW-hr

Table B-17
Proposed Massachusetts Emission Limits for Emergency Turbines

Rated Power Output	Oxides of Nitrogen
< 1 MW	2 0.60 lbs/MW-hr

Non-emergency engines are subject to declining emissions output regulations through the use of three phases based on the RAP Model Rule. The first phase would occur on July 1, 2004. The second phase is 2008-2012. The third phase is 2012 and beyond. The phase-in is intended to encourage the development and commercialization of new technologies. Table B-18 summarizes the proposed limits for non-emergency engines. Unlike the Model Rule, the proposed rule does not create or provide any recognition for concurrent emissions reductions, combined heat and power or end-use efficiency.

Table B-18
Proposed Massachusetts Emission Limits for Non-Emergency Engines

Installation Date	Oxides of Nitrogen	Particulate Matter (Liquid Fuel)	Carbon Monoxide	Carbon Dioxide
On and after 01/01/2004	0.6 lbs/MWh	0.7 lbs/MWh; ≥ 1 MW 0.09 lbs/MW	10 lbs/MWh	1900 lbs/MWh
On and after 01/01/2008	0.3 lbs/MWh	0.07 lbs/MWh	2 lbs/MWh	1900 lbs/MWh
On and after 01/01/2012	0.15 lbs/MWh	0.03 lbs/MWh	1 lb/MWh	1650 lbs/MWh

The emission limits for turbines (Table B-19) are consistent with the Texas general permit for DG (See Section B.2.3). They vary by generator size but are not phased in over time.

Table B-19
Proposed Massachusetts Emission Limits for Non-Emergency Turbines

Rated Power Output	Oxides of Nitrogen	Ammonia	Particulate Matter	Carbon Monoxide
Less than 1 MW	0.47 lbs/MWh	(sic)	0.10 lbs/MWh	0.47 lbs/MWh
1 to 10 MW	Gas - 0.14 lbs/MWh Oil - 0.34 lbs/MWh	3 2.0 ppm	0.10 lbs/MWh	Gas - 0.09 lbs/MWh Oil - 0.18 lbs/MWh

Additional information:
Bob Donaldson
Department of Environmental Protection Business Compliance Division
One Winter Street Boston, MA 02108
Voice: (617) 292-5619
FAX: (617) 556-1063

B.2.7 New York 6 NYCRR Part 222 Emissions from Distributed Generation

The state of New York's Department of Environmental Conservation (DEC) is proposing output-based standards for nitrogen oxides and carbon monoxide. The regulations would include separate standards for new and existing generators. Currently, there is no recognition of CHP. Additionally, the rule makes no distinction between emergency and non-emergency generators. The proposed limits in Tables B-20 through B-25 below are from a working draft released in the spring of 2003. However, the department has signaled its intention to change these limits in an upcoming revised draft rule.

Table B-20
Proposed New York Emission Limits for Microturbines

Standard	NO_x (lb/MWh)	CO (lb/MWh)
New DG	1.30[1]	1.70
Existing DG	1.30[2]	NA

[1] Based upon the data supplied by Energy and Environmental Analysis (through NYSERDA), the 1.30 lb/MWh proposed standard corresponds to a concentration of approximately 25 ppmv @ 15% O_2.
[2] Microturbines are a new technology. It is anticipated that existing units would be compliant with the proposed standard for new units.

Table B-21
Proposed New York Emission Limits for Natural Gas-fired Turbines

Standard	NO_x (lb/MWh)	CO (lb/MWh)
New DG	2.20[1]	1.70
Existing DG	Annual tune-up[2]	4 NA

[1] Based upon the data supplied by Energy and Environmental Analysis (through NYSERDA), the 2.20 lb/MWh proposed standard corresponds to a concentration of approximately 41 ppmv @ 15% O_2. Further this proposed standard corresponds to an emission rate of approximately 0.15 lb/MMBTU.

[2] Existing sources would be required to meet the NO_x standard for new sources as of January 1, 2008.

Table B-22
Proposed New York Emission Limits for Oil-fired Turbines

Standard	NO_x (lb/MWh)	CO (lb/MWh)
New DG	4.40	1.60
Existing DG	Annual tune-up[1]	NA

[1] Existing sources would be required to meet the NO_x standard for new sources as of January 1, 2008.

