August 2003 • NREL/SR-560-33167

Subcontractor Report

Technical Status Report of the Regulatory Assistance Project

October 2001–February 2003

The Regulatory Assistance Project
Gardiner, Maine
Montpelier, Vermont

National Renewable Energy Laboratory

1617 Cole Boulevard
Golden, Colorado 80401-3393

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Operated by Midwest Research Institute • Battelle • Bechtel

Contract No. DE-AC36-99-GO10337

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NREL Technical Monitor: Thomas Basso

Prepared under Subcontract No. ADD-0-30605-03

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Foreword

This report discusses the work undertaken by the Regulatory Assistance Project under subcontract to the National Renewable Energy Laboratory. The work is part of a larger U.S. Department of Energy effort to further the development and safe and reliable deployment of distributed resources within the nation's electricity system.

Distributed resources offer many economic and reliability benefits to customers, utilities, and society as a whole. But in some very important ways, our state regulatory practices inadvertently have made it difficult for these resources to be deployed. Understanding the existing regulatory barriers may lead to their removal. States such as Texas, New York, and California have already undertaken new regulatory approaches that simplify the technical integration of distributed resources into their local distribution networks. We encourage regulators and interested parties to become familiar with the work now under way in these states and to take steps to ease the integration of small-scale resources into local distribution systems.

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1. Background

As the electric industry has restructured over the past several years, the interest in using cost-effective distributed resources (DR) has begun to grow among some customers, utilities, and utility regulators. The development of small, modular generation technologies such as photovoltaics, microturbines, and fuel cells along with newer, small-scale combustion technologies — all of which offer unprecedented opportunities for highly customized applications — have helped stimulate this interest.

Today, a variety of DR deployment choices exist on both the utility and the customer side of the electrical meter. From the customer point of view, DR offer increased reliability, a high degree of individual load-following capability, and lower cost for power and power delivery. For the distribution utility, the strategic use of DR can defer or avoid larger capital investments in the distribution system and improve the quality of service to customers.

Utility regulatory practice, however, is not entirely friendly to the use of DR. More as an artifact of history than by intention, electricity utility regulation developed around an industry based on central station generation and ownership of generation facilities by a single regulated monopoly. In general, most regulatory practice is designed to reward sales, and many costs are averaged across large numbers of customers when rates are established. Thus, the economic value of installing DR is often not apparent to the person or entity making the deployment decision. This is particularly true for DR deployed on the customer's side of the meter. In addition to the problem of current regulatory practice blocking decision-makers from seeing the value of DR, the newly developed wholesale power markets have generally provided little opportunity for DR to participate. Thus, the economic value of DR deployment goes unrealized at both the retail and wholesale levels.

The task of addressing these regulatory barriers belongs to state and federal electricity regulators, but in many instances, the regulators are unaware of the problems or of the economic value of DR that is being lost to the system as a whole.

The work undertaken over the past year by the Regulatory Assistance Project (RAP) under contract to the National Renewable Energy Laboratory (NREL) has focused on identifying and removing the regulatory and institutional barriers that keep the full economic value of DR from being realized. The Department of Energy (DOE) Distribution and Interconnection R&D was initiated in January 1999 to address overall systems operation, reliability, safety, power quality, and institutional issues by focusing on three main R&D activities: (1) strategic research, (2) system integration, and (3) institutional issues. RAP's work for NREL, as part of the overall initiative, focuses on institutional issues.

2. Objectives

The objectives of RAP's work in this contract period were to develop regulatory policy options that would reduce the institutional and infrastructure barriers to full-value deployment of distributed power systems. Several players in the electricity industry could realize the economic benefits of DR: customers, distribution utilities, DR vendors, wholesale market participants, and, of course, regulators. Because existing regulatory systems often do not allow these benefits to be realized, many who could benefit from using DR are either unaware of those potential benefits or, worse, would actually experience economic penalty if DR were deployed. Policies are needed to establish cost and price signals that will reveal the value of DR to the parties most likely to deploy it. Regulation should provide the right incentives to reward the entity in the best position to deploy DR. Finally, wholesale and retail market structures and rules must operate to allow DR to be a competitive choice.

Specifically, RAP's objectives in carrying out this work were to:

1. Develop information, tools, and options for regulatory policies that will encourage the deployment of DR where cost-effective and environmentally beneficial

2. Implement the above information, tools, and proposed options along with additional related information and refine those and further establish both the means and the targeted draft proposals for removing or overcoming regulatory and institutional barriers to distributed power and energy efficiency resources (DR)

3. Establish and foster the adoption of a national model for output-based emissions performance standards for DR that could inform state utility and environmental regulator actions in each state.

RAP's two specific tasks in the current contract period were to:

- Task 4
  Lead at least two technical workshops for state utility regulators, including key staff, on removing or overcoming several regulatory barriers to DR. The workshops were expected to occur in the West, Mid-America, and the East as part of the annual regional meetings of state utility regulators in the spring and summer of 2002. The workshops were to use the material refined under Task 2 and the four studies competed under Task 1 of this contract as well as additional materials on removing regulatory barriers.

- Task 5
  Complete development of a draft model rule on emission performance standards for distributed generation (DG).

3. Approach

3.1 Task 4: Regulatory Workshops

RAP conducted two workshops and made two presentations in June 2002 on the Distributed Resources Policy Series papers.

The first workshop was conducted at the Western Conference of Public Service Commissioners in Phoenix, Arizona, on June 11. Approximately 30 commissioners and others attended. This workshop was facilitated by Wayne Shirley and Rick Weston. Presentations focused on the simplified cost methodologies paper and the DR credit pilot program proposal. In addition, Rick Weston presented a status and summary report on the model DG emissions rule.

The second workshop was given at the Mid-America Regional Commissioners Conference in Bismarck, North Dakota. The presentations were essentially the same as in the WCPSC workshop and were conducted by Wayne Shirley and Richard Sedano. Again, approximately 30 commissioners and others attended.

Richard Sedano made a presentation to the New England Conference of Public Utility Commissioners on the model rule for DG air emissions. Approximately 60 people heard this presentation, including PUC commissioners and staff and electric industry managers. The presentation was abbreviated as another topic, transmission siting, was also included in the time.

3.2 Task 5: DG Emissions Draft Model Rule

The electric industry has substantial and well-documented effects on our local, regional, and global environments. As our country's demand for electricity has grown, so has the number of ways that demand can be met. Innovations in technology, changes in the economics of the industry, and a variety of regulatory reforms (PURPA, the Electricity Policy Act of 1992, and restructuring in a number of states) have combined to create new opportunities for small-scale, DG. The effect could be, in a sense, self-perpetuating: the growing availability of cost-effective DG — microturbines, diesel "gen-sets," fuel cells, solar panels, reciprocating engines, etc. — has the potential to further change the nature of the electric network, thereby creating more opportunities for new applications.[1]

But with those opportunities come new challenges. Although the potential electric benefits of such technologies (improved reliability and security, lower costs, and so on) are becoming better understood, their environmental effects, and benefits, may be less so. To help states prepare for the potential proliferation of new sources of air emissions, the Distributed Resources Emissions Working Group was formed to develop a draft model rule that states can adopt in whole or adapt and that will foster the deployment of DG and other resources in ways that are both environmentally sustainable and economically efficient.

[1] Smaller-scale generation technologies have benefited, and will continue to benefit, from research and development activities by manufacturers, industry associations, and federal and state agencies. For more information about distributed power and current research efforts, visit the US Department of Energy's Distribution and Interconnection R&D Web site at http://www.eere.energy.gov/distributedpower/.

RAP enlisted Nancy L. Seidman of the Massachusetts Department of Environmental Protection and Christopher James of the Connecticut Department of Environmental Protection to act as co-coordinators of the project. After consulting with utility regulators, environmental regulators, industry representatives, and other interested persons, a list of potential members of the working group was put together. In the fall of 2000, letters of invitation were sent out. The work began in earnest in January 2001 with a "kick-off" conference call and, at the end of the month in Chicago, the first in-person meeting.

That first meeting was dedicated primarily to developing a set of objectives and principles to guide the work and a time line in which to finish it. The group discussed a series of questions: What do we hope to accomplish? What is the purpose of the rule? What is its scope? What constraints do we face? What approach to emissions regulation should we take? A "Statement of Objectives, General Principles, and Scope" emerged over the following months (and is included in the draft model in Appendix B).

The working group organized itself into several sub-groups that addressed specific issues: applicability, emissions, manufacturer certification, and offsets (credits for combined heat and power, etc.). The subgroups developed information and suggested approaches for tackling certain issues. The applicability subgroup considered the scope of the rule. How would the rule's applicability be defined — by generating capacity, output, technology, generation duty-cycle (i.e., emergency, peaking, base load), or location (e.g., attainment or nonattainment area)? The emissions subgroup put together a comprehensive spreadsheet detailing the emissions performance of current distributed generating technologies — that is to say, the state of the art for technologies that are now, or will very shortly be, available in the market. The certification subgroup studied how other manufacturer certification programs currently work — for example, the US EPA's ENERGY STAR program for appliances and its off-road mobile engine program. The offsets subgroup considered methods for calculating the net emissions reductions resulting from combined heat and power (CHP) installations and administratively streamlined and reliable ways to credit such installations with those savings.

The subgroups reported regularly on their progress to the working group. By spring 2001, the work had advanced sufficiently to convene a second in-person meeting that focused on the central, interrelated substantive issues — applicability and emissions standards. Proposals that had been developed by various working group members formed points of departure for the discussion. The meeting revealed areas of consensus and disagreement, and an action plan for resolving outstanding issues was set out.

Rulemakings in Texas and California also informed the working group's efforts. In June 2001, the Texas Natural Resource Conservation Commission adopted an "Air Quality Permit for Electric Generating Units" that established output-based standards for nitrogen oxides from generating facilities of less than 10 MW. The standards differ between east Texas and west Texas, are phased in over 4 years, and give emissions credits for CHP systems. Around the same time, the staff of the California Air Resources Board (CARB) issued a proposed rule that also set output-based standards for nitrogen oxides. But it also set standards for carbon monoxide, volatile organic compounds, and particulate matter. Like the Texas rule, the CARB rule has a two-step phase-in (the second phase begins in

2007) and gives credit for CHP savings. It also calls for a technology review, to be completed a year and a half before the 2007 standards go into effect. The CARB adopted the rule in November 2001 (with minor amendments early in 2002).[2]

After the May 2001 meeting, discussions continued, and an ad hoc drafting committee formed. Several drafts of the rule circulated through the ad hoc committee during the summer of 2001, so that by September, a draft could be forwarded to the group as a whole for its consideration. In October, after further review and revision, the working group agreed to release the draft for public comment. Early the next month, under the title "Public Review Draft," it was distributed widely.

In February 2002, after many responses to the draft were received, the working group began the process of molding the draft into its final form. Although reflective of the general inclinations of the working group as expressed in the Statement of Principles, the public review draft did not represent a full consensus of the group. Indeed, there were a number of key issues that required further consideration, and working through them took much of the winter and spring. By summer, most of the pieces had fallen into place, and the work turned to the final drafting and editing of the rule and accompanying text.

Most members of the working group who were active in the process during 2002 support the draft model rule presented here. There are, of course, certain provisions of the draft that do not fully satisfy some members; this is in the nature of compromise and consensus building. The members are, of course, free to express their specific concerns in state proceedings or other forums, as appropriate. However, the majority feels that the rule, taken as a whole, will, when implemented, lead to improvements in the regulation of air emissions from these sources in the country. There were, however, significant disagreements over CO_2. [3]

The proposed model rule is intended to apply to the wide variety of smaller-scale electric generating resources that are becoming increasingly available and that are consequently falling within the ambit of policymakers' interest. They are often referred to collectively as "distributed generation," or DG, a term that we will use for simplicity's sake in this document, but we note that it does not fully describe the set of resources that this draft model rule covers. The US Department of Energy's Distribution and Interconnection R&D Web site defines DG as follows:

> Distributed power is modular electric generation or storage located near the point of use. Distributed systems include biomass-based generators, combustion turbines, concentrating solar power and photovoltaic systems, fuel cells, wind turbines, microturbines, engines/generator sets, and storage and control technologies. Distributed resources can either be grid-connected or operate independently of the grid. Those connected to the grid are typically interfaced at

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[2] The Texas standard permit is authorized under Title 30, Texas Administrative Code, Part 1, Chapter 116.601-116.603; see http://www.tnrcc.state.tx.us/permitting/airperm/nsr_permits/athrize.htm. The California requirements are found in Title 17, California Code of Regulations, Division 3, Chapter 1, Subchapter 8, Article 3, Secs. 94200-94214.

[3] The reasons for a lack of broad consensus on carbon dioxide are described in Chapter IV, Commentary on the Rule.

> the distribution system. In contrast to large, central-station power plants, distributed power systems typically range from less than a kilowatt to tens of megawatts in size.[4]

This definition is, for the most part, suitable for our purposes here, though with one clarification. The working group saw no reason to limit its applicability simply to those resources "located near the point of use." Those deployed in remote locations will likely also produce air emissions, and, although their air quality and public health effects may differ from those sited in more populated areas, the group concluded that those potential effects, the desire to cover facilities that state laws do not now cover, and the general goal of administrative simplicity warranted a broader applicability requirement.

[4] DOE definition found at http://www.eren.doe.gov/distributedpower/whatis_main.html at time of writing. However, this Web page is no longer available.

4. Outcomes

4.1 Task 4: Regulatory Workshops

Attendees were attentive and interested at all three workshops. Many questions focused on the incentive problems inherent in regulation that bias utilities against customer use of distributed technologies and approaches regulators should take to understand and capitalize on the cost-avoidance values of DR. Some participants expressed an interest in pursuing a DR credit pilot program and wanted to know what companies, if any, had expressed an interest in participating. Other than some expression of interest from Commonwealth Edison two years ago, no utilities have publicly expressed an interest to participate. However, based on questions and post-session discussions with some utility personnel, some utilities might be interested.

Following all of these presentations and workshops, numerous requests were made for additional copies of the DR Policy Series booklets and for the lookup spreadsheet that has been posted on the RAP Web site. In all, the outreach efforts were well-received and reached interested parties.

The materials used at the workshops were the four publications developed under Task 2, RAP's other publications on DG policy issues, and overhead slides. The slides are attached to this report as Appendix A.

In addition to the workshops for utility regulators, Wayne Shirley also made a presentation on distribution system costs and the DR credit pilot concept to the American Solar Energy Society conference in Reno, Nevada, June 19. This presentation was very well attended, with approximately 60 people present. Attendees were largely hardware manufacturers and systems marketers and integrators. Although this was not our typical regulatory audience, interest levels were very high. This audience was especially interested in identifying and capturing values associated with system expansion costs for utilities. In the long run, it is likely that it is this audience that will have to bring many of the regulatory issues before the commissions.

4.2 Task 5: DG Emissions Draft Model Rule

The draft model rule regulates five air pollutants: nitrogen oxides, particulate matter, carbon monoxide, sulfur dioxide, and carbon dioxide. It takes an output-based (pounds per megawatt-hour) and fuel- and technology-neutral approach to controlling the emissions (except in the case of sulfur dioxide, which is readily addressed through a fuel sulfur-content requirement). The group opted for this approach on the grounds that it recognizes and rewards efficiency and will promote innovation. It is also relatively straightforward, allows for compliance through manufacturer certification, and is compatible with competitive markets and other regulatory schemes such as generation performance standards and tradable emissions allowances.

The working group recognized, however, that not all DG is the same. Given the range of technologies, uses, and environmental profiles, single-point emissions standards applicable to all would not be practical. Depending on how such standards might be set, they would be either ineffective (not stringent enough) or a barrier to DR deployment and its benefits (too stringent). Consequently, the group developed a draft model rule that differentiates not by technology but by the needs served, which in turn were defined by the circumstances of operation (duty cycles). In addition, the draft calls for the standards for each pollutant to be phased in three steps over a 10-year period. Originally, the group identified three duty cycles — emergency, peaking, and base load — and proposed standards for them, but further analysis led the group to conclude that only two categories are needed: emergency and non-emergency. Emergency generation is limited in its total annual hours of operation to 300 hours, of which a maximum of 50 hours may be for maintenance operations. Non-emergency covers all other applications.

The general premise of the draft model rule is that the more a generator operates, the less its emissions per megawatt-hour must be. This is consistent with the historic approach to the permitting of larger sources, which relates compliance requirements to the cost per ton of reduction. The compliance costs for sources that run very few hours (such as peaking facilities) will be more likely to exceed the thresholds. When the compliance cost is spread out over a greater number of hours of operation, the requirement can be more stringent. Emergency generators can also be seen in this light, although it is complicated by public health and safety imperatives at times of blackout. Emergency generators will run to provide electricity, particularly for essential services such as hospitals, until grid power is restored. These events are unpredictable and usually of limited duration, given the high reliability record of the US power system.

The emissions limits in each category are based on the levels of emissions that current technologies can achieve or are expected to achieve over the next decade. There are three phase-in periods, during which the limits are "ratcheted down." In this sense, the approach resembles the BACT (best available control technology) approach historically used in US air regulation (i.e., the standards tighten as cost-effective improvements in technology are achieved), but it differs in important ways. BACT has traditionally been interpreted to mean that a new project has to be as "clean" as the cleanest current model of the particular technology in question, i.e., diesel, gas combined cycle, oil, atmospheric fluidized bed coal, etc. The approach taken in the draft model rule is not to categorize the emissions standards by technology type but rather by use or need, recognizing that certain technologies are better suited to particular needs, e.g., diesels for emergency operations and microturbines and gas reciprocating engines for extended use. In addition, to give added flexibility to suppliers to meet the standards, credits for emissions savings or offsets are given for CHP applications, renewables, and end-use efficiency. The emissions limits push for the cleanest applicable technologies. For reasons explained in detail in Chapter IV, Commentary on the Rule, the draft model rule applies only to new installations, not existing ones. The rule also differs from BACT in that it sets standards for technology that have not yet been achieved; BACT, in contrast, requires compliance with performance standards that have already been demonstrated and is determined on a case-by-case basis.

This is a draft model rule for states, which they will adopt as they see fit. Even so, the rule is intended to promote national consistency across the states, thereby reducing the costs of compliance for suppliers and easing administrative burdens for regulators. For that hope to be realized, several states will need to adopt it (or a rule very similar to it).

