Stationary Diesel Engines in the Northeast:

An Initial Assessment of the Regional Population,
Control Technology Options and Air Quality Policy Issues

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Founded in 1967, NESCAUM is a non-profit association of the state air quality management offices of Connecticut, Maine, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island and Vermont.

The cover photo shows a 315 kW stationary diesel generator, courtesy of: www.utilitywarehouse.com

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List of Abbreviations and Acronyms

ºC/ºF – degree Celsius/Fahrenheit
A/F – air to fuel ratio
BACT – Best Available Control Technology
bhp – brake horsepower
bhp-hr – brake horsepower-hour
Btu – British thermal unit
CARB – California Air Resources Board
CHP – combined heat and power
CI – compression ignition
CO – carbon monoxide
CRF – capital recovery factor
DEC – Department of Environmental Conservation
DEM – Department of Environmental Management
DEP – Department of Environmental Protection
DES – Department of Environmental Services
DG – distributed generation
DOC – diesel oxidation catalyst
DOE – Department of Energy
DPF – diesel particulate filter
DR – demand response
ECP – energy clearing price
EGR – exhaust gas recirculation
EDRP – emergency demand response program
EPA – U.S. Environmental Protection Agency
FERC – Federal Energy Regulatory Commission
FTP – Federal Test Procedure
g – gram
GPDG – General Permit for Distributed Generation
GPEE – General Permit for Emergency Engines
GW – gigawatt (=1,000 MW)
HAP – hazardous air pollutant
HC – hydrocarbons
hp – horsepower
IC – internal combustion
ISO – Independent System Operator
kW – kilowatt
kWh – kilowatt-hour
LAER – Lowest Achievable Emission Rate
lb – pound
lb/MMBtu – pounds per million Btu
lb/MWh – pounds per megawatt-hour
LBMP – Location Based Marginal Price
MACT – Maximum Achievable Control Technology
MMBtu – million Btu
MW – megawatt (= 1,000 kW)
MWh – megawatt-hour
NAICS – North American Industry Classification System
NEDRI – New England Demand Response Initiative
NESCAUM – Northeast States for Coordinated Air Use Management
N_2 - nitrogen
NMHC – non-methane hydrocarbons
NOx – nitrogen oxides
NRDC – Natural Resources Defense Council
NSR – New Source Review
O_2 – oxygen
OAQPS – Office of Air Quality Planning and Standards (EPA)
OTC – Ozone Transport Commission
PAH – polycyclic aromatic hydrocarbons
PM – particulate matter
$PM_{2.5}$ – PM < 2.5 microns in diameter
PM_{10} – PM < 10 microns in diameter
ppm – parts per million
ppmvd – parts per million volume, dry
PJM – ISO for the Mid-Atlantic states
PRP – price response program
PSR – Power Systems Research
PTE – potential to emit
RACT – Reasonably Available Control Technology
RAP – Regulatory Assistance Project
RBL – RACT/BACT/LAER
SCR – selective catalytic reduction
SI – spark ignition
SIC – Standard Industrial Classification
SMAQMD – Sacramento Metropolitan Air Quality Management District
SOTA – state of the art
SO_X/SO_2 – sulfur oxides/sulfur dioxide
TPY – tons per year
TWC – three-way catalyst
VOC – volatile organic compounds

Executive Summary

Stationary diesel internal combustion (IC) engines constitute a significant component of the nation's electricity generating infrastructure. Estimates of installed diesel generator capacity in the United States range as high as 350,000 units totaling more than 127 gigawatts (GW);[1] estimates developed for this report suggest that the total population of diesel generators in the Northeast could include well over 30,000 units with a combined capacity exceeding 10 GW. Historically, the vast majority of these engines has been used primarily or exclusively to provide back-up power in emergency (i.e. outage) situations and in some cases to reduce reliance on grid-supplied electricity during periods of peak demand. Consequently, most diesel generators have been operated infrequently and have not been subject to the kinds of environmental regulation applicable to large central-station power plants.

More recently, emerging concerns about system reliability and price volatility in deregulated electricity markets have prompted interest in making greater use of all forms of distributed generation capacity to lower demand for grid-supplied electricity during high price and peak use periods. While this interest may eventually lead to increased reliance on fuel cells, microturbines, renewable power and other advanced distributed generation technologies, diesel IC engines are likely to remain by far the most ubiquitous distributed generating resource available in the short term. Therefore, any increase in the near-term use of these resources in general, must raise environmental concerns related to the operation of diesel engines in particular. Most diesel IC engines emit high levels of pollutants such as nitrogen oxides (NOx), a key ingredient in the formation of ground-level ozone, and particulate matter (PM). In addition, diesel exhaust contains numerous toxic and potentially carcinogenic components. In fact, emissions rates per unit of electrical output for diesel IC engines are typically several times higher than those of conventional fossil fuel power plants and orders of magnitude higher than those of the cleanest conventional central-station generating technologies, such as large combined-cycle natural gas turbines.

State and federal regulators recognize that existing environmental policies will need to be updated or augmented to ensure that a new generation of cleaner distributed technologies becomes available in the future and to manage any adverse impacts from the existing generator population in the transition, especially if market conditions and/or government policies prompt increased use of this capacity in the near-term. Unfortunately, the situation is complicated by a shortage of reliable information on the current population of small distributed generators. The chief purpose of this study was therefore to begin developing a more complete inventory of the numbers and types of diesel IC engines that exist in the eight-state NESCAUM region.[2] In addition, the study reviews current state policies concerning the permitting and operation of diesel generators, provides

[1] National diesel generator population estimate from Natural Resources Defense Council (NRDC) report *Distributed Resources and Their Emissions: Modeling the Impacts*, Greene, Hammerschlag, and Keith, 2001. These figures were provided to NRDC by Power Systems Research (see Footnote 4).

[2] Specifically, the states of Connecticut, Maine, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island and Vermont. All of these states are members of NESCAUM.

preliminary estimates of emissions impacts associated with current levels of diesel generator operation, reviews control technology options (including case studies of several actual installations) and provides a number of specific policy recommendations.

A. Summary of Current Permitting Requirements for Diesel IC Engines in the Northeast States

Distributed generators, and stationary internal combustion engines in general, are for the most part regulated and permitted at the state and local level. Table ES-1 summarizes the different permitting requirements applicable to electricity generating engines in the eight NESCAUM states. As seen in Table ES-1, most states make a distinction between emergency and non-emergency engines. Emergency engines are often exempt from emissions limits or control technology requirements, however their operation is usually

Table ES-1
Summary of State Permitting Requirements for Distributed Generators

State	Non-Emergency Engines[a]		Emergency Engines		
	Threshold	Requirements[b]	Threshold	Restrictions	Demand Response[d]
CT	PTE 15 TPY[c] of any criteria pollutant	BACT, LAER based on emissions	CT: permit-by-rule SW CT: 50 hp (37 kW)	500 hrs/yr and maximum of 5 TPY NOx, 5 TPY CO, 3 TPY PM, and 3 TPY SO2	no PRP; EDRP in SW CT for add'l 300 hrs/yr, only nat. gas or ULSD[e]
ME	5 MMBtu/hr (approx. 500 kW), 0.5 MMBtu/hr if at major source	SCR over 20 TPY NOx, BACT case-by-case, on-road diesel	0.5 MMBtu/hr (approximately 50 kW)	500 hrs/yr	no additional restrictions
MA	3 MMBtu/hr (approx. 300 kW), smaller if at facility with other permitted engines	case-by-case BACT	3 MMBtu/hr permit-by-rule, over 10 MMBtu/hr case-by-case BACT	300 hrs/yr, cannot create a "condition of air pollution," must have a noise muffler	no PRP; may run once ISO has called for voltage reductions (OP-4 step 12 or 14)
NH	1.5 MMBtu/hr (150 kW) diesel, 10 MMBtu/hr (1 MW) natural gas, PTE 25 TPY[c] NOx	over 400 kW may require RACT	no threshold	500 hrs/yr, limit sulfur content of diesel, and limit emissions	neither type of DR for emergency engines
NJ	1 MMBtu/hr (approximately 100 kW)	BACT for new/modified; existing diesel engines require 8g/bhp-hr NOx (being revised to 2.3 g/bhp-hr)	1 MMBtu/hr (approximately 100 kW)	no control if PTE NOx is less than 25 TPY	neither type of DR for emergency engines
NY	NY: 300 kW, 160 kW if non-att., NYC: 280 kW, 33 kW if diesel	diesel engines are not allowed to participate in PRP[d]	NY: no threshold, NYC: over 280 kW must register	NY: 500 hrs/yr, no permits, NYC: register but no restrictions	no PRP; EDRP less than 200 hrs/yr, 30 ppm sulfur diesel fuel required
RI	500 kW diesel, 1 MW natural gas	BACT based on emissions	no threshold	500 hrs/yr, 0.3% sulfur diesel fuel	neither type of DR for emergency engines
VT	450 hp (337 kW)	must meet EPA's non-road standards	no threshold	200 hrs/yr	neither type of DR for emergency engines

[a] non-emergency engines are not restricted from participating in demand response programs, except as noted in NY

[b] abbreviations: BACT=Best Available Control Technology; MACT=Maximum Achievable Control Technology; RACT= Reasonably Available Control Technology; LAER=Lowest Achievable Emission Rate; SCR=Selective Catalytic Reduction; SOTA=State of the Art

[c] PTE=potential to emit, and TPY=tons per year

[d] demand response (DR) programs include the emergency demand response program (EDRP) which is called by the ISO in the event of an imminent capacity shortfall, and the price response program (PRP) in which customers respond to high prices

[e] ultra-low sulfur diesel fuel

strictly limited to certain situations and a maximum number of hours (typically from 200 to 500 hours) per year. By contrast, non-emergency engines are typically regulated down to smaller sizes and to more stringent emissions control requirements. Table ES-1 also notes different state policies regarding the eligibility of emergency generators to participate in formal “demand response” programs.[3] In some states, emergency units are allowed to operate under emergency demand response programs – which are invoked at times of imminent supply shortfalls to avert loss of grid power – while in others, operation of emergency units remains constrained to actual outage situations only. Emergency units are generally precluded in all Northeast states from participating in price response programs which are designed to reduce system load during periods of high prices (as opposed to supply shortages).

B. Northeast States Distributed Generator Inventory

In an attempt to develop more precise inventories of the population of diesel and other distributed generators in the Northeast, NESCAUM relied on estimates developed by a consultant, Power Systems Research[4] (PSR), together with information gathered from individual state permit records. The PSR estimates were derived using a methodology developed from national sales data and field surveys that correlates engine population to the numbers and types of businesses present in a given geographic area. Table ES-2 summarizes the PSR population estimates for the NESCAUM region. Engine totals are shown by number and by capacity, sorted by size range and type of application.

Table ES-2
PSR Estimates of Diesel Engines in the NESCAUM Region by Number and Capacity

Number Totals	Emergency	Peak	Baseload	Total
25-50 kW	1,768	0	0	**1,768**
50-100 kW	5,798	1,375	107	**7,280**
100-250 kW	9,226	2,236	95	**11,557**
250-500 kW	5,918	1,231	7	**7,156**
500-750 kW	1,296	316	47	**1,659**
750-1000 kW	1,164	292	51	**1,507**
1000-1500 kW	641	677	39	**1,357**
1500+ kW	1,073	284	37	**1,394**
Total	**26,884**	**6,411**	**383**	**33,678**

Capacity Totals (MW)	Emergency	Peak	Baseload	Total
25-50 kW	59	0	0	**59**
50-100 kW	462	114	9	**584**
100-250 kW	1,564	371	14	**1,949**
250-500 kW	2,126	443	3	**2,572**
500-750 kW	801	196	29	**1,026**
750-1000 kW	921	230	40	**1,191**
1000-1500 kW	769	837	48	**1,654**
1500+ kW	2,053	615	68	**2,736**
Total	**8,756**	**2,805**	**211**	**11,772**

Overall, PSR estimates that a total of 33,678 diesel IC engines, with a total capacity of 11,772 MW, are currently installed in the eight NESCAUM states. Of this population, a very large fraction, estimated at 80% of the engines (accounting for 74% of total MW capacity), is designated for emergency use.

Information on the diesel generator population from state permitting records is summarized in Table ES-3, below. Because the amount of information and unit-level

[3] With the exception of New York (as detailed in Table ES-1), non-emergency engines are not restricted from participation in demand response programs.
[4] Power Systems Research (PSR) is a market research company for the engine industry.

detail available from each state varied, the size or capacity distribution for some engines needed to be estimated for at least part of the permitted population in some states.

Table ES-3
Number of Permitted Engines in the Northeast States

	CT	ME	MA	NH	NJ	NY	RI	VT	TOTAL
25-50 kW	112	2	11	1	4	26	0	0	**156**
50-100 kW	208	78	13	2	120	93	0	9	**523**
100-250 kW	411	184	278	65	1,432	337	4	18	**2,729**
250-500 kW	321	158	156	126	1,247	410	1	17	**2,436**
500-750 kW	273	64	138	71	927	272	20	7	**1,772**
750-1000 kW	144	28	73	39	837	201	11	2	**1,335**
1000-1500 kW	153	36	160	47	698	175	11	10	**1,290**
1500+ kW	99	28	275	9	558	148	25	3	**1,145**
Total	**1,721**	**578**	**1,104**	**360**	**5,823**	**1,662**	**72**	**66**	**11,386**

Comparing Tables ES-2 and ES-3 suggests that current state permit records capture approximately one-third of the total number of diesel IC generators estimated by PSR for the NESCAUM region. As one would expect, based on the fact that many smaller engines fall below current state permitting thresholds, the agreement between PSR's estimates and state permitting records generally improves in the larger engine size categories (i.e. > 250 kW). However, it is important to note that PSR's estimation methodology is inherently inaccurate. A closer comparison to state permit records (as described in detail in Chapter III of this report) reveals both that the discrepancies are significant and that there is no particular pattern to the variance between states' permit data and PSR's population estimates for different engine size categories. This suggests either that the PSR estimates are inexact, or that available state permit records are incomplete, or some combination of both.

C. Results of Detailed Engine Surveys in New York City and Fairfield County, Connecticut

As a follow-up and complement to the engine inventory efforts described above, PSR conducted detailed telephone surveys to obtain information on the distributed engine population in New York City and Fairfield County, Connecticut. These areas were selected because both face severe transmission constraints and have been the focus of recent efforts by electric system operators to encourage customer-side demand responses during periods of peak electrical demand. The results obtained by PSR in the telephone surveys were compared to available information from state or city permit records for these two areas. This analysis differed from the statewide estimates above in that it was possible to determine from the telephone survey data specifically which engines were (or were not) included in state permit files.

In general, the comparison revealed surprisingly little overlap between the telephone survey results and available permit records, even for many of the larger engines identified by PSR. The percentage of surveyed engines for which there was no record in state or city databases was over 50% in the case of New York City and over 80% in the case of Fairfield County. Clearly, a significant portion of this discrepancy can be explained by a lack of data for those engines for which no permit is required (or available) because they are operating under an emergency exemption or permit-by-rule exclusion, or simply fall below applicable permitting thresholds. Nevertheless, this result suggests that neither the survey/estimation methodology used by PSR, nor current state permitting systems can be relied upon for comprehensive coverage of the existing population of small generators

Table ES-4 summarizes the combined population of diesel generators identified through either the survey and/or available permit records for the two survey areas.