Table B-23
Proposed New York Emission Limits for Natural Gas Lean-burn Engines

Standard	NO_x (lb/MWh)	CO (lb/MWh)
New DG	4.40	6.50
Existing DG	Annual tune-up[1]	NA

[1] Existing sources would be required to meet the NO_x standard for new sources as of January 1, 2008.

Table B-24
Proposed New York Emission Limits for Natural Gas-fired Rich Burn Engines

Standard	NO_x (lb/MWh)	CO (lb/MWh)
New DG	0.890[1]	3.6[1]
Existing DG	Annual tune-up[2]	NA

[1] Based upon the use of a 3-way catalyst (non-selective catalytic reduction).
[2] Existing sources would be required to meet the NO_x standard for new sources as of January 1, 2008.

Table B-25
Proposed New York Emission Limits for Diesel-fired Compression Engines

Standard	NO_x (lb/MWh)	CO (lb/MWh)
New DG	Peaking Units: 16.0 Baseload Units: 1.60[1]	6.50 (for units rated less than 75 kW) 2.20 (for all other diesel-fired compression engines)
Existing DG	Annual tune-up[2]	NA

[1] Based upon use of selective catalytic reduction emission control system.
[2] Existing sources would be required to meet the NO_x standard for new sources as of January 1, 2008.

The DEC hopes to have a new proposed regulation by spring 2004.

Additional Information:

John Barnes
New York Department of Environmental Conservation
625 Broadway
Albany, NY 12233-3254
(518) 402-8403

B.3 Allowance Allocation in Emission Trading Programs

In emission cap and trade programs, the total tons of emissions for a given sector are capped. Allowances represent a permit to emit one ton. Allowances are allocated to the affected sources, and each source is required to hold allowances equal to its emissions during each regulated period. Sources are allowed to buy and sell allowances from each other to help them meet their compliance requirement. In itself, these trading programs promote an output-based view on the part of affected sources. Affected sources must try to maximize their production within the overall emission cap, thus they are driven to relate their emissions directly to their productive output. However, other aspects of the program can more directly relate to output-based regulation.

In these programs, the emission allowances must be allocated to participating sources at the beginning of the program. The early cap and trade programs performed this allocation based on historical emissions or heat input. More recently, there has been interest in doing the allocation based on energy output. An output-based allocation can serve to recognize the benefits of efficient generation, end use efficiency and renewables. The current programs that include output-based allocation are primarily state programs under the NO_X SIP call program, described here. Some actual and proposed multi-pollutant legislation also includes output-based allocation (see sections B.4 and B.5).

B.3.1 Connecticut

Allowances for existing electric generating units in the NO_x SIP call trading program (Sec. 22a-174-22b) are allocated every two years based on the percentage of each unit's average electric generation during the previous two years relative to the total generation from affected units. The allocation for new units, cogenerators, and industrial boilers is based on heat input. There is no special treatment for CHP facilities.

Additional information:
Chris Nelson
Department of Environmental Protection at Bureau of Air Management
79 Elm Street, 5th Floor
Hartford, CT 06106-5127
(860) 424-3454
http://www.dep.state.ct.us/air2/regs/mainregs/sec22.pdf

B.3.2 Massachusetts

Allocations of allowances for the NO_X SIP call trading program will be revised annually, three years ahead of the compliance year. Allocation for electric generators is based on the average of the two highest years of generation (output) in the 4^{th}, 5^{th}, and 6^{th} years prior to the allocation year. Allocation for industrial boilers is based on the two highest years of steam output in 4^{th}, 5^{th}, and 6^{th} years prior to the allocation year. Sources with both electric and thermal output (including CHP facilities) receive allocations for both output streams.

Additional information:
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Department of Environmental Protection
One Winter Street
Boston, MA 02108-4746
(978) 661-7657
http://www.state.ma.us/dep/bwp/daqc/daqcpubs.htm#regs

B.3.3 New Hampshire

New Hampshire has a NO_X cap and trade program for the ozone season starting in 2003 (NH CAR Env-A 3207). The allowances for the first three years of program are allocated to electric generating units based on historical generation with some modifications to allow for new units. Starting in 2006, allocations will be based directly on generation output. The state is currently considering inclusion of nuclear units in the allocation based on their generation. There is no special treatment for CHP facilities.