Appendix A: Material from Regulatory Workshops

Workshop on Distributed Generation

Economic and Environmental Issues
Wayne Shirley and Frederick Weston

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Distributed Resources Overview

- Distributed Generation
- Load Response
  - Price-response
  - Reliability and ancillary services
- End-Use Efficiency

DR: The Good, The Bad and The Ugly

- Good: DR that:
  - Costs Less Than Avoided Cost
  - Minimizes Or Avoids Revenue Shifting
  - Participates In Demand Response Market
- Bad: DR that:
  - Costs More Than Avoided Cost
  - Result In Revenue Shifting
  - Has No Demand Response Market Available
- Ugly DR With:
  - High Emissions
  - Poor Power Quality Characteristics
  - High System Costs To Interconnect

What Regulators Need To Know About Distributed Resources

- Safety
- Impact On Reliability
- Impact on System Costs
  - Transmission
  - Distribution
- Emissions

Safety

- Disconnect events
  - Automatic Disconnect With Power Quality Event on System Side of Meter
  - Utility Accessible Lock Out
  - Reactivation Criteria and Procedures

Reliability

- Operational Necessities
  - Harmonics
  - Power Factor
  - Voltage
  - Stability
- Ancillary Services Resource
- As Size Increases, Local Conditions More Relevant

Distribution System Costs

- Classification
  - Lines and Feeders
  - Transformers and Substations
- Plant Investments
- Related O&M Expenses

Representative Real World Data Marginal Investment/MW Growth 5 Yr. Average 1994-1999

Company	Transformers &Substations National Rank- ($/MW)	Lines & Feeders National Rank- ($/MW)
PGE	5 - $374,748	9 - $1,429,544
Pacificorp	11 - $274,883	12 - $1,393,458
PNM	17 - $201,792	17 - $1,192,783
PG&E	28 - $113,418	37 - $657,265
PSCo	39 - $87,478	70 - $347,832
APS	45 - $77,283	21 - $942,846
Sierra Pacific	56 - $60,899	65 - $385,991
Idaho Power Co.	69 - $49,589	69 - $347,956
Puget Sound	121 - ($380,387)	123 - ($4,183,553)
Montana Power	122 - ($391,590)	121 - ($1,844,562)

Source: *Distribution System Cost Methodologies for Distributed Generation,* The Regulatory Assistance Project, September 2001 (based on FERC Form 1 data 1994-1999 for 124 companies)

Cost Drivers

- Topology of System
  - Overhead vs. Underground
  - Retrofit vs. New
  - Urban vs. Rural
  - Flat/Sandy vs. Mountainous/Rocky
- "Local" Rate of Growth

Location and Utility Specific

- High variance among utilities
- High variance within utilities
- High variance geographically
- Conclusion: Requires project by project analysis

High Value Cases

- Low to Moderate Growth
- Where System Is At or Near Capacity
- Where Solution Is Capital Intensive
- MWs Involved Are Sized To Match DR Alternatives

Deferral Values of DR Transformers & Substations

Years of Deferral	1 Yr.		5 Yrs.		10 Yrs.		30 Yrs.	
Company/Case	A	H	A	H	A	H	A	H
PGE	$46	$81	$190	$333	$294	$515	$399	$696
Pacificorp	$34	$59	$139	$244	$215	$377	$291	$510
PNM	$25	$43	$103	$179	$159	$278	$216	$376
PG&E	$14	$24	$58	$101	$89	$156	$121	$211
PSCo	$11	$19	$45	$78	$69	$121	$94	$163
APS	$10	$17	$40	$69	$61	$107	$83	$145
Sierra Pacific	$8	$13	$31	$55	$49	$85	$67	$115
Idaho Power	$6	$11	$27	$45	$41	$71	$57	$96

A = Actual Average Costs 1994-1999 H = High Case

Deferral Values of DR
Lines & Feeders

	1 Yr.		5 Yrs.		10 Yrs.		30 Yrs.	
Company/Case	**A**	**H**	**A**	**H**	**A**	**H**	**A**	**H**
PGE	$181	$343	$750	$1,420	$1,166	$2,201	$1,598	$2,995
Pacificorp	$176	$334	$729	$1,383	$1,134	$2,143	$1,554	$2,915
PNM	$150	$286	$623	$1,182	$968	$1,833	$1,326	$2,491
PG&E	$91	$165	$381	$689	$599	$1,075	$848	$1,491
PSCo	$47	$86	$195	$358	$305	$557	$428	$767
APS	$118	$225	$489	$931	$760	$1,443	$1,038	$1,959
Sierra Pacific	$51	$95	$214	$395	$335	$615	$468	$845
Idaho Power	$48	$87	$200	$364	$315	$567	$445	$785

A = Actual Average Costs 1994-1999 H = High Case

Distributed Resources and the Environment

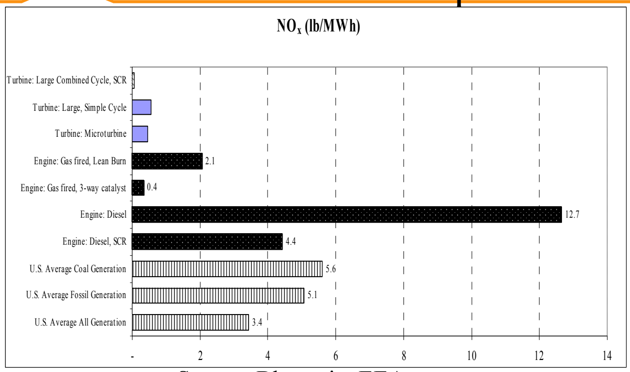
Purpose

- Recognizing the role of DR in existing and restructured electricity markets
- Collaborating to develop model emissions standards for distributed generation

Purpose

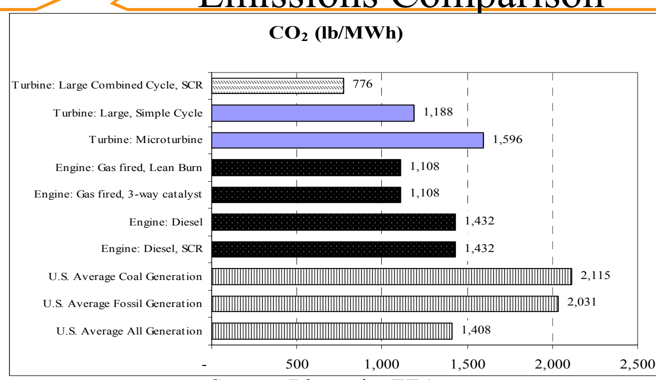
- What concerns are being addressed?
  - Environmental protection with technology and industry changes
  - Promoting clean DR
  - Administrative simplicity
  - Promoting certification of small engines at clean standards

Emissions Comparison



Source: Bluestein, EEA

Emissions Comparison



Source: Bluestein, EEA

Principles Guiding Development of the Rule

- The model emissions standards should:
  - Lead to improved air quality, or at least do no additional harm
  - Be technology-neutral and fuel-neutral, to the extent possible
    - Address issues surrounding existing vs. new DR

Principles Guiding Development of the Rule

- The model emissions standards should:
  - Promote technological improvements in efficiency and emissions output
    - Encourage the use of non-emitting resources
    - Account for the benefits of CHP and the use of otherwise flared gases
  - Be easy to administer
    - Facilitate the development, siting, and efficient use of DR

Organization of the Working Group

- 25-30 members encompassing: state energy regulators, state and federal air quality regulators, manufacturers, interest groups (environmental and industry)
- Work done primarily by conference call and e-mail; two face-to-face meetings

Status of Effort

- Three work groups established after January 2001 meeting
  - Emissions, Certification, Credits for Offsets (CHP, flared gases, energy efficiency)
- May 2001 meeting
- November 2001 Public Review Draft
- Revisions, winter and spring 2002
- Final model rule, Summer 2002

Key Issue: Applicability

- What types of sources should be covered?
- What sizes of engines should be addressed? (not covered by NSR or state BACT)
  - Limit by tons, kW, hours of operation?
  - Less than 1 MW, 500 kW, 200 kW, 50 kW?
- What functions should be covered?
  - Emergency, peaking, baseload

Key Issue: Emissions

- Establish "appropriate" emissions standards
  - Better than grid average, as good as new BACT for large combined cycle sources, LAER?
- Pollutants: NO_X, PM, CO, CO_2, SO_2

Proposed Emissions Limits

- For NO_X, PM, CO, CO_2:
  - Output-based limits: pounds per MWh
- For SO_2:
  - Diesel is the issue
  - Ultra-low sulfur fuel requirement
  - Following EPA on-road requirements
- Technology review prior to Phase Three

Proposed Emissions Limits

- Emergency Generators
  - 300 hours annual operation
  - 30 hours annual maintenance (included in the 300 total)
  - EPA off-road engine standards, expressed in pounds/MWh

Proposed NO_X Limits

	Non-Emergency Generators	
	Non-Attainment	Attainment
Phase I (2004)	0.6	4
Phase II (2008)	0.3	1.5
Phase III (2012)	0.15	0.15

Proposed PM Limits

	All Duty Cycles, All Areas
Phase One (2004)	0.7
Phase Two (2008)	0.07
Phase Three (2012)	0.03

Proposed CO Limits

	All Duty Cycles, All Areas
Phase One (2004)	10.0
Phase Two (2008)	2.0
Phase Three (2012)	1.0

Proposed CO_2 Limits

	All Duty Cycles, All Areas
Phase One (2004)	1900
Phase Two (2008)	1900
Phase Three (2012)	1650

Other Issues

Pricing and Markets

- De-averaged Distribution Credits
  - Targets DR deployment in high-cost areas of the grid
- DR in Wholesale Markets
  - Simplified approaches to dispatching DR: generation, load management, and efficiency
  - New England Demand Response Initiative

Where To Go From Here?

- Information on Distribution System
- Possible Rulemaking
  - Interconnections
    - Technical Standards
    - Economic Issues
- Coordination With Environmental Regulators
- Other?

RAP Work On Distributed Resource Issues

- ***Profits and Progress Through Distributed Resources,*** David Moskovitz, February 2000
- ***Performance-based Regulation for Distribution Utilities,*** RAP, November 2000
- ***Charging for Distribution Utility Services: Issues in Rate Design***, Frederick Weston, December 2000
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- ***Available on RAP's Website: http://www.raponline.org***

Appendix B: Commentary and Draft Model Distributed Generation Emissions Rule

**Draft Model Regulations for the
Output of Specified Air Emissions
from Smaller-Scale Electric Generation Resources**

Report on the Efforts of the
Distributed Resources Emissions Working Group

February 2003

Preface and Acknowledgements

Under a contract with the National Renewable Energy Laboratory (NREL), the Regulatory Assistance Project (RAP) convened a working group of state utility regulators, state air pollution regulators, representatives of the distributed resources industry, environmental advocates, and federal officials. These approximately 30 people came together in an effort to develop emissions standards for smaller-scale electric generation technologies. The effort began late in 2000 and was conducted mostly through e-mail, list-serve, and telephone conference calls. In addition, there were two in-person meetings of the group during 2001.

This document is the second draft product in that nearly 2-year effort. Although consensus was not a prerequisite for development of a model rule, it has, with respect to the rule's central features, been for the most part achieved. The members of the working group can — and should — applaud themselves for that accomplishment. Their hard work, attention to detail, and continuing belief in the value of the project made this document not only possible but, we hope, also helpful to state and local air quality agencies.

There are a number of people whose contributions should be individually recognized. Nathanael Greene of the Natural Resources Defense Council and Joel Bluestein of Energy and Environmental Analysis Inc. challenged each other and the group to construct a solid intellectual framework on which to hang the rule; out of their dialectic, creative resolutions often emerged. They and their organizations and Tim French of the Engine Manufacturers Association, Professor Jim Lents of the University of California, Riverside, Leslie Witherspoon of Solar Turbines Inc., John Kelly of the Gas Technology Institute, and Joseph Bryson of the US Environmental Protection Agency provided much of the data, analysis, and insight that the group needed to make informed policy choices. In addition, we are grateful to the many people and organizations outside the working group who took an interest in the rule and whose comments and suggestions on earlier drafts were invaluable. Lastly, we thank Thomas Basso and Gary Nakarado, both of NREL, and Joseph Galdo of the US Department of Energy for their enthusiastic support of the work. They and their agencies recognize the value of distributed resources and that strong environmental regulation is a critical component of an integrated energy policy that will foster the sustainable development and use of these resources. Their vision was an elemental part of our work.

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I. Introduction and Process

The electric industry has substantial and well-documented effects on our local, regional, and global environments. As our country's demand for electricity has grown, so has the number of ways that demand can be met. Innovations in technology, changes in the economics of the industry, and a variety of regulatory reforms (PURPA, the Electricity Policy Act of 1992, and electric industry restructuring in a number of states) have combined to create new opportunities for small-scale, distributed generation. The effect could be, in a sense, self-perpetuating: the growing availability of cost-effective distributed generation (DG) — micro-turbines, diesel "gen-sets," fuel cells, solar panels, reciprocating engines, etc. — has the potential to further change the nature of the electric network, thereby creating more opportunities for new applications.[1]

But with those opportunities come new challenges. Although the potential electric benefits of such technologies (improved reliability and security, lower costs, and so on) are becoming better understood, their environmental impacts, and benefits, may be less so. Although there have been efforts to address electric industry emissions at the national level — such as the Bush Administration's Clear Skies Initiative and other congressionally sponsored proposed legislation — these efforts do not address smaller electric generating resources. To help states prepare for the potential proliferation of new, smaller sources of air emissions, the Distributed Resources Emissions Working Group was formed to develop a draft model rule that states can adopt in whole or adapt and that will foster the deployment of distributed generation and other resources in ways that are both environmentally sustainable and economically efficient.

RAP enlisted Nancy L. Seidman of the Massachusetts Department of Environmental Protection and Christopher James of the Connecticut Department of Environmental Protection to act as co-coordinators of the project. After consulting with utility regulators, environmental regulators, industry representatives, and other interested persons, the working group put together a list of potential members and, in the fall of 2000, sent out letters of invitation. The work began in earnest in January 2001 with a "kick off" conference call and, at the end of the month in Chicago, the first in-person meeting.

That first meeting was dedicated primarily to developing a set of objectives and principles to guide the work and a time line in which to finish it. The group discussed a series of questions: What do we hope to accomplish? What is the purpose of the rule? What is its scope? What constraints do we face? What approach to emissions regulation should we take? A "Statement of

[1] Smaller-scale generation technologies have benefited, and will continue to benefit, from research and development activities by manufacturers, industry associations, and federal and state agencies. For more information about distributed power and current research efforts, visit the US Department of Energy's Distribution and Interconnection R&D Web site at http://www.eere.energy.gov/distributedpower/.

Objectives, General Principles, and Scope" emerged over the following couple of months (and is included herein as Appendix A).

The working group organized itself into several subgroups that addressed specific issues: applicability, emissions, manufacturer certification, and offsets (credits for combined heat and power, etc.). The subgroups developed information and suggested approaches for tackling certain issues. The applicability subgroup considered the scope of the rule. How would the rule's applicability be defined — by generating capacity, output, technology, generation duty-cycle (i.e., emergency, peaking, base load), or location (e.g., attainment or non-attainment area)? The emissions subgroup put together a comprehensive spreadsheet detailing the emissions performance of current distributed generation technologies — that is to say, the state of the art for technologies that are now, or will very shortly be, available in the market. The certification subgroup studied how other manufacturer certification programs currently work — for example, the US EPA's ENERGY STAR program for appliances and its off-road mobile engine program. The offsets subgroup considered methods for calculating the net emissions reductions resulting from combined heat and power (CHP) installations and administratively streamlined and reliable ways to credit such installations with those savings.

The subgroups reported regularly on their progress to the working group. By spring 2001, the work had advanced sufficiently to convene a second in-person meeting that focused on the central, interrelated, substantive issues: applicability and emissions standards. Proposals that had been developed by various working group members formed points of departure for the discussion. The meeting revealed areas of consensus and disagreement, and an action plan for resolving outstanding issues was set out.

Rulemakings in Texas and California also informed the working group's efforts. In June 2001, the Texas Natural Resource Conservation Commission adopted an Air Quality Permit for Electric Generating Units that established output-based standards for nitrogen oxides (NO_X) from generating facilities of less than 10 MW. The standards differ between east Texas and west Texas, are phased in over 4 years, and give emissions credits for CHP systems. Around the same time, the California Air Resources Board (CARB) issued a proposed rule that also set output-based standards for NO_X. However, its rule also set standards for carbon monoxide (CO), volatile organic compounds, and particulate matter (PM). Like the Texas rule, the CARB rule has a two-step phase-in (the second phase begins in 2007) and gives credit for CHP savings. It also calls for a technology review, to be completed a year and a half before the 2007 standards go into effect. The CARB adopted the rule in November 2001 (with minor amendments early in 2002).[2]

[2] The Texas standard permit is authorized under Title 30, Texas Administrative Code, Part 1, Chapter 116.601-116.603; see http://www.tnrcc.state.tx.us/permitting/airperm/nsr_permits/athrize.htm. The California requirements are found in Title 17, California Code of Regulations, Division 3, Chapter 1, Subchapter 8, Article 3, Secs. 94200-94214.

After the May 2001 meeting, discussions continued, and an ad hoc drafting committee was formed. Several drafts of the rule circulated through the ad hoc committee during the summer of 2001, so that by September a draft could be forwarded to the group as a whole for its consideration. In October, after further review and revision, the working group agreed to release the draft for public comment. Early the next month, under the title *Public Review Draft*, it was distributed widely.

In February 2002, after many responses to the public review draft were received, the working group began the process of molding the draft into its present form. Although reflective of the general inclinations of the working group as expressed in the Statement of Principles, the public review draft did not represent a full consensus of the group. Indeed, there were a number key issues that required further consideration, and working through them took much of the winter and spring. By summer, most of the pieces had to fallen into place, and the work turned to the detailed drafting and editing of the rule and accompanying text.

Most members of the working group who were active in the process during 2002 support the draft model rule presented here. There are, naturally, certain provisions of the rule that do not fully satisfy some members; this is in the nature of compromise and consensus building. Mostly, members differed in their philosophies of emissions regulation; as described in greater detail in Chapter IV, these differences were never reconciled. The members are, of course, free to express their specific concerns in state proceedings or other forums, as appropriate. However, the majority feels that the rule, taken as a whole, will, when implemented, lead to improvements in the regulation of air emissions from these sources in the country. There were, however, significant disagreements over carbon dioxide ($CO_{2)}$.[3]

Additional copies of this document can be found on the RAP Web site: http://www.raponline.org/index.htm.

[3] The reasons for the absence of carbon dioxide from the rule are described in Chapter IV, Commentary on the Rule.

II. General Description of the Rule

This model rule applies to the wide variety of smaller-scale electric generating resources that are becoming increasingly available and that are consequently falling within the ambit of policymakers' interest. They are often referred to collectively as "distributed generation," a term that we will use for simplicity's sake in this document, but we note that it does not fully describe the set of resources that this rule covers. The US Department of Energy defines DG as follows:

> Distributed power is modular electric generation or storage located near the point of use. Distributed systems include biomass-based generators, combustion turbines, concentrating solar power and photovoltaic systems, fuel cells, wind turbines, microturbines, engine/generator sets, and storage and control technologies. Distributed resources can either be grid-connected or operate independently of the grid. Those connected to the grid are typically interfaced at the distribution system. In contrast to large, central-station power plants, distributed power systems typically range from less than a kilowatt to tens of megawatts in size.[4]

This definition is, for the most part, suitable for our purposes here, though with one clarification. The working group saw no reason to limit its applicability simply to those resources "located near the point of use." Those deployed in remote locations will likely also produce air emissions and, though their air quality and public health effects may differ from those sited in more populated areas, the group concluded that those potential effects, the desire to cover facilities that state laws do not now cover, and the general goal of administrative simplicity warranted a broader applicability requirement.

The model rule regulates four air pollutants: NO_X, PM, CO, and sulfur dioxide (SO_2). It takes an output-based (pounds per megawatt-hour) and fuel- and technology-neutral approach to controlling the emissions (except in the case of SO_2, which is readily addressed through a fuel sulfur-content requirement). The group opted for this approach on the grounds that it recognizes and rewards efficiency and will promote innovation. It is also relatively straightforward, allows for compliance through manufacturer certification, and is compatible with competitive markets and other regulatory schemes such as generation performance standards and tradable emissions allowances. The working group recognized, however, that not all distributed generation is the same. Given the range of technologies, uses, and environmental profiles, single-point emissions standards applicable to all would not be practical. Depending on how such standards might be set, they would be either ineffective (not stringent enough) or a barrier to DR deployment and its benefits (too stringent). Consequently, the group developed a rule that differentiates not by technology but by the needs served, which in turn were defined by the circumstances of

[4] DOE definition found at http://www.eren.doe.gov/distributedpower/whatis_main.html at time of writing. However, this Web page is no longer available.

operation (duty-cycles). In addition, the rule calls for the standards for each pollutant to be phased in three steps over a 10-year period. Originally, the group identified three duty-cycles — emergency, peaking, and base load — and proposed standards for them, but further analysis led the group to conclude that only two categories are needed: emergency and non-emergency. Emergency generation is limited in its total annual hours of operation to 300 hours, of which a maximum of 50 hours may be for maintenance operations. Non-emergency covers all other applications.

The general premise of the rule is that the more a generator operates, the less its emissions per megawatt-hour (MWh) must be. This is consistent with the historic approach to the permitting of larger sources, which relates compliance requirements to the cost per ton of reduction. The compliance costs for sources that run very few hours (such as peaking facilities) will be more likely to exceed the thresholds. When the compliance cost is spread out over a greater number of hours of operation, the requirement can be more stringent. Emergency generators can also be seen in this light, although it is complicated by public health and safety imperatives at times of blackout. Emergency generators will run to provide electricity, particularly for essential services such as hospitals, until grid power is restored. These events are unpredictable and usually of limited duration, given the extremely high reliability record of the US power system.