Table ES-4
Identified Engine Populations for New York City and Fairfield County

	New York City			Fairfield County, CT		
Engine Size	Total Number	% of Engines	Capacity Total (MW)	Total Number	% of Engines	Capacity Total (MW)
25-50 kW	26	1.2%	1	29	5.2%	1
50-100 kW	123	5.5%	8	108	19.3%	7
100-250 kW	426	19.1%	70	135	24.1%	21
250-500 kW	509	22.8%	178	148	26.4%	48
500-750 kW	389	17.4%	229	66	11.8%	37
750-1000 kW	328	14.7%	277	19	3.4%	16
1000-1500 kW	319	14.3%	346	29	5.2%	32
1500+ kW	116	5.2%	211	26	4.6%	74
Total	2,236	100%	1,320	560	100%	235

D. Emissions Estimates

Because small diesel generators are often located near or in densely populated urban areas and because their emissions tend to be released closer to the ground, operation of these engines – especially during peak demand hours (which typically occur on hot summer days when air quality is already poor) – poses particular public health concerns. Because no mechanism has existed to comprehensively track these units, empirical data on their historic emissions have been scarce. The telephone survey portion of this study enabled NESCAUM to collect information on the actual operation of engines known to exist in New York City and Fairfield County, Connecticut. Table ES-5 summarizes our estimate of annual emissions associated with the total engine population identified through either the telephone surveys or permitting records in these two areas. Emissions totals are calculated using emissions factors and average operating hours for different types and sizes of engines as reported by owners contacted in the telephone surveys. The emissions factors used for purposes of this analysis are summarized in Table ES-6.[5]

[5] The emissions factors shown in Table ES-6 are from the Sacramento Metropolitan Air Quality Management District's (SMAQMD) September 2002 *Internal Combustion Engine Manual*. The SMAQMD Manual uses AP-42 emissions factors, except where emissions tests conducted by California for purposes of Best Available Control Technology (BACT) determinations revealed higher emissions factors (see further discussion in Chapter V).

Table ES-5
Emissions Estimates for Engine Populations in New York City and Fairfield County

	New York City					Fairfield County, CT				
	Number of Engines	MWh/yr	NOx (tons/yr)	PM_{10} (tons/yr)	VOC (tons/yr)	Number of Engines	MWh/yr	NOx (tons/yr)	PM_{10} (tons/yr)	VOC (tons/yr)
Diesel	1,652	379,620	6,480	260	580	447	313,040	5,220	190	470
Natural Gas	549	144,720	2,320	30	90	90	3,700	60	0.8	2.5
Gasoline	35	7,360	50	5	110	23	2,820	20	1.4	40
Total	2,236	531,700	8,850	295	780	560	319,560	5,300	192	513

Table ES-6
Distributed Generator NOx, PM_{10} and VOC Emissions Factors

Engine Type	NOx		PM_{10}		VOC	
	g/hp-hr	lb/MWh	g/hp-hr	lb/MWh	g/hp-hr	lb/MWh
Diesel < 600 hp	14.06	41.47	1.00	2.95	1.14	3.36
Diesel > 600 hp	10.86	32.04	0.32	0.94	1.00[b]	2.95[b]
Natural Gas[a]	10.89[b]	32.12[b]	0.15[b]	0.45[b]	0.43[b]	1.27[b]
Gasoline	5.00	14.72	0.33	0.97	9.79	28.88

a Emissions factors represent an average for three types of natural gas engines. Additional detail in Table VI-2.
b SMAQMD emission factors used in place of AP-42, see Footnote 5.

Note that emissions were not calculated for the broader engine population estimates developed by PSR for the NESCAUM region as a whole. The results of such a calculation would be questionable due to the higher level of uncertainties involved.

In addition, NESCAUM analyzed the emissions impacts associated with engine operation under formal demand response programs sponsored by the New York and New England grid operators or independent system operators (ISO's) in recent years. Tables ES-7 and ES-8 summarize the results of this analysis for the summer 2002 economic or "price response" programs,[6] using the emissions factors shown in Table ES-6.

Table ES-7
Estimated Emissions for 2002 NY-ISO Price Response Program in New York City

Date	MWh Generated	NOx (tons)	PM_{10} (tons)	VOC (tons)
04/17/02	154.6	2.48	0.07	0.23
04/18/02	191.5	3.07	0.09	0.28
07/30/02	267.7	4.29	0.13	0.39
08/14/02	251.3	4.03	0.12	0.37
Total	**865.1**	**13.86**	**0.41**	**1.28**

[6] Neither ISO invoked its emergency demand response program in 2002.

Table ES-8
Estimated Emissions for 2002 NE-ISO Price Response Program in New England

State	MWh Curtailed	MWh Generated	NOx (tons)	PM_{10} (tons)	VOC (tons)
Connecticut	272.25	421.97	6.76	0.20	0.62
Massachusetts	88.38	27.07	0.43	0.01	0.04
Maine	62.55	81.82	1.31	0.04	0.12
New Hampshire	7.48	0.00	0.00	0.00	0.00
Rhode Island	3.44	0.00	0.00	0.00	0.00
Vermont	0.04	72.53	1.16	0.03	0.11
Total	**434.13**	**603.39**	**9.67**	**0.28**	**0.89**

In general, this preliminary analysis suggests that additional emissions impacts associated with the use of stationary diesel generators *in recently introduced formal demand response programs* have to date been small – on an annual basis – relative to state and local inventories of emissions from all pollutant sources. Moreover, emissions from the existing operation of larger, non-emergency engines for peak-shaving and baseload purposes are likely to dwarf any near-term increase in emissions associated with the use of diesel generators under the formal demand response programs being introduced or augmented by grid operators. In New Hampshire, for example, no new generation occurred under the New England ISO's formal price response program in 2002. However, the New Hampshire Department of Environmental Services had documented a significant increase in NOx emissions from stationary IC engines in the 1990s, presumably as the result of the increased operation of non-emergency engines in response to other market factors.[7]

In any case, the potential for increased reliance on distributed generation resources in general, and smaller diesel-powered IC engines in particular, could grow in the future if demand response programs are substantially expanded and/or if increasing numbers of large customers with on-site generating capacity opt to purchase electricity on the spot market or are otherwise exposed to real-time spot market prices. In that case, the economic incentives for switching from grid-supplied electricity to on-site generation might be substantial during some hours of the year. Our preliminary analysis indicates that wholesale electricity prices in the New England and New York power pools have risen above 8 cents per kilowatt-hour (the level above which it might be economic to switch to on-site generation) on the order of 100 to 200 hours per year in recent years. This range may increase in future years as demand catches up to the substantial new central-station generating capacity that was added in the region between 1999 and 2002. Meanwhile high prices are already occurring much more often (on the order of 500 hours per year) in transmission-constrained load pockets such as New York City.

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[7] Specifically, NOx emissions from fossil-fuel fired IC engines grew from 1.4% to 14% of New Hampshire's total ozone season NOx inventory from electric generating units between 1993 and 1999. In just the 3 years between 1996 and 1999, estimated NOx emissions from these engines more than doubled – from 243 tons in the 1996 ozone season to 576 tons in the 1999 ozone season. Moreover, the NH Department of Environmental Services was aware of at least two instances where multiple IC engines were installed to reduce electricity costs. These developments prompted NH to adopt new emissions rules for IC engines in 2001.

It is important to emphasize that the more important emissions and public health concerns related to diesel generators probably have less to do with their NOx emissions or their contribution to the overall emissions inventories typically used for traditional attainment planning purposes. Rather, short-term, highly localized impacts associated with particulate matter and toxic emissions are likely to constitute the most significant air quality and health concerns relevant to the use of these engines.

E. Emissions Control Options for Stationary Diesel Generators

As described in Chapter VI, various control technologies exist that can substantially reduce diesel engine emissions. For example, particulate emission control options include filters – which can provide 80-90% levels of control – and oxidation catalysts. The latter technology achieves more modest PM reductions (about 20%), but is also less costly. In addition, both filter and catalyst controls can provide significant (80-90%) reductions in hydrocarbon (HC) emissions, including toxic hydrocarbons, as well as carbon monoxide (CO) reductions. Selective catalytic reduction (SCR) technology has been successfully applied to large diesel engines where it can achieve NOx reductions of 80-90% or more. However, these systems are more cost-effective for large engines that operate frequently. Less costly NOx control strategies include injection timing adjustments; these generally provide more modest reductions (on the order of 10-20%).

Chapter VII reviews six case studies which provide useful information on the technical feasibility and cost effectiveness of various diesel engine emission control options. Four of the case studies examine the use of particulate filters, one analyzes the combined application of particulate filters and SCR, and one describes an installation that employed oxidation catalysts. Based on the case studies, the capital cost of a filter system ranges from about $45,000 to about $120,000. The sole diesel oxidation catalyst installation, by contrast, had a more modest capital cost of $25,000. The capital cost of the SCR installation was estimated to be just under $180,000. It should be cautioned, however, that all the case study installations involved generally large engines (in the range of 1,000-3,000 hp, approximately equivalent to 750-2,250 kW). Hence, the applicability of these cost estimates to smaller engines may be somewhat uncertain.

The chief issue for emissions control of diesel IC generators, particularly in the case of smaller engines, is one of cost and cost-effectiveness, rather than technical feasibility. If an engine runs for only a few tens of hours in a year, a given control technology will likely remove only relatively small amounts of emissions (say, compared to a central-station power plant) for a given capital cost. Not surprisingly, data from the case studies indicate that cost effectiveness – as measured by the conventional metric of tons removed per dollar of control cost – improves as operating hours increase. At 500 hours per year of operation, control costs for the filter and catalyst installations in the case studies range from $2,000-$90,000 per combined ton of PM, CO and HC reductions; at 2,000 hours per year, the costs fall to $1,000-$23,000 per ton. For the SCR case study, estimated control costs were just under $8,000 per ton of NOx removed. Cost-effectiveness also varies with the size of the engine involved.

In this context, innovative regulatory approaches can provide attractive alternatives to mandating costly retrofit controls. For example, New Hampshire has introduced a program of emissions fees for small diesel generators. Fees are imposed per ton of NOx generated and are scheduled to increase over time. Similar incentive programs could be used to promote less polluting engines elsewhere, with resulting revenues applied to research, development and demonstration and to support available cleaner technologies. Another option would be to require distributed generators to obtain pollution allowances, especially where emissions budget and trading programs already exist.

Finally, new federal standards recently introduced for non-road diesel engines used in farming, construction and industrial activities are relevant to the future regulation of stationary engines. The standards require substantial reductions in NOx and PM emissions; in addition, they establish fuel content requirements (i.e. sulfur limits) in recognition of the fact that many advanced control technologies require low-sulfur fuel. Importantly, low-sulfur fuel will provide immediate emissions reductions in the existing engine fleet, in addition to any reductions that are gradually achieved by the introduction of new engine models. Meanwhile, efforts are also underway to develop and apply retrofit emissions control technologies for existing on-road and non-road engines, many of which are likely to be similarly applicable to existing stationary diesel generators.

F. Current State, Regional and National Policy Initiatives Related to Diesel IC Generators

A number of policy initiatives aimed at regulating diesel generators specifically and promoting cleaner distributed generation alternatives more broadly have recently been undertaken at the state, regional, and national levels. At the state level, several states – notably Texas and California – have recently adopted more stringent emissions standards for stationary diesel generators. Similarly, several Northeast states are currently in the process of reviewing and updating their standards and/or permitting requirements; while others plan to do so in the near future. At the regional and national levels, the Ozone Transport Commission (OTC) and the Regulatory Assistance Project (RAP) have recently developed model rules for the regulation of diesel and other distributed generators. The OTC model rule recommends fuel-specific NOx standards for all non-emergency natural gas and diesel engines and suggests a number of operational and record-keeping requirements or restrictions for emergency engines. By contrast, the RAP model rule is aimed at new engines only and recommends the phased introduction of progressively more stringent output-based, fuel-independent emissions standards for several pollutants. Table ES-9 summarizes the specific recommendations in the RAP and OTC model rule, as well as new requirements adopted in Texas and California.

Table ES-9
Summary of Recommended/Adopted Distributed Generation Emissions Standards

	Emission Limits (lb/MWh)					
Regulation	**NOx (Ozone Attainment Areas)**	**NOx (Ozone Non-Attainment Areas)**	**CO**	**VOCs**	**PM**	**CO_2**
OTC Model Rule[a] - new and in use engines (emissions factors converted from g/bhp-hr)						
Natural Gas (except emergency)	4.4	4.4				
Diesel (except emergency)	6.8	6.8				
RAP Model Rule - new engines						
After January 1, 2004	4	0.6	10		0.7	1900
After January 1, 2008	1.5	0.3	2		0.07	1900
After January 1, 2012	0.15	0.15	1		0.03	1650
California Air Resources Board						
Distributed Generation Certification Rule for New Non-Emergency Engines						
After January 1, 2003	0.5	0.5	6	1	fuel req.[b]	
After January 1, 2007	0.07	0.07	0.1	0.02	fuel req.[b]	
Airborne Toxics Control Measure for New and In-Use Stationary IC Engines (DRAFT 6/5/03)						
New diesel engines > 50 hp				(converted from g/bhp-hr)		
Baseload power	off-road standards apply[c]				0.03	
Emergency power	off-road standards apply[c]				0.44[d]	
Exisiting diesel engines > 50 hp						
Baseload power	NOx, CO and VOCs not to increase > 10% to meet PM limits[e]				0.03[f]	
Emergency power	NOx, CO and VOCs not to increase > 10% to meet PM limits[e]				1.48[d]	
Texas - new engines						
Before January 1, 2005						
less than 300 hrs/yr	21	1.65				
more than 300 hrs/yr	3.11	0.47				
After January 1, 2005						
less than 300 hrs/yr	21	0.47				
more than 300 hrs/yr	3.11	0.14				

[a] The OTC Model Rule offers three compliance options: 1) meet the NOx emission limit specified above, 2) meet a percentage reduction of NOx emissions specific to the type of engine, and 3) purchase of NOx allowances.
[b] PM emission limit corresponding to natural gas with fuel sulfur content of no more than 1 grain/100 standard cubic foot.
[c] Engine must meet model year off-road compression-ignition engine standards, or Tier 1 off-road certification standards.
[d] Allowable hours of operation increase as the emissions factor of an engine decreases.
[e] Many engines may require control technology to meet the PM limits set in this rule, and these technologies must not increase the emisisons of NOx, CO or VOC by more than 10%.
[f] Engines can meet this standard or reduce PM emissions by 85%.

Another recent regional initiative that is addressing issues relating to diesel generators is the New England Demand Response Initiative (NEDRI), a multi-stakeholder process aimed at developing policy recommendations to promote demand response more broadly in New England. State air agency officials have been participating actively in NEDRI, which has already endorsed a number of specific policies aimed at ensuring that on-site generators participating in future New England demand response programs have appropriate permits and provide information to the ISO and state regulators. These new information collection and record-keeping practices should help address current data gaps and provide state and federal authorities with a better foundation for estimating emissions impacts of demand response programs and developing future policies related to the regulation of distributed generators.

G. Policy Recommendations

This report closes with a number of policy recommendations for states to consider concerning the future use and regulation of diesel IC engines used to generate electricity. The recommendations are divided into three categories: (1) updating emissions standards and air permitting requirements; (2) regulating use of diesel generators in demand response programs; and (3) improving regional coordination and data collection. Specific policy recommendations are summarized in Table ES-10, below.

Table ES-10
Summary of NESCAUM Recommendations

Updating Emissions Standards & Permitting Requirements	• Review adequacy of current permitting size thresholds and requirements, especially in light of new health concerns associated with localized exposure to diesel exhaust. • Update requirements for existing peak, baseload and emergency generators accordingly, especially for those units eligible to participate in ISO or utility-sponsored demand response programs. • Consider additional fuel requirements (e.g. use of low or ultra-low sulfur fuel) for diesel generators, especially for operation in demand response or other non-emergency applications. • Adopt stringent output-based emissions standards for new distributed generators, which – in the case of combined heat and power systems – appropriately account for useful thermal, as well as electrical output.
Regulating Use of Diesel Generators in Demand Response Programs	• Limit participation in *non*-emergency economic (price-driven) demand response programs to generators that meet minimum emissions control requirements (e.g. BACT-level controls, RAP model rule, etc.) • Limit participation of emergency generators to *emergency* demand response programs, subject to additional requirements as deemed appropriate under recommendations above. • Clarify regionally consistent definition of “emergency”. • Consider appropriateness of restrictions and/or additional emissions control or operating requirements (e.g. fuel sulfur requirements) for diesel generators participating in demand response programs. • Continue implementing NEDRI recommendations concerning the obligation of demand response participants to verify permit status and provide unit specific information, together with the ISO’s obligation to provide detailed information about program outcomes on a regular basis. The information provided must be specific enough to allow regulators to make a reliable assessment of associated environmental and public health impacts.
Improving Regional Coordination and Data Collection	• Promote more regional consistency in permitting requirements and emissions standards for new and existing distributed generators. • Promote more regional consistency in state record-keeping practices, with the aim of eventually developing integrated, user-friendly information databases. • Continue to develop and refine inventories of generator population and potential emissions impacts. Promote regional consistency in related policies (e.g. interconnection standards, pricing policies, other air regulatory programs, etc.)