Additional information:
Joe Fontaine
Department of Environmental Services
Air Resources Division
P.O. Box 95
Concord, NH 03302-0095
(800) 498-6868
http://www.des.state.nh.us/ard/ert.htm

B.3.4 New Jersey

The New Jersey allocation system for NO_X allowances under the SIP call (NJ AC Title 7 Chapter 27 Subchapter 31) treats sources differently depending on their emission rate. Allocations are done annually three years in advance. Allowances for sources with an emission rate less than or equal to 0.15 lb/MMBtu $_{\text{heat input}}$ are based on actual emissions. Allowances for sources with an emission rate greater than 0.15 lb/MMBtu $_{\text{heat input}}$ are allocated based on output. For electric generating units, the allocation is 1.5 lb/MWh times the average of the two highest years' electrical generation outputs in the three ozone seasons prior to the allocation. For industrial boilers, the allocation is 0.44 lb/MMBtu $_{\text{heat output}}$ times the average of the two highest years' heat outputs for the three ozone seasons prior to the allocation.

Additional information:
Tom McNevin
Air Quality Management
Bureau of Regulatory Development
401 East State Street, 7th Floor
P.O. Box 418
Trenton, NJ 08625-0418
(609) 984-9766
http://www.state.nj.us/dep/aqm/

B.4 State Multi-Pollutant Programs

Several states have recently implemented multi-pollutant regulations for power generators. These regulations comprise integrated emission reduction programs for power generators. Some are cap and trade programs, while others are conventional emission rate limit programs. Several programs include output-based approaches to regulation.

B.4.1 Massachusetts Multi-Pollutant Program

Massachusetts has a multi-pollutant regulation (310 CMR 7.29) for SO_2, NO_X, mercury, and CO_2 from older coal-fired power plants in the state. The regulation sets output-based emission limits for NO_X, SO_2, and CO_2 (Table B-26). The state has released a draft proposal for mercury limits from affected facilities. The regulation targets specific coal-fired plants, including Brayton Point, Canal Electric, Mt. Tom, Mystic Station, Salem Harbor Station, and Somerset Station.

The NO_x emission standards will be 1.5 lbs/MWh rolling annual average (beginning October 2004) with an additional 3.0 lbs/MWh monthly average taking effect in October 2006. The limit of 1.5 lbs/MWh is the nominal level established for the ozone season by the NO_x SIP call, however, this regulation expands compliance with the SIP call standard to a year-round requirement, rather than the ozone season. It also sets a fixed standard rather than a cap and trade program. Compliance dates are moved two years in the future for units that have been approved for major modifications or repowering prior to 2003.

Table B-26
Massachusetts Multi-Pollutant Program Emission Limits

	Emission Limits (lb/MWh, Rolling 12-month Average)			
Effective Date	**NO_x**	**SO_2**	**CO_2**	**Mercury**
2002	-	-	-	See proposed limits below
2004	1.5	6.0	Historical Emissions	
2006	1.5*	3.0**	1,800	

* Must also meet 3.0 lb/MWh monthly average.
** Must also meet 6.0 lb/MWh monthly average.

SO_2 emission standards will be 6.0 lbs/MWh (as of October 2004). Early reduction credits can be generated by participating facilities and used by these facilities to meet emissions above the 6.0 lbs/MWh annual level. Beginning in October 2006, the standard will drop to 3.0 lbs/MWh (rolling annual) and 6.0 lbs/MWh (monthly). Title IV SO_2 allowances can be purchased and used for compliance with the 3.0 lbs/MWh standard but will be discounted at a 3:1 ratio. Title IV allowances used for this purpose must be excess allowances above those used to comply with the federal requirements. These standards reduce nominal emission levels allowed under Title IV by half and set specific limits. Compliance dates are moved to 2008 for units that have been approved for major modifications or repowering prior to 2003.

CO_2 emissions from 2004 to 2006 must not exceed historical annual emissions from a facility. Beginning in 2006, facilities must have an average emission rate not greater than 1,800 lbs/MWh (annual average). The average emission rate is calculated by dividing pounds of CO_2 emitted by net electrical output. Compliance with these standards may be demonstrated by using offsite reductions or sequestration to offset emissions.