The emissions limits in each category are based on the levels of emissions that current technologies can achieve or are expected to achieve over the next decade. There are three phase-in periods, during which the limits are "ratcheted down." In this sense, the approach resembles the BACT (best available control technology) approach historically used in US air regulation (i.e., the standards tighten as cost-effective improvements in technology are achieved), but it differs in important ways. BACT has traditionally been interpreted to mean that a new project has to be as "clean" as the cleanest current model of the particular technology in question, i.e., diesel, gas combined cycle, oil, atmospheric fluidized bed coal, etc. The approach taken in the rule is not to categorize the emissions standards by technology type but rather by use or need, recognizing that certain technologies are better suited to particular needs, e.g., diesels for emergency operations and microturbines and gas reciprocating engines for extended use. In addition, to give added flexibility to suppliers to meet the standards, credits for emissions savings or offsets are given for CHP applications, renewables, and end-use efficiency. The emissions limits push for the cleanest applicable technologies. For reasons explained in detail in Chapter IV, Commentary on the Rule, the rule applies only to new installations, not existing ones. The model rule also differs from BACT in that it sets standards for technology that have not yet been achieved; BACT, in contrast, requires compliance with performance standards that have already been demonstrated and is determined on a case-by-case basis.

This is a model rule for states, which they will adopt as they see fit. Even so, the rule is intended to promote national consistency across the states, thereby reducing the costs of compliance for suppliers and easing administrative burdens for regulators. For that hope to be realized, several states will need to adopt it (or a rule very similar to it).

This version of the rule differs from the November public review draft in several ways. The timing of the phase-in periods has been extended slightly to better accommodate manufacturers' research and development cycles. Phase 1 begins in 2004, Phase 2 in 2008, and Phase 3 in 2012. Previously, Phase 3 began in 2009. For emergency generators, the rule adopts the US EPA standards for off-road engines (converted to lbs/MWh). In the case of NO_X produced by non-emergency generators, the Phase 1 and Phase 2 limits are differentiated for attainment and non-attainment areas. This enables a state with attainment areas to give some added flexibility to suppliers, if it were to conclude, for instance, that the air quality benefits of the stricter emissions standards are not great enough to justify the higher technology costs in the early years. As technology develops, driven in part by increased deployment of distributed resources and stricter standards for on-road engines, the justification for a real differentiation diminishes. With Phase 3, both attainment and non-attainment areas will face the same NO_X limits.

The working group recognizes that the model rule's Phase 3 standards are "stretch" goals intended to push technology improvements. Although aggressive, the limits are based in large measure on the expected trajectories of technology performance over the next decade. However, given uncertainties about the state of DR technology 10 years hence, or of air quality and environmental regulations, the working group concluded that a technology review, to be completed a year before the Phase 3 standards go into effect, would be appropriate. The review will require the state to evaluate whether the Phase 3 limits are still apt and, if not, how they should be changed. To the extent that states can conduct this review jointly or with federal agencies, its costs can be significantly reduced and national consistency of standards promoted.

III. The Rule

Draft Model Regulations for the Output of Specified Air Emissions from Smaller-Scale Electric Generation Resources

Title AA: Emissions Standards for Smaller-Scale Electric Generation Facilities

I. Purpose. The purpose of this rule is to:

(A) Regulate the emissions of certain air pollutants from smaller-scale electric generating units in this jurisdiction; and

(B) Reduce the regulatory and administrative requirements for siting units that are affected by this rule.

II. Definitions.

(A) **Agency**: The local or state governmental department, division, or agency that has jurisdiction over air pollution emissions of electric generating units.

(B) **Combined Heat and Power**: A generator that sequentially produces and uses both electric power and thermal energy from a single source. Herein referred to as CHP.

(C) **Design System Efficiency**: For CHP, the sum of the full load design thermal output and electric output divided by the heat input.

(D) **Dual-Fuel Generator**: A generator that has the capacity to be fired by either natural gas (including landfill methane, digester gas, or similarly produced gases) or a liquid fuel (e.g., diesel or #2 oil) but not by both fuels simultaneously.

(E) **Emergency**: An electric power outage due to a failure of the electrical grid, on-site disaster, local equipment failure, or public service emergencies such as flood, fire, or natural disaster.

(F) **Emergency Generators**: Generators used only during emergencies or for maintenance purposes, provided that the maximum annual operating hours, including maintenance, shall not exceed 300 hours per calendar year. Emergency generators shall not be operated in conjunction with any voluntary demand-reduction program or any other interruptible power supply arrangement with a utility, other market participant, or system operator.

(G) **Generator**: Any equipment that converts primary fuel (including fossil fuels and renewable fuels) into electricity or electricity and thermal energy.

(H) **Installation**: A generator is installed when it begins generating electricity.

(I) **ISO**: International Organization for Standardization.

(J) **Landfill Gas**: Gas generated by the decomposition of organic waste deposited in a landfill (including municipal solid waste landfills) or derived from the evolution of organic compounds in the waste.

(K) **Mobile Diesel Fuel**: Diesel fuel that meets current US Environmental Protection Agency sulfur limits for fuel used by on-highway diesel engines (40 CFR 86).

(L) **Non-Emergency Generator**: Any generator that is not defined herein as an emergency generator.

(M) **Other Gaseous Fuels**: Gaseous fuels other than natural gas, including but not limited to landfill gas, waste gas, and anaerobic digester gas.

(N) **Owner**: The owner of, or person responsible for, a generator subject to the requirements of this rule.

(O) **Power to Heat Ratio**: For a CHP unit, the design electrical output divided by the design recovered thermal output in consistent units.

(P) **Supplier**: A person or firm that manufactures, assembles, or otherwise supplies generators subject to the requirements of this rule.

(Q) **US EPA**: The United States Environmental Protection Agency.

(R) **Waste Gas**: Manufacturing or mining byproduct gases that are not used and are otherwise flared or incinerated. A manufacturing or mining byproduct is a material that is not one of the primary products of a particular manufacturing or mining operation, is a secondary and incidental product of the particular operation, and would not be solely and separately manufactured or mined by the particular manufacturing or mining operation. The term does not include an intermediate manufacturing or mining product that results from one of the steps in a manufacturing or mining process and is typically processed through the next step of the process within a short time.

III. Effective Date. This rule is effective on [date].

IV. Applicability.

(A) This rule applies to all non-mobile generators that are installed on or after the effective date and that are not subject to Prevention of Significant Deterioration (40 CFR 52.21) or Review of New Sources and Modifications (40 CFR 51.160).

(B) **Exemptions.** Generators whose engines are subject to the 40 CFR 89, 90, 91,and 92, (the US EPA's Non-Road Engine Program) will be exempt from compliance with the requirements of this rule.

V. Emissions. A generator's emissions of nitrogen oxides (NO_X), particulate matter (PM), and carbon monoxide (CO) under full load design conditions or at the load conditions specified by the applicable testing methods shall not exceed the standards set out in the following subparagraphs. Standards are expressed in pounds per megawatt-hour (lbs/MWh) of electricity output. A generator shall meet the applicable standard in effect on the date that the unit is manufactured or on the date one year prior to the installation date of the unit, whichever is later.

(A) **Emergency generators.** A generator may run up to a maximum of 300 hours per year for maintenance, testing, and emergencies. Within that limit of 300 hours per year, a generator may run up to a maximum of 50 hours per year for maintenance and testing. Emergency generators must meet the emissions standards set by the US EPA for non-road engines (40 CFR 89) at the time of installation. Any engine that is certified under the US EPA non-road standards is automatically certified under this rule to operate as an emergency generator.

(B) **Non-Emergency Generators.** Emissions standards for non-emergency generators are as follows:

Non-Emergency Generators (operating more than 300 hours/year)	**Nitrogen Oxides: Ozone Attainment Areas**	**Nitrogen Oxides: Ozone Non-Attainment Areas**
Phase 1 (installed on or after 1/1/04)	4.0 lbs/MWh	0.6 lbs/MWh
Phase 2 (installed on or after 1/1/08)	1.5 lbs/MWh	0.3 lbs/MWh
Phase 3* (installed on or after 1/1/12)	0.15 lbs/MWh	0.15 lbs/MWh
*Technology review: to be completed by Dec. 31, 2010 to determine whether the Phase 3 standards should be amended based on the state of and expected changes in technology [refer to Section V(C)(1)]		

Non-Emergency Generators (operating more than 300 hours/year)	**Particulate Matter:** Liquid-fuel reciprocating engines	**Particulate Matter:** Liquid-fuel only non-reciprocating engines	**Carbon Monoxide**
Phase 1 (installed on or after 1/1/04)	0.7 lbs/MWh	To be determined	10 lbs/MWh
Phase 2 (installed on or after 1/1/08)	0.07 lbs/MWh	To be determined	2 lbs/MWh
Phase 3 (installed on or after 1/1/12)*	0.03 lbs/MWh	To be determined	1 lb/MWh
*Technology Review: to be completed by Dec. 31, 2010 to determine whether the Phase 3 standards should be amended based on the state of and expected changes in technology [refer to Section V(C)(1)]			

(C) **Technology Review.**

(1) By Dec. 31, 2010, the agency shall complete a review of the state of, and expected changes in, technology and emissions rates. This review shall be used by the agency in considering whether the Phase 3 standards (beginning 1/1/12) should be amended.

(2) Beginning in 2017 and every five years thereafter, the agency shall review the state of technology and emissions rates and determine whether the emissions set out herein should be amended.

(D) **Dual-Fuel Generators.** Dual-fuel generators must meet all applicable requirements of this rule when operated on gaseous fuels. Such generators may operate no more than thirty (30) days per year on liquid fuel. The liquid fuel must meet current US EPA sulfur limits for fuel used by on-highway diesel engines.

VI. Emissions Certification, Compliance, and Enforcement.

(A) **Emissions Certification.** A supplier may seek to certify that its generators meet the provisions of this rule.

(1) **Certification Process.** Emissions of nitrogen oxides, particulate matter, and carbon monoxide from the generator shall be certified in pounds of emissions per megawatt hour (lb/MWh) at full load design (ISO) conditions or at the load conditions specified by the applicable testing methods. If the design of a certified generator is modified, the generator will need to be re-certified. Certification means that a generator meets the required emissions standards and can be installed as supplied. With respect to nitrogen oxides and carbon monoxide, test results from EPA Reference Methods, California Air Resources Board methods, or equivalent testing may be used to verify this certification. When testing the output of particulate matter from liquid-fuel reciprocating engines, ISO Method 8178 shall be used. Test results shall be provided upon request to the agency. Any engine that has been certified to meet the currently applicable US EPA non-road emissions standards shall be deemed to be certified for use in emergency generators. A statement attesting to certification must be displayed on the nameplate of the unit or on a label attached to the unit with the following text:

> This engine has met the standards defined by [state/US EPA] regulation and is certified as meeting applicable emission levels when it is maintained and operated in accordance with the supplier's instructions.

(2) **Responsibility of Supplier.** Certification will apply to a specific make and model of generator. For a make and model of a generator to be certified, the supplier must certify that the generator is capable of meeting the requirements of this rule for the lesser of 15,000 hours of operation or three years. During the initial 15,000-hour operating period, the Agency may enforce compliance with these standards.

(B) An owner of a generator that is not certified under the terms of Section VI. A. will need to demonstrate compliance with this rule through on-site testing using procedures set out in [other applicable state regulations].

(C) **Duty to Comply.** An owner shall comply with the requirements of this rule or with the terms and conditions of any permit issued pursuant to this rule. Neither certification nor compliance with this rule relieves owners from compliance with all other applicable state and federal regulations (e.g., a general permit or a new source review permit).

(D) **Enforceability.** This rule and any permit issued pursuant to it are enforceable by the Agency as provided by law.

VII. Credit for Concurrent Emissions Reductions.

(A) **Flared Fuels.** If a generator uses fuel that would otherwise be flared (i.e., not used for generation or other energy-related purpose), the emissions that were or would have been produced through the flaring can be deducted from the actual emissions of the generator for the purposes of calculating compliance with the requirements of this rule. If the actual emissions from flaring can be documented, they may be used as the basis for calculating the credit, subject to the approval of the Agency. If the actual emissions from flaring cannot be documented, then the following default values shall be used:

Emissions	Waste, Landfill, Digester Gases
Nitrogen Oxides	0.1 lbs/MMBtu
Particulate Matter	N/A
Carbon Monoxide	0.7 lb/MMBtu

(B) **Combined Heat and Power.**

(1) CHP installations must meet the following requirements to be eligible for emissions credits related to thermal output:

(a) At least 20% of the fuel's total recovered energy must be thermal and at least 13% must be electric. This corresponds to an allowed power-to-heat ratio range of between 4.0 and 0.15.
(b) The design system efficiency must be at least 55 percent.

(2) A CHP system that meets these requirements can receive a compliance credit against its actual emissions based on the emissions that would have been created by a conventional separate system used to generate the same thermal output. The credit will be subtracted from the actual generator emissions for purposes of calculating compliance with the limits in section V.B. The credit will be calculated according to the following assumptions and procedures:

(a) The emission rates for the displaced thermal system (e.g., boiler) will be:
   i. For CHP installed in new facilities, the emissions limits applicable to new natural gas-fired boilers in [state code reference for boiler standards or Standards of Performance for New Sources (40 CFR 60, Subparts Da, Db, Dc), whichever is more stringent] in lb/MMBtu.
   ii. For CHP facilities that replace existing thermal systems for which historic emission rates can be documented, the historic emission rates in lbs/MMBtu but not more than:

Emissions	Maximum Rate
Nitrogen Oxides	0.3 lbs/MMBtu
Particulate Matter	N/A
Carbon Monoxide	0.08 lbs/MMBtu

(b) The emissions rate of the thermal system in lbs/MMBtu will be converted to an output-based rate by dividing by the thermal system efficiency. For new systems, the efficiency of the avoided thermal system will be assumed to be 80% for boilers or the design efficiency of other process heat systems. If the design efficiency of the other process heat system cannot be documented, an efficiency of 80% will be assumed. For retrofit systems, the historic efficiency of the displaced thermal system can be used if that efficiency can be documented and if the displaced thermal system is either enforceably shut down and replaced by the CHP system or if its operation is measurably and enforceably reduced by the operation of the CHP system.

(c) The emissions per MMBtu of thermal energy output will be converted to emissions per MWh of thermal energy by multiplying by 3.412 $MMBtu/MWh_{thermal}$.

(d) The emissions credits in $lbs/MWh_{thermal}$, as calculated in (c), will be converted to emissions in $lbs/MWh_{emissions}$ by dividing by the CHP system power-to-heat ratio.

(e) The credit, as calculated in (d), will be subtracted from the actual emission rate of the CHP unit to produce the emission rate used for compliance purposes.

(f) The mathematical calculations set out in subsections (a) through (d) above are expressed in the following formula:

Credit $lbs/MWh_{emissions}$ = [(boiler limit lbs/MMBtu)/(boiler efficiency)] * [3.412/(power to heat ratio)]

(C) **End-Use Efficiency and Non-Emitting Resources.** When end-use energy efficiency and conservation measures or electricity generation that does not produce any of the emissions regulated herein are installed and operated contemporaneously at the facility where the generator is installed and operated, then the electricity savings credited to the efficiency and conservation measures or supplied by the non-emitting electricity source shall be added to the electricity supplied by the generator for the purposes of calculating compliance with the requirements of this rule, subject to the approval of the Agency and in accordance with guidelines established by the Agency for determining such savings.

VIII. Fuel Requirements.

(A) **Mobile Diesel Fuel.** Generators powered by diesel internal combustion engines shall use only on-road mobile diesel fuel.

(B) **Natural Gas and Other Gaseous Fuels.** Gaseous fuels combusted in these generators shall contain no more than ten grains total sulfur per 100 dry standard cubic feet.

(C) **Monitoring.** If the generator is powered by an engine supplied with fuel from more than one tank or if multiple sources (engines and other devices that use the fuel) are supplied fuel by one fuel tank, a non-resettable fuel metering device shall be used to continuously monitor the fuel consumption by the generator's engine. Generators whose total capacity is 200 kW or less will be exempt from this requirement.

IX. Record Keeping and Reporting.

(A) **Record-Keeping Requirements.** At the premises where the generator is installed, or at such other place as the Agency approves in writing, the owner shall maintain the records as described in subsections (1) through (4) following. Non-emergency generators with electric generating capacity of less than 200 kW shall be exempt from these requirements. Emergency generators shall be exempt from subsections (1) and (2):

(1) *Monthly and annual amounts of fuel(s) consumed*. For the purposes of this subparagraph, annual fuel consumption shall be calculated each calendar month by adding (for each fuel) the current calendar month's fuel consumption to those of the previous eleven months;

(2) *Monthly and annual operating hours*. For the purpose of this subparagraph, annual operating hours shall be calculated each calendar month by adding the current calendar month's operating hours to those of the previous eleven months;

(3) *With respect to each shipment of liquid fuel (other than liquefied petroleum gas), to be used in each engine authorized hereunder, a shipping receipt and certification from the fuel supplier of the type of fuel delivered, the percentage of sulfur in such fuel (by weight dry basis), and the method used by the fuel supplier to determine the sulfur content of such fuel*; and

(4) *Date, duration, and type of emergency during which an emergency generator is operated*. Owner must certify that non-maintenance run hours occurred only during emergencies. Maintenance hours must be separately accounted for. Owner shall record operations when they occur.

(B) **Availability of Records.** Unless the Agency provides otherwise in writing, the owner shall maintain each record required by this subsection for a minimum of five years after the date such record is made. An owner shall promptly provide any such record, or copy thereof, to the Agency upon request.

(C) **Duty to Report.**

(1) **Additional Information.** If the Agency requests any information pertinent to the authorized activity or to compliance with a general permit issued pursuant to this rule, the owner shall provide such information within thirty days of such request.

IV. Commentary on the Rule[5]

The draft model rule attempts to translate into statutory language the objectives and principles that the working group developed (see Appendix A). It is divided into eight sections. The first section states its purpose. The second defines specialized terms used in the rule, and the third establishes its effective date.

A. Definitions (Section II)

The definitions were culled from a variety of sources (e.g., state and federal rules and regulations) or, where necessary, were developed anew for the rule (i.e., "non-emergency generator," "owner," and "supplier"). They are consistent with the current and plain uses of these terms. A state considering adoption of this rule may discover that many of these terms are already defined in its rules and regulations and should require little if any modification for the purposes here.

Some of the issues surrounding the definition of "emergency" bear elucidation here. As the working group ultimately decided, an emergency is "[a]n electric power outage due to a failure of the electrical grid, on-site disaster, local equipment failure, or public service emergencies such as flood, fire, or natural disaster." The group considered a more expansive definition that would allow for the operation of emergency generators in the face of an imminent failure of the electrical grid to stave off the failure. An argument in favor of such an approach posited that strategic operation of emergency generators prior to a failure could result in *lower* net emissions on the assumption that, by avoiding the failure, fewer such generators would be called on to operate. Whether this would, in fact, be the case depends on several factors, among them the operational characteristics of the generators used and the amount of electricity produced. There were some concerns with this approach, however, having to do with determining what constitutes an "imminent failure" and what entity makes the determination. Given the competing considerations, the group decided to stick to the simpler and more restrictive definition while acknowledging that individual states may want to consider alternative approaches. In any event, however, the working group feels that the definition should not allow for the operation of emergency generators simply to overcome what might be termed "economic" emergencies, i.e., high wholesale prices not associated with grid failure, imminent or otherwise.

B. Applicability (Section IV)

The fourth section addresses the first of the rule's two central issues, applicability. The rule is intended to regulate the emissions of a class of electric generation — smaller-scale, distributed

[5] The members of the working group have had an opportunity to review this commentary and to provide feedback on it. The Regulatory Assistance Project carefully considered their responses and suggestions and made changes to the document. It remains, however, RAP's account of the process and does not necessarily reflect all the views of the working group members.

resources — that are not covered, or not covered consistently, under existing state or federal regulations. Historically, distributed resources have accounted for a very small percentage of the nation's installed capacity and even less of its energy, but as technological change and regulatory reform advance, the potential for these new applications to proliferate increases. With it comes a need to ensure that such resources contribute to an improved environmental profile of the electric sector, or at least to one that is no worse that it would have otherwise been.