I. Introduction

Stationary diesel internal combustion engines constitute a largely unseen, but significant component of the nation's electricity generating infrastructure. Estimates of installed diesel generator capacity in the United States range as high as 350,000 units totaling more than 127 gigawatts (GW).[1] That compares to more than 5,000 central station power plants with a combined generating capacity of more than 850 GW.[2] Although the combined generating capacity of these stationary diesel engines is significant, the vast majority – especially of the small engines – are used primarily or exclusively to provide back-up power in emergency (i.e. outage) situations and in some cases to reduce consumption of grid-supplied electricity during periods of peak demand. Consequently, most small diesel generators run relatively infrequently and provide only limited amounts of power. As a result, they have generally not been subject to the kinds of environmental regulation applicable to large central station power plants.

Despite their small size and typically infrequent operation, small diesel generators and other distributed resources play an important role in the nation's electric power system – from a reliability standpoint and because they provide some customers with the ability to quickly reduce their demand for grid-supplied electricity. In fact, the emergence of new concerns about electric system reliability and excessive price volatility – particularly since the 2000-2001 California energy crisis – has prompted new interest in all forms of distributed generation. Increased reliance on these resources, it is hoped, can reduce capacity requirements for central station generators as well as transmission and distribution infrastructure needs, while improving the competitiveness and stability of electric markets by allowing a more robust demand response capability to develop on the customer side. Indeed, the Federal Energy Regulatory Commission (FERC) recently articulated its interest in promoting demand response capabilities generally in the context of its proposed Standard Market Design rulemaking:

> Allowing demand response infrastructure to satisfy the [resource adequacy] requirement removes bias toward exclusive reliance on new generation to meet regional needs. Better demand response to high prices when a shortage condition approaches will lower demand and reduce the use of high-cost power resources. Demand response will help ensure reliability, prevent a shortage that could produce a curtailment, act as a check against market power, and provide a yardstick for the value that buyers place on supply.[3]

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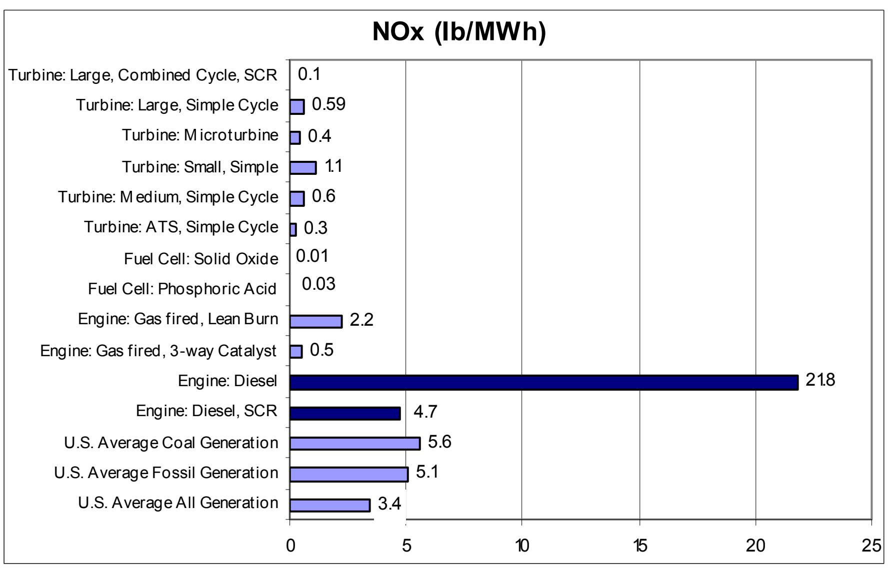
[1] National diesel generator population estimate from Natural Resources Defense Council (NRDC) report *Distributed Resources and Their Emissions: Modeling the Impacts*, Greene, Hammerschlag, and Keith, 2001. These figures were provided to NRDC by Power Systems Research (see Footnote 6).

[2] National power plant capacity information from EIA's *Annual Energy Review,* 2001. Electricity Table 8.7a "Electric Net Summer Capacity: Total 1949-2001." http://www.eia.doe.gov/emeu/aer/elect.html

[3] Though the passage cited refers to "demand response" generally, FERC indicates elsewhere in the Standard Market Design Notice of Proposed Rulemaking that customer-sited distributed generation can be viewed as part of demand response, stating for example that: "Distributed generation that is interconnected with a customer, a load-serving entity, or an energy services company, although it is technically generation and not demand response, can also be used by a local distributor to reduce the demand that the distribution

While increased reliance on distributed generation resources during peak demand periods can provide obvious benefits in terms of enhancing system reliability and dampening price volatility and market power opportunities, it raises significant policy concerns from an environmental standpoint. At present, diesel internal combustion (IC) engines account for the vast majority of installed distributed generation capacity. When they are operated, these engines typically emit very high levels of pollutants such as particulate matter (PM) and nitrogen oxides (NOx), as well as toxic compounds. In fact, per unit of electricity generated, diesel IC engines emit far more pollution than other distributed generation technologies (e.g. fuel cells, microturbines, etc.) and far more pollution than most central station power plants. Figures I-1 and I-2 show emissions rates for a new, uncontrolled diesel IC engine relative to other generation options. Figure I-1 indicates that NOx emissions rates per megawatt-hour of electricity generated by a new diesel IC engine are up to 200 times higher than for a combined cycle natural gas turbine, the technology of choice for most recent new investments in central-station generator capacity. The fact that distributed generators are typically located in or nearer to populated areas than large power plants, and the fact that their emissions are typically vented not through tall smokestacks, but rather closer to ground level, further amplifies the public health concerns associated with their use. Finally, such generators are most likely to be operated during periods of peak electricity demand and high prices, which in many parts of the country typically occur on summer days when urban air quality tends to be especially poor.

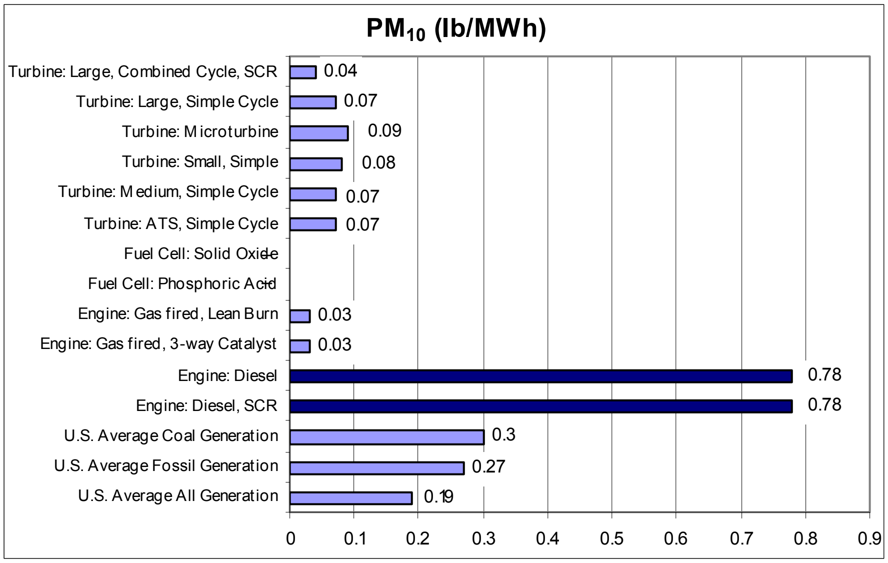
Figure I-1
NOx Emissions Factors of Diesel Engines Relative to Other Types of Generation[4]



system places on the grid." The text of the FERC notice is available at: http://www.ferc.gov/Electric/rto/Mrkt-Strct-comments/discussion_paper.htm.

[4] These emissions rates are typical of new units, and do not apply to older existing units. For this reason the NOx and PM_{10} emissions factors presented here are smaller than the emissions factors used later in the report, and smaller than the likely average emissions from the existing population of diesel generators. Figures I-1 and I-2 are from Joel Bluestein, *Emission Rates for New DG Technologies*, May 2001 and are available at: http://www.raponline.org/ProjDocs/DREmsRul/Collfile/DGEmissionsMay2001.pdf.

Figure I-2
PM_{10} Emissions Factors of Diesel Engines Relative to Other Types of Generation[4]



State and federal regulators recognize that existing environmental policies will need to be updated or augmented to ensure that a new generation of cleaner distributed technologies becomes available in the future and to manage any adverse impacts from the existing generator population in the transition, especially if market conditions and/or government policies prompt increased reliance on this population in the near-term. Unfortunately, the situation is complicated by a shortage of reliable information on the current population of small, distributed generators. Many existing engines fall below current state permitting thresholds and/or are permitted for emergency use only. In addition, there are undoubtedly some units unknown to state authorities that should be permitted but currently are not. As a result, regulators have had difficulty assessing the potential air quality impacts of increased use of these resources. Uncertainty about the existing capacity base of distributed generation also complicates efforts to weigh the costs and regulatory trade-offs associated with introducing new emissions control or permitting requirements.

This study aims to begin addressing the current information shortfall, at least in the Northeast, by developing a more complete inventory of the numbers and types of diesel IC engines that exist in the eight-state NESCAUM region.[5] Two sources of information were used to develop the inventory: (1) estimates generated by Power Systems Research[6] (PSR), a private consultant, using a methodology based on national sales and survey information combined with census information on numbers and types of business establishments, and (2) state permitting records. Additional information was gathered using telephone surveys (also conducted by PSR) for two areas in the Northeast (New

5 Specifically, the states of Connecticut, Maine, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island and Vermont. All of these states are members of NESCAUM.
6 Power Systems Research (PSR) is a market research company for the engine industry.

York City and Fairfield County, Connecticut) where there has been a recent emphasis on distributed generation because of transmission constraints.

Chapter II provides background and context for these results, including a discussion of current applications of diesel IC engines in the Northeast and a review of current state permitting requirements. The results of the inventory analysis and the additional telephone surveys conducted in New York City and Fairfield County are detailed in Chapters III and IV of this study. Chapter V presents some estimates of emissions impacts from the operation of diesel IC engines in the Northeast and summarizes information available from the New England Independent System Operator on the actual operation of distributed generators as part of its summer 2001 and 2002 demand response programs. Chapters VI and VII, prepared by ESI International, Inc., review available emission control technologies for IC engines and present six case studies involving the application of these technologies. Finally, Chapter VIII describes current state and federal activities related to the use and regulation of distributed resources (including stationary diesel IC engines) and provides some initial policy recommendations.

II. Background and Context

A. Current Role of Electricity-Generating Diesel Engines in the Northeast

Electricity-generating diesel IC engines can be found at many medium to large commercial and industrial facilities throughout the Northeast and elsewhere. Often, these engines are installed to provide emergency power and lighting in outage situations and to enhance reliability and power quality for sensitive computer and telecommunication systems. In some cases, on-site generators may be used more routinely to curtail demand for grid-supplied power during peak electricity use hours (also known as "peak-shaving"). Incentives for peak shaving may exist where customers are exposed to real-time electricity prices (which are typically highest during peak demand periods), where customers have explicitly agreed to curtail their demand for system power when called by the utility or system operator (usually in exchange for lower rates and/or incentive payments), or where customers are in a position to avoid or reduce utility demand charges, which are typically set according to peak usage.

As indicated in the Introduction to this report, emerging concerns about system reliability and price volatility in deregulated electricity markets have prompted interest in making greater use of distributed generation capacity. In the long run, this capacity is likely to include a growing contribution from fuel cells, microturbines, renewable power and other advanced distributed generation technologies. In the short term, however, diesel IC engines are likely to remain by far the most ubiquitous distributed generation technology available. According to the Power Systems Research (PSR) estimates described in later chapters, the population of diesel IC generators already in place in the Northeast states may number well over 30,000 units with a combined capacity in excess of 10 GW.[7] Of these engines, the great majority (80%) is estimated to be installed for emergency use; the remaining 19% is operated for peak-shaving purposes, and the last 1% is intended for baseload operation. Engines designated for emergency use only are generally limited by state regulations to operate only during bona-fide "emergency" (i.e. outage or imminent outage) situations and for a specified maximum number of hours of operation per year (a typical figure is 500 hours). Given the infrequency of actual outage events in recent years, most of these engines should have operated well below state-imposed limits – in many cases less than the 50 hours or so of annual operation required for maintenance and testing. Depending on permit limits and market conditions, peak shaving engines – by contrast – may operate considerably more hours per year (typically anywhere from 200 to 700 hours, annually). Because electricity demand peaks in the Northeast on hot summer days, this is the time when all types of small engines are most likely to operate, whether for emergency "back-up" purposes or in response to high grid prices and/or supply shortfalls.

[7] By comparison, total grid-connected generating capacity totaled some 86 GW in 2000 for the NESCAUM region (capacity data from EIA: http://www.eia.doe.gov/cneaf/electricity/ipp/ipp_sum.html and http://www.eia.doe.gov/cneaf/electricity/ipp/ipp_sum2.html).

At present, both the New York and New England Independent System Operators (ISOs) have introduced formal programs aimed at improving system reliability.[8] These programs enlist customers to lower their demand for grid-supplied electricity at times of high prices and/or when demand threatens to overwhelm system capacity. Customers can reduce demand by curtailing load (e.g. shutting down equipment), increasing on-site generation or some combination of both. Under the ISO programs introduced to date, customers can receive incentives, including capacity payments, for being available to reduce load on short notice. Subject to certain conditions, some customers may also be eligible to bid their demand resources into day-ahead wholesale electricity markets in the same way that generation owners bid in supply resources.[9] Because participants in these programs must be registered with the ISO, it is generally possible to collect some information on individual on-site generators operated as part of the customer's demand response capability.[10] In the future, however, other types of customer-initiated demand response may be more difficult to monitor. For example, customers (particularly larger commercial and industrial customers) that opt to purchase electricity based on real-time spot market prices might face significant incentives to reduce their consumption of grid-supplied electricity during high price periods, even without participating in an ISO or utility-sponsored program. If reducing demand in these instances involved the utilization of on-site generators, neither the ISO nor state regulators would necessarily be aware of it.

The policy issues associated with a potentially significant increase in the use of distributed generators are explored in more detail in Chapter VIII of this report, following a discussion of population estimates, survey results, potential emissions impacts, control technologies and case studies in Chapters III, IV, V, VI and VII, respectively. To provide context for the information presented in these chapters, it is useful to begin by reviewing current state permitting requirements and regulations as they pertain to the use of power-generating diesel IC engines in the Northeast states.

[8] Note that New Jersey, the southern-most NESCAUM state, is served by PJM which is the regional transmission organization that coordinates the wholesale electricity market for all or parts of Delaware, Maryland, New Jersey, Pennsylvania, Virginia, West Virginia and the District of Columbia. The acronym 'PJM' comes from the original Pennsylvania-New Jersey-Maryland power pool. PJM is the largest of the three ISOs serving northeastern states and is scheduled to become even larger in the future as additional areas to the south and west become members.

[9] Generally, Northeast states have prohibited engines permitted for emergency use from participating in ISO-sponsored demand response programs. In particularly transmission-constrained areas such as southwest Connecticut and New York City, emergency generators have been allowed to operate – subject to certain limitations – in the ISO's emergency response programs, which are designed to avert imminent shortfalls and are called only when the system is strained to the point of necessitating voltage reductions. So far, emergency generators have generally not been eligible to participate in purely economic or so-called "price-response" programs which are triggered by high prices, rather than capacity shortfalls. See further discussion in Chapters V and VIII.

[10] In fact, a recent recommendation of the New England Demand Response Initiative described in Chapter VIII involves information collection requirements, both for participants in ISO-sponsored demand response programs and on the part of the ISO managing these programs.

B. Summary of Current State Permitting Requirements for Diesel IC Engines

Distributed generators, and stationary internal combustion engines in general, are for the most part regulated and permitted at the state and local level. Some large engines fall under federal regulations, which include the New Source Review (NSR) program for permitting sources before construction, and the Title V program for permitting sources in operation. These engines are generally far larger than any considered in this report. The NSR program includes a major and minor source component. The minor source component is applied in some states to non-emergency engines that have the potential to exceed certain pollution thresholds (applicable thresholds are lower for ozone non-attainment areas). Because there are no federal requirements for many smaller engines, states over the years have generally developed their own permitting requirements for this class of emissions sources.