Mercury emission limits were set in January 2002 at the average historical annual emissions level from a facility. This average was calculated using the results of stack tests. The Massachusetts Department of Environmental Protection (DEP) first completed an evaluation of the technological and economic feasibility of controlling and eliminating emissions of mercury from the combustion of solid fossil fuel in December 2002. Recently, the DEP released a draft proposal for mercury emission regulations.

The draft mercury regulations will affect four large coal-burning power plants, which contribute 17% of the point source mercury emissions in Massachusetts. The DEP concluded a Mercury Feasibility report last year by finding that there is strong evidence that the removal of 85-90% of mercury in flue gas is technologically and economically feasible for coal-fired power plants. The draft regulation and technical support documents have been released for public comment.

The proposed regulations contain output-based mercury rate limitations implemented in two phases (Table B-27). Under the first phase of the mercury reductions, each utility is provided with a choice between a minimum 85% removal of mercury from inlet levels measured in 2001-2002 or a maximum Hg emission rate of 0.0075 pounds per net gigawatt-hour of electricity generated, calculated as a rolling annual average. This standard would take effect October 1, 2006, with the first annual average calculated for the October 1, 2006 to September 30, 2007 period.

Table B-27
Massachusetts' Proposed Mercury Emission Regulations

Phase	Mercury Limit
Phase 1 - By October 1, 2006	85% Hg removal efficiency or maximum emission limit of 0.0075 lbs/GWh_{net}
Phase 2 - By October 1, 2012	95% Hg removal efficiency or maximum emission limit of 0.0025 lbs/GWh_{net}

Under the second phase, each utility is provided with a choice between a minimum 95% removal of mercury from inlet levels measured in 2001-2002 or a maximum Hg emission rate of 0.0025 pounds per net gigawatt-hour of electricity generated, calculated as a rolling annual average. This standard would take effect October 1, 2012, with the first annual average calculated for the October 1, 2012 to September 30, 2013 period.

The inlet levels measured in 2001-2002 are used as the basis of the removal standard so that a facility cannot increase overall emissions by meeting the removal efficiency standard based on a higher inlet measurement. The department is allowing some flexibility for compliance. Through December 31, 2009, compliance with the mercury emission rate limitations may be demonstrated by using offsite reductions to offset excess emissions. The draft rule does allow averaging between a facility's units, but not between facilities.

Emission averaging among boilers within a plant is allowed for all standards. Early reduction credits can be created to meet the SO_2 standards.

Additional information:
Sharon Weber
Massachusetts Department of Environmental Protection
One Winter Street
Boston, MA 02108-4746
(617) 292-5500
http://www.state.ma.us/dep/

B.4.2 New Hampshire Multi-Pollutant Program

On May 8, 2002, New Hampshire passed a multi-pollutant law for existing fossil fuel power plants. The rule specifies emission reduction requirements for four pollutants (SO_2, NO_x, mercury, and CO_2). This law appears to be aimed at controlling emissions from three plants: Merrimack Station in Bow, Schiller Station in Portsmouth, and Newington Station in Newington. The language, however, is somewhat vague and could include other existing units.

The law sets annual emission caps. Allowances will be allocated to the plants on an output basis, and trading is allowed for SO_2, NO_X, and CO_2. The language also allows for trading of mercury, however, the supplementary information does not list mercury as a tradable pollutant. Caps are as follows:

- SO_2 emissions: 7,289 tpy. This is a 75 percent reduction from current levels by the end of 2006.

- NO_X emissions: 3,644 tpy. This is a 70 percent reduction from current levels by the end of 2006.

- CO_2 emissions: 5,425,866 tpy. This reduction will put emissions at 1990 levels by 2010. The 2010 date aligns the target and timetable for carbon reductions with those of the New England Governors and Eastern Canadian Premiers Climate Change Action Plan, adopted in August 2001. A lower cap for years after 2010 will be recommended no later then April 2004.

- A cap for mercury emissions from coal burning plants must be recommended to the Legislature by the Department of Environmental Services by early 2004. This schedule allows the cap to be set taking into account a specific assessment of mercury emissions from the Public Service of New Hampshire's facilities and the results of federal mercury limits that will be proposed by EPA in late 2003.