The applicability provision is therefore intended to close the "gap" in a state's existing air regulations. The rule "applies to all non-mobile generators that are installed on or after the effective date and that are not subject to Prevention of Significant Deterioration (40 CFR 52.21) or Review of New Sources and Modifications (40 CFR 51.160)." Major new source review is triggered by specifications relating to its potential to emit; consequently, the rule defines applicability in similar terms. To the extent that a state has minor source review requirements for new sources derived from federal regulations (40 CFR 51.160) or for some portion of the generation that the rule covers, then the rule's value to a state lies in its codification of emissions standards and in the administrative streamlining that the optional certification process offers. Some states may find that it will be necessary to tailor the applicability provision more specifically to their existing rules and regulations.

Because they are already covered under federal regulations, certain resources are exempted from meeting the rule's emissions standards. These are those whose engines are subject to Parts 89, 90, and 92 of the EPA's Non-Road Engine Program (e.g., construction equipment, temporary facilities, marine engines, and locomotives).[6] Included in this category of engines are mobile off-road generators, sited temporarily and used typically for construction or some emergency purposes. This class of generation makes up a small portion of the overall market. Exempting it also reduces administrative burdens on both owners of such facilities and state environmental regulators.

Lastly, the rule applies only to new — not existing — installations. Information available to the working group suggested that existing installations are, by and large, intended for emergency purposes and are, in most states, already covered under the terms of previously approved permits. However, a state may choose to require that existing units be subject to emissions limits of some sort (possibly those in this rule, subject perhaps to a different timing of the phase-ins, or other standards altogether). One concern voiced in the group was that the standards for new

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[6] Interestingly, there is a potential for railroad locomotives to be used as generators supplying electricity to the grid. California's Sierra Railroad Company recently announced plans to use 48 surplus locomotives as power sources over the next 5 years for the purpose of providing extra power to the state during peak periods of electrical use. According to the company, the trains will produce enough electricity to light 100,000 homes. The company calls the proposal "PowerTrainUSA," and expects to operate the trains for about 1,000 hours per year for the next 5 years. The company will fuel the locomotives with about 7.5 million gallons of biodiesel fuel annually. See the World Energy Web site at http://www.worldenergy.net. State environmental regulators may want to consider whether the potential consequences of these kinds of innovation warrant modifications to the applicability requirements of the rule.

installations would invariably require the retrofitting of add-on controls or the entire replacement of some generation, which could be too cumbersome or expensive for these applications. In addition, it was felt by some that, insofar as the rule was being developed in response to a concern about the proliferation of new DG assets, it would be inappropriate to make the requirements retroactive.[7] However, to the extent that an owner of an existing facility would like to alter a generator's conditions of operation, he or she would, presumably, have to obtain an amended permit from the appropriate state agency. Such an amended permit could require compliance with the provisions of this rule.

C. Emissions (Section V)

The fifth section of the rule sets out the emissions standards themselves. When viewed together with the applicability provisions, the overall approach to the rule emerges. One objective is to regulate "the emissions output of distributed generation in a technology-neutral and fuel-neutral approach." Another is to "facilitat[e] the development, siting, and efficient use of distributed generation in ways that improve or, at least, do not degrade air quality." A third is to "encourage technological improvements that reduce emissions output."[8] In addition, there was a desire to express the standards in a consistent set of units. This, and the explicit intention to credit efficiency gains, led the working group to adopt electrical output-based (pounds of emissions per megawatt-hour) standards.

1. Emissions Regulated, Duty-Cycles, and the Phasing-In of Standards

The first question to be answered by the working group was "What emissions should be regulated?" NO_X and SO_2 were the obvious firsts to be identified, followed by PM, CO, and CO_2. Unburned hydrocarbons were also considered. In the end, the working group settled on five pollutants, although only four would be subject to output-based limits.[9] There was no debate about NO_X because they contribute to ground-level ozone, acid rain, and other environmental impacts. SO_2 was not made subject to an emissions limit, despite its elemental connection to acid rain, because many DG technologies run on natural gas, which generally has very little sulfur in it. The exceptions to that are diesel engines or those using diesel (or similar) fuel, but the

[7] Application of this rule to existing facilities raised a number of issues with which the working group grappled. Although confident in its assumption that the vast majority of existing DG is permitted for emergency use only, the working group lacked sufficient information about the national (or regional) inventories of such units: their numbers, technologies, or vintages. These uncertainties, together with the group's schedule and limited resources, would have made it difficult to assess the potential and costs for emissions control retrofits on existing units, as a prelude to setting standards that would be both achievable and beneficial. In addition, there were concerns about the administration of a retrofit rule: it was not immediately apparent that a significant investment in the time and effort of state environmental regulators would offer significant air quality benefits. However, given the incomplete information available on this topic, the working group believes that efforts to more fully understand the scope and nature of the existing fleet of small-scale generation in an area or the nation, and an examination of the potential for cost-effective emissions controls, would be worthwhile.

[8] See Appendix A, "Statement of Objectives, Principles, and Scope," April 30, 2001.

[9] We note that inclusion of the fifth, CO_2, at the levels recommended, has broad, but not full, support of the working group. It is not included in this version of the rule for reasons discussed in Section 2.b.iv., below.

working group concluded that it was administratively easier, and equally as effective, to address this issue through a low-sulfur content fuel requirement rather than an emission standard.[10] Low-sulfur fuel also allows the use of catalyst-based control technologies for other pollutants, technologies that may otherwise be poisoned by sulfur in the exhaust stream. PM is the third pollutant. There was a desire to specify that the limits applied to PM no larger than 2.5 microns in size, but this proved impractical for reasons of testing (refer to the discussion on Emissions Certification, Compliance, and Enforcement below). Moreover, the group realized that a PM-2.5 standard would target primarily NO_X and SO_2, which the rule already addresses separately.[11] CO, because of its direct health impacts, its role in the formation of ground-level ozone, its role a surrogate for air toxics, and as an indicator of combustion efficiency, is the fourth pollutant to be regulated. The fifth is CO_2, considered by many to be a primary contributor to global climate change.

The working group educated itself on how the various pollutants are formed, their impacts on public health and the environment, and how they can be controlled. The relationships among various pollutants and the factors affecting their production were of particular significance. A change in combustion temperature or combustion characteristics may, for example, increase or decrease the amount of NO_X that an engine or turbine produces but may have the opposite effect with respect to CO. And, because CO_2 production is a function of how much fuel is used to produce a given amount of power, any action that affects an engine's efficiency directly affects its output of CO_2. The group's multi-pollutant approach takes these relationships into account.

The working group also concluded that phasing the standards in is necessary to provide time to accommodate manufacturers' research and development cycles. Three phases are envisioned. The first begins on Jan. 1, 2004. The second begins four years later, on Jan. 1, 2008. The third begins on Jan. 1, 2012, and continues indefinitely thereafter. Which standards apply depends on the date a unit is installed (i.e., begins generating electricity). In addition, the rule provides for a technology review to be completed a year before the final (Phase 3) standards take effect. On the basis of that review, the rulemaking agency can evaluate whether the final standards remain appropriate or need to be amended in any way. The rule also calls for periodic (quinquennial) technology reviews thereafter.

Distributed generation technologies vary widely, and, consequently, so do their applications. The fast-start capabilities and relatively low cost of diesel generators, for example, make them ideal for emergency back-up service. Microturbines can provide energy for longer durations, as can reciprocating engines (both diesel and gas) and other technologies, and their overall efficiencies are much improved when their waste heat can be put to use in some other mechanical or thermal process (i.e., CHP). Moreover, the emissions characteristics of the technologies also vary greatly.

[10] There is also a low-sulfur content requirement for gaseous fuels (Section VIII (B)).
[11] The group also recognized that US EPA has not yet classified areas for PM-2.5 air quality designations. Once such designations are made, air regulators will be required to establish state implementation plans to achieve the PM-2.5 public health standards and will therefore need to revisit the PM standards in this rule (if adopted in their states).

Depending on the pollutant and the technologies being compared, the differences can be quite substantial. Appendix B contains a spreadsheet developed by the working group in 2001 that describes the general emissions characteristics of then-current DG technologies. The information was used to inform the group's deliberations, with the understanding that the actual emissions rates of particular generators might differ from the rates calculated in the spreadsheet.[12]

These facts persuaded the working group that one set of emissions standards to cover all potential applications would not be feasible. On the one hand, if the standards are very strict, they could greatly restrict the ability of distributed generation to provide real benefits to the electric system because certain technologies might be unnecessarily prohibited from operating under circumstances when their benefits are great and their environmental impacts small. But on the other hand, if the standards are too loose, the rule might fail to serve the environmental purposes for which it is intended.

In the public review draft of November 2001, three categories of generation were set out, differentiated not by technology but by the needs served, which, in turn, were defined by the circumstances and annual hours of operation (duty cycles). The categories were emergency, peaking, and base load. In light of the comments on the draft, of proposed revisions to it, and of further analysis, the majority of the group concluded that there are no significant technological (with respect to emissions and control methods) reasons that separate small-scale generation into clearly differentiable categories of peaking and base load. However, some in the group did not agree with this and thought that the peaking category should remain in the final draft. Ultimately, only two duty-cycle categories were identified in this version of the rule: emergency and non-emergency. Emergency generation is limited in its annual hours of operation to 300 hours, of which a maximum of 30 hours may be for maintenance operations.[13] Non-emergency is all else.

2. Factors Considered in Determining the Standards

The general premise underpinning the rule is that the more a generator operates, the lower its emissions per unit of electricity output must be. As explained earlier (Chapter II, General Description of the Rule), this is consistent with the historic approach to the permitting of larger sources, which relates compliance requirements to the cost per ton of reduction — that is, which

[12] For one assessment of the current state of technology and projections for improvement, see Energy Nexus Group, "Performance and Cost Trajectories of Clean Distributed Generation Technologies," May 6, 2002. It can be found at http://www.energynexusgroup.com/reports.asp.

[13] The group considered whether a cap on emergency generators' total annual operating hours was appropriate. The logic was that, because the purpose is to provide power at the very times it is most needed, a cap could threaten public safety if it caused an emergency generator to be prematurely shut down. The countervailing concern was that US EPA rules under the Clean Air Act currently distinguish among sources on the basis of operating hours and that enforceability problems are raised in the absence of boundaries on those hours. The concept of "practical enforceability" was articulated by the DC Circuit Court in *National Mining Association v. EPA* [No.95-1006, argued April 20, 1995, decided July 21, 1995], but the EPA has yet to develop a rule and currently relies on various policy memos that are inherently inconsistent and difficult to enforce. Consequently, the group decided to retain the 300-hour limit, which, given the current level of electric system reliability in the US, is unlikely to be exceeded.

requires the best achievable performance within certain thresholds based on the costs of control. The compliance costs for sources that run very few hours will tend to exceed the thresholds. When the compliance cost is spread out over a greater number of hours of operation, the requirement can be more stringent. Times of blackout, where the trade-off between emergency power needs and air quality may be great, are the obvious example. Emergency generators will run to provide electricity, particularly for essential services such as hospitals, until grid power is restored. These events are unpredictable and usually of limited duration. Given the extremely high reliability record of the US power system, the working group concluded that the potential pollution from emergency generation is not a significant risk and is certainly one worth bearing at times when public health and safety are threatened by the loss of electric power.

This "performance versus cost" basis for emissions regulation was complicated in this case insofar as the working group was attempting to set limits for multiple technologies and multiple pollutants. The various technologies have different strengths and weaknesses, and, as noted earlier, there are trade-offs both between performance and emissions reductions and among the emissions themselves. Put another way, some emissions reductions come at the cost of efficiency and some at the cost of other emissions. For example, significant reductions in NO_X have been achieved through changes in combustion processes (in both reciprocating engines and turbines), but some thermal efficiency is sacrificed in doing so. Thus, there are increases in CO_2 output. In addition, CO output is often increased, a so far common consequence of a combustion process configured to minimize NO_X.

Similar challenges are raised by the variety of post-combustion ("after treatment exhaust" or "tailpipe") controls. There are two primary methods of removing NO_X from an exhaust stream: selective catalytic reduction (SCR) and the three-way catalyst. SCR is highly effective (although it can be costly for small-scale applications), and it is typically used in large industrial and electric generating facilities. It makes use of toxic chemicals (e.g., urea, ammonia) and produces solid waste — two features (aside from its handling and removal costs) that render it impractical for many DG applications. Three-way catalyst technologies, similar to those used in motor vehicles, convert NO_X to elemental nitrogen and oxygen (and also convert CO and hydrocarbons to CO_2 and water). Three-way catalysts will not operate in the presence of, and will be damaged by, high proportions of oxygen in the exhaust stream; thus, lean-burn gas-fired reciprocating engines and combustion turbines face a particular challenge in cost-effectively achieving low levels of NO_X emissions.[14] The three-step phase-in of the emissions standards is an implicit recognition of the engineering and cost hurdles that DG manufacturers will confront over the

[14] For a fuller general description of DG technologies, their emissions and operational characteristics, and emissions control technologies, see generally: Bluestein, Joel. *Environmental Benefits of Distributed Generation*, Energy and Environmental Analysis (Arlington, VA, December 2000). It is available on the RAP Web site: http://www.raponline.org/.

coming decade; the timing is designed to give them an opportunity and an incentive to overcome those hurdles.[15]

a. Emergency Generators

The rule requires that emergency generators meet the emissions standards for NO_X (and non-methane hydrocarbons, NMHC), CO, and PM set by the US EPA for non-road engines. The Tier 1 standards reflect the current state of non-road diesel in-cylinder technology, differentiated by size (in kilowatts). The Tier 2 and 3 standards reflect expected technological changes in diesels over the coming 5 years. In the November public review draft, the working group had proposed standards phased in, like those for the other categories of generation, over 3 years. Commenters on that draft noted that the proposed limits were, for the most part, *less* stringent than those of the EPA and that the phasings-in did not coincide with those in the EPA's program. For these reasons, they recommended that the rule simply reference the EPA's requirements, thus achieving some measure of administrative efficiency while sparing suppliers from having to comply with duplicative, but not altogether consistent, requirements. The group agreed.[16]

The working group considered CO_2 limits for emergency generators. On the grounds that diesels, for reasons already mentioned, will likely remain the primary form of emergency generation for a number of years to come, they are already highly efficient, and no significant improvements in their efficiency over the coming decade are predicted, the group first settled on 1,450 lbs/MWh for all three phases of the rule. Later, the group concluded that other technologies can also provide emergency service, and, therefore, the standards applicable to non-emergency generators should apply to emergency facilities as well. For reasons given in the following discussion on non-emergency generators, CO_2 limits were not unanimously adopted by the group.

b. Non-Emergency Generation

The working group considered whether the emissions standards for non-emergency generation should, in some way, be related to the emissions output of the facilities that might or would be displaced by that new generation. This became a central debate among the group members. Some members argued that new DG would often displace higher-emitting central generation, including

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[15] Section B.5 of the Statement of Objectives, Principles, and Scope states that "[a] phase-in schedule should be set so as to be technology-forcing while giving manufacturers a reasonable opportunity to meet the targets." (See Appendix A below.)

[16] Although at least as stringent as the limits originally proposed by the working group, the EPA's standards are still not so low as to require that new emergency generators be immediately fitted with exhaust after-treatment emissions controls. It is expected that manufacturers will find ways to comply with the later standards (referred to by EPA as Tier 2 and 3 standards; see Appendix C) that will not require tailpipe controls, i.e., through improved combustion processes. Tier 4 standards are currently being developed, and it is anticipated that they will be adopted sometime in the near future. It is likely that the Tier 4 standards will be such as to require exhaust after-treatment control systems. Such controls cannot function if the exhaust stream contains a high level of sulfur; therefore, the Tier 4 standards will be accompanied by a low-sulfur fuel requirement, along the lines of that already included in the model rule.

coal-fired facilities whose emissions output in many instances is greater than that of the new DG. They made reference to computer models developed by the US EPA and Oak Ridge National Laboratory that estimate displaced emissions. They contended that central station generators are dispatched in blocks, based on their marginal operating costs, and that this places large blocks of coal and older fossil fuel-fired boilers on the margin and therefore subject to displacement. Thus they argued that policymakers should consider providing credit for displaced central station emissions where analysis supported such a credit because air quality overall would therefore be improved.

Others in the group disagreed with this approach. They argued that displacement is not a basis for regulation under the Clean Air Act — that emissions regulation under the act is not intended merely to achieve marginal improvements over existing air quality but rather to meet public health-based ambient air standards. They contended, moreover, that it would be difficult to establish with a high degree of confidence what emissions are actually being displaced by new DG. They asserted that the operations of thousands of dispersed DG units, operating independently, would be impractical to model, and that their effects on the dispatch of the electric system would vary significantly from hour to hour, day to day, and year to year. It is possible, they argued, that DG would displace less-polluting resources at certain times. They also pointed out that, even if the displaced emissions of central generating facilities could be quantified, those emissions (typically exhausted through tall stacks in remote areas) are not directly comparable to DG emissions (near ground level in populated areas) and thus should not form the basis for the rule's limits.

The contending positions were never reconciled. This did not, however, prevent the group from reaching agreement on the standards (with the exception, as noted, of CO_2). Acknowledging the impasse, the group turned instead to an examination of the practical implications of emissions limits on distributed generation and approached the problem with an eye to technological capabilities and expectations for improvements over time.

i. Nitrogen Oxides

Perhaps the most controversial aspect of the rule is that it sets NO_X standards for non-emergency generators that are differentiated by area: attainment and non-attainment. This distinction is shorthand for describing whether an area of the country meets the EPA's ambient air quality standards for ground-level ozone (of which NO_X is a precursor). If it does not, it is considered to be in "non-attainment," and the state is required, among other things, to develop a state implementation plan (SIP) that delineates the actions it will take to bring the area into attainment.

The working group members were divided on this issue at first. For those opposed to the distinction, there was a concern that less stringent standards would contribute to a speedier deterioration of air quality in attainment areas. They contended also that, if machines are being built to meet non-attainment standards, it makes sense for several reasons to promote their deployment in all areas: differentiation would not promote the goal of national consistency in standards, it would weaken the technology-forcing effects of the rule, and, because of diminished economies of scale, it would likely increase the per-unit costs of machines to be deployed in non-attainment areas.

Balanced against these points was the argument that the kinds of facilities covered by the rule produce emissions that are, by definition, below the federal New Source Review (NSR) significance level — which is to say, they are small contributors to the overall emissions inventory. As such, it seemed reasonable to suppose that limits could be set for non-attainment areas that might have the effect of excluding certain technologies (e.g., gas reciprocating engines without after-treatment exhaust controls) that might, in the near term at least, be acceptable in attainment areas (that is, would have a minimal impact on ambient air quality, and thus controls would not be cost-justified). Moreover, went the argument, the attainment/non-attainment distinction would remove some of the financial pressure that a ubiquitous non-attainment-based standard would impose on manufacturers in the short term.

The opposing views were reconciled by an understanding that, in the longer run, more stringent emissions limits for the broad range of combustion technologies and uses (of which DG is a small part) will be both necessary and inevitable. This gave currency to a proposal within the working group that called for differentiated NO_X standards in the first two phases of the rule and a combined standard in the third phase, after the technology review. It turned out to be more than a solid enough foundation on which to proceed.

US EPA determines whether an area is in attainment or not on a pollutant-by-pollutant basis. In the rule, NO_X is the only pollutant treated differently in attainment and non-attainment areas. The group considered whether CO deserved similar treatment, but, given that there are very few CO non-attainment areas in the nation and that CO problems are caused primarily by mobile sources, decided against it. The group concluded that any additional requirements to address CO concerns in those areas would best be handled by local air regulators.

The Phase 1 NO_X attainment standard for non-emergency generators approximates the uncontrolled emissions output of today's smaller (50-kW to 1-MW) lean-burn gas-fired reciprocating engines, which are in the range of 3–4 lbs/MWh. Today, lean-burns less than 1 MW in size are the most common and efficient DG technology (excluding emergency diesels). As the size of the lean-burn engine increases, its NO_X output decreases somewhat. Engines in the 1–5 MW range emit approximately 2.2–3.0 lbs/MWh, and the 5–10 MW engines emit around 1.5–2.2 lbs/MWh. The Phase 1 attainment standard allows the smaller engines to compete in the short term because tailpipe controls (SCR) are not cost-effective for them. Other technologies — small turbines, controlled rich-burns, and perhaps SCR-controlled diesels — come in well below this limit. The Phase 2 standard anticipates technological improvements to the small lean-burns that will bring them into line with their larger siblings, without necessarily requiring controls. Moreover, it is equivalent to the level called for in the regional NO_X "SIP Call" for large power plants.