Table II-1 summarizes the different permitting requirements applicable to electricity generating engines in the eight NESCAUM states. As indicated by Table II-1, most states make a distinction between emergency and non-emergency engines. Emergency engines are often exempt from emissions limits or control technology standards, however their operation is strictly limited to certain situations and maximum numbers of hours. In many states, owners of emergency engines need not obtain individual permits but can avail themselves of a permit-by-rule option which authorizes operation provided the owner complies with a prescribed set of restrictions and requirements – typically concerning maximum rated heat input, fuel type, fuel consumption and record keeping. By contrast, non-emergency engines are generally regulated down to smaller sizes and under more stringent emissions control requirements.

Though most state permitting programs share several common features, the specific requirements and permitting thresholds applicable to distributed generators vary widely from state to state. Many states regulate engines on the basis of fuel input or heat rate (e.g. million British thermal units per hour: MMBtu/hr); others use engine power output (e.g. horsepower, brake horsepower or kilowatt) to determine the applicability of different regulatory requirements. Converting heat input to power output is straightforward, provided the efficiency of the engine is known. Throughout this report, the generic efficiency assumed for stationary generator engines is 33%.[11] This assumption yields the following conversion factors:

1 MMBtu/hr = 100 kW = 0.1 MW = 134 hp

[11] Engine efficiency is measured as the ratio of useful energy output to fuel energy input. In the case of an electric generator, an efficiency of 33% indicates that one-third of the energy content of the input fuel is converted to electrical power, while the remaining two-thirds is lost (usually in the form of waste heat). Combined heat and power systems can achieve much higher efficiencies because they capture this otherwise wasted heat to supply useful thermal energy (typically in the form of steam) as well as electricity.

Table II-1
Summary of State Permitting Requirements for Distributed Generators

State	Non-Emergency Engines[a]		Emergency Engines		
	Threshold	Requirements[b]	Threshold	Restrictions	Demand Response[d]
CT	PTE 15 TPY[c] of any criteria pollutant	BACT, LAER based on emissions	CT: permit-by-rule SW CT: 50 hp (37 kW)	500 hrs/yr and maximum of 5 TPY NOx, 5 TPY CO, 3 TPY PM, and 3 TPY SO2	no PRP; EDRP in SW CT for add'l 300 hrs/yr, only nat. gas or ULSD[e]
ME	5 MMBtu/hr (approx. 500 kW), 0.5 MMBtu/hr if at major source	SCR over 20 TPY NOx, BACT case-by-case, on-road diesel	0.5 MMBtu/hr (approximately 50 kW)	500 hrs/yr	no additional restrictions
MA	3 MMBtu/hr (approx. 300 kW), smaller if at facility with other permitted engines	case-by-case BACT	3 MMBtu/hr permit-by-rule, over 10 MMBtu/hr case-by-case BACT	300 hrs/yr, cannot create a "condition of air pollution," must have a noise muffler	no PRP; may run once ISO has called for voltage reductions (OP-4 step 12 or 14)
NH	1.5 MMBtu/hr (150 kW) diesel, 10 MMBtu/hr (1 MW) natural gas, PTE 25 TPY[c] NOx	over 400 kW may require RACT	no threshold	500 hrs/yr, limit sulfur content of diesel, and limit emissions	neither type of DR for emergency engines
NJ	1 MMBtu/hr (approximately 100 kW)	BACT for new/modified; existing diesel engines require 8g/bhp-hr NOx (being revised to 2.3 g/bhp-hr)	1 MMBtu/hr (approximately 100 kW)	no control if PTE NOx is less than 25 TPY	neither type of DR for emergency engines
NY	NY: 300 kW, 160 kW if non-att., NYC: 280 kW, 33 kW if diesel	diesel engines are not allowed to participate in PRP[d]	NY: no threshold, NYC: over 280 kW must register	NY: 500 hrs/yr, no permits, NYC: register but no restrictions	no PRP; EDRP less than 200 hrs/yr, 30 ppm sulfur diesel fuel required
RI	500 kW diesel, 1 MW natural gas	BACT based on emissions	no threshold	500 hrs/yr, 0.3% sulfur diesel fuel	neither type of DR for emergency engines
VT	450 hp (337 kW)	must meet EPA's non-road standards	no threshold	200 hrs/yr	neither type of DR for emergency engines

[a] non-emergency engines are not restricted from participating in demand response programs, except as noted in NY

[b] abbreviations: BACT=Best Available Control Technology; MACT=Maximum Achievable Control Technology; RACT= Reasonably Available Control Technology; LAER=Lowest Achievable Emission Rate; SCR=Selective Catalytic Reduction; SOTA=State of the Art

[c] PTE=potential to emit, and TPY=tons per year

[d] demand response (DR) programs include the emergency demand response program (EDRP) which is called by the ISO in the event of an imminent capacity shortfall, and the price response program (PRP) in which customers respond to high prices

[e] ultra-low sulfur diesel fuel

1. <u>Connecticut</u>

Connecticut's permitting program currently provides four tracks for regulating IC engines. The first track involves the application of NSR minor source requirements to individual units. Prior to December 1989, NSR applied to any combustion source with fuel input greater than or equal to 5 MMBtu/hr heat input, approximately 500 kW output, or a potential to emit in excess of 8 tons per year of any criteria air pollutant. After 1989, NSR applicability thresholds were lowered to include any source with the potential to emit 5 tons per year or more of any criteria pollutant. Due to the large number of small engines being reviewed, changes were made to the NSR requirements in 2002. Currently, a new or modified engine with the potential to emit 15 tons per year or more of any air pollutant requires an individual permit. Engines permitted under NSR are subject to Best

Available Control Technology (BACT) and Lowest Achievable Emission Rate (LAER) requirements as necessary, based on emissions. There may also be "grandfathered" sources that are registered but unrestricted.

A second compliance option, introduced in 1996, allows emergency engines to register with the state under a General Permit for an Emergency Engine (GPEE). This general permit limits annual operation of emergency units to a maximum of 500 hours each year and limits combined emissions of nitrogen oxides (NOx), particulate matter (PM) and carbon monoxide (CO) to a maximum of 5 tons per year, among other restrictions. In 2002, Connecticut introduced a third compliance option known as the General Permit for Distributed Generation (GPDG). This option is geographically restricted to engines over 50 hp (37 kW) located in the 51 towns that comprise the southwest Connecticut "load pocket" and it expires at the end of 2003. The GPDG allows engines to operate when called upon by the ISO under the emergency demand response program for a maximum of 300 hours per year, provided they run on natural gas or ultra-low sulfur diesel fuel.[12] A final compliance option, also introduced in March 2002, is Connecticut's permit-by-rule exemption, which allows emergency engines to operate subject to certain restrictions on maximum rated heat input, fuel type and fuel consumption. In addition, the exemption requires the owner of the engine to be responsible for record keeping. Connecticut's permit-by-rule exemption does not allow for the operation of emergency engines in any type of demand response program. In order for an emergency engine to participate in ISO New England's emergency demand response program, the engine must be permitted under the GPDG (and thus be located in southwest CT). Engines permitted for non-emergency use in Connecticut are allowed to participate in both price response and emergency demand response programs, regardless of location.

2. Maine

In Maine, owners of engines with heat input greater than 5 MMBtu/hr (approximately 500 kW output) must obtain a permit. Permits are also required for smaller engines (down to a heat rate input of 0.5 MMBtu/hr, or approximately 50 kW) if they are located at a facility with a combined heat input of 5 MMBtu/hr or more. Finally, facilities with operation-specific air permits must obtain permits for any on-site engines larger than 0.5 MMBtu/hr. Non-emergency engines are required to use on-road diesel fuel and are required to install selective catalytic reduction (SCR) technology for NOx control if their potential annual NOx emissions exceed 20 tons. Emergency engines larger than 0.5 MMBtu/hr require a permit, and are restricted to no more than 500 hours of operation each year. There are no additional restrictions preventing engines from participating in demand response programs.

[12] In the emergency demand response program, the NE-ISO can call on participating distributed generators to help avert an imminent power shortage. Generally, the ISO must have called for an actual system voltage reduction before emergency units are eligible to respond under this type of program. By contrast, under a price response program, distributed generators can operate whenever prices are high, even if a power shortage is not necessarily imminent. Since high price periods occur more frequently than voltage reduction/imminent shortfall situations, which in turn occur more frequently than actual emergency (i.e. black-out) situations, generators can be expected to operate with varying degrees of frequency depending on their eligibility to participate in these different types of programs.

3. Massachusetts

In Massachusetts, permits or "plan approval" must be obtained for all engines (including emergency engines) with heat input greater than 10 MMBtu/hr (approximately 1 MW output). A lower permitting threshold of 3 MMBtu/hr (approximately 300 kW) applies to any engines intended for use in non-emergency situations. Facilities with a combined heat input greater than 10 MMBtu/hr must file a statement of emissions at least every three years. Permits for non-emergency engines are reviewed on a case-by-case basis and generally require BACT-level emissions controls. Emergency engines between 3 and 10 MMBtu/hr heat input may operate under permit-by-rule, but are restricted for use only during emergencies and for a total of no more than 300 hours per year. The Massachusetts Department of Environmental Protection (MA DEP) has recently indicated that emergency generators may be allowed to operate to avert imminent outage, but only *after* the ISO has called for voltage reductions (i.e. corresponding to Step 12 or 14 of ISO-NE's Operating Procedure 4).[13] Emergency engines in Massachusetts are prohibited from operating in price response programs.

4. New Hampshire

Engines powered by liquid fuel (i.e. diesel) require a permit in New Hampshire if they have a heat rate input of 1.5 MMBtu/hr (approximately 150 kW output) or greater. A higher size threshold of 10 MMBtu/hr (1 MW output) applies to engines that operate on gaseous fuel. Additionally, any type of engine requires a permit if it emits more than 25 tons per year of NOx. Non-emergency engines larger than 550 hp (approximately 400 kW) may be required to implement Reasonably Available Control Technology (RACT). Emergency engines can obtain a general permit for emergency exemption, which limits operation to a maximum of 500 hours per year, requires use of low-sulfur fuel and restricts total emissions. Engines with an emergency exemption may operate only in bona fide emergency situations (i.e. they cannot participate in emergency demand response or price response programs).

5. New Jersey

In New Jersey, all new or modified engines with a heat rate input greater than 1 MMBtu/hr (equivalent to about 100 kW output) require a permit. In addition, any new or modified engine with the potential to emit more than 5 tons per year of any criteria pollutants must meet "state of the art" (SOTA) control technology requirements. The recently published (May 2003) applicable SOTA performance standards for new or modified engines are 0.15 g/bhp-hr for NOx, 0.5 g/bhp-hr for CO and 0.15 g/bhp-hr for volatile organic compounds (VOC). In addition, ammonia slip is limited to 10 ppmvd @ 15% O_2. For liquid fuel firing, the particulate limit is 0.02 g/bhp-hr and the sulfur limit is 30 ppm. Meanwhile, existing engines larger than 500 bhp (approximately 375 kW) must also comply with minimum emissions performance requirements, specifically: (1) a rich

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[13] Letter of James C. Colman, Assistant Commissioner, Bureau of Waste Prevention, MA DEP to Steve Whitley, Chief Operating Officer, ISO-NE (May 28, 2002).

burn NOx emissions limit of 1.5 g/bhp-hr and a lean burn NOx emissions limit of 2.5 g/bhp-hr for gaseous fuels; (2) a NOx emissions limit of 8.0 g/bhp-hr for liquid fuels; and (3) a CO emissions limit (on all engines) of 500 ppmvd at 15% O_2. Emergency engines are exempt from NOx control requirements provided they operate no more than 500 hours per year and only during actual emergencies or for maintenance purposes; and provided their potential to emit NOx is below 25 tons per year.

6. New York

The New York State Department of Environmental Conservation (NY DEC) has established a permitting threshold for IC engines in ozone attainment areas of 400 bhp (approximately 300 kW). In ozone non-attainment areas (New York City, Long Island, and the lower Hudson Valley) a lower permitting threshold of 225 bhp (160 kW) applies. Emergency generators are exempt from permit requirements but are limited to a maximum of 500 hours per year of operation and may operate only when usual sources of heat and power are not available and during fire emergencies. To verify compliance, emergency generators are required to maintain records of operation on-site for five years. Emergency diesel generators may participate in the emergency demand response program called by the ISO to avert outage situations, but must use 30 ppm ultra-low sulfur fuel and are restricted to operating a maximum of 200 hours per year in the program (as part of their overall operational limit of 500 hours per year). Finally, the state of New York has banned all emergency generators and all diesel generators from participating in the price response program.

NY DEC issues three types of permits: (1) "Registration certificates" with a "cap-by-rule" which restricts actual NOx emissions in ozone non-attainment areas to no more than 12.5 tons per year and NOx emissions in other areas to no more than 50 tons per year; (2) state facility permits for facilities that do not qualify for a registration certificate, but whose potential to emit is lower than the threshold for Title V permits; and (3) Title V permits, if the potential to emit is higher than Title V thresholds.[14] Additional permitting requirements are enforced by the New York City Department of Environmental Protection (as distinct from the NY State DEC) for units located in New York City. In New York City, all diesel engines over 33 kW must – at a minimum – be registered. Engines over 2.8 MMBtu/hr (280 kW) must obtain a work permit unless they are emergency engines, in which case they must simply register. Emergency engines are not restricted in terms of the number of hours they may operate <u>in emergency situations</u>. In addition, they may participate in *emergency* demand response programs, but may not be used for peak or baseload generation and must comply with state regulations.

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[14] Title V permits are issued under the 1990 Clean Air Act Amendments to all existing major sources (as distinct from new or modified sources, which are regulated under NSR). The emissions thresholds required to classify a source as "major" depend on the attainment status of the area for different pollutants. For areas in attainment, the major source threshold is usually a PTE of 100 TPY; in moderate non-attainment areas, the threshold is lower at a PTE of 50 TPY, and in severe non-attainment areas the threshold is a PTE of 25 TPY. Note that the lower thresholds for non-attainment areas apply only to those pollutants (or their precursors) for which the area is in non-attainment.

7. Rhode Island

Diesel engines in Rhode Island must obtain a pre-construction permit if their heat input is greater than 5 MMBtu/hr (approximately 500 kW). If operating on natural gas, an engine over 10 MMBtu (approximately 1 MW) requires a permit. Additionally, smaller engines (down to a size threshold of 1 MMBtu/hr or 100 kW) must be included in facility operating permits if located at a major source facility. Engines for emergency use are allowed to operate for no more than 500 hours per year and only during power outages. In addition, diesel fuel used to operate an emergency engine in Rhode Island must have sulfur content no higher than 0.3%.

8. Vermont

The permitting threshold for generator engines in Vermont is 450 bhp (337 kW). Engines above this size threshold that were installed after June 1999 must meet emissions standards comparable to federal requirements for non-road sources. Engines larger than 200 bhp (150 kW) that are located at an otherwise permitted facility must be covered by amendments to the permit. Emergency engines can operate a maximum of 200 hours per year, during emergency situations only, and are not allowed to participate in emergency demand response or price response programs.

III. Northeast States Inventory

A. Introduction

This chapter describes the results of an effort to inventory the existing population of distributed generator engines in the eight NESCAUM states. It combines information gathered from state environmental agencies with population estimates generated by Power Systems Research (PSR) using a methodology developed from engine sales data and field surveys. Together, these two sources of information provide estimates of both the permitted and the total engine population in the NESCAUM region, including the number of engines in each state, their capacity and whether they are covered by state permitting requirements. The results provide some indication of the extent to which current state permitting programs capture the population of existing generators.

This chapter begins with a description of the methodology and data sources used to compile the Northeast distributed generation inventory. Later sections summarize the results for the region as a whole and then for individual states, each of which has different permitting requirements and record-keeping practices.

B. Methodology

1. <u>PSR Population Estimates</u>

PSR developed estimates of the population of distributed generation engines in the NESCAUM region using their *Partslink* database.[15] The database uses a mathematical model, developed by PSR over the last 23 years, to estimate the number of "engine powered products" in service in the United States based on actual sales data and survey results. Key inputs to the model include: (1) a continuous record of shipments from U.S. factories that manufacture engines, as well as records of imports from foreign suppliers; (2) a record of exports from the U.S. of this type of equipment; and (3) an attrition curve for estimating the retirement of "engine powered products."