Affected units must file compliance plans to meet the requirements of the new bill and to describe monitoring and reporting procedures for mercury content in emissions. Caps may be met through reductions or trading. Allowances from federal and regional trading programs may be used as well, however, mercury credits from other programs are only valid for reductions above the level required by federal limits. An SO_2 allowance from an upwind state will be upgraded by 25 percent, meaning 0.8 tons purchased from an upwind state will be credited as 1.0 allowances by the state. NO_x discrete emission reduction credits cannot be used for compliance from May to September. Credit will be given for early reductions of CO_2 and mercury. Voluntary expenditures for energy efficiency, renewable energy, and conservation programs will be provided allowances equivalent to the cost of the renewable, efficiency, and conservation programs.

State officials are in the initial stages of proposing a regulation to implement the law. The first draft of the regulation determines the annual allocation approach as follows:

- SO_2 - baseline power generation multiplied by 3 lbs/MWh

- NO_x - baseline power generation multiplied by 1.5 lbs/MWh

- CO_2 (Phase I) - 1990 emissions

- Mercury and CO_2 (Phase II) – TBD

Individual unit allocations for NO_X and SO_2 will be based on the unit's average electrical output from two years prior multiplied by the emission factors above.

Additional information:
Joe Fontaine
Department of Environmental Services
Air Resources Division
P.O. Box 95
Concord, NH 03302-0095
(800) 498-6868
http://www.des.state.nh.us/ard_intro.htm

B.5 Federal Multi-Pollutant Proposals

A number of bills for multi-pollutant emission controls on power generators have been introduced in the U.S. Congress in recent years. Most of the bills involve emissions trading, and many incorporate output-based components. This section describes the output-based components of the primary multi-pollutant proposals from the 108th Congress.

B.5.1 Carper Bill – S843 & H.R. 3093

The Carper Bill, titled the "Clean Air Planning Act of 2003," establishes emission caps for four pollutants: SO_2, NO_X, mercury, and CO_2. The bill also sets certain reforms for New Source Review (NSR). The four pollutant caps are established as cap and trade programs. Allocation of allowances for these caps varies by pollutant. The allocations for NO_X, mercury, and CO_2 are based on electrical generating output, though the applicability of the program varies by pollutant. The bill also includes allocations for renewable generators in the CO_2 program. EPA is instructed to develop appropriate allocation procedures for CHP facilities in the program. The senate bill currently has not passed out of the Committee on Environment and Public Works and the house bill has not passed out of the Subcommittee on Energy and Air Quality.

B.5.2 Jeffords Bill – S366

The Jeffords Bill is also a four-pollutant program, titled the "Clean Power Act of 2003. The bill is a cap and trade program for $SO_{2,}$ NO_x, and $CO_{2.}$ Allocation of emission allowances is primarily accomplished through auctions. However, the bill creates set-asides for renewables, clean combustion units, and end-use efficiency. These set-asides are to be allocated based in part on generation output. The bill also contains specific incentives for CHP. It does not allow trading for mercury. The bill currently has not passed out of the Committee on Environment and Public Works

B.5.3 Clear Skies Initiative - S485 & H.R. 999

The Bush Administration plan calls for a cap and trade program on three pollutants: SO_2, NO_x, and mercury. During the first year of the trading program, 99% of the SO_2, NO_x and mercury allowances would be allocated to affected units with an auction for the remaining 1%. Each subsequent year for 20 years, an additional 1% of the allowances will be auctioned. Thereafter, an additional 2.5% will be auctioned until eventually all the allowances are auctioned annually. The non-auctioned allowances for NO_x and mercury are allocated based on historic heat input. The non-auctioned SO_2 allowances are allocated based on holdings of Acid Rain allowances (i.e., historic heat input). No allocations are provided directly to new units. Instead, new units can acquire any needed allowances from either the auction or the allowance market created from allocations received by existing sources.

There is one output-based component of the bill, however. The bill proposes revised NSPS emission limits as a replacement for NSR permitting. These emission limits output-based (Table B-28).

Table B-28
Clear Skies Initiative NSPS Emission Limits

Type of Unit	SO_2	NO_X	PM	Hg
Boilers, All Fuels, Coal-fired Turbines, and IGCC	2.0 lb/MWh	1.0 lb/MWh	0.2 lb/MWh	0.15 lb/GWh
Turbine, Oil-fired, or Other Fuels	2.0 lb/MWh	0.289-1.01 lb/MWh*	0.2 lb/MWh	--
Turbines, Gas-fired	--	0.084-0.56 lb/MWh*	--	--

* Depends on type of combustion cycle and proximity to Class I PSD areas.