The Phase 1 NO_X non-attainment standard requires the installation of exhaust after-treatment controls on the various technologies but is set so as to enable them, in their current state, to meet the standard. The Phase 2 limit demands technological improvements, though ones that are within the range of current expectations.

The Phase 3 NO_X standard applies to machines in both attainment and non-attainment areas. It is set at a level that is approximately 70% cleaner than today's cleanest combustion-based DG technologies. Meeting it will require significant combustion and tailpipe control improvements and, in some cases, will also require that the generator be deployed in a CHP configuration. The working group considers the standard to be a "stretch" goal but one that is within the range of expectations for technology improvements.[17] The future, however, is uncertain. The technology review in 2010 affords policymakers an opportunity to evaluate the standards in light of then current information and, if appropriate, modify them.

ii. Particulate Matter

The setting of standards for PM was complicated by uncertainties arising from the manner in which the emissions are measured. The methods for testing PM output differ by technology type — some methods simply cannot be used with certain technologies — and they differ in ways that mean their measurements cannot be meaningfully compared. These differences mean that PM testing in one technology may identify particles that go unrecorded in the testing of other technologies. For instance, turbine testing typically captures both the filterable ("front half") and condensable ("back half") emissions, whereas testing of reciprocating engines only catches the front half.[18] Consequently, reciprocating engines appear, in certain instances, to produce significantly less PM than turbines, which, when both are gas-fired, seems improbable.

The group considered briefly whether to resolve the PM problem through a fuel-input, rather than emissions-output, requirement. The logic behind such an approach lay in the understanding that imminent federal standards for PM-2.5 (PM below 2.5 microns in size) will be focused on reducing the primary PM contributors: NO_X and SO_2 derivatives. Because gas technologies do not produce any SO_2 to speak of and the model rule already addressed NO_X, there was a certain appeal to the idea of a fuel-input requirement. However, there was still strong support among

[17] Refer, for example, to the US DOE's Advanced Reciprocating Engine System (ARES) program at http://www.eere.energy.gov/der/ and the California Energy Commission's Public Interest Energy Research programs into environmentally preferred advanced generation at www.energy.ca.gov/pier/epag.

[18] The quantity of PM produced by combustion is not an absolute, as the form it takes is a function of temperature and, to a lesser extent, pressure. In general terms, particulates can be broken down into two categories: a "filterable" fraction and a "condensable" one. The "filterable" fraction exists as a solid at the temperature of the sampling filter. This is also referred to as the "front half." The "condensable" fraction is a vapor at the temperature of the sampling filter, and it passes through the filter. At lower temperatures, a portion of the vapor may condense and become solid. Typically, particulate sampling equipment consists of a filter and a set of condensers (or impingers). Vapor that is collected in the impingers is considered the "condensable" fraction. It is also referred to as the "back half."

members for an output standard, in keeping with the overall objectives that we had set for ourselves.

The group ultimately decided on a dual approach that would simplify the testing requirements and, for the most part, make use of output-based limits. It is the closest that the rule comes to technology-differentiated standards. The PM limits and testing requirements apply only to liquid fuel generators. Gas-fired machines are exempt from the PM standards (however, as noted earlier, air regulators will need to reconsider the PM standards when the US EPA determines PM-2.5 air quality designations), and the rule specifies that ISO Method 8178 be used for testing reciprocating engines.[19] Generators fired by gaseous fuels (including waste, landfill, and other gases) are subject to a low-sulfur fuel requirement (Section VII: 10 grains per 100 dry standard cubic feet). In this way, the vagaries associated with the PM testing of turbines are avoided, but low PM output is ensured. Lastly, dual-fuel generators (by which is meant generators that operate on either gas or liquid fuel, though not simultaneously) are also exempt from the output-based standards; they are, however, bound by the low-sulfur fuel requirements that the rule sets for both gas and liquid fuels. Generators of this type operate primarily on natural gas, but they may, for regulatory or other reasons, be subject to interruption at times of high gas demand. During those hours, they will operate on liquid fuel. The working group did not want to craft a rule that inhibited this kind of market behavior. However, to ensure that liquid-fuel operations are kept at a reasonable minimum, the rule caps such operations at 30 days per year.

US EPA's PM emissions limits for on-road engines are more stringent than they are for off-road engines (as are the NO_X and CO limits). In 2007, the federal limit will be 0.03 lbs/MWh (that is, 0.01 g/bhp-hr) for on-road engines, whereas by 2009, it is expected to be 0.07 lbs/MWh (0.02 g/bhp-hr) for off-road engines. The different standards flow, in part, from technological differences between on-road and off-road diesel engines. Off-road engines typically lag behind their on-road counterparts in the application of high-pressure fuel injection and, lacking increased airflow and cooling capabilities, cannot run at the higher temperatures (and thus with the improved combustion characteristics) of on-road engines. The stationary engines used in electric generation are based on off-road engine designs.

It is, however, reasonable to expect that, over the next decade, the emissions output of off-road engines will be brought in line with those of on-road engines. In light of this, the group settled on the off-road limit for Phase 2 and the on-road limit for Phase 3. The Phase 1 PM limit is based on the current capabilities of liquid-fuel generators (primarily diesels). The Phase 2 and 3 standards will require improved combustion processes and the use of particulate traps.

[19] ISO Method 8178 is referred to as a "partial dilution" method; it doesn't measure the "back half." It is used for testing, among other things, on-road engines and the performance of after-treatment exhaust controls. The method works both in the field and under controlled circumstances. Whether ISO Method 8178 or another method is used, the key for regulators is to be sure that the chosen test is reliable under all relevant conditions. For a discussion of these and related issues, refer to the report "Evaluation of PM-2.5 Testing Issues For Electric Generating Reciprocating Engines and Turbines," M.J. Bradley & Associates, June 20, 2002. It can be found at http://www.raponline.org/.

The rule's approach to PM addresses most, though not all, potential sources of PM from DG. Noticeably absent from it are standards applicable to non-reciprocating, liquid fuel-only engines (e.g., turbines). A lack of time and reliable information prevented the group from more fully investigating the questions surrounding this subset of generators. As with the gas-fired technologies, the critical issues are the consistency of testing and the setting of standards that reasonably relate to the measurements that can be taken. Some members of the group felt that non-reciprocating, liquid fuel-only generators will likely make up a small, possibly very small, share of new DG installations and thus it was not necessary, as a practical matter, to propose PM standards for them. Others were concerned that the group's inability to propose standards might be understood (wrongly) to mean that the group had concluded that this potential source of emissions need not be regulated. Although unable to resolve the dilemma, the group acknowledges it by identifying an additional category of standards and noting that they have yet to be determined. Policymakers in each state will need to take up the question as they consider adoption of this rule.

iii. Carbon Monoxide

CO is a product of incomplete combustion, and its emissions are higher for reciprocating engines than they are for other technologies subject to the rule. As previously mentioned, CO output is also affected by changes to the combustion process that are aimed at reducing NO_X. With this understanding, the group set CO standards that, though aggressive, are intended not to handicap manufacturers' ability to decrease NO_X output. The Phase 1 standard can be met by uncontrolled gas-fired lean-burn engines and by rich-burns with a three-way catalyst. The Phase 2 standard will require tailpipe controls on both lean- and rich-burns. Lean-burns will be able to meet the Phase 3 standard with an oxidation catalyst; but, for the rich-burns to achieve it, significant technological advancements will likely be necessary. Most turbines are already able to meet the Phase 3 limit.

iv. Carbon Dioxide

As noted earlier, CO_2 output is a function of an engine's thermal efficiency. There are no currently practical after-treatment controls that remove CO_2 from an exhaust stream. In setting CO_2 standards, the group wanted to encourage the deployment of efficient technologies, but it did not want CO_2 to prove the disqualifying factor for a technology that otherwise satisfies the requirements of the rule. The following limits were developed for inclusion in sections V(A) and (B) of the rule:

Emergency and Non-Emergency Generators	Carbon Dioxide
Phase 1 (installed on or after 1/1/04)	1,900 lbs/MWh
Phase 2 (installed on or after 1/1/08)	1,900 lbs/MWh
Phase 3 (installed on or after 1/1/12)*	1,650 lbs/MWh
Technology review: to be completed by Dec. 31, 2010 to determine whether the Phase 3 standards should be amended based on the state of and expected changes in technology [refer to Section V(C)(1) of the rule]	

In addition, the following emissions credit was developed for inclusion in sections VII(A) and (B) of the rule:

Emissions	Flared Fuel and CHP credit
Carbon Dioxide	117 lb/MMBtu

The Phase 1 and 2 standard of 1,900 lbs/MWh can be met by the turbines and reciprocating engines. The Phase 3 standard of 1,650 lbs/MWh assumes an efficiency among the gas-fired technologies of at least 24% and will require improvements in some small turbine models. Because increases in efficiency reduce a user's fuel costs, it is reasonable to expect that the needed improvements will be largely market-driven.

Although the working group's Statement of Principles identified CO_2 as one of the emissions to be regulated by the rule, in the end, the proposed CO_2 standards did not receive the group's full support. At least one member felt that the limits were not stringent enough, and another opposed their inclusion altogether. Most members, however, feel that CO_2 warrants the attention of policymakers and support its retention in the rule.[20] RAP concurs. However, it is not included in this version of the rule because the US government is still evaluating the role of CO_2 in climate change and is not prepared to endorse mandatory CO_2 limits at this time.

[20] In fact, policymakers in a number of jurisdictions have already begun to take up the question of CO_2 emissions. For example, in 1997, Oregon authorized its Energy Facility Siting Council to set output-based CO_2 emissions standards for new energy facilities. In 2001, Massachusetts enacted a multi-pollutant law that calls for reductions in NO_X, SO_2, CO_2, and mercury. Also in that year, the Conference of New England Governors and Eastern Canadian Premiers adopted a Climate Change Action Plan. In April 2002, the New Hampshire legislature passed a law mandating reductions of carbon emissions from fossil fuel-burning power plants. And, in January 2003, Canada announced the steps it will take to reduce CO_2 in accordance with international conventions.

3. Other Issues

The working group recognizes that the Phase 2 and Phase 3 standards are rigorous "stretch" goals that should have the desired "technology forcing" effect. Technology-forcing regulation has, in a number of instances, proved to be both effective and cost-effective (e.g., automobile mileage and emissions standards); and, in certain instances, the improvements (particularly emissions reductions) have been achieved at lower cost and with less disruption than initially foreseen by the affected industry. For such standards to be effective, they must be related in some way to industry research and development, to the expectations for technological progress, and to the market for the technologies under consideration. The DR market differs significantly from, say, the automobile market — it is much smaller — and this affects whether and at what rate changes in technology can be effected. It was an appreciation for these considerations, among others, that led the group to settle on the phase-in durations, the technology review, and the duty-cycle characterizations in this version of the rule that differ from those first proposed in the public review draft.

In keeping with the goal of technology-neutrality, this rule offers no dispensations for specific kinds of generating facilities.[21] This was of special concern to several members and commenters. In particular, the working group was urged to set alternative standards and offsets for biomass (primarily wood-burning) facilities. The argument was that these facilities, which tend to produce significant quantities of PM, provide other benefits (fuel diversity, local employment, long-term carbon-neutrality, and so on) of sufficient value to trade against their emissions profiles. Several members of the working group found this reasoning at least partly persuasive, but the potential public health impacts of PM were of greater concern to the group as a whole. For this reason, the group decided against special provisions for biomass generation.[22]

The rule does not give explicit credit for reductions in line losses that DR, when sited near load, provide. There are several reasons for this. First, the rule is intended to apply to all smaller-scale facilities, regardless of location. Second, a credit provision that would apply to some facilities but not others would create an undue administrative burden and would complicate the manufacturer certification component of the rule. Third, the value of such a credit is highly dependent on the physical and operational characteristics of the network and generation market

[21] It does, however, give credit for emissions offsets through CHP and the installation of end-use efficiency and non-emitting renewables (Section VII).

[22] In light of other policy initiatives to promote renewables-based generation, a state might conclude that alternative standards for emissions from biomass facilities, or other regulatory approaches, are also warranted. One suggestion, for instance, would give a biomass facility credit against its CO_2 output for the carbon in its fuel, so long as that fuel is procured through sustainable harvesting methods. The reasoning is that sustainable harvesting, in effect, keeps the carbon in a "closed loop" between the forest and the generating facility, and thus no incremental carbon emissions are created. Under this approach, if all of the facility's fuel were harvested in a sustainable manner, its CO_2 output would net to zero.

in which the DR is situated. The group concluded that the calculation and application of such a credit would impose difficulties that outweigh the benefits of the simpler approach.[23]

As stated previously, the rule is intended to apply to facilities that are not covered under existing state and federal air regulations, and the applicability provision is written to achieve that result. The working group considered, however, whether other provisions of the rule could, in some way, affect the behavior of owners whose facilities are components of larger energy-using processes that come under the jurisdiction of the federal Clean Air Act (specifically, the Amendments of 1990, or CAA) or state requirements. The rule is not intended to enable those subject to it to evade other applicable regulatory requirements. In particular, it should not be construed to allow facilities otherwise subject to new source review under the CAA to avoid that review. For instance, the model rule imposes no requirement that a CHP system and the displaced emissions source be owned by the same party. The question arose as to whether this might allow an owner to treat its energy-using systems in a way that would reduce the regulatory requirements with which those systems would otherwise be required to comply under the CAA. The group concluded that the opportunity for such behavior was slight, if not non-existent. The rule focuses on small sources, those that generally come in below Title V requirements but are not always picked up by state minor new source permitting programs.

Last, the rule does not aim to pick “winners and losers,” but it would be disingenuous to assert that the standards will not affect resource choices over time. In light of our growing understanding of atmospheric chemistry, environmental impacts, and public health, it seems only reasonable to expect that the regulation of air pollutants will become increasingly strict. The rule is an attempt to balance the sometimes competing concerns about air quality, technology development and deployment, and cost-effectiveness.

D. Emissions Certification, Compliance, and Enforcement (Section VI)

The rule does not include testing and other procedures for owners to follow to establish that their DG installations meet the emissions standards. The rule does, however, give DG manufacturers and suppliers the option to certify the emissions output of their products. The approach taken is fairly straightforward and relies on testing procedures already developed, or under development, by the US EPA, the California Air Resources Board, or other expert bodies named by the state. In the case of PM, it identifies the specific protocol to be used. Such certification should reduce the administrative burdens on entire product lines, for both suppliers and state regulators.

The rule specifies that the emissions standards apply to full load design conditions or at the load conditions specified by the applicable testing methods. ISO Method 8178 specifies a range of load conditions for testing, but other test methods do not necessarily do so. The rule allows for

[23] At least one member of the working group noted that the rule could be seen to give some (albeit implicit) credit to DG for emissions reductions resulting from reduced line losses. The “credit” comes in the form of Phase 3 standards that are slightly less stringent than limits set to match the output of the most efficient gas-fired combined cycle units.

full load testing in such circumstances. The working group understands that DG does not always operate under full load, but also under a range of partial loads, and that emissions output often varies with those loads. The group nevertheless opted for this approach for two reasons. One, it should greatly simplify matters for both suppliers and regulators. And two, it avoids the difficult job of developing representative operating cycles for the variety of technologies, the emissions profiles associated with those cycles, and the emissions limits themselves in light of the varied operations. The group did not have sufficient information at this point to warrant a more sophisticated approach but expects that, in light of more information and experience, this decision may need to be revisited. Actual emissions from a unit will not differ merely because the standards reflect a weighted average of partial and full load operations. Except to the extent that the standards prevent a unit or technology from operating at all, they will have no effect on how an owner actually operates a machine. Consequently, what matters is to have standards that will serve the objectives sought while easing the means and costs of compliance and enforcement.

Experience with DG over the coming years will reveal whether this approach is appropriate. New information may cause regulators to give an answer to the question "Should facilities be required to meet the standards under all operating conditions?" that differs from the one implicit in the model rule now. Similarly, new federal regulations with respect to PM (PM-2.5), for example, may require changes in standards and testing. The technology review will provide policymakers an opportunity to examine these issues in greater detail.

The rule states that "For a make and model of a generator to be certified, the supplier must certify that the generator is capable of meeting the requirements of this rule for the lesser of 15,000 hours of operation or three years." This is, in effect, a manufacturer warranty that the engine will meet the standards for the first 15,000 hours of its life (or 3 years, whichever comes first). The provision does not require that each machine, or that some number of machines from the model line, be tested for 15,000 hours to be certified. The provision merely establishes the performance requirements for a machine that is certified. Environmental regulators will, presumably, conduct random tests of certified units in the field to determine whether they are performing as expected and whether the model line shall continue to enjoy certification (i.e., whether new units in the line will be entitled to the certification).

E. Credit for Concurrent Emissions Reductions (Section VII)

This section of the rule sets out the circumstances under which a DG facility can be credited for displacing emissions that would have otherwise occurred in the absence of the DG. Specifically, generation that is fired by gases that otherwise would have been burned off or emitted directly into the atmosphere will be able, upon demonstration, to claim an offset to its own emissions of the emissions avoided. Similar credit will also be given to CHP applications, where the waste heat from generation is put to productive mechanical or thermal use, thereby avoiding the incremental emissions that a separately fired process would have produced.

In the case of flared gases, a developer will have the option of demonstrating the actual emissions offsets or using the rule's default values. The default values are based on emissions data provided by the US EPA (AP-42), modified slightly in light of technological capabilities and current practices. The low Btu content of landfill and digester gases proscribes, in certain cases, the use of low-NO_X combustion technologies. In those instances, the simple flaring of the gas will produce less NO_X than internal combustion will. The question for policymakers then is whether the incremental generation of electricity from these gases is worth a slightly higher NO_X output than the standards would otherwise allow. The default values in the rule presume, as do the rules in Texas and California, that it is better to use the fuels to produce electricity than it is to merely flare them off and that, in these limited circumstances, the value of the incremental electricity is greater than the cost of the incremental emissions. However, we acknowledge that in some areas local air quality conditions may counsel for a different approach.

In the case of CHP, the rule sets out the formula used to calculate the offsets but leaves it to the state to determine the appropriate boiler and other standards that will provide the inputs for the calculations.[24]

There is also a provision that gives emissions credit for grid-electricity savings achieved at a site by non-emitting resources (e.g., certain renewables) and end-use efficiency measures installed simultaneously with the generation. The intent of such a provision is to promote other, cost-effective emissions-reducing strategies. This provision, when first proposed, was attended by some controversy. A number of commenters and members of the working group voiced concern about it. Although there was broad support for the concept, there were worries that it might be unworkable in practice. There is a risk of problems with "free-ridership" (that is, the taking of credit for savings that would have occurred anyway) and a risk that the savings themselves may be incorrectly calculated. Here was an opportunity, some argued, for regulators (particularly in states with little previous experience in evaluating end-use efficiency savings) to be taken advantage of.

[24] One commenter pointed out that the CHP provision gives credit for the displacement of emissions from an on-site combustion source rather than, for example, some form of electric cooling. Although the proposed methodology does not directly address the emissions associated with displaced electric cooling, it could address this circumstance by giving credit for the direct-fired absorption chiller or desiccant system that would be displaced by the CHP system. Ultimately, heat recovered from a CHP system will replace heat that could have otherwise been provided by direct combustion, and the proposed methodology can give credit for the associated emissions. The working group considered whether CHP that displaces emissions from central station electric generation should be credited for those savings. Although recognizing that the concept is theoretically sound, there were several reasons the group nevertheless decided against including it in the rule. The first was our conclusion that most CHP systems will replace on-site boiler and other combustion systems, and thus the rule captures the lion's share of applications. Second was the problem of calculating the displaced emissions (e.g., average versus marginal). And third was the practical difficulty posed by the wide variation in emissions rates from area to area; establishing system emissions rates across the country was beyond the scope and resources of the group.