To translate data on the number of engines sold into an estimate of engines currently in use, a number of assumptions must be made about equipment turnover or attrition, taking into account factors such as the average life of an engine, hours of use each year and typical load factors for different engine applications. PSR continually checks and updates benchmarks for these characteristics by conducting surveys of equipment owners. PSR surveys 100 owners for each engine model and application each year to obtain information on the age and application of the equipment, as well as cumulative lifetime hours of operation, annual hours of operation and fuel consumption. Information on average total hours of operation for different models (and at different load factors) is typically available from engine manufacturers and other sources, but fuel use – which is

[15] A more detailed description of the methodology, provided by PSR, is included as Appendix A.

directly related to load factor – can be used as an alternate indicator to verify these assumptions. Data on engine characteristics, such as horsepower, speed, cylinders, weight and displacement, are then combined with the survey results to calculate a projected life span for every engine in the database. This estimated life span, expressed in horsepower-hours, is assumed to represent the statistical mean for each engine type and application and a normal distribution is used to describe all retirements.

The *Partslink* model includes detailed information on engines for many different uses. For the NESCAUM inventory, PSR provided information on stationary and portable electricity-producing generators powered by diesel and natural gas in the eight Northeast states. As noted previously, the inventory subsequently compiled by NESCAUM using PSR's estimates focuses only on stationary diesel generators because this is the population most likely to be captured in state permit records.[16] In addition, PSR provided estimates of the geographic distribution of different engine types based on profile norms that describe the probability that a certain type of business or consumer will own a specific type of equipment. The profile norms were combined with the Census Bureau's County Business Patterns (year 2000) statistics to allocate types and numbers of engines based on the distribution of businesses in each state. A spreadsheet for estimating the number of engines in any state or other geographic area by industry is provided in Appendix C of this report.

In addition to estimating numbers of engines, PSR developed estimates of the distribution of engine capacities and applications in each state. Engine applications, described in more detail in Chapter II, are divided into three categories – emergency, baseload and peak shaving – depending on typical hours of use and purpose. Emergency engines are used to power a facility or building in the event of a power outage. Absent such events, they may operate as few as 50 hours per year (for testing and maintenance). Even when emergencies occur, their cumulative operating hours are unlikely to exceed 100-150 hours per year. Baseload engines are used as a primary power source, and can run as infrequently as 700 hrs/yr to nearly full-time (up to 8760 hrs/yr). Engines used for peak shaving are defined more by their purpose than hours of use, but they generally run fewer than 700 hrs/yr. Peak shavers are usually operated at times of peak demand for grid-supplied electricity to avoid high electricity prices and/or demand charges, which are typically based on peak usage and can be quite expensive.

While PSR's estimation methodology represents one of the few sources of information available on the total population of distributed generators, it is inherently inaccurate. Because multiple assumptions are involved in generating the estimates, it is difficult to know how much confidence can be placed in the results. Comparison with state permit records (as described in the remainder of this chapter) reveals both that the discrepancies are significant and that there is no particular pattern to the variance between states' permit data and PSR's population estimates for different engine size categories. This suggests either that the PSR estimates are highly inexact, or that available state permit records are incomplete, or some combination of both.

[16] A chart showing the estimated population of natural gas generator engines in the eight NESCAUM states is included as Appendix B of this report.

2. State Permit Data

NESCAUM requested a detailed list of permitted engines from the air quality bureau of each state's environmental agency. Typically, the state lists included details such as the size of the engine (in kW capacity, heat input or brake horsepower), application, fuel, emissions and control technology. Some states were not able to provide details for each listed engine and it was sometimes necessary to extrapolate the size distribution of engines when size information was not available. The extrapolations used were different in each case, and are described in detail in the state summaries below.

For the most part, state permit data were provided electronically. For some states (primarily MA and NJ) this meant the information did not include engines permitted prior to the mid-1990s, when many states switched over to electronic record keeping. Other states have transferred all of their permits to electronic files and were able to provide information on older permits as well. For Rhode Island and Vermont, NESCAUM actually reviewed paper permits.[17] This was feasible because of the relatively smaller number of permitted engines in these two states.

For purposes of this report, NESCAUM's primary interest was diesel-powered internal combustion engines used to generate electricity. State permit records included a number of types of equipment that do not fall in this category, such as diesel engines used for primarily mechanical purposes (e.g. stone cutters, wood chippers, and snow makers), as well as small engines used as fire pumps, air compressors, and water pumps. The latter types of equipment are typically under 250 kW and are usually permitted as emergency engines subject to annual caps on hours of operation. State permit data on mechanical IC engines are summarized separately in the tables that follow, because PSR's estimates were designed to cover only electricity-generating engines. Nevertheless, both types of engines have similar level of emissions. In addition to mechanical engines, state permit records included some non-internal combustion equipment, such as gas turbines and boilers, which were also removed for purposes of comparison with PSR's population estimates.

C. Northeast Distributed Generation Inventory Results

1. NESCAUM Region Totals

Table III-1 shows the results of PSR's estimation methodology for the NESCAUM states as a region. Engine totals are sorted by size, capacity and type of application.

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[17] In the case of Rhode Island, it was necessary to review the state's paper permits to get information on engine size. In the case of Vermont, only paper permits were available.

Table III-1
PSR Estimates of Diesel Engines in the NESCAUM Region by Number and Capacity

Number Totals	Emergency	Peak	Baseload	Total		Capacity Totals (MW)	Emergency	Peak	Baseload	Total
25-50 kW	1,768	0	0	**1,768**		**25-50 kW**	59	0	0	**59**
50-100 kW	5,798	1,375	107	**7,280**		**50-100 kW**	462	114	9	**584**
100-250 kW	9,226	2,236	95	**11,557**		**100-250 kW**	1,564	371	14	**1,949**
250-500 kW	5,918	1,231	7	**7,156**		**250-500 kW**	2,126	443	3	**2,572**
500-750 kW	1,296	316	47	**1,659**		**500-750 kW**	801	196	29	**1,026**
750-1000 kW	1,164	292	51	**1,507**		**750-1000 kW**	921	230	40	**1,191**
1000-1500 kW	641	677	39	**1,357**		**1000-1500 kW**	769	837	48	**1,654**
1500+ kW	1,073	284	37	**1,394**		**1500+ kW**	2,053	615	68	**2,736**
Total	**26,884**	**6,411**	**383**	**33,678**		**Total**	**8,756**	**2,805**	**211**	**11,772**

Overall, PSR estimates that a total of 33,678 diesel IC engines, with a total of capacity of 11,772 MW, are currently installed in the eight NESCAUM states. Of this population, an estimated 80% of the engines (accounting for 74% of total capacity) are designated for emergency use.

Information on the electricity-generating IC engine population (distinct from the mechanical IC engine population) from the permit records of all eight NESCAUM states is summarized in Table III-2, below. As noted previously, state permit records differed in the amount of information and detail available. In Connecticut, Massachusetts and New Jersey, size or capacity information was available for only some of the permitted engines. In these cases, the size distribution for the subset of known engines was assumed to be representative of the total population of permitted engines. Further detail on the information available from different states is provided in the state summaries that follow.

Table III-2
Number of Electricity-Generating Engines in NESCAUM State Permit Records

	CT	ME	MA	NH	NJ	NY	RI	VT	TOTAL
25-50 kW	112	2	11	1	4	26	0	0	**156**
50-100 kW	208	78	13	2	120	93	0	9	**523**
100-250 kW	411	184	278	65	1,432	337	4	18	**2,729**
250-500 kW	321	158	156	126	1,247	410	1	17	**2,436**
500-750 kW	273	64	138	71	927	272	20	7	**1,772**
750-1000 kW	144	28	73	39	837	201	11	2	**1,335**
1000-1500 kW	153	36	160	47	698	175	11	10	**1,290**
1500+ kW	99	28	275	9	558	148	25	3	**1,145**
Total	**1,721**	**578**	**1,104**	**360**	**5,823**	**1,662**	**72**	**66**	**11,386**

Table III-3 compares PSR's total estimated population figures with the permit records available from each NESCAUM state for only the electricity-generating IC engines. With the exception of Maine, PSR estimates indicate a significantly larger engine population in place than state permit records alone would indicate. For the other states, permits are on file for anywhere from 11% to 69% of the total engine population estimated by PSR and in four of the states (MA, NY, RI, VT) the figure is below 25%. This is not surprising for several reasons. First and most obvious, is the fact that many engines in each state fall below the size thresholds of current permitting requirements, which typically range from 75 kW to 500 kW, depending on the state. While some small engines fall within "facility clauses" which require smaller engines to register if they are located at a larger facility, many others simply do not require a permit. In several states a large number of engines may also operate under emergency exemptions or permit-by-rule provisions, in which case the state would not have records for individual units. Another explanation is that some older permits still filed on paper may not have been included in the electronic records most states provided to NESCAUM. In addition, there are undoubtedly some engines that should have permits, but whose owners do not obtain them, either because they are unaware of permitting requirements or because they wish to avoid the fees, hassle or restrictions associated with obtaining a permit. Finally, the PSR estimates themselves – as indicated previously – are subject to significant uncertainties and errors in approximation.[18]

Table III-3
Comparison of PSR Estimated Generators and State Permit Records

DATA SOURCE	CT	ME	MA	NH	NJ	NY	RI	VT	Total
PSR Estimated Generators	3,223	560	5,027	743	8,415	15,037	363	310	**33,678**
Generators in State Permit Records	1,721	578	1,104	360	5,823	1,662	72	66	**11,386**
% of PSR Estimates in Permitting Records	53%	103%	22%	48%	69%	11%	20%	21%	**34%**

As indicated previously, engines used for mechanical power – wherever these were distinguishable from the general engine population – were treated distinctly in the development of this preliminary regional inventory. In particular, mechanical engines were not compared to the population estimates generated by PSR (as these estimates were designed to include only IC engines used to generate electricity) and are not included in Table III-3 above. Instead, Table III-4 below summarizes information on mechanical IC engines included in the state permit data obtained by NESCAUM for the region as a whole. These mechanical engines represent 15% of the total population of permitted engines in the region, and 12% of the total engine capacity estimated for the NESCAUM region.

[18] In fact, the discrepancy between the PSR figures and state permit records may in fact be greater than indicated by these tables, because the state totals in Table III-2 may include some non-diesel engines. In cases where a state permit did not identify fuel source, the engine was assumed to operate on diesel. This likely led to some overstatement of the numbers of diesel engines in state permit records.

Table III-4
Mechanical Engines in NESCAUM State Permit Records

	CT	ME	MA	NH	NJ	NY	RI	VT	Total
25-50 kW	5	0	0	1	0	44	0	1	**51**
50-100 kW	31	11	2	0	32	37	0	14	**127**
100-250 kW	91	51	33	12	314	43	0	31	**575**
250-500 kW	40	16	19	5	374	21	0	73	**548**
500-750 kW	16	5	12	4	97	4	11	9	**158**
750-1000 kW	7	2	2	0	0	2	0	14	**27**
1000-1500 kW	2	0	5	0	20	1	0	8	**36**
1500+ kW	13	0	12	0	34	7	3	0	**69**
Total	**205**	**85**	**85**	**22**	**871**	**159**	**14**	**150**	**1,591**

2. Connecticut Inventory

Table III-5 summarizes the engine population and size distribution estimated by PSR for the state of Connecticut. According to these estimates, over 81% of diesel engines and 76% of total engine capacity in Connecticut are designated for emergency use.

Table III-5
PSR Estimates of Diesel Engines in Connecticut by Number and Capacity

Number Totals	Emergency	Peak	Baseload	Total
25-50 kW	168	0	0	**168**
50-100 kW	555	123	2	**680**
100-250 kW	883	202	3	**1,088**
250-500 kW	563	118	0	**681**
500-750 kW	127	28	1	**156**
750-1000 kW	112	27	3	**142**
1000-1500 kW	63	64	2	**129**
1500+ kW	143	33	3	**179**
Total	**2,614**	**595**	**14**	**3,223**

Capacity Totals (MW)	Emergency	Peak	Baseload	Total
25-50 kW	6	0	0	**6**
50-100 kW	45	10	0	**55**
100-250 kW	149	34	0	**183**
250-500 kW	202	43	0	**245**
500-750 kW	78	17	1	**96**
750-1000 kW	89	21	2	**112**
1000-1500 kW	76	79	3	**158**
1500+ kW	275	70	5	**350**
Total	**919**	**275**	**11**	**1,205**

Connecticut provided NESCAUM with two databases of information on specific IC engines. The first is Connecticut's emergency engine database, which includes 1,085 electricity-generating engines whose owners applied for the state's General Permit for Emergency Engines from 1996 through early 2002. The emergency engine database provided specific size or capacity information on 845 of the engines listed; the size distribution of the remaining 240 engines for which this information was not available was assumed to be the same for purposes of this inventory. A second state database provides information on 636 non-emergency engines used to produce electricity, including heat input and fuel type. Some of the engines in this database are not permitted, but their size and location are noted because they are installed at a major source facility. The size distribution for all 1,721 generators listed in the two Connecticut databases is shown in the left-hand side of Table III-6. The right-hand side of Table III-6 summarizes information on an additional 205 engines in the Connecticut database that are used in mechanical applications (as opposed to generating electricity).

Table III-6
Connecticut Permit Records for Electricity Generators and Mechanical Engines

Electricity Generators	Number of Engines	Capacity Totals (MW)	Mechanical Engines	Number of Engines	Capacity Totals (MW)
25-50 kW	112	4	**25-50 kW**	5	<1
50-100 kW	208	13	**50-100 kW**	31	2
100-250 kW	411	60	**100-250 kW**	91	12
250-500 kW	321	111	**250-500 kW**	40	12
500-750 kW	273	158	**500-750 kW**	16	9
750-1000 kW	144	118	**750-1000 kW**	7	6
1000-1500 kW	153	174	**1000-1500 kW**	2	2
1500+ kW	99	219	**1500+ kW**	13	29
Total	**1,721**	**857**	**Total**	**205**	**74**

Table III-7 summarizes the agreement between PSR's estimates and state permitting records for different size categories of engines. The red line in Table III-7 and in subsequent tables comparing PSR estimates to state records shows the operative permitting threshold for most engines in each state. In theory, there should be much greater agreement between PSR's estimates and state records in the size categories over applicable permitting thresholds. Therefore, the last two rows in Table III-7 show overall agreement for all size categories, as well agreement for just those categories over the applicable permitting threshold. The fact that substantial discrepancies remain in the larger size categories may nevertheless be explained by a number of factors, including the existence of permit-by-rule provisions, different permitting thresholds for emergency and non-emergency engines, incomplete state information and uncertainties in PSR's estimation methodology.

Table III-7
Connecticut Engine Data Comparison by Number and Capacity

	TOTAL ENGINES			TOTAL CAPACITY (MW)		
	PSR	State	% State/PSR Agreement	PSR	State	% State/PSR Agreement
25-50 kW	160	112	70%	5	4	79%
50-75 kW	227	153	67%	15	9	58%
75-100 kW	461	55	12%	41	4	11%
100-250 kW	1,088	411	38%	183	60	33%
250-500 kW	681	321	47%	245	111	45%
500-750 kW	156	273	175%	96	158	163%
750-1000 kW	142	144	101%	112	118	106%
1000-1500 kW	129	153	119%	158	174	110%
1500+ kW	179	99	55%	350	219	63%
Total	3,223	1,721	53%	1,205	857	71%
Total above permit size	2,836	1,456	51%	1,185	844	71%

3. Maine Inventory

Table III-8 summarizes PSR's engine population and size distribution estimates for the state of Maine. According to these estimates, emergency engines account for over 86% of all diesel engines and 69% of total engine capacity in Maine.