B.6 Emission Performance Standards

Several states have developed programs to set emission performance standards for retail sellers of electricity. These output-based programs apply to all sellers, including those using non-combustion generation. Emission performance standards (EPS), as discussed in this section, refer to a state rule limiting the average emissions of the entire generation portfolio of a retail seller of electricity.

The main impetus for the programs described in this section is the Massachusetts restructuring legislation, which requires the establishment of an EPS for at least one pollutant by May 2003. The principle is that each retail seller of electricity must meet certain emission limits in lb/MWh for its portfolio of electricity. These limits extend to all sellers and all sources of electricity, including those outside the state. This raises some complicated issues of tracking of electricity sales, emissions, and even of limits on interstate commerce. After Massachusetts passed its EPS language, Connecticut and New Jersey passed similar language. These programs, however, are contingent on adoption of similar programs by other states in the region.

In 1999, the Northeast States for Coordinated Air Use Management (NESCAUM) sponsored the development of a model rule approach to an EPS that would address some of the critical issues and allow states to implement such a program on a consistent basis. A stakeholder group was convened to discuss these issues and a proposed model approach was released[1].

Under the rule, any electric generating unit that sells electricity in a state would be subject to the performance standards. The proposed standards are listed in Table B-29.

---

[4] http://www.nescaum.org/pdf/EPSRuleFINAL.pdf

Table B-29
NESCAUM Model Rule Emissions Performance Standards

Pollutant	Emissions (lb/MWh)
NO_X	1
SO_2	4
CO_2	1,100
CO	Reserved
Mercury	Each retail supplier is limited to no more than the actual emission rate for the reporting calendar year.

CHP units would be assigned an emission rate calculated by allocating emissions on a pro-rata basis between electric energy output and thermal energy output multiplied by CHP factor. The factor is initially set at 50 percent.

At this time both Connecticut and Massachusetts have committed to EPS. At the printing of this report, Massachusetts had not yet completed their EPS proposal and the May 2003 deadline had been pushed back indefinitely.

> The state of Connecticut released a draft EPS in early 2004 in accordance with the legislative mandate of section 22a-174j of the General Statutes. The proposed regulation currently uses the NESCAUM Model Rule Emissions Performance Standards for NO_x, SO_2 and CO_2. However, emissions of mercury and carbon monoxide are not regulated. A utility only needs to record and report the level of these emissions. CHP units would be assigned an emission rate calculated by allocating emissions on a pro-rata basis between the electric energy output and the thermal energy output, the latter to be adjusted using the operating standard calculations for a "qualifying facility" pursuant to the federal Public Utility regulatory Policies Act, 16 USC 824a-3.
>
> The proposed Connecticut regulation is not binding until the commissioner finds that at least three states that were members of the Ozone Transport Commission as of July 1, 1997, with a total combined population of at least twenty-seven million persons at that time, have adopted an emission performance standard.

Additional Information:
Patricia Downes
Department of Environmental Protection
79 Elm Street
Hartford, CT 06106-5127
(860) 424-3027
http://dep.state.ct.us/air2/siprac/2004/22a17434.pdf

B.7 Section 1605 (b) Greenhouse Gas Registry

On November 26, 2003, the Department of Energy (DOE) released proposed revised general guidelines for the voluntary reporting of greenhouse gas emissions and emission reductions under section 1605(b) of the Energy Policy Act. The section requires the DOE to develop a accurate and voluntary system to record the reporting of information on: (1) greenhouse gas emission levels for a baseline period (1987-1990) and thereafter, annually; (2) greenhouse gas emission reductions and carbon sequestration, regardless of the specific method used to achieve them; (3) greenhouse gas emission reductions achieved because of voluntary efforts, plant closings, or state or federal requirements; and (4) the aggregate calculation of greenhouse gas emissions by each reporting entity. The current proposal is for revised reporting guidelines to improve the accuracy of the reporting program.

The guideline applies to emissions of carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons and sulfur hexafluoride. Emissions are reported on an output basis in terms of the mass (not volume) of each gas. Although the 1605b program is not a mandatory program or an emission limit, the primary focus of the proposed guidelines is tracking based on energy intensity, such as lb/MWh. The proposed guidelines stress that this type of format is necessary to capture the beneficial effects of increasing energy efficiency as a method of reducing GHG emissions.