These are reasonable concerns and worthy of some attention by policymakers if they choose to retain this provision. The working group concluded that the provision has merit and that its implementation challenges can be overcome. Each state is free to determine whether and how to do so.

F. Miscellaneous Provisions (Sections VIII and IX)

Last, the rule sets out monitoring and record-keeping requirements. These are typical of those required of other emissions sources. Generators under 200 kW and emergency generators are exempt from certain provisions, reducing administrative burdens that would yield only small benefit.

Appendix A. Statement of Objectives, Principles, and Scope

Statement of Objectives, General Principles, and Scope
Regarding Proposed Rules and Standards
for the Regulation of Air Emissions from Distributed Resources
April 30, 2001

A. Objectives

The Distributed Resources Emissions Working Group will identify the issues and will develop the background, criteria, and requirements for a set of recommended rules and performance standards for regulating the air pollutant emissions of smaller-scale electric system generating resources, commonly referred to as distributed generation, or DG (see section on Applicability). The rules and standards are expected ultimately to take the form of a model rule that states can adopt to address the potential air quality impacts of new and existing sources of electric generation that are not, for the most part, covered by current state air regulations, policies, or permits. The purpose is to help reduce institutional and infrastructure barriers to cost-effective deployment of distributed power systems and to do so by facilitating the development, siting, and efficient use of distributed generation in ways that improve or, at least, do not degrade air quality. More specifically, the objectives are:

(1) To research and develop information, tools, and options for regulatory policies that will encourage the deployment of distributed resources where cost-effective and environmentally beneficial; and

(2) To establish and foster adoption of a national model for output-based emissions performance standards for distributed resources that state utility and environmental regulators and other key stakeholders have developed through a collaborative approach.

B. Principles To Guide the Working Group's Effort

1. Environmental Impacts

The recommended rules and standards should regulate the emissions output of distributed generation in a technology-neutral and fuel-neutral approach, as appropriate.

2. Other Distributed Resources

The recommended rules and standards are intended to encourage, or at least not discourage, the deployment of non-emitting distributed resources.

3. Usefulness

The recommended rules and standards should be of immediate use to states and the electric power industries. They should be acceptable to environmental and utility regulators, energy service providers, and manufacturers of distributed generation; and they should, among other things, simplify the administrative processes of siting and permitting.

4. Impacts on the DR and Electric Industries

The recommended rules and standards should have positive impacts on the DR and electric industries. By promoting consistent or uniform standards in multiple jurisdictions, they can enable manufacturers to standardize designs and capture the benefits of economies of scale. The recommended rules should also encourage pre-installation certification of a unit's emissions output, and compliance with the standards should facilitate siting and permitting.

In addition, the rules and standards should be set so as to encourage technological improvements that reduce emissions output. This characteristic is commonly referred to as *technology-forcing*. In this way, the rules should promote, or at least not hinder, the deployment of environmentally sustainable DR.

5. Timing

The recommended rules and standards can be phased in, or staged, over a specified period. A phase-in schedule should be set so as to be technology-forcing, while giving manufacturers a reasonable opportunity to meet the targets.

C. Scope of Draft Rules

1. Applicability

The proposed regulations should be applicable to DG of specified types and sizes. Approaches for specifying the DG to be covered include:

1. *First Alternative:* The recommended rules and standards should apply to generating facilities not already covered under Title V (Clean Air Act) regulations.

2. *Second Alternative:* These recommended rules and standards should apply to generating facilities whose nameplate capacity is XX megawatts or less, interconnected or serving load at the primary or secondary voltage levels.

2. Standards Expressed

The Working Group will consider whether emissions requirements for distributed generation should be output-based performance standards (expressed in terms of pounds per megawatt-hour or kilowatt-hour), to promote innovation, efficiency, and improvements in generation technology.

3. Emissions Covered

The air pollutants to be considered will include nitrogen oxides, sulfur dioxide, particulates, volatile organic compounds, CO, and toxics.

4. Methods for Recognizing the Benefits of CHP and Non-Emitting DR

The working group will explore whether the recommended rules should include methods for accounting for the potential air quality benefits of distributed resources whose waste heat is recovered and used in other processes (e.g., space and water heating, industrial processes, etc.), thus displacing combustion of fuels and production of emissions. In addition, the working group should explore methods for accounting for the emissions reductions of using gas that would otherwise be flared (e.g., landfill gas) to fuel distributed generation and of on-site end-use efficiency improvements.

5. Certification of Emissions Output

The working group will consider means for establishing the emissions output of distributed generation facilities. More specifically, the working group should explore approaches by which the emissions output of a unit can be certified in advance, through either a self-certification program or through some other appropriate means.

6. Existing and New Units

The working group should explore approaches for addressing the emissions output of existing and new facilities. In this context, it may be appropriate, for example, to differentiate between units used solely for emergency purposes and units available for a wider range of electric system needs — that is, to differentiate on the basis of “duty cycles.”

Appendix
[to the Statement of Objectives]

Commentary on the Statement of Objectives, Principles, and Scope of the Distributed Resources Emissions Working Group

What follows here is a description of some of the issues that the working group is exploring. It describes questions that have been raised, but not necessarily settled, by members of the working group. The outline of this commentary generally follows that of the principles.

A. Objectives

Should the deployment of DG result in better (or at least not worse) environmental outcomes than what would have occurred in the absence of the DG? If so, then the question of what generation resources will be displaced (and their emissions, if any) by the use of both existing and new DG becomes relevant to the design of proposed DG emissions standards. Most currently available distributed generation technologies produce air pollutants at a greater rate (on an output basis) than a state-of-the-art natural gas-fired, combined-cycle central generating station (GCC) with best available control technologies (BACT) installed. In contrast, some DG technologies produce emissions at a lower rate than certain other fossil-fuel burning technologies (both existing and new).

An alternative view holds that, for most applications, DG does not compete with or replace central generating facilities, and therefore a comparison to such units is not relevant. In addition, it was noted that air pollution regulation in the United States is not typically based on the concept of emissions displaced by the new technology, but rather on the basis of achievable limits. This approach may or may not be tempered by a consideration of the technology's contribution to the overall emissions of an airshed.

Development of proposed air emissions standards requires the careful balancing of a rules benefits and consequences. Factors to be considered may include the environment, consumer choice, integrated energy and land-use planning, economic efficiency of electricity markets, availability of electricity supplies, and competitiveness of the business sector.

B. Principles To Guide the Working Group's Effort

1. Environmental Impacts

The role of a technology-neutral and fuel-neutral standard is being considered. Such a standard could, depending on how it is set, preclude the deployment of certain technologies. Also, should the standards differ depending on whether the DG will be deployed in attainment or non-attainment areas? Lastly, the question arose whether other potential environmental harms (e.g., land use and water pollution) should be addressed in addition to air emissions.

2. Other Distributed Resources

The working group concluded that, given its limited time frame and primary focus, the development of explicit rules to encourage the deployment of non-polluting distributed resources (e.g., end-use efficiency, photovoltaics, wind power, etc.) is beyond the scope of work. Future work on this topic could include identifying unintended disincentives in existing permitting processes, developing proposals to undo such disincentives, and creating rules and other policy instruments that recognize the zero emissions of certain distributed resources.

3. Impacts on the DR and Electric Industries

It was noted, however, that current technology-forcing regulations (BACT/LAER) require case-by-case, technology-specific determinations, and that a technology-neutral approach to setting emissions limits that "force" improvements would be new.

C. Scope of Draft Rules

1. Applicability

The working group makes a distinction between distributed resources (DR) and distributed generation (DG). Generally speaking, *distributed resources* refers to the broad range of technologies that are not intended to be connected to the bulk electric power transmission system and are typically deployed in close proximity to load. DR includes smaller-scale generation technologies (smaller than traditional central station generator units), energy storage devices, load management activities, and end-use efficiency and conservation measures. *Distributed generation* refers only to the generation subset of DR. Examples of DG include micro-turbines, fuel cells, reciprocating engines, photovoltaics, and wind turbines. The work of the working group will focus on regulating the emissions of DG and identifying other, non-emitting DR technologies.

The first alternative expresses the notion that the rule's applicability should be broad, including even the smallest of units (to be covered under some sort of certification program). The second alternative may be narrower in scope, but the practical differences between the two will depend on the applicability of existing state regulations and the definitions of "primary and secondary voltage levels." There seemed to be a general feeling among the participants that favored the first alternative, but then there was the question of whether the rule captures more than regulators want or need to be concerned with (i.e., very small generators used by residences and businesses during blackouts or at remote locations for limited periods of time, *e.g.*, at construction sites before line extensions are installed). By the same token, however, the point was made that the rule should be written to include non-grid-connected units because they too can contribute emissions to an airshed.

Other approaches to the applicability question were raised for consideration. Should the permitting process differ on the basis of a facility's size (generating capacity) or its potential to emit (PTE) or another attribute? Given other aims of the proposed rules (simplicity and DG development), it seemed that too complex an applicability requirement would create more problems than it would solve.

2. Standards Expressed

Output-based standards encourage efficient operation of facilities. Input-based standards (standards calculated on the basis of the amount of pollutant per unit of fuel input) do not reward increases in efficiency and, moreover, are typically differentiated by fuel-type, often discouraging substitution of less polluting fuels. The general preference is for the standards to be expressed in terms of pound of emissions per unit (kWh or MWh) of output, although the idea of using kilowatt-years in the denominator was raised. Because this latter approach may pose certain operational difficulties, it did not find much enthusiasm in the group.

The working group may also want to consider other, non-numerical approaches to regulating air emissions. There may, for instance, be ways of permitting facilities that have the effect of limiting emissions without actually specifying their levels, such as through certification standards, definitions, hours of operation, etc.

3. Emissions Covered

The working group is considering whether carbon dioxide should be included among the emissions to be regulated.

4. Methods for Recognizing the Benefits of CHP and Non-Emitting DR

This, like other aspects of the effort, requires gathering information and developing options, which are two purposes of the working group.

5. Certification of Emissions Output

Certification could be mandatory for the smaller units, so that additional permitting is not required, whereas alternative approaches to certification (e.g., case by case permitting) may be appropriate for large units. The cut-off between "smaller" and "larger" would need to be addressed. The program could also call for periodic testing of units that are in use to measure on-going compliance. This approach to certification provides for a kind of "product labeling" that will be helpful to purchasers of distributed resources, particularly as the size of the units decreases.

6. New and Existing

A question raised by this is what constitutes emergency service? Many states already have rules on this topic (e.g., with respect to actions taken immediately before an ISO calls for voltage reductions), but there is concern among some of the participants that "emergency service" may constitute a significant loophole for DR operations. In addition, it would be helpful to have information on the inventories of existing and expected new facilities to determine whether emergency units could be pressed into service for other purposes.

Appendix B. Emissions Calculations

Table 1: Emission Rates for New DG Technologies (Based on best available information in 2001)

		Solid Oxide Fuel Cell	Phosphoric Acid Fuel Cell	Uncontrolled Gas-Fired Lean Burn IC Engine	3-way Catalyst Gas-Fired Rich Burn IC Engine	Uncontrolled Diesel Engine	SCR Controlled Diesel Engine	Unc. Micro Turbine	Unc. Small Gas Turbine	Unc. Medium Gas Turbine	Large Gas Combined Cycle (SCR)	Unc. Large Gas Turbine	ATS Simple Cycle Gas Turbine	1998 Average Coal Boiler	1998 Average Fossil	1998 Average PowerGen
Efficiency	% (HHV)	42%	37%	36%	29%	38%	38%	25%	27%	30%	51%	31%	35%	33%	33%	47%
	Btu/kWh	8,126	9,224	9,481	11,769	8,982	8,982	13,652	12,780	11,353	6,640	10,964	9,870	10,322	10,382	7,197
Typical Capacity (kW)		25	200	1,000	1,000	1,000	1,000	25	4,600	12,900	500,000	70,140	4,200	300,000	300,000	300,000
NOx	gm/hp-hr			0.70	0.15	7	1.5									
	ppm@15%O2	0.2	1.0					9	25	15	2.5	15.0	9.0			
	lb/MMBtu	0.0007	0.0036								0.01	0.05	0.03			
								0.03	0.09	0.05						
	lb/day	0.0035	0.2	52.2	11.2	522.1	111.9	0.3	126.9	189.7	716.5	996	32.2	40,291	36,448	24,684
	Tons/yr	0.001	0.03	9.5	2.0	95.3	20.4	0.05	23.2	34.6	131	182	5.9	7,353	6,652	4,505
SO2	lb/MMBtu	0.0006	0.0006	0.0006	0.0006	0.0505	0.0505	0.0006	0.0006	0.0006	0.0006	0.0006	0.0006			
	lb/day	0.0029	0.0266	0.14	0.17	10.9	10.9	0.005	0.8	2.1	47.8	11.1	0.60	96,490	83,771	56,732
	Tons/yr	0.0005	0.0048	0.02	0.031	2.0	2.0	0.0009	0.15	0.38	8.7	2.0	0.11	17,610	15,288	10,354
PM-10	gm/hp-hr			0.01	0.01	0.25	0.25									
	ppm@15%O2	0	0													
	lb/MMBtu	0	0					0.0066	0.0066	0.0066	0.0066	0.0066	0.0066			
	lb/day	-	-	0.75	0.75	18.6	18.6	0.05	9.3	23.2	525.9	121.8	6.6	2,175.0	1,952.9	1,353.9
	Tons/yr	-	-	0.14	0.14	3.4	3.4	0.01	1.7	4.2	96.0	22.2	1.2	396.9	356.4	247.1
CO2	lb/MMBtu	117	117	117	117	159	159	117	117	117	117	117	117			
	lb/day	570	5,175	26,594	33,014	34,356	34,356	957	164,912	410,826	9,313,126	2,157,211	116,289	15,229,728	14,622,394	10,137,077
	Tons/yr	104	944	4,853	6,025	6,270	6,270	175	30,097	74,976	1,699,645	393,691	21,223	2,779,425	2,668,587	1,850,017
CO	gm/hp-hr			1.6	1.3	2	2									
	ppm@15%O2	?	?					40	25	25	6	25	25			
	lb/MMBtu	?	?	-	-	-	-	0.09	0.05	0.05	0.01	0.05	0.05			
	lb/day	0.0000	0.0	119	96	149	149	1	77	193	1048	1012	55	0	0	0
	Tons/yr	0.000	0.00	22	18	27	27	0	14	35	191	185	10	0	0	0
UHC	gm/hp-hr	?	?	5.3	0.13	0.4	0.4									
	ppm@15%O2	?	?					9	25	25	2	25	25			
	lb/MMBtu	?	?	-	-	-	-	0.03	0.09	0.09	0.01	0.09	0.09			
	lb/day	0.0000	0.0	395	10	30	30	0.3	122	303	550	1591	86	0	0	0
	Tons/yr	0.000	0.00	72	2	5	5	0.0	22	55	100	290	16	0	0	0
NOx	lb/MWh	0.01	0.03	2.2	0.5	21.8	4.7	0.44	1.15	0.61	0.06	0.59	0.32	5.60	5.06	3.43
SO2	lb/MWh	0.005	0.006	0.006	0.007	0.454	0.454	0.008	0.008	0.007	0.004	0.007	0.006	13.4	11.6	7.9
PM-10	lb/MWh	-	-	0.03	0.03	0.78	0.78	0.09	0.08	0.07	0.04	0.07	0.07	0.30	0.27	0.19
CO2	lb/MWh	950	1,078	1,108	1,376	1,432	1,432	1,596	1,494	1,327	776	1,281	1,154	2,115	2,031	1,408
CO	lb/MWh	?	?	5.0	4.0	6.2	6.2	1.2	0.7	0.6	0.1	0.6	0.5			
UHC	lb/MWh	?	?	16.5	0.4	1.2	1.2	0.42	1.10	0.98	0.05	0.95	0.85			

Number of Units to Equal the Major Source Threshold for NOx

Threshold (TPY)												
250	390,529	8,601	26	122	3	12	5,166	11	7	2	1	43
100	156,212	3,440	10	49	1	5	2,066	4	3	1	1	17
50	78,106	1,720	5	24	1	2	1,033	2	1	0	0	9
25	39,053	860	3	12	0	1	517	1	1	0	0	4
10	15,621	344	1	5	0	0	207	0	0	0	0	2

This spreadsheet shows air emissions values for a number of distributed generation technologies. The values are given for a variety of emissions — NO_X, SO_2, CO, CO_2, PM (PM-10), and unburned hydrocarbons — and they are characterized in terms of pounds of emissions per unit of electrical output. These are typical values for new units of the specified technologies. They do not apply to older, existing units. The values were calculated on the basis of assumptions about typical operating conditions; however, because actual operating conditions are rarely typical, the actual emissions performance of a unit may differ from these values.

Table 2:

Value	*Factor*	*Source*	*Notes*

Solid Oxide Fuel Cells (Based on best available information in 2001)

42%	Efficiency	http://www.fe.doe.gov/techline/tl_ sofcdemo.html	
0.2	ppm NOx	http://www.fe.doe.gov/techline/tl_ sofcdemo.html	
0.0006	lb/MMBtu SO2	AP-42 Chapter 1, Section 4	
0	ppm PM-10	no data, no source	
116.88	lb/MMBtu CO2	EIIP Report, Vol. VIII, Table 1.4-3	

Phosphoric Acid (ONSI) Fuel Cells (Based on best available information in 2001)

37%	efficiency	NREL paper	http://www.sercobe.es/espejo/Energia/EnergiasNoNucleares/UsoRacional/IndustEnergia/PilaComb/Tutorial/Fuelcells.htm
1.00	ppm NOx	Phone: Herb Healy, ONSI, 860-727-2200	
0.0006	lb/MMBtu SO2	AP-42 Chapter 1, Section 4	
0	ppm PM-10	no data, no source	
116.88	lb/MMBtu CO2	EIIP Report, Vol. VIII, Table 1.4-3	

Gas IC Engine (Based on best available information in 2001)

7,011	Btu/hp-hr for 770 kW Cat Model G3516	Caterpiller Website, gas model G3516, 130 LE	
36%	*efficiency lean burn*	*Onsite Energy/Caterpiller*	36%
29%	*efficiency rich burn*	*Onsite Energy/Caterpiller*	
0.70	gm/hp-hr NOx lean burn engine	NSR/RBLC Identifier NM-0026	Clean Burn engine Cat 3612 TA/SW66
9.00	ppm NOx @15% O2	NSR/RBLC Identifier CA-0645	3-way catalyst
0.150	*gm/hp-hr NOx 3-way catalyst*	*Bluestein assumption*	
0.0006	lb/MMBtu SO2	AP-42 Chapter 1, Section 4	
0.0100	gm/hp-hr PM-10 - filterable+condensable	NSR/RBLC Identifier CO-0032,CO-0033	
1.6	g/hp-hr CO lean burn	Caterpiller G3516 Data Sheet DM5150	
5.3	g/hp-hr UHC lean burn	Caterpiller G3516 Data Sheet DM5150	
12.9	g/hp-hr CO rich burn engine out	Caterpiller G3516 Data Sheet DM5145	
90%	TWC cat CO reduction		
1.3	g/hp-hr HC rich burn	Caterpiller G3516 Data Sheet DM5145	
90%	TWC cat HC reduction		
116.88	lb/MMBtu CO2	EIIP Report, Vol. VIII, Table 1.4-3	

This spreadsheet shows air emissions values for a number of distributed generation technologies. The values are given for a variety of emissions — NO_X, SO_2, CO, CO_2, PM (PM-10), and unburned hydrocarbons — and they are characterized in terms of pounds of emissions per unit of electrical output. These are typical values for new units of the specified technologies. They do not apply to older, existing units. The values were calculated on the basis of assumptions about typical operating conditions; however, because actual operating conditions are rarely typical, the actual emissions performance of a unit may differ from these values.