Table III-8
PSR Estimates of Diesel Engines in Maine by Number and Capacity

Number Totals	Emergency	Peak	Baseload	Total
25-50 kW	29	0	0	**29**
50-100 kW	107	13	0	**120**
100-250 kW	159	16	0	**175**
250-500 kW	111	6	0	**117**
500-750 kW	20	0	0	**20**
750-1000 kW	22	3	0	**25**
1000-1500 kW	4	5	0	**9**
1500+ kW	34	27	4	**65**
Total	**486**	**70**	**4**	**560**

Capacity Totals (MW)	Emergency	Peak	Baseload	Total
25-50 kW	0	0	0	**0**
50-100 kW	9	1	0	**10**
100-250 kW	27	3	0	**30**
250-500 kW	41	2	0	**43**
500-750 kW	12	0	0	**12**
750-1000 kW	17	2	0	**20**
1000-1500 kW	5	6	0	**11**
1500+ kW	64	57	8	**129**
Total	**175**	**72**	**8**	**255**

The Maine Department of Environmental Protection (ME DEP) provided NESCAUM with a list of all IC engines currently permitted in the state, including emergency engines. The state's permitting guidelines indicate that Maine's permits should capture all engines larger than 500 kW and many smaller ones as well. Maine currently allows engines smaller than 50 kW to operate without a permit or any other restriction on hours of operation or emissions. Non-emergency engines between 50 kW and 500 kW may also fall outside permitting requirements, unless they are located at a facility with multiple emission sources. In addition to the engines shown on the left-hand side of Table III-9, Maine's database included 85 engines that were used in mechanical applications. These engines, which are summarized on the right-hand side Table III-9, were mostly emergency fire pumps, drives and wood chippers.

Table III-9
Maine Permit Records for Electricity Generators and Mechanical Engines

Electricity Generators	Number of Engines	Capacity Totals (MW)
25-50 kW	2	<1
50-100 kW	78	6
100-250 kW	184	32
250-500 kW	158	56
500-750 kW	64	40
750-1000 kW	28	23
1000-1500 kW	36	45
1500+ kW	28	60
Total	**578**	**262**

Mechanical Engines	Number of Engines	Capacity Totals (MW)
25-50 kW	0	0
50-100 kW	11	1
100-250 kW	51	8
250-500 kW	16	5
500-750 kW	5	2
750-1000 kW	2	2
1000-1500 kW	0	0
1500+ kW	0	0
Total	**85**	**19**

Table III-10 compares PSR's engine population estimates for Maine with the information contained in state permit records. As noted earlier in this Chapter, Maine is the only NESCAUM state for which PSR's estimates *under* predict the total number of engines identified in state permit records. This is not the case in all size categories, however, as indicated in Table III-9. State permit records indicate a greater number of engines in the 500-750 kW and 1000-1500 kW size ranges than PSR estimates, whereas PSR's methodology predicts more than twice the number of permitted engines in the larger 1500+ kW size category. As one would expect given current state permitting thresholds, PSR also estimates a larger number of small engines (<100 kW) than are indicated by state permit records.

Table III-10
Maine Engine Data Comparison by Number and Capacity

	TOTAL ENGINES			TOTAL CAPACITY (MW)		
	PSR	State	% State/PSR Agreement	PSR	State	% State/PSR Agreement
25-50 kW	29	2	7%	<1	<1	16%
50-100 kW	120	78	65%	10	6	58%
100-250 kW	175	184	105%	30	32	108%
250-500 kW	117	158	135%	43	56	130%
500-750 kW	20	64	320%	12	40	320%
750-1000 kW	25	28	112%	20	23	119%
1000-1500 kW	9	36	400%	11	45	411%
1500+ kW	65	28	43%	129	60	47%
Total	560	578	103%	254	262	103%
Total above permit size	119	156	131%	172	168	98%

4. Massachusetts Inventory

Table III-11 summarizes PSR's engine population and size distribution estimates for the state of Massachusetts. According to these estimates, emergency engines account for 79% of all diesel engines and 75% of total engine capacity in Massachusetts.

Table III-11
PSR Estimates of Diesel Engines in Massachusetts by Number and Capacity

Number Totals	Emergency	Peak	Baseload	Total
25-50 kW	245	0	0	**245**
50-100 kW	837	207	13	**1,057**
100-250 kW	1,368	355	7	**1,730**
250-500 kW	914	195	0	**1,109**
500-750 kW	198	44	5	**247**
750-1000 kW	175	41	5	**221**
1000-1500 kW	101	121	4	**226**
1500+ kW	156	20	16	**192**
Total	**3,994**	**983**	**50**	**5,027**

Capacity Totals (MW)	Emergency	Peak	Baseload	Total
25-50 kW	8	0	0	**8**
50-100 kW	67	17	1	**85**
100-250 kW	234	59	1	**295**
250-500 kW	328	70	0	**398**
500-750 kW	123	28	3	**153**
750-1000 kW	139	32	4	**175**
1000-1500 kW	120	151	5	**275**
1500+ kW	301	47	32	**379**
Total	**1,319**	**403**	**46**	**1,768**

The Massachusetts Department of Environmental Protection (MA DEP) provided NESCAUM with two data sets of permitted engines. The first is a permit list that contains information on all engines and facilities with fuel input greater than or equal to 10 MMBtu/hr. The earliest issued permits in the database are from 1998; thus it may fail to include many older engines. MA DEP also provided a second list that included only emergency engines. The emergency engine database did not specify the size of every listed engine, though size could be inferred from other information for about half the engines on the list. The resulting size distribution was assumed to be representative of those engines whose size could not be determined. The left-hand side of Table III-12 summarizes state permit information for electricity generating IC engines in Massachusetts; engines used to produce mechanical power for fire pumps and air compressors are included on the right-hand side of Table III-12.

Table III-12
Massachusetts Permit Records for Electricity Generators and Mechanical Engines

Electricity Generators	Number of Engines	Capacity Totals (MW)	Mechanical Engines	Number of Engines	Capacity Totals (MW)
25-50 kW	11	<1	**25-50 kW**	0	0
50-100 kW	13	1	**50-100 kW**	2	0
100-250 kW	278	38	**100-250 kW**	33	5
250-500 kW	156	54	**250-500 kW**	19	6
500-750 kW	138	77	**500-750 kW**	12	7
750-1000 kW	73	61	**750-1000 kW**	2	2
1000-1500 kW	160	188	**1000-1500 kW**	5	6
1500+ kW	275	602	**1500+ kW**	12	35
Total	**1,104**	**1,021**	**Total**	**85**	**59**

Table III-13 compares PSR's population estimates with data from Massachusetts permit records. According to PSR's estimation methodology, engines that fall below the Massachusetts permitting threshold of 300 kW are likely to account for nearly 70% of all engines in the state. Overall, state permit records would appear to account for just 22% of PSR's estimated engine population between 300 kW and 1500 kW for Massachusetts. However, this population likely includes a number of emergency engines below 1 MW in size that are eligible to operate under permit-by-rule, in which case they are not included in the state database.

Table III-13
Massachusetts Engine Data Comparison by Number and Capacity

	TOTAL ENGINES			TOTAL CAPACITY (MW)		
	PSR	State	% State/PSR Agreement	PSR	State	% State/PSR Agreement
25-50 kW	245	11	4%	8	<1	5%
50-100 kW	1,057	13	1%	85	1	1%
100-250 kW	1,730	278	16%	295	38	13%
250-300 kW	275	16	6%	74	4	6%
300-500 kW	834	140	17%	324	50	15%
500-750 kW	247	138	56%	153	77	50%
750-1000 kW	221	73	33%	175	61	35%
1000-1500 kW	226	160	71%	275	188	68%
1500+ kW	192	275	143%	379	602	159%
Total	5,027	1,104	22%	1,768	1,021	58%
Total above permit size	1,720	786	46%	1,307	978	75%

5. New Hampshire Inventory

Table III-14 summarizes PSR's engine population and size distribution estimates for the state of New Hampshire. According to these estimates, emergency engines account for 88% of all diesel engines and 85% of total engine capacity in New Hampshire.

Table III-14
PSR Estimates of Diesel Engines in New Hampshire by Number and Capacity

Number Totals	Emergency	Peak	Baseload	Total		Capacity Totals (MW)	Emergency	Peak	Baseload	Total
25-50 kW	17	0	0	**17**		**25-50 kW**	1	0	0	**1**
50-100 kW	130	15	0	**145**		**50-100 kW**	11	1	0	**12**
100-250 kW	220	28	0	**248**		**100-250 kW**	38	5	0	**42**
250-500 kW	145	15	0	**160**		**250-500 kW**	53	6	0	**59**
500-750 kW	29	4	0	**33**		**500-750 kW**	18	2	0	**20**
750-1000 kW	27	4	0	**31**		**750-1000 kW**	21	3	0	**24**
1000-1500 kW	6	7	0	**13**		**1000-1500 kW**	8	9	0	**16**
1500+ kW	81	8	7	**96**		**1500+ kW**	156	18	11	**185**
Total	**655**	**81**	**7**	**743**		**Total**	**304**	**44**	**11**	**359**

The New Hampshire Department of Environmental Services (NH DES) provided NESCAUM with a list of both emergency and non-emergency engines. Engine characteristics – such as type, size and fuel – were specified in this list, but not engine application. The left-hand side of Table III-15 summarizes information from New Hampshire's list of electricity-generating IC engines, while the right-hand side of Table III-15 summarizes state information on 22 mechanical IC engines.

Table III-15
New Hampshire Permit Records for Electricity Generators and Mechanical Engines

Electricity Generators	Number of Engines	Capacity Totals (MW)		Mechanical Engines	Number of Engines	Capacity Totals (MW)
25-50 kW	1	<1		**25-50 kW**	1	<1
50-100 kW	2	<1		**50-100 kW**	0	0
100-250 kW	65	12		**100-250 kW**	12	2
250-500 kW	126	44		**250-500 kW**	5	2
500-750 kW	71	41		**500-750 kW**	4	2
750-1000 kW	39	32		**750-1000 kW**	0	0
1000-1500 kW	47	56		**1000-1500 kW**	0	0
1500+ kW	9	30		**1500+ kW**	0	0
Total	**360**	**215**		**Total**	**22**	**6**

Table III-16 compares PSR's population estimates with data from New Hampshire's permitted engine list. The comparison suggests that few engines under the 150 kW threshold are included in state records. For engines over 150 kW generally, state records would appear to capture a larger fraction of the estimated population. However, the numeric discrepancy between known and estimated engines varies considerably across different size categories. In the 150-500 kW size range, PSR estimates a significantly larger number of engines than is reflected in the state's list; the same applies in the over 1500 kW size range, whereas the opposite is true in the 500 to 1500 kW size range.

Again, this result may be indicative of the difficulty of estimating engine populations with the degree of specificity involved in these state-level analyses.

Table III-16
New Hampshire Engine Data Comparison by Number and Capacity

	TOTAL ENGINES			TOTAL CAPACITY (MW)		
	PSR	State	% State/PSR Agreement	PSR	State	% State/PSR Agreement
25-50 kW	17	1	6%	1	<1	8%
50-100 kW	145	2	1%	12	<1	1%
100-150 kW	67	10	15%	8	1	15%
150-250 kW	181	55	30%	35	11	32%
250-500 kW	160	126	79%	59	44	75%
500-750 kW	33	71	215%	20	41	202%
750-1000 kW	31	39	126%	24	32	134%
1000-1500 kW	13	47	362%	16	56	344%
1500+ kW	96	9	9%	185	30	16%
Total	743	360	48%	359	215	60%
Total above permit size	514	347	68%	339	214	63%

6. New Jersey Inventory

Table III-17 summarizes PSR's engine population and size distribution estimates for the state of New Jersey. According to these estimates, emergency engines account for 79% of all diesel engines and 73% of total engine capacity in New Jersey.

Table III-17
PSR Estimates of Diesel Engines in New Jersey by Number and Capacity

Number Totals	Emergency	Peak	Baseload	Total	Capacity Totals (MW)	Emergency	Peak	Baseload	Total
25-50 kW	453	0	0	**453**	**25-50 kW**	15	0	0	**15**
50-100 kW	1,454	358	19	**1,831**	**50-100 kW**	115	30	2	**147**
100-250 kW	2,325	588	23	**2,936**	**100-250 kW**	393	97	3	**494**
250-500 kW	1,461	312	1	**1,774**	**250-500 kW**	525	112	0	**637**
500-750 kW	326	83	12	**421**	**500-750 kW**	202	51	8	**260**
750-1000 kW	290	78	15	**383**	**750-1000 kW**	230	61	12	**303**
1000-1500 kW	169	166	7	**342**	**1000-1500 kW**	202	206	9	**417**
1500+ kW	189	86	0	**275**	**1500+ kW**	356	180	0	**535**
Total	**6,667**	**1,671**	**77**	**8,415**	**Total**	**2,038**	**737**	**33**	**2,808**

The New Jersey Department of Environmental Protection (NJ DEP) provided NESCAUM with two lists of permitted engines. The first is a list of 5,016 emergency engines, which includes 552 mechanical engines used to power fire pumps, air compressors and water pumps. Of the remaining 4,464 engines, information on engine size was available for a subset of 1,220 engines, or 27% of the total list. In the summary information presented below, the size distribution of the remaining engines was imputed based on this known subset. The second list provided by NJ DEP contains 1,771 non-emergency engines, 412 of which were removed because they are mechanical or non-IC engine turbines and boilers. Information on engine size was available for 637 (47%) of the remaining 1,359 generator engines; as with the emergency engines, the size distribution of this subset was assumed to be representative of the entire group. Table III-18 summarizes information from the NJ DEP engine lists, incorporating the size assumptions noted above. Given the large number of engines for which size had to be imputed, a caution is in order concerning the accuracy of the size distribution indicated in Table III-18.

Table III-18
New Jersey Permit Records for Electricity Generators and Mechanical Engines

Electricity Generators	Number of Engines	Capacity Totals (MW)	Mechanical Engines	Number of Engines	Capacity Totals (MW)
25-50 kW	4	0	**25-50 kW**	0	0
50-100 kW	120	12	**50-100 kW**	32	3
100-250 kW	1,432	224	**100-250 kW**	314	52
250-500 kW	1,247	416	**250-500 kW**	374	132
500-750 kW	927	527	**500-750 kW**	97	55
750-1000 kW	837	664	**750-1000 kW**	0	0
1000-1500 kW	698	875	**1000-1500 kW**	20	24
1500+ kW	558	1,158	**1500+ kW**	34	51
Total	**5,823**	**3,876**	**Total**	**871**	**316**

Because NJ DEP's engine lists do not include size information for many permitted engines, it is difficult to make a meaningful comparison between the PSR estimates and state records. If the size distribution from known engines is applied to all other engines in the state lists (as described above), the results suggest that PSR's methodology substantially underestimates the New Jersey engine population over 500 kW. However, given the multiple assumptions involved in both sets of data, it is difficult to place much confidence in this comparison.

Table III-19
New Jersey Engine Data Comparison by Number and Capacity

	TOTAL ENGINES			TOTAL CAPACITY (MW)		
	PSR	State	% State/PSR Agreement	PSR	State	% State/PSR Agreement
25-50 kW	453	4	1%	15	<1	1%
50-100 kW	1,831	120	7%	147	12	8%
100-250 kW	2,936	1,432	49%	494	224	45%
250-500 kW	1,774	1,247	70%	637	416	65%
500-750 kW	421	927	220%	260	527	202%
750-1000 kW	383	837	219%	303	664	219%
1000-1500 kW	342	698	204%	417	875	210%
1500+ kW	275	558	203%	535	1,158	216%
Total	8,415	5,823	69%	2,808	3,876	138%
Total above permit size	6,131	5,699	93%	1,516	3,225	213%

7. New York Inventory

Table III-20 summarizes PSR's engine population and size distribution estimates for the state of New York. According to these estimates, emergency engines account for approximately 79% of the total engine population and 74% of total capacity.