Additional information:
Mark Friedrichs
PI-40
Office of Policy and International Affairs
US Department of Energy
Room 1E190
1000 Independence Avenue S.W.
Washington, DC 20585
http://www.pi.energy.gov/enhancingGHGregistry/index.html

B.8 New Source Review

NSR requires a case-by-case determination of BACT for new and modified emission sources. It is one of the most important components of environmental permitting. Although there has been significant interest in developing an output-based approach to NSR, such an approach has yet to be developed. Recently, NSR for combustion sources has been based on determination of the best add-on control, regardless of the baseline efficiency. Although EPA guidance (*New Source Review Workshop Manual, October 1990*) allows states to consider the baseline emission levels, most states have not done so. The manual states:

> *"In many cases, a given production process or emissions unit can be made to be inherently less polluting (e.g., the use of water-based versus solvent-based paints in a coating operation or a coal-fired boiler designed to have a low emission factor for NO_X). In such cases, the ability of design considerations to make the*

process inherently less polluting must be considered as a control alternative for the source."

Permit levels resulting from NSR determinations could be expressed in output-based format rather than conventional input-based or concentration-based units. This would allow some consistency in measurement. However, it would not integrate efficiency into the actual determination of control requirements.

While there is continuing discussion of how to address this issue within the existing structure of NSR, one state, Connecticut, has directly addressed the possibility in its regulations. The state's revised NSR regulation (22a-174-3a, effective March 15, 2002) specifically allows for BACT to be determined on an output basis, though it does not specify how it would be done.

Additional information:
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http://dep.state.ct.us/air2/siprac/2002/sip02.htm

APPENDIX C

ENVIRONMENTAL ORGANIZATIONS THAT SUPPORT THE USE OF OUTPUT-BASED REGULATIONS

Appendix C

Environmental Organizations That Support the Use of Output-based Regulations

In addition to EPA, several other key groups, including air regulators, environmental groups, and proponents of energy efficiency and clean technology have recognized the benefits of using output-based regulations. This section highlights the positions of these organizations and demonstrates the broad support for output-based approaches.

STAPPA/ALAPCO

In 1999, the State and Territorial Air Pollution Program Administrators/Association of Local Air Pollution Control Officials (STAPPA/ALAPCO) commissioned a study on integrating air regulations for air quality and control of greenhouse gases. This study highlights the value of output-based regulations. Key excerpts from the document follow:

> *Policies to support fuel switching and increased efficiencies from power plants and other industrial sources include fuel-neutral, output-based emissions standards and comparable emission standards for all facilities.*
>
> *The move to output-based emission standards, expressed in terms of the amount of pollutant emitted per unit of energy produced, usually pounds of pollution per megawatt-hour (lb/MWh) for CO_2, NO_x and possibly SO_2, would incentivize efficiency enhancements and the use of lower-carbon fuels by making it easier for efficient and cleaner facilities and more difficult for inefficient and more polluting facilities to meet emission limits. These incentives would make it more difficult to operate older, inefficient units and would enhance the value of units with very low emission rates.*
>
> —*Reducing Greenhouse Gases and Air Pollution: A Menu of Harmonized Options,* October 1999, <http://www.4cleanair.org/comments/execsum.PDF>.

Ozone Transport Commission

The Ozone Transport Commission (OTC) is composed of the air quality agencies in the Northeast Ozone Transport Region. The OTC has been involved in the development of new and innovative pollution control programs. In 2002, the OTC commissioned a survey and report on the development of new clean air/efficiency programs in the region. This report highlights the development of output-based regulations - for example, as in the Massachusetts multi-pollutant program:

> *Output-based standards encourage generation efficiency. When implemented in the context of a cap and trade emissions program, output-based standards can ensure reductions from specific facilities in response to local air quality concerns. Multi-pollutant regulations can reduce the total costs of compliance with regulations because of the opportunity for integrated decision making on compliance options. [Massachusetts*

Department of Environmental Protection] anticipates that emission reductions from the electric generating industry, and the affected facilities of this regulation, will reduce air pollution, benefit the environment and be cost-effective. The regulation establishes a regulatory program implementing a comprehensive and integrated emission reduction approach for the largest emitting sources among Massachusetts' electric generating plants. Emission control strategies implemented for compliance will allow for more efficient combustion units and air pollution controls that reduce multi-pollutant emissions in a manner that is technically and economically feasible.