Diesel Engine (Based on best available information in 2001)

114	gal/hr for 1,640 kW Cat Model 3516B	Caterpiller Website, diesel model 3516B	
38.0%	*efficiency*	*calculated*	35%
	gm/hr NOx uncontrolled	Caterpiller Website, diesel model 3516B	
7	*gm/hp-hr NOx uncontrolled*	Caterpiller Website, diesel model 3516B	
1.50	gm/hp-hr NOx with SCR	Hedman/SCAQMD	SCR
500.00	ppm sulfur in diesel, on road	current requirement for road diesel	Federal Register: 5/13/99 Vol 64 #92
3,300.00	ppm sulfur in diesel, nonroad	typical, offroad diesel	Federal Register: 5/13/99 Vol 64 #92
30.00	ppm sulfur in diesel, possible proposed	potential future requirement	Federal Register: 5/13/99 Vol 64 #92
0.25	gm/hp-hr PM-10	NSR/RBLC Identifier CA-0691	
0.4	g/hp-hr HC	Caterpiller	
2	g/hp-hr CO	Caterpiller	
159.38	lb/MMBtu CO2	EIIP Report, Vol. VIII, Table 1.4-3	

Microturbine (Based on best available information in 2001)

25%	Efficiency	Capstone Model 330, 30 kW	Capstone Turbines webpage
9	ppm NOx	Capstone Model 330, 30 kW	Capstone Turbines webpage
0.0006	lb/MMBtu SO2	AP-42 Chapter 3, Section 1	
0.0066	lb/MMBtu total PM-10 filterable + condensable	AP-42 Chapter 3, Section 1	
40	ppm CO	Capstone	
9	ppm HC	Capstone	
116.88	lb/MMBtu CO2	EIIP Report, Vol. VIII, Table 1.4-	

SmallTurbine (Based on best available information in 2001)

12,780	Btu/kWh heat rate HHV	Solar Centaur 50 - 4.6 MW	Solar Data
25	ppm NOx	Solar	
0.0006	lb/MMBtu SO2	AP-42 Chapter 3, Section 1	
0.0066	lb/MMBtu total PM-10 filterable + condensable	AP-42 Chapter 3, Section 1	
25	ppm CO		
25	ppm UHC		
116.88	lb/MMBtu CO2	EIIP Report, Vol. VIII, Table 1.4-3	

Medium Turbine (Based on best available information in 2001)

11,353	Btu/kWh HHV	Alstom Cyclone - 12.9 MW	Intl. Turbomachinery Handbook 1999, page 121 10,900 kj/kWh LHV
15	ppm NOx	Bluestein assumption	
0.0006	lb/MMBtu SO2	AP-42 Chapter 3, Section 1	
6.60E-03	lb/MMBtu total PM-10 filterable + condensable	AP-42 Chapter 3, Section 1	
25	ppm CO		
25	ppm UHC		
116.88	lb/MMBtu CO2	EIIP Report, Vol. VIII, Table 1.4-3	

This spreadsheet shows air emissions values for a number of distributed generation technologies. The values are given for a variety of emissions — NO_X, SO_2, CO, CO_2, PM (PM-10), and unburned hydrocarbons — and they are characterized in terms of pounds of emissions per unit of electrical output. These are typical values for new units of the specified technologies. They do not apply to older, existing units. The values were calculated on the basis of assumptions about typical operating conditions; however, because actual operating conditions are rarely typical, the actual emissions performance of a unit may differ from these values.

Large Gas Combined Cycle (Based on best available information in 2001)

6,640	Btu/kWh heat rate HHV	GE S-207FA (MS7001FA), 529.9 MW	Intl. Turbomachinery Handbook 1999, page 128 6375 kj/kWh LHV
2.5	ppm NOx	NSR/RBLC Identifier ME-0018	
0.0006	lb/MMBtu SO2	AP-42 Chapter 3, Section 1	
6.60E-03	lb/MMBtu total PM-10 filterable + condensable	AP-42 Chapter 3, Section 1	
6	ppm CO		
2	ppm HC		
116.88	lb/MMBtu CO2	EIIP Report, Vol. VIII, Table 1.4-3	

Large Gas Turbine (Based on best available information in 2001)

10,964	Btu/kWh heat rate HHV	GE PG6101(FA), 70.1 MW	Intl. Turbomachinery Handbook 1999, page 116 10,526 kj/kWh LHV
15	ppm NOx	Bluestein estimate	
0.0006	lb/MMBtu SO2	AP-42 Chapter 3, Section 1	
6.60E-03	lb/MMBtu total PM-10 filterable + condensable	AP-42 Chapter 3, Section 1	
25	ppm CO		
25	ppm UHC		
116.88	lb/MMBtu CO2	EIIP Report, Vol. VIII, Table 1.4-3	

ATS Gas Turbine (Based on best available information in 2001)

9,870	Btu/kWh heat rate	Caterpiller/Solar Turbines website	
9	ppm NOx	Stategic Goal of ATS program	http://www.fe.doe.gov/coal_power/ats/ats_so.html
0.0006	lb/MMBtu SO2	AP-42 Chapter 3, Section 1	
6.60E-03	lb/MMBtu total PM-10 filterable+condensable	AP-42 Chapter 3, Section 1	
25	ppm CO		
25	ppm UHC		
116.88	lb/MMBtu CO2	EIIP Report, Vol. VIII, Table 1.4-3	

This spreadsheet shows air emissions values for a number of distributed generation technologies. The values are given for a variety of emissions — NO_X, SO_2, CO, CO_2, PM (PM-10), and unburned hydrocarbons — and they are characterized in terms of pounds of emissions per unit of electrical output. These are typical values for new units of the specified technologies. They do not apply to older, existing units. The values were calculated on the basis of assumptions about typical operating conditions; however, because actual operating conditions are rarely typical, the actual emissions performance of a unit may differ from these values.

AEO Data (Based on best available information in 2001)

6,701,000	tons/year NOx from coal boilers	1998 EPA Vol 2, Table 25	
11,671,000	tons/year SO2 from coal boilers	1998 EPA Vol 2, Table 25	
273,000	tons/year PM10 from coal boilers	1998 National Emissions Trends, Table A-5	
138,000	tons/year PM25 from coal boilers	1998 National Emissions Trends, Table A-5	
1,911,627,000	tons/year CO2 from coal boilers	1998 EPA Vol 2, Table 25	
377,000	tons/year NOx from gas boilers	1998 EPA Vol 2, Table 25	
1,000	tons/year SO2 from gas boilers	1998 EPA Vol 2, Table 25	
1,000	tons/year PM10 from gas combustion	1998 National Emissions Trends, Table A-5	
1,000	tons/year PM25 from gas combustion	1998 National Emissions Trends, Table A-5	
195,868,000	tons/year CO2 from gas boilers	1998 EPA Vol 2, Table 25	
137,000	tons/year NOx from oil boilers	1998 EPA Vol 2, Table 25	
759,000	tons/year SO2 from oil boilers	1998 EPA Vol 2, Table 25	
9,000	tons/year PM10 from oil combustion	1998 National Emissions Trends, Table A-5	
8,000	tons/year PM25 from oil combustion	1998 National Emissions Trends, Table A-5	
100,895,000	tons/year CO2 from oil boilers	1998 EPA Vol 2, Table 25	
19,000	tons/year PM10 from IC engines	1998 National Emissions Trends, Table A-5	
19,000	tons/year PM25 from IC engines	1998 National Emissions Trends, Table A-5	
0.1022	lb/MMBtu NOx rate for turbines	2000 1st Qtr CEM data	include only blrtype=CC or CT, delete 16 records with no NOx rate
0.0102	lb/MMBtu SO2 rate for turbines	2000 1st Qtr CEM data	include only blrtype=CC or CT, delete 16 records with no NOx rate
1,807,480,000	MWh/year coal boiler generation	1998 EPA Vol 1, Table A2	
247,956,000	MWh/year gas boiler generation	1998 EPA Vol 1, Table A4	
102,669,000	MWh/year oil boiler generation	1998 EPA Vol 1, Table A3	
673,702,000	MWh/year nuclear generation	1998 EPA Vol 1, Table A2	
304,403,000	MWh/year hydro generation	1998 EPA Vol 1, Table A2	
7,206,000	MWh/year renewable generation	1998 EPA Vol 1, Table A2	
7,489,000	MWh/year oil turbine/IC generation	1998 EPA Vol 1, Table A3	
61,266,000	MWh/year gas turbine/IC generation	1998 EPA Vol 1, Table A4	
910,867,000	tons/year consumption for coal boilers	1998 EPA Vol 1, Table A5	
161,821,000	bbls/year consumption for oil boilers	1998 EPA Vol 1, Table A6	
16,793,000	bbls/year consumption for oil turbine/IC	1998 EPA Vol 1, Table A6	
2,618,037,000	mcf/year consumption for gas boilers	1998 EPA Vol 1, Table A7	
640,017,000	mcf/year consumption for gas turbine/IC	1998 EPA Vol 1, Table A7	
511,000	tons/year consumption anthracite coal	1998 Cost and Quality of Fuels, Table ES4	
478,252,000	tons/year consumption bituminuous coal	1998 Cost and Quality of Fuels, Table ES4	
373,496,000	tons/year consumption sub-bituminuous coal	1998 Cost and Quality of Fuels, Table ES4	
77,189,000	tons/year consumption lignite coal	1998 Cost and Quality of Fuels, Table ES4	
8,255,000	bbls/year consumption of #2 oil	1998 Cost and Quality of Fuels, Table 9	
156,851,000	bbls/year consumption of #4,#5,#6 oil	1998 Cost and Quality of Fuels, Table 9	
7,479	Btu/lb anthracite coal	1998 Cost and Quality of Fuels, Table ES4	
12,033	Btu/lb bituminous coal	1998 Cost and Quality of Fuels, Table ES4	
8,728	Btu/lb sub-bituminous coal	1998 Cost and Quality of Fuels, Table ES4	
6,471	Btu/lb lignite coal	1998 Cost and Quality of Fuels, Table ES4	

This spreadsheet shows air emissions values for a number of distributed generation technologies. The values are given for a variety of emissions — NO_X, SO_2, CO, CO_2, PM (PM-10), and unburned hydrocarbons — and they are characterized in terms of pounds of emissions per unit of electrical output. These are typical values for new units of the specified technologies. They do not apply to older, existing units. The values were calculated on the basis of assumptions about typical operating conditions; however, because actual operating conditions are rarely typical, the actual emissions performance of a unit may differ from these values.

10,241	Btu/lb average U.S. Coal	1998 Cost and Quality of Fuels, Table 4	
151,066	Btu/gallon average U.S. oil	1998 Cost and Quality of Fuels, Table 9	
138,766	Btu/gallon average U.S. fuel oil	1998 Cost and Quality of Fuels, Table 9	
151,723	Btu/gallon average U.S. #4, #5, #6 oil	1998 Cost and Quality of Fuels, Table 9	
1,022	Btu/cf average U.S. gas	1998 Cost and Quality of Fuels, Table 14	
	Btu/gallon #1 distillate (diesel)		
7,248,543	*NOx tons/yr from fossil generation*	*calculated*	
12,434,348	*SO2 tons/yr from fossil generation*	*calculated*	
302,000	*PM-10 tons/yr from fossil generation*	*calculated*	
2,261,251,666	*CO2 tons/yr from fossil generation*	*calculated*	

CEM Data (Based on best available information in 2001)

5,425,799	tons/year NOx from Title IV units	1999 CEM Data	
474,399	tons/year NOx from T4 units, not coal	1999 CEM Data	
4,951,400	*tons/year NOx from T4 coal units*	*calculated*	
12,470,504	tons/year SO2 from Title IV units	1999 CEM Data	
612,716	tons/year SO2 from T4 units, not coal	1999 CEM Data	
11,857,788	*tons/year SO2 from T4 coal units*	*calculated*	
1,769,627,431	MWh/year coal generation	1999 EIA Form 759	
2,143,656,841	MWh/year fossil generation	1999 EIA Form 759	
3,165,331,454	MWh/year generation	1999 EIA Form 759	

This spreadsheet shows air emissions values for a number of distributed generation technologies. The values are given for a variety of emissions — NO_X, SO_2, CO, CO_2, PM (PM-10), and unburned hydrocarbons — and they are characterized in terms of pounds of emissions per unit of electrical output. These are typical values for new units of the specified technologies. They do not apply to older, existing units. The values were calculated on the basis of assumptions about typical operating conditions; however, because actual operating conditions are rarely typical, the actual emissions performance of a unit may differ from these values.

Table 3:
(Based on best available information in 2001)

Value	*Factor*	*Source*
278	lb/MMBtu HHV to ppm for NOx, gas	EEA - Dist Gen Appendix B
456	lb/MMBtu HHV to ppm for CO, gas	EEA - Dist Gen Appendix B
200	lb/MMBtu HHV to ppm for SO2, gas	EEA - Dist Gen Appendix B
290	lb/MMBtu HHV to ppm for HC, gas	EEA - Dist Gen Appendix B
3,413	% efficiency to Btu/kWh	EEA - Dist Gen Appendix B
2,545	Btu per hp-hr	EEA - Dist Gen Appendix B
239	factor for gm/hp-hr to ppm for gas engine	EEA - Dist Gen Appendix B
0.91	conversion HHV to LHV for natural gas	EEA - Dist Gen Appendix B
0.7457	kW per hp	EEA - Dist Gen Appendix B
0.95	% generator efficiency	assumed
0.7	lb/hr	
47.6	MMBtu/hr	
0.0170	g/hp-hr	
2.9526	g/hp-hr to lb/MWh	
116.88	CO2 lb/MMBtu for natural gas	EIIP Report, Vol. VIII, Table 1.4-3
161.22	CO2 lb/MMBtu for distillate oil	EIIP Report, Vol. VIII, Table 1.4-3
159.38	CO2 lb/MMBtu for kerosene	EIIP Report, Vol. VIII, Table 1.4-3
173.67	CO2 lb/MMBtu for residual oil	EIIP Report, Vol. VIII, Table 1.4-3
227.53	CO2 lb/MMBtu for anthracite coal	EIIP Report, Vol. VIII, Table 1.4-3
205.18	CO2 lb/MMBtu for bituminous coal	EIIP Report, Vol. VIII, Table 1.4-3
212.15	CO2 lb/MMBtu for sub-bituminous coal	EIIP Report, Vol. VIII, Table 1.4-3
215.08	CO2 lb/MMBtu for lignite coal	EIIP Report, Vol. VIII, Table 1.4-3
173.10	*CO2 lb/MMBtu for oil*	*calculated*
208.10	*CO2 lb/MMBtu for coal*	*calculated*

This spreadsheet shows air emissions values for a number of distributed generation technologies. The values are given for a variety of emissions — NO_X, SO_2, CO, CO_2, PM (PM-10), and unburned hydrocarbons — and they are characterized in terms of pounds of emissions per unit of electrical output. These are typical values for new units of the specified technologies. They do not apply to older, existing units. The values were calculated on the basis of assumptions about typical operating conditions; however, because actual operating conditions are rarely typical, the actual emissions performance of a unit may differ from these values.

Figure 1:

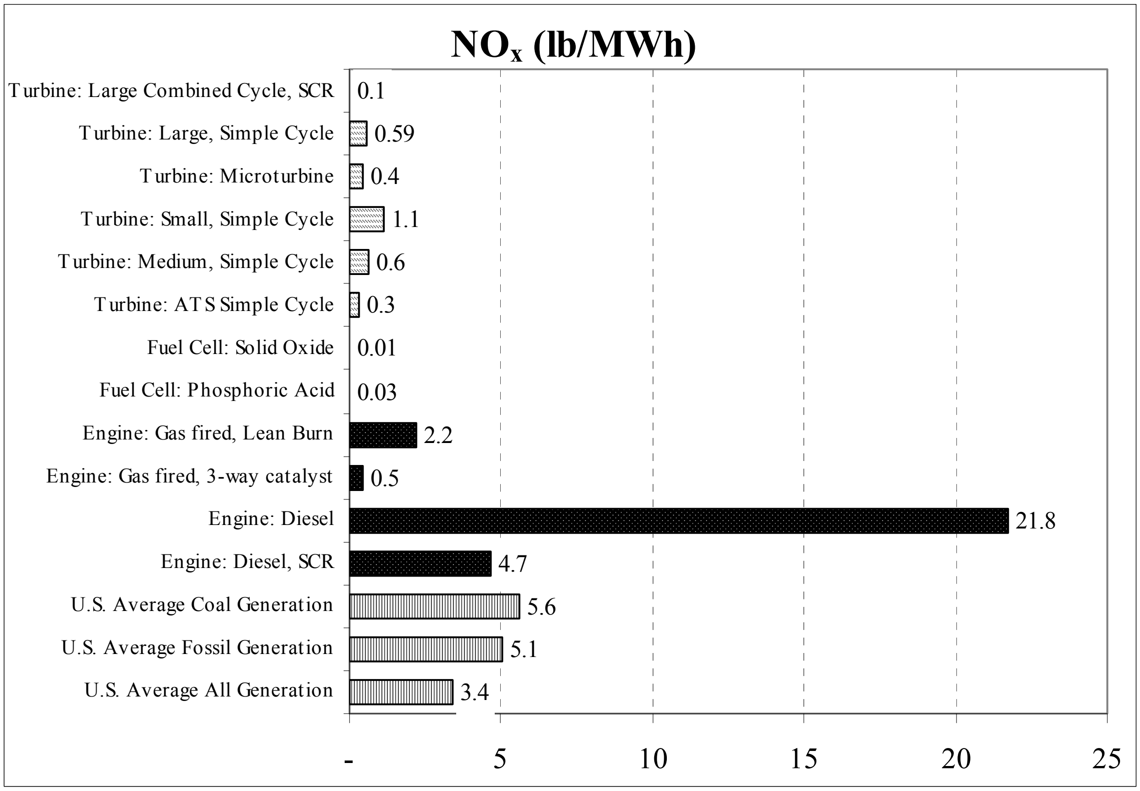


Figure 2:

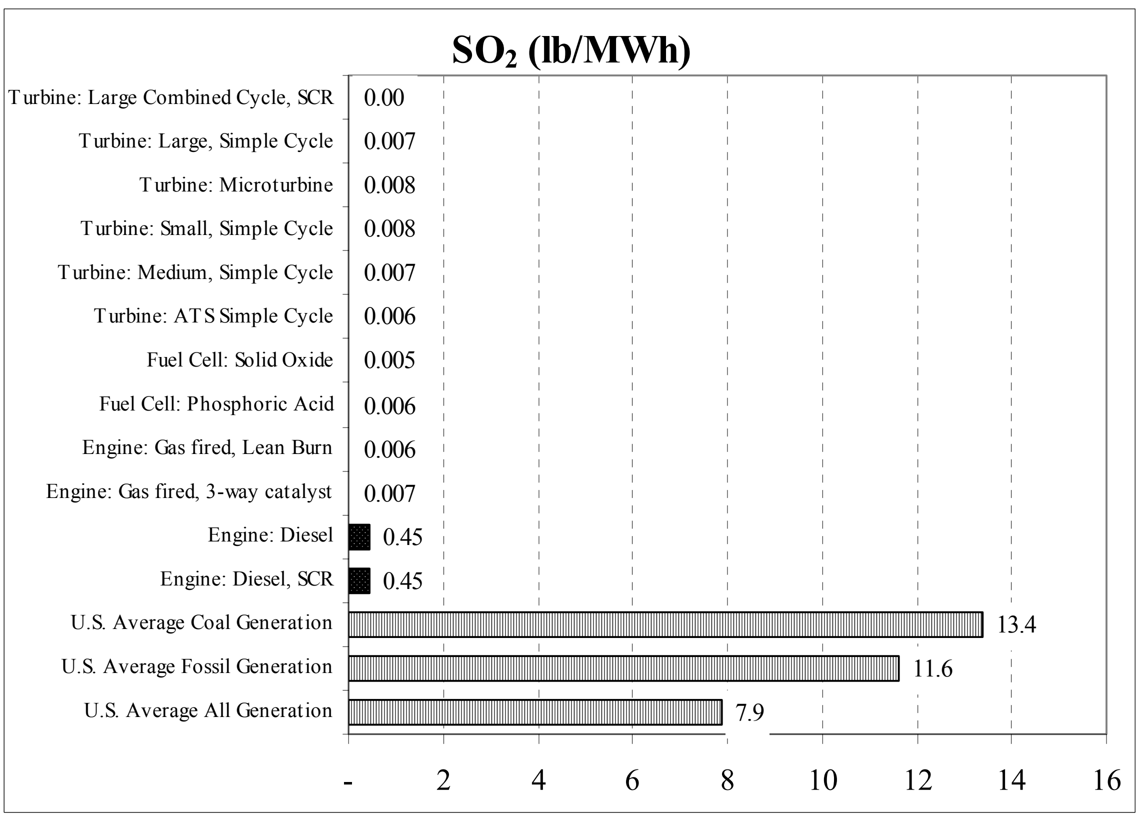


Figure 3:

These figures show air emissions values for a number of distributed generation technologies. The values are given for a variety of emissions — NO_X, SO_2, CO, CO_2, PM (PM-10), and unburned hydrocarbons — and they are characterized in terms of pounds of emissions per unit of electrical output. These are typical values for new units of the specified technologies. They do not apply to older, existing units. The values were calculated on the basis of assumptions about typical operating conditions; however, because actual operating conditions are rarely typical, the actual emissions performance of a unit may differ from these values.