Table III-20
PSR Estimates of Diesel Engines in New York by Number and Capacity

Number Totals	Emergency	Peak	Baseload	Total	Capacity Totals (MW)	Emergency	Peak	Baseload	Total
25-50 kW	827	0	0	**827**	**25-50 kW**	28	0	0	**28**
50-100 kW	2,562	644	73	**3,279**	**50-100 kW**	203	53	6	**262**
100-250 kW	4,060	1,025	62	**5,147**	**100-250 kW**	688	169	9	**866**
250-500 kW	2,575	578	6	**3,159**	**250-500 kW**	923	207	2	**1,132**
500-750 kW	569	157	29	**755**	**500-750 kW**	352	97	18	**466**
750-1000 kW	505	137	28	**670**	**750-1000 kW**	400	108	22	**530**
1000-1500 kW	293	306	26	**625**	**1000-1500 kW**	352	377	32	**761**
1500+ kW	458	110	7	**575**	**1500+ kW**	877	242	13	**1,133**
Total	**11,849**	**2,957**	**231**	**15,037**	**Total**	**3,822**	**1,254**	**103**	**5,179**

NESCAUM obtained two lists of engines permitted in New York. The first is a list of 311 permitted, non-emergency engines from the state DEC. It provides detailed information on engine owner, location, model and size for 237 (76%) of the listed engines. The second list is from the New York City DEP, and contains specific information on the owner, location, model and size of 1,351 permitted emergency generator engines in New York City. Because the New York City DEP database includes engines permitted over the last 25 years, it should provide reliable information on emergency engines in the NYC area. Information from both lists is combined and summarized in Table III-21.

Table III-21
New York Permit Records for Electricity Generators and Mechanical Engines

Electricity Generators	Number of Engines	Capacity Totals (MW)	Mechanical Engines	Number of Engines	Capacity Totals (MW)
25-50 kW	26	1	**25-50 kW**	44	2
50-100 kW	93	7	**50-100 kW**	37	3
100-250 kW	338	57	**100-250 kW**	43	7
250-500 kW	407	141	**250-500 kW**	21	7
500-750 kW	274	158	**500-750 kW**	4	2
750-1000 kW	199	163	**750-1000 kW**	2	2
1000-1500 kW	176	206	**1000-1500 kW**	1	1
1500+ kW	149	268	**1500+ kW**	7	13
Total	**1,662**	**998**	**Total**	**159**	**36**

Table III-22 compares PSR's population estimates for New York with data from state and city permit records. The total number of engines included in the state and city lists described above account for only 11% of the engine population estimated by PSR for the state of New York. The fact that information on emergency engines was only available for New York City, and not for the state as a whole, combined with the fact that many engines statewide are likely too small to trigger permitting requirements, probably accounts in some measure for this discrepancy.

Table III-22
New York Engine Data Comparison by Number and Capacity

	TOTAL DIESEL ENGINES			TOTAL CAPACITY (MW)		
	PSR	State	% State Agreement	PSR	State	% PSR Agreement
25-50 kW	827	26	3%	28	1	2%
50-100 kW	3,279	93	3%	262	7	3%
100-250 kW	5,147	337	7%	866	57	7%
250-300 kW	1,072	82	8%	211	21	10%
300-500 kW	2,087	328	16%	922	119	13%
500-750 kW	755	272	36%	466	158	34%
750-1000 kW	670	201	30%	530	163	31%
1000-1500 kW	625	175	28%	761	206	27%
1500+ kW	575	148	26%	1133	268	24%
Total	15,037	1,662	11%	5179	998	19%
Total above permit size	4,712	1,124	24%	3812	913	24%

8. Rhode Island Inventory

Table III-23 summarizes PSR's engine population and size distribution estimates for the state of Rhode Island. According to these estimates, emergency engines account for approximately 91% of both total engine population and capacity.

Table III-23
PSR Estimates of Diesel Engines in Rhode Island by Number and Capacity

Number Totals	Emergency	Peak	Baseload	Total
25-50 kW	15	0	0	**15**
50-100 kW	81	8	0	**89**
100-250 kW	111	13	0	**124**
250-500 kW	79	5	0	**84**
500-750 kW	14	0	0	**14**
750-1000 kW	17	1	0	**18**
1000-1500 kW	3	4	0	**7**
1500+ kW	12	0	0	**12**
Total	**332**	**31**	**0**	**363**

Capacity Totals (MW)	Emergency	Peak	Baseload	Total
25-50 kW	0	0	0	**0**
50-100 kW	7	1	0	**7**
100-250 kW	19	2	0	**21**
250-500 kW	29	2	0	**31**
500-750 kW	9	0	0	**9**
750-1000 kW	13	1	0	**14**
1000-1500 kW	4	5	0	**9**
1500+ kW	25	0	0	**25**
Total	**106**	**11**	**0**	**117**

The data set available from Rhode Island's Department of Environmental Management (RI DEM) contains 86 engines, 14 of which are used to produce mechanical power instead of electricity. Size information is available for all engines in the data set and is summarized in Table III-24.

Table III-24
Rhode Island Permit Records for Electricity Generators and Mechanical Engines

Electricity Generators	Number of Engines	Capacity Totals (MW)	Mechanical Engines	Number of Engines	Capacity Totals (MW)
25-50 kW	0	0	**25-50 kW**	0	0
50-100 kW	0	0	**50-100 kW**	0	0
100-250 kW	4	1	**100-250 kW**	0	0
250-500 kW	1	<1	**250-500 kW**	0	0
500-750 kW	20	12	**500-750 kW**	11	7
750-1000 kW	11	10	**750-1000 kW**	0	0
1000-1500 kW	11	13	**1000-1500 kW**	0	0
1500+ kW	25	139	**1500+ kW**	3	6
Total	**72**	**174**	**Total**	**14**	**13**

Table III-25 compares PSR's estimates to the information available from Rhode Island's permit records. Not surprisingly, given current permitting thresholds, few of the smaller engines estimated by PSR have been permitted by the state. For larger engines, PSR appears to have underestimated the actual Rhode Island engine population in all but the 750-1000 kW size bracket.

Table III-25
Rhode Island Engine Data Comparison by Number and Capacity

	TOTAL ENGINES			TOTAL CAPACITY (MW)		
	PSR	State	% PSR Agreement	PSR	State	% PSR Agreement
25-50 kW	15	0	0%	<1	0	0%
50-100 kW	89	0	0%	7	0	0%
100-250 kW	124	4	3%	21	1	3%
250-500 kW	84	1	1%	31	<1	1%
500-750 kW	14	20	143%	9	12	132%
750-1000 kW	18	11	61%	14	10	68%
1000-1500 kW	7	11	157%	9	13	150%
1500+ kW	12	25	208%	25	139	554%
Total	363	72	20%	116	174	149%
Total above permit size	51	67	131%	57	173	306%

9. <u>Vermont Inventory</u>

Table III-26 summarizes PSR's engine population and size distribution estimates for the state of Vermont. According to these estimates, emergency engines account for approximately 93% of engines and 89% of total engine capacity in Vermont.

Table III-26
PSR Estimates of Diesel Engines in Vermont by Number and Capacity

Number Totals	Emergency	Peak	Baseload	Total	Capacity Totals (MW)	Emergency	Peak	Baseload	Total
25-50 kW	14	0	0	**14**	**25-50 kW**	0	0	0	**0**
50-100 kW	72	7	0	**79**	**50-100 kW**	6	1	0	**7**
100-250 kW	100	9	0	**109**	**100-250 kW**	17	2	0	**18**
250-500 kW	70	2	0	**72**	**250-500 kW**	26	1	0	**27**
500-750 kW	13	0	0	**13**	**500-750 kW**	8	0	0	**8**
750-1000 kW	16	1	0	**17**	**750-1000 kW**	13	1	0	**13**
1000-1500 kW	2	4	0	**6**	**1000-1500 kW**	3	5	0	**8**
1500+ kW	0	0	0	**0**	**1500+ kW**	0	0	0	**0**
Total	**287**	**23**	**0**	**310**	**Total**	**73**	**9**	**0**	**81**

For this report, NESCAUM reviewed information from the Vermont Department of Environmental Conservation (VT DEC) including Title V permits, state operating permits, pre-construction permits and file correspondence. Review of the Title V permits yielded detailed information regarding the location of generators, their size and fuel type. Of the 216 engines described in state records, 66 are used to generate electricity and 150 produce mechanical power. The latter category includes large IC engines used at lumber mills, ski resorts and quarries. Details on both engine populations are summarized in Table III-27 below.

Table III-27
Vermont Permit Records for Electricity Generators and Mechanical Engines

Electricity Generators	Number of Engines	Capacity Totals (MW)	Mechanical Engines	Number of Engines	Capacity Totals (MW)
25-50 kW	0	0	**25-50 kW**	1	<1
50-100 kW	9	1	**50-100 kW**	14	1
100-250 kW	18	3	**100-250 kW**	31	6
250-500 kW	17	5	**250-500 kW**	73	24
500-750 kW	7	4	**500-750 kW**	9	5
750-1000 kW	2	2	**750-1000 kW**	14	13
1000-1500 kW	10	11	**1000-1500 kW**	8	9
1500+ kW	3	6	**1500+ kW**	0	0
Total	**66**	**32**	**Total**	**150**	**58**

Table III-28 compares information available from the VT DEC with PSR's population estimates. The comparison suggests that the state may have permitted only about a third of the total engine population estimated by PSR to meet current permitting thresholds.

Table III-28
Vermont Engine Data Comparison by Number and Capacity

	TOTAL ENGINES			TOTAL CAPACITY		
	PSR	State	% PSR Agreement	PSR	State	% PSR Agreement
25-50 kW	14	0	0%	<1	0	0%
50-100 kW	79	9	11%	7	1	11%
100-250 kW	109	18	17%	18	3	17%
250-337 kW	24	12	50%	7	4	50%
337-500 kW	48	5	10%	20	2	9%
500-750 kW	13	7	54%	8	4	47%
750-1000 kW	17	2	12%	13	2	12%
1000-1500 kW	6	10	167%	8	11	146%
1500+ kW	0	3	---	0	6	---
Total	310	66	21%	81	32	39%
Total above permit size	84	27	32%	49	24	50%

IV. Engine Population Surveys – New York City and Fairfield County, CT

A. Introduction

As a follow-up and complement to the inventory efforts described in Chapter III, Power Systems Research (PSR) conducted detailed telephone surveys to obtain information on distributed generator populations in New York City and Fairfield County, Connecticut. These areas were selected because both face severe transmission constraints and have been the focus of recent efforts by electric system operators to encourage customer-side demand responses during periods of peak electrical demand. As indicated in Chapter II, customer-side demand response can include efforts to curtail load (e.g. turning off equipment), increased on-site generation, or a combination of both. Thus, both New York City and Fairfield County are areas where the potential for increased use of diesel engines as a supplemental power source during periods of peak demand is likely to be higher than in other areas of the Northeast. For Fairfield County, in particular, this potential may be further increased by the recent introduction of locational marginal pricing in the New England power pool. Because locational marginal pricing is designed to more closely reflect the marginal price of supplying grid power to specific areas within the larger power pool, it will tend to enhance the price signals promoting demand response in transmission-constrained areas.

After briefly reviewing the methodology used by PSR in conducting the telephone surveys, this chapter reviews the survey results and compares them to permit data on file with the relevant state environmental agencies.

B. Methodology

The first step in conducting the telephone survey was to identify likely owners of diesel generators. To do so, PSR applied the same basic estimation methodology used to develop the state-level population estimates described in the previous chapter.[19] Using business data from Fairfield County and New York City, PSR developed an initial estimate of the likely number of units in each area and identified potential owners to be contacted.[20] This information was used to help prioritize survey calls in terms of the highest incidence group and successively lower probability owners. In general, PSR started with phone calls to businesses having more than 50 employees and with SIC codes identified as higher probability for owning on-site generators. If this initial sample was exhausted before the survey quota was reached, additional calls were made to

[19] The description of PSR's *Partslink* methodology in Appendix A, includes a section (starting on page 3) entitled "Application to the NESCAUM Survey" that describes the survey methodology in more detail.
[20] In some cases, owners identified for this effort had previously been surveyed by PSR in the development of its *Partslink* database.

businesses with less than 50 employees until PSR identified more than 70-75% of the number of engines estimated to be in the area.

PSR initially calculated that the likely generator populations for the five-county New York City area and for Fairfield County totaled more than 24,000 and 5,000 units, respectively. However, these initial estimates included both portable and stationary generator sets. Of the total generator population estimated for New York City, PSR's methodology indicated that more than 18,000 units were likely to be smaller than 10 kW in size; the comparable estimate for very small units in Fairfield County was 4,300. All of these smaller than 10 kW units and half of the remaining estimated generator population up to a capacity of 300 kW were assumed to be portable and were excluded from the survey sample.

PSR began contacting potential generator owners in the spring of 2002. In each call, PSR sought to determine first whether an engine was present and, if so, to follow-up with a series of questions about engine application and use, as well as size, age, fuel and hours of operation during a typical 12-month period.[21] Survey efforts were eventually completed in August 2002, at which point PSR had identified more than 1,700 generator sets owned by 1,536 organizations in New York City and 292 generator sets owned by 227 organizations in Fairfield County.

C. Telephone Survey Results

1. <u>New York City</u>

PSR contacted 2,475 businesses in New York City, of which 1,536 were found to own a total of 1,724 generators. According to surveyed owners, 1,075 (62%) of these engines were installed for emergency use. Current state permitting requirements specify that emergency engines may only be used in the case of actual or imminent electric supply shortfalls and are limited to less than 500 hours of operation each year. The great majority of engines surveyed in New York City (1,440 engines or 84% of the total sample of 1,724 units) run on diesel fuel; of these diesel engines, 903 (63%) are for emergency use only. Tables IV-1 and IV-2 summarize the distribution of engine sizes, fuel sources and potential applications for engines identified in the New York City telephone survey.

[21] Due to security concerns, PSR encountered significant difficulties collecting information – especially from New York City businesses – after September 11, 2001. To obtain information, it became necessary in some cases to send formal letters to target businesses explaining the purpose of the survey and urging cooperation.

Table IV-1
New York City PSR Survey Results by Engine Fuel and Application

	Emergency	Peak	Baseload	Total
Diesel	903	10	527	1,440
Natural Gas	149	2	98	249
Gasoline	23	0	12	35
Total	1,075	12	637	1,724

Table IV-2
New York City PSR Survey Results by Engine Size and Capacity

	Engine Totals	% Engines	Total Capacity (MW)
25-50 kW	5	0.3%	0
50-100 kW	82	4.8%	4
100-250 kW	257	14.9%	39
250-500 kW	379	22.0%	135
500-750 kW	334	19.4%	202
750-1000 kW	322	18.7%	272
1000-1500 kW	319	18.5%	346
1500+ kW	26	1.5%	56
Total	1,724	100.0%	1,054

Table IV-2 indicates that more than half (58%) of the engines identified in PSR's survey are larger than 500 kW, most operate on diesel fuel and most are intended for emergency use. The total generating capacity of all engines identified in the New York City telephone survey is 1,054 MW. This compares to a peak summer demand for the New York City area of approximately 11,000 MW in 2003.[22]

In addition to information on numbers and sizes of engines in place, the telephone survey was used to collect information on engine operation in a typical 12-month period. Reported hours of operation were then combined with information on engine capacity to calculate electrical generation in MWh per year. The results of this calculation, by engine fuel and application, are summarized in Table IV-3 below. Overall, the 1,724 engines identified in the survey were estimated to generate a total of 490,000 MWh in a typical year.[23] Non-emergency operation (baseload and peak operation) accounted for 80% of this generation total, while diesel engines accounted for 72% (355,000 MWh) of total reported generation.

Table IV-3
New York City PSR Survey Generation Totals in MWh/yr by Fuel and Application

[22] In February 2003, the New York ISO forecast peak summer demand for 2003 at 11,020 MW (http://www.nyiso.com/topics/articles/news_releases/2003/nr_022503_summer_outlook.pdf).
[23] The 490,000 MWh total is the equivalent of a 100 MW power plant running 60% of the time, or 5000 hours/yr.

	Emergency	Peak	Baseload	Total
Diesel	84,401	2,524	268,258	355,183
Natural Gas	14,830	291	111,690	126,811
Gasoline	1,749	0	5,614	7,363
Total	100,981	2,815	385,562	489,357

2. Fairfield County, CT

PSR contacted 1,557 businesses in Fairfield County, Connecticut, of which 227 were found to own a total of 294 generators. Nearly all of these engines (280) are designated for emergency use only (meaning they can operate only in cases of actual or imminent outages, when the ISO has officially called for voltage reductions) and most (195) are diesel-powered. Of the 14 non-emergency engines identified, none were diesel powered. Rather, natural gas fueled units accounted for most of the generators designated for peak shaving and baseload purposes, with gasoline powered engines making up the remaining non-emergency population.