—*Survey of Clean Power and Energy Efficiency Programs,* <http://www.sso.org/otc/Publications/2002/OTC-Synapse-Survey-Report-020114-FINAL.doc>.

Environmental Groups

Many environmental groups strongly support the recognition of efficiency as an emission control measure and the use of CHP - and the use of output-based regulation to support both. In 2001, the Natural Resources Defense Council, the American Council for an Energy Efficient Economy, and the Energy Foundation wrote a white paper on methods of encouraging CHP through appropriate environmental regulation. The paper notes that:

Current air regulations do not take into account the increased efficiency benefits that occur when heat is recovered in a generation system. Creating output-based standards for pollutants (in pounds per megawatt-hour [lbs/MWh] output (or equivalent unit) for emissions would allow CHP to take ***credit*** *for this increased fuel utilization. The creation of output-based standards is absolutely key in encouraging the adoption of the cleanest and most efficient electricity generation technologies.*

—*Certification of Combined Heat and Power Systems: Establishing Emissions Standards,* September 2001, <http://www.aceee.org/pubs/ie014full.pdf>.

In 2001, the Renewable Energy Policy Project issued a report to investigate clean generating options to provide power for the southeastern United States. Its conclusions included:

When setting state-wide and regional pollution limits from power plants, state environmental agencies should base limits on output-based criteria rather than input-based criteria. Under past and current air pollution policies, regulators set emissions limits for power plants based on emissions per unit of heat input to the plant. Many analysts, however, believe that basing limits on emissions per unit of power generated from the power plant is more appropriate. Such a standard rewards more efficient plants rather than compensating inefficiency by giving higher emissions limits to plants that use excessive amounts of coal.

—*Powering the South,* Renewable Energy Policy Project, <http://www.poweringthesouth.org/articles/static/1/1013097470_1012401107.html#pol_4>.

Northeast-Midwest Institute

The Northeast-Midwest Institute (NEMW) is a Washington-based non-profit and non-partisan research organization dedicated to economic vitality, environmental quality, and regional equity for Northeast and Midwest states. It has a strong focus on regional energy and environmental problems and has determined that the development of CHP can play an important role in the cost effective resolution of these issues. NEMW states in a recent report:

> *Our policy case analysis indicates that 73 GW of additional CHP capacity could be achieved by 2010 and 152 GW by 2020. We project that new CHP will result in net energy savings of 2.6 quads and carbon emissions reductions of 74 million metric tons of carbon equivalent (MMT_{CE}) in 2010. Since sufficient data were not available to estimate other benefits for the buildings sector, the industrial and DES systems together would avoid the emissions of 1.4 million tons of SO_2 and 0.6 million tons of NO_x. These systems would require cumulative investments of roughly $47 billion over years. Consequently, CHP could contribute to approximately 15 percent of U.S. Kyoto carbon obligations.*
>
> *Despite our technologically moderate projections, these benefits may not be realized because of current and emerging policy barriers that limit widespread use of CHP in the U.S. These barriers must be reduced or eliminated so that the U.S. does not bypass a golden economic and environmental opportunity. We can learn from the Europeans - their marketplace experienced similar barriers at the beginning of the 1990s. By providing open electricity markets, moving to output-based environmental permitting standards, and providing exemptions from stranded cost recovery in some countries, they now predict a doubling of CHP's current nine percent share of the EU electricity market by 2010. Similar bold strategies are needed in the United States if the current CHP slowdown is to be reversed.*
>
> *—An Integrated Assessment of the Energy Savings and Emissions-Reduction Potential of Combined Heat and Power*, <http://www.nemw.org/CHPpotential.htm>.

In a recent outreach guide for state and federal governments, NEMW concludes:

> *Another new barrier (to CHP) can be an inappropriate allocation of emission **credits** within a cap-and-trade program. To encourage efficient technologies, an initial allocation must not treat **credits** as a property right of the existing sources, it must be output-based, and it must be updated frequently.*
>
> *—Combined Heat and Power Education and Outreach Guide to State and Federal Government, October 2000* (Updated March 2001), <http://www.nemw.org/CHPguide.pdf>.