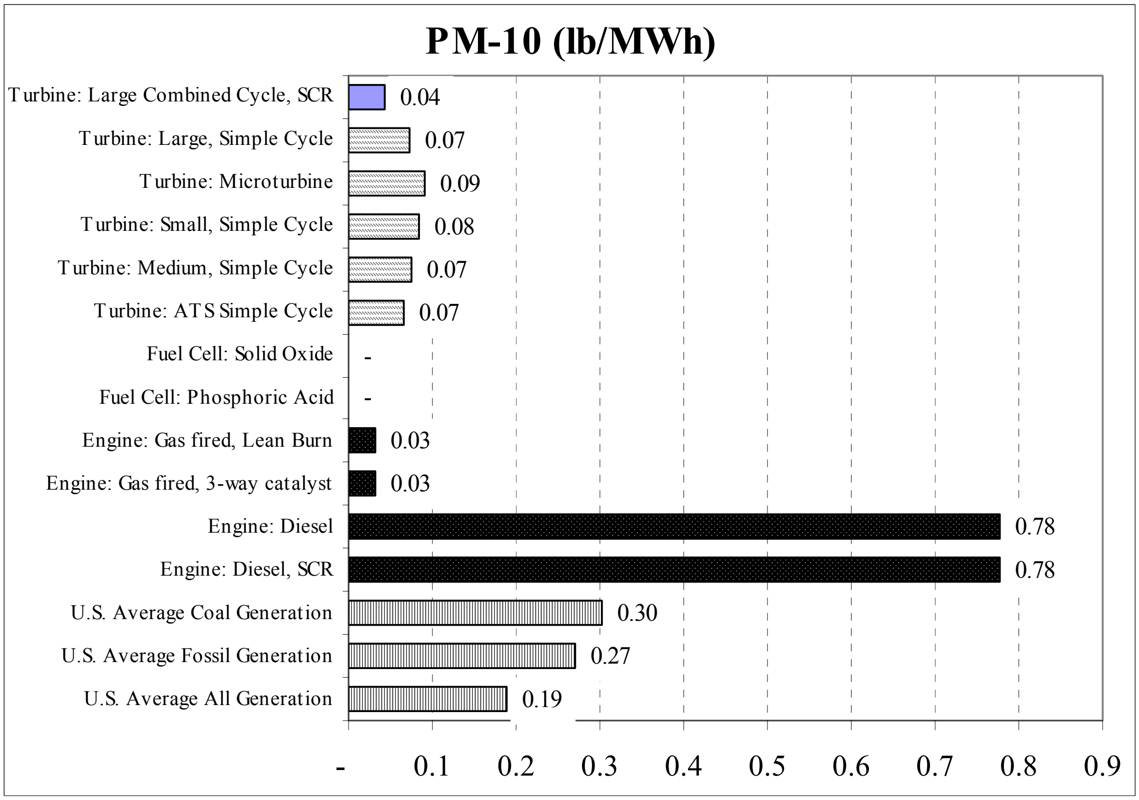
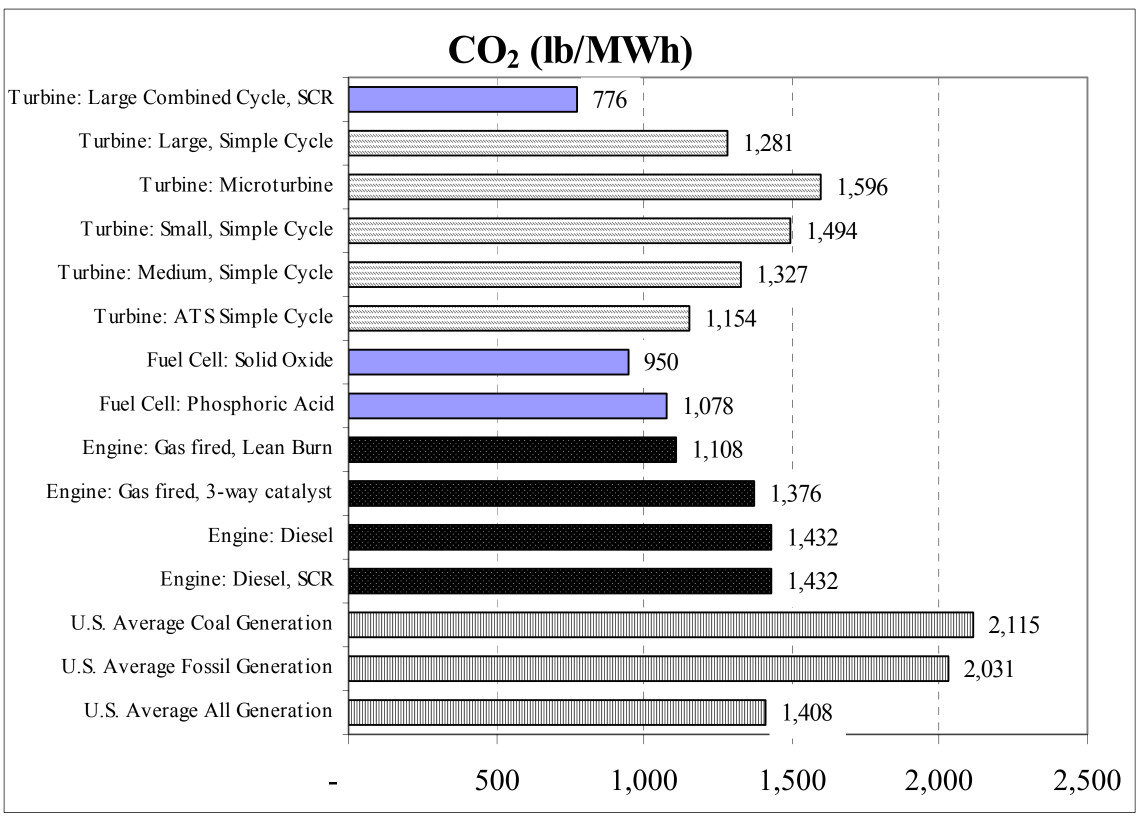
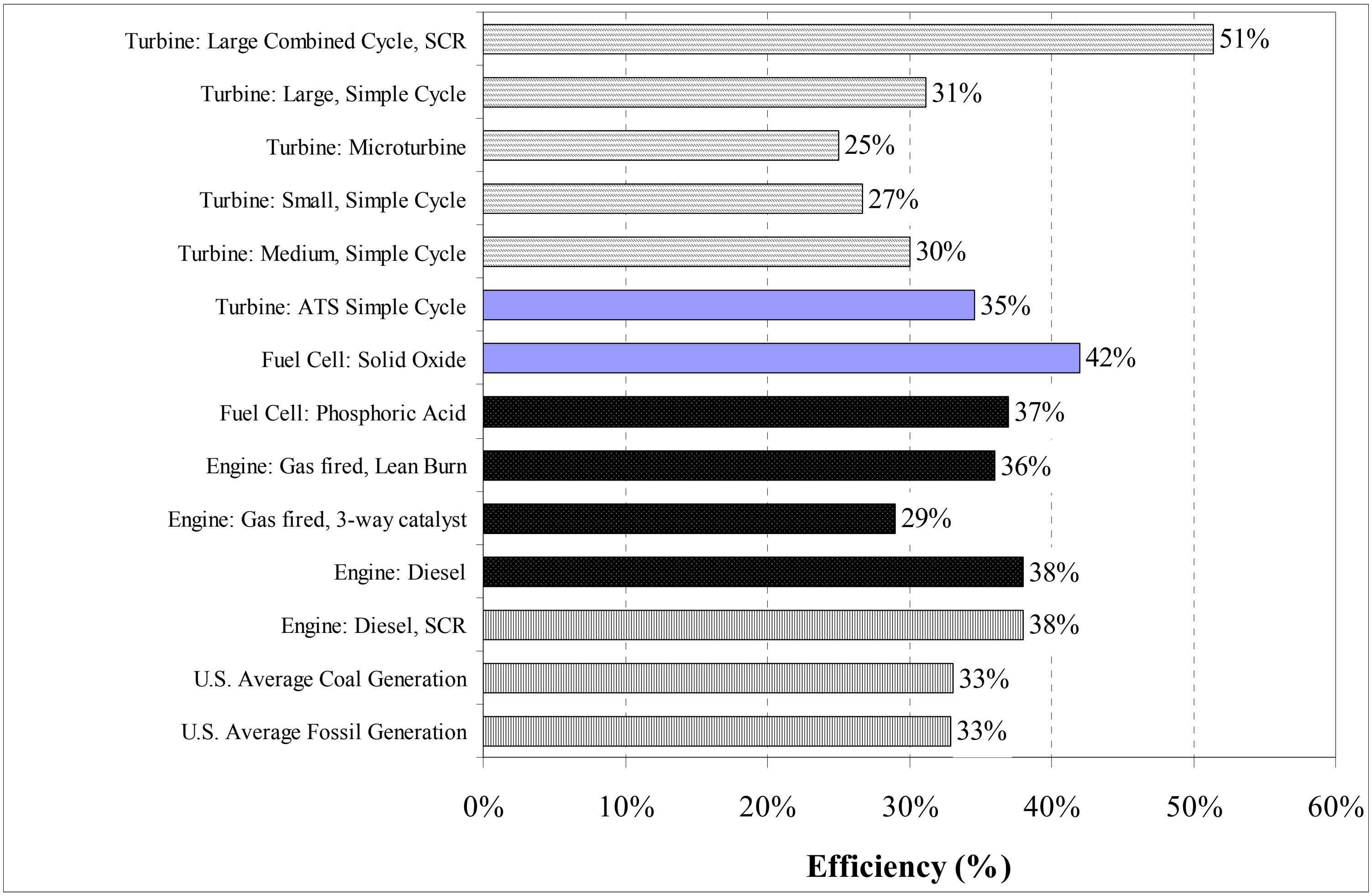


Figure 4:



These figures show air emissions values for a number of distributed generation technologies. The values are given for a variety of emissions — NO_X, SO_2, CO, CO_2, PM (PM-10), and unburned hydrocarbons — and they are characterized in terms of pounds of emissions per unit of electrical output. These are typical values for new units of the specified technologies. They do not apply to older, existing units. The values were calculated on the basis of assumptions about typical operating conditions; however, because actual operating conditions are rarely typical, the actual emissions performance of a unit may differ from these values.

Figure 5:



This figure shows air emissions values for a number of distributed generation technologies. The values are given for a variety of emissions — NO_X, SO_2, CO, CO_2, PM (PM-10), and unburned hydrocarbons — and they are characterized in terms of pounds of emissions per unit of electrical output. These are typical values for new units of the specified technologies. They do not apply to older, existing units. The values were calculated on the basis of assumptions about typical operating conditions; however, because actual operating conditions are rarely typical, the actual emissions performance of a unit may differ from these values.

Appendix C. US EPA Non-Road Engine Standards

The emissions values for NMHC + NO_X, CO, and PM are given in two units of measurement. The first unit of measurement is grams per kilowatt-hour (g/kWh), the second (in parentheses) is pounds per megawatt-hour (lbs/MWh). The emissions rates in lbs/MWh were calculated by multiplying the rates in g/kWh by a conversion factor of 2.2 (assuming 453.59 grams per pound).

Rated Power (kW)	Tier	Model Year	NO_X	HC	NMHC + NO_X	CO	PM
kW <8	Tier 1	2000	-	-	10.5 (23.1)	8.0 (17.6)	1.0 (2.2)
	Tier 2	2005	-	-	7.5 (16.5)	8.0 (17.6)	0.8 (1.8)
8≤ kW<19	Tier 1	2000	-	-	9.5 (20.9)	6.6 (14.5)	0.8 (1.8)
	Tier 2	2005	-	-	7.5 (16.5)	6.6 (14.5)	0.8 (1.8)
19≤ kW <37	Tier 1	1999	-	-	9.5 (20.9)	5.5 (12.1)	0.8 (1.8)
	Tier 2	2004			7.5 (16.5)	5.5 (12.1)	0.6 (1.3)
37≤ kW <75	Tier 1	1998	9.2	-	-	-	-
	Tier 2	2004	-	-	7.5 (16.5)	5.5 (12.1)	0.4 (.9)
	Tier 3	2008	-	-	4.7 (10.3)	5.0 (11.0)	
75≤ kW <130	Tier 1	1997	9.2	-	-	-	-
	Tier 2	2003	-	-	6.6 (14.52)	5.0 (11.0)	0.3 (.7)
	Tier 3	2007	-	-	4.7 (8.8)	5.0 (11.0)	
130≤ kW <225	Tier 1	1996	9.2	1.3	-	11.4 (25.1)	0.5 (1.1)
	Tier 2	2003	-	-	6.6 (14.6)	3.5 (7.7)	0.2 (.4)
	Tier 3	2006	-	-	4.0 (8.8)	3.5 (7.7)	
225≤ kW <450	Tier 1	1996	9.2	1.3	-	11.4 (25.1)	0.5 (1.1)
	Tier 2	2001	-	-	6.4 (14.1)	3.5 (7.7)	0.2 (.4)
	Tier 3	2006	-	-	4.0 (8.8)	3.5 (7.7)	
450≤ kW <560	Tier 1	1996	9.2	1.3	-	11.4 (25.1)	0.5 (1.1)
	Tier 2	2002	-	-	6.4 (14.1)	3.5 (7.7)	0.2 (.4)
	Tier 3	2006	-	-	4.0 (8.8)	3.5 (7.7)	
KW >560	Tier 1	2000	9.2	1.3	-	11.4 (25.1)	0.5 (1.1)
	Tier 2	2006	-	-	6.4 (14.1)	3.5 (7.7)	0.2 (.4)

The source of this table is the Federal Register/Vol. 63, No. 205/Friday, Oct. 23, 1998/Rules and Regulations/ Page 57001.

Appendix D. Working Group Members

The draft model rule was nearly 2 years in the making. During that time, the membership of the working group changed somewhat, as some members left and new ones joined. The following is a list of all past and present members.

State Environmental Regulators
Grant Chin, California Air Resources Board
Christopher James, Connecticut Department of Environmental Protection
Janet McCabe, Office of Air Management, Indiana Department of Environmental Management
Ron Methier, chief, Georgia Air Protection Branch, Department of Natural Resources
Brock Nicholson, Division of Air Quality, North Carolina Department of Environment and Natural Resources
Brad Nelson, North Carolina Department of Environment and Natural Resources
Nancy L. Seidman, Massachusetts Department of Environmental Protection
Nancy Sutley, California Environmental Protection Agency

State Energy Officials
Paul Burks, executive director, Division of Energy Resources, Georgia Environmental Facilities Authority
Fred Hoover, director, Maryland Energy Administration
William Keese, chairman, California Energy Commission
Ethan Rogers, programs manager, Energy Policy Division, Indiana Department of Commerce
William Steinhurst, director of Regulated Utility Planning, Vermont Department of Public Service
Scott Tomashevfky, California Energy Commission
Linda Taylor, Minnesota Energy Office

State Utility Regulators
James Burg, chairman, South Dakota Public Utilities Commission
John Farrow, commissioner, Wisconsin Public Utilities Commission
Edward Garvey, commissioner, Minnesota Public Utilities Commission
Roger Hamilton, commissioner, Oregon Public Utilities Commission
Terry Harvill, commissioner, Illinois Commerce Commission
Alison Silverstein, advisor to the chairman, Public Utilities Commission of Texas

Non-State Governmental Participants
Thomas Basso, National Renewable Energy Laboratory
Joel Bluestein, Energy and Environmental Analysis Inc.
Joe Bryson, United States Environmental Protection Agency
Kevin Duggan, Capstone Turbines Inc.
Tim French, Engine Manufacturers Association
Joseph Galdo, United States Department of Energy
Nathanael Greene, Natural Resources Defense Council
Eric Heitz, Energy Foundation
John Kelly, Gas Research Institute

Jim Lents, Professor, CERT, University of California, Riverside
Katie McCormack, Energy Foundation
Catherine Morris, Center for Clean Air Policy
Gary Nakarado, National Renewable Energy Laboratory
Merrill Smith, United States Department of Energy
Joseph Suchecki, Engine Manufacturers Association
Carl Weinburg, The Regulatory Assistance Project
Frederick Weston, The Regulatory Assistance Project
Leslie Witherspoon, Solar Turbines Inc.
Eric Wong, Caterpillar Inc.

Appendix E. Commenters

American Gas Cooling Center, Mark E. Krebs, AGCC education committee chairman, Laclede Gas Company, Dec. 14, 2001, and Aug. 13, 2002
Biomass Energy Resource Center, Tim Maker, director, Dec. 19, 2001
Burlington Electric Department, John Irving, Dec. 24, 2001
Conservation Law Foundation, Richard B. Kennelly Jr., director, Energy Project, Dec. 31, 2001
Cummins Power Generation, Michael Brand, Sept. 24, 2002
Elliott Energy Systems, J. Britt Ingram, Combustor Development Group, Jan. 28, 2002
Engine Manufacturer's Association, Joseph Suchecki, director, Public Affairs, Jan. 11, 2002
Environmental Defense, Mark MacLeod, Feb. 20, 2002
Gas Technology Institute, John Kelly, director, Distributed Energy Resources, Dec. 26, 2001
H Power, Chris Haun, Nov. 27, 2001
Innovative Technology Group, Larry Reinhart, Sales Manager, Nov. 19, 2001
International District Energy Association, Mark Spurr, June 28, 2002
Massachusetts Department of Environmental Protection, Donald Squires, Nov. 6, 2001
Millennium Cell, Adam Briggs, Nov. 6, 2001
Missouri Department of Natural Resources, Roger T. Randolph, director, Dec. 19, 2001
New Hampshire Department of Environmental Services, Andrew M. Bodnarik, Regional & National Issues manager, Air Resources Division, Nov. 20, 2001.
NiSource, Bruce M. Diamond, director, Environmental & Agency Relations, Nov. 2001
North East Environmental Products, Bruce Lamarre, Dec. 2001 (received Jan. 3, 2002)
Natural Resources Defense Council, Nathanael Greene, Senior Policy Analyst, Jan. 15, 2002
National Rural Electric Cooperative Association, Rae Cronmiller, environmental counsel, and John Holt, manager, Generation and Fuels, Feb. 19, 2002
Pace Energy Project, Fred Zalcman, executive director, Jan. 25, 2002
Rolls-Royce Energy Business, Al Wei, Business Development director, Dec. 31, 2001
Solar Turbines, Leslie Witherspoon, manager Environmental Programs, Feb. 4, 2002
Vermont Agency of Natural Resources, Conrad W. Smith, Counsel, Air Pollution Control Division, Sep. 25-26, 2002
Vermont Department of Public Service, Michael R. Kundrath, Policy and Program Analyst, Nov. 2, 2001
Waukesha Engine, Robert Stachowicz, Sept. 13 and 17, 2002

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13. ABSTRACT *(Maximum 200 words)*
This report details the work undertaken from October 2001 to February 2003 by the Regulatory Assistance Project under subcontract to the National Renewable Energy Laboratory. The objectives of this work were to develop regulatory policy options that would reduce the institutional and infrastructure barriers to full-value deployment of distributed power systems. Specific tasks included leading technical workshops on removing or overcoming regulatory barriers to distributed resources for state utility regulators and developing a draft model rule on emission performance standards for distributed generation.

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