Table IV-4
Fairfield County PSR Survey Results by Engine Fuel and Application

	Emergency	Peak	Baseload	Total
Diesel	195	0	0	195
Natural Gas	65	5	6	76
Gasoline	20	1	2	23
Total	280	6	8	294

Table IV-5
Fairfield County PSR Survey Results by Engine Size and Capacity

	Engine Totals	% Engines	Capacity Totals (MW)
25-50 kW	18	6.1%	1
50-100 kW	72	24.5%	5
100-250 kW	79	26.9%	12
250-500 kW	86	29.3%	27
500-750 kW	21	7.1%	11
750-1000 kW	4	1.4%	3
1000-1500 kW	7	2.4%	8
1500+ kW	7	2.4%	22
Total	294	100%	88

In both numbers and total capacity, the generator population in Fairfield County was smaller than that in New York City, as seen in Tables IV-4 and IV-5. In addition, the Connecticut units were generally smaller, with 85% reporting capacity ratings less than 500 kW.

As in New York City, the telephone surveys were used to collect additional information on hours of operation for surveyed engines. The resulting estimates of electrical production by these engines are summarized in Table IV-6. They indicate that the 294 engines identified in the survey generate a total of 9,300 MWh in a typical 12-month period.[24] More than half (62%) of this total output for a typical year was generated by the 8 baseload and 6 peak shaving engines. The remaining 3,500 MWh was generated by emergency engines.

Table IV-6
Fairfield County PSR Survey Generation Totals in MWh/yr by Fuel and Application

	Emergency	Peak	Baseload	Total
Diesel	2,860	0	0	2,860
Natural Gas	563	834	2,249	3,646
Gasoline	89	100	2,628	2,817
Total	3,512	934	4,877	9,323

D. Overlap between Survey Results and State Permitting Records

To better assess the extent to which current state permitting requirements and records capture the population of surveyed engines, the results of PSR's telephone surveys were compared to permitting records compiled by the New York City and State of Connecticut Departments of Environmental Protection (DEPs). The results of this comparison for the two survey areas are discussed below.

1. New York City

Although engines in New York City are regulated by both the State Department of Environmental Conservation (DEC) and the New York City DEP (see discussion in Chapter II), the permit information NESCAUM used to compare survey results for New York City are available only from the City DEP. The City DEP has permit information on 1,351 emergency engines. As indicated in Chapter II, New York City DEP regulations require that diesel units down to a size threshold of 33 kW (350,000 Btu/hr) be registered with the City. Engines over 280 kW (2.8 MMBtu/hr) must obtain a work permit unless they are emergency engines, in which case they must simply register. The state requires permits for all engines over 160 kW (225 hp) in the New York City metropolitan area. Emergency engines are limited to a total of 500 hours of operation per year (of which 200 hours may be used when called by the New York ISO as part of its emergency demand response program; that is, when outage is imminent, as opposed to when it has already occurred).[25]

Table IV-7 summarizes the size distribution of emergency engines registered with the New York City DEP. More than half the engines are smaller than 500 kW; median size is 413 kW.

[24] The 9,300 MWh total is equivalent to a 2 MW power plant running 60% of the time, or for 5000 hrs/yr.

[25] Because the NY ISO's emergency demand response program is limited to situations of imminent shortfall, it may be distinguished from peak shaving or price-responsive demand response programs. Emergency generators in NYC are prohibited from operation for peak shaving or price response reasons.

Table IV-7
New York City DEP Permitted Emergency Engines

	Engine Totals	% Engines	Capacity Totals (MW)
25-50 kW	26	1.9%	1
50-100 kW	90	6.7%	6
100-250 kW	313	23.2%	52
250-300 kW	69	5.1%	18
300-500 kW	244	18.1%	89
500-750 kW	195	14.4%	111
750-1000 kW	148	11.0%	119
1000-1500 kW	142	10.5%	168
1500+ kW	124	9.2%	222
Total	1,351	100%	786

Comparing the specific New York City engines identified in PSR's telephone survey to the DEP database, PSR found that 839 engines (based on owner, address and size) were included in both lists. This suggests that 512 engines registered with the City were not captured by the telephone survey. Conversely, the comparison indicates that 885 engines identified in the survey are not registered with the City DEP, 796 of which *should be* registered according to the regulations outlined above. Combining both databases, a total of 2,236 individual engines were identified in New York City. The size distribution of this combined population is summarized in Table IV-8 below.

Table IV-8
Total Engine Inventory for New York City

	Engine Totals	% Engines	Capacity Totals (MW)
25-50 kW	26	1.2%	1
50-100 kW	123	5.5%	8
100-250 kW	426	19.1%	70
250-500 kW	509	22.8%	178
500-750 kW	389	17.4%	229
750-1000 kW	328	14.7%	277
1000-1500 kW	319	14.3%	346
1500+ kW	116	5.2%	211
Total	2,236	100%	1,320

2. Fairfield County, Connecticut

The state of Connecticut maintains extensive permitting data on distributed generator engines. As described in more detail in Chapter II, current state permit requirements distinguish between engines intended for emergency use only and other engines. In addition, lower permitting thresholds have recently been instituted for the transmission-constrained southwestern Connecticut load pocket (including Fairfield County). In this area, any emergency engine over 37 kW (50 hp) is required to obtain a permit. Thus, Connecticut's permit records should capture most engines over 500 kW throughout the state, and many more of the smaller engines in southwestern Connecticut. However, the permit requirements that established the 37 kW threshold were new in 2002, and only 10 additional engines were permitted under them as of March 2003. As indicated by Table IV-9 below, state permitting records imply that 58% of permitted engines are smaller than 500 kW (as opposed to 85% in the PSR survey data).

Table IV-9
Connecticut DEP Permitted Engine Summary for Fairfield County

	Engine Totals	% Engines	Capacity Totals (MW)
25-50 kW	11	3.5%	0
50-100 kW	40	12.7%	3
100-250 kW	58	18.4%	9
250-500 kW	75	23.8%	26
500-750 kW	54	17.1%	31
750-1000 kW	22	7.0%	18
1000-1500 kW	29	9.2%	33
1500+ kW	26	8.3%	63
Total	315	100%	184

PSR compared the results of its Fairfield County telephone survey with state permit records for engines located in Fairfield County. The comparison found an overlap of only 49 individual engines between the two databases. Combining all individual engines identified in either the telephone survey or state permit records results in a total database of 560 engines with a combined capacity of 235 MW (see Table IV-10).

Table IV-10
Total Engine Inventory for Fairfield County

	Engine Totals	% Engines	Capacity Totals (MW)
25-50 kW	29	5.2%	1
50-100 kW	108	19.3%	7
100-250 kW	135	24.1%	21
250-500 kW	148	26.4%	48
500-750 kW	66	11.8%	37
750-1000 kW	19	3.4%	16
1000-1500 kW	29	5.2%	32
1500+ kW	26	4.6%	74
Total	560	100%	235

3. Analysis

The fact that there is so little overlap between the PSR telephone survey data and permit records for New York City and Fairfield County suggests that neither the survey methodology used by PSR nor current state permitting systems can be relied upon for comprehensive coverage of the existing population of small generators. The percentage of surveyed engines for which there was no record in state or city databases was over 50% in the case of New York City and over 80% in the case of Fairfield County. While the percentage overlap is smaller for Fairfield County, the number of unregistered engines identified in the telephone survey was actually larger in New York City (885 units compared to 245 in Fairfield County).

The fact that the telephone surveys did not capture all permitted engines is not particularly surprising given a number of known flaws in the survey approach. In the first place, the estimation methodology used to identify likely generator owners was inexact. Moreover, the list of target businesses that PSR began with seems to have excluded certain types of institutions, such as government agencies and healthcare facilities, which are likely to have on-site generators. (The list used by PSR came from American Business Lists, and after comparison with the permitted engines it was evident that a few SIC categories were not listed on the primary business list. The reason for this is not known, but PSR has concluded that its results nevertheless represent statistically valid estimates.[26]) Additional inaccuracies were introduced by the fact that PSR targeted likely generator owners, rather than likely facilities or locations. In some cases a single owner might own multiple generators at different locations and might not have identified them all when contacted. Or the owner of a generator installed within the survey area might not have been contacted because the owner was listed as having a different location outside the survey area. Finally, some contacted businesses did not respond, while others claimed not to have a generator engine on site despite permit information to the contrary.

The fact that the telephone survey identified significant numbers of engines that were not included in state databases is therefore of more concern than the fact that the survey appears to have missed a number of engines on record with state agencies. Unfortunately, it is difficult to determine precisely which engines located in the telephone survey *should be* – but aren't – either permitted or registered with the relevant state or city authorities. The list of engines available from the New York City DEP, for example, included only permitted emergency engines. As such, it did not include any engines that might qualify for a permit-by-rule or any non-emergency engines. A list of non-emergency engines was not available from the City DEP, while the State DEC's database on permitted non-emergency engines did not provide sufficient information to determine which engines were located within New York City. In Fairfield County, many of the 245 engines that were identified in the survey but that are not included in the state's database fall below the CT DEP's permitting threshold of 500 kW. Nearly all of these engines *would be* subject to the lower 37 kW permitting threshold for engines in southwestern Connecticut. However, as noted previously, the regulations introducing this lower permitting threshold did not take effect until 2002, and had resulted in the permitting of only 10 additional engines in southwestern Connecticut as of March 2003.

[26] Specifically, the description of PSR's methodology in Appendix A states: "As a result, our compilation is probably over representative in some SIC's and under representative in others. Nonetheless, the results and incidence of ownership in the target areas were similar enough to the national pattern to make statistically valid estimates of the installed generator set population."

V. Emissions Estimates

This study was motivated by a lack of information on the existing base of distributed generation capacity in the Northeast and by a corollary lack of information on the potential environmental impacts associated with increased use of that capacity under changing electricity market conditions. As foregoing chapters have indicated, the existing base of distributed generation capacity in the Northeast and elsewhere in the nation is overwhelmingly dominated by diesel internal combustion engines, which typically have very high emissions rates for several pollutants of concern. All or nearly all of these diesel engines are also most likely to operate during periods of peak electricity demand, whether in response to an emergency shortfall in grid-supplied electricity, to assist a utility in avoiding such a shortfall, or simply to avoid the high prices that may occur during peak periods. Throughout most of the Northeast, peak electricity demand occurs in the summer time, during the hottest hours of the day. These are also the times when air quality is likely to be at its worst and states and localities are most apt to be in violation of federal ambient air quality standards. Because small diesel generators are often located near or in densely populated urban areas, and because their emissions – which include toxic constituents and high levels of particulate matter, as well as pollutants like nitrogen oxides (NOx), hydrocarbons or volatile organic compounds (HC or VOC),[27] sulfur dioxide (SO_2) and carbon monoxide (CO) – tend to be released closer to the ground, operation of these engines, especially during peak hours, poses particular public health concerns. Because no mechanism has existed to comprehensively track these units, empirical data on their actual historic emissions or potential future impact have been scarce. Hence, an important aspect of the survey effort was the collection of information on engine operation.

This chapter begins by providing some additional detail on the particular health risks associated with diesel exhaust. Although many previous analyses and many existing state regulatory provisions focus on NOx emissions,[28] other components of the exhaust emissions from a diesel generator are likely to pose more significant air quality and public health risks, particularly in the immediate vicinity of such a generator. In fact, emissions of particulate matter and toxic or hazardous air pollutants are likely to be

[27] The term "hydrocarbons" encompasses a very large number of chemical compounds characterized by different molecular combinations of hydrogen and carbon. Together, nitrogen oxides (NOx) and hydrocarbons are the primary precursor pollutants in the photochemical formation of ground-level ozone (commonly known as "smog"). Technically, VOCs are a subset of hydrocarbons. Additional terms that are used for this class of pollutants in some regulatory settings include NMHC (non-methane hydrocarbons), NMOG (non-methane organic gases) and NMOC (non-methane organic compounds). While the specific set of chemical compounds encompassed by each of these terms and acronyms differs slightly, we utilize the terms VOC and HC more or less interchangeably throughout this report.

[28] The focus on NOx is likely due to the fact that most of the Northeast's non-attainment problems with respect to federal health-based air quality standards have centered on ground-level ozone. Nitrogen oxides, together with hydrocarbons, are the chief pollutants responsible for ozone pollution. As noted in the introduction to this report, NOx emissions for uncontrolled diesel generators are far higher on a per MWh basis than for most other conventional generation options. However, total NOx emissions from distributed diesel electricity generators to date are probably relatively small compared to other NOx sources in most state inventories. Hence the discussion in this chapter focuses on diesel particulate emissions.

responsible for some of the most significant health impacts associated with diesel IC generators.

The second section of this chapter describes the results of a preliminary emissions impact analysis using data collected in the Power Systems Research (PSR) telephone survey, as well as initial assessments of the emissions impacts associated with on-site generators operated as part of recent summer demand response programs sponsored by the New York and New England ISOs. Overall, these results indicate that emissions from on-site generators operated under these programs *to date* are relatively small compared to overall emissions inventories for pollutants such as NOx and PM_{10} at the state or regional level.[29] For comparison with the emissions estimates presented later in this chapter, for example, the U.S. Environmental Protection Agency's (EPA's) estimated 1999 NOx and PM_{10} inventories for the state of New York totaled over 830,000 tons and 558,000 tons, respectively. The estimated 1999 emissions inventory for these pollutants in Connecticut was over 140,000 tons for NOx and almost 64,000 tons for PM_{10}.[30]

However, any comparisons based on annual or seasonal emissions totals fail to capture important dimensions of the public health concern, which include the spatial and temporal concentration of distributed generator emissions as well as the toxic and potentially carcinogenic nature of diesel emissions in particular. Another study, currently underway with funding from EPA, is attempting to model the emissions impacts of demand response programs in New England and has come to similar preliminary conclusions: that net emissions from on-site generators operating under formal demand response programs are likely to be small in most years compared to total electric system emissions, but that these emissions could nevertheless pose local health threats in cases where generators are located in densely populated areas.[31]

A. Health Risks Associated with Diesel Exhaust

Diesel exhaust is a complex mixture of gases and particles. Its characteristics – in terms of chemical composition and constituent particle sizes – vary significantly across different engine types, engine operating conditions and fuel formulations. The gaseous fraction of diesel exhaust is composed of typical combustion gases as well as hazardous air pollutants including volatile organics, alkenes, aromatic hydrocarbons, and aldehydes.[32] One of the main characteristics of diesel engines is the release of tiny

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[29] PM_{10} refers to particulate matter 10 microns in aerodynamic diameter or smaller. Elsewhere in this report we refer to "fine" particles or $PM_{2.5}$, which includes particles 2.5 microns in aerodynamic diameter or smaller.

[30] This emissions information is from the EPA's 1999 National Emissions Inventory.

[31] The analysis: *Estimating Emissions from Demand Response Programs in New England,* is being conducted by Synapse Energy Economics with EPA funding. Its results are expected to be released during the summer of 2003.

[32] EPA has collected and reviewed emissions data on hazardous air pollutants (HAPs) as part of its proposed MACT rulemaking on reciprocating internal combustion engines (RICE), available at http://www.epa.gov/ttn/atw/mactprop.html. Additional information on HAP emissions from IC engines is available from EPA's Industrial Combustion Coordinated Rulemaking (ICCR) Federal Advisory

particles that are mainly aggregates of spherical carbon particles coated with inorganic and organic substances. These substances consist of elemental carbon and soluble compounds such as aldehydes, alkanes and alkenes, and high-molecular weight polycyclic aromatic hydrocarbons (PAH) and PAH-derivatives.

A large percentage of the U.S. population is exposed to ambient fine particles ($PM_{2.5}$),[33] of which diesel particulate matter is typically a significant constituent. An extensive epidemiological literature – including several major studies – provides evidence of the adverse health effects of airborne particles on human health. Short and long-term exposures to fine particles are associated with acute and chronic excess morbidity and mortality in the general population. Vulnerable subgroups include those individuals who have existing respiratory or lung inflammation, repeated respiratory infections, or chronic bronchitis or asthma. Children and the elderly may also have increased sensitivity to $PM_{2.5}$ exposure. Recent epidemiological research suggests that sub-daily exposures on a time-scale of 1-5 hours can produce heart attacks and exacerbate allergenic responses.

Available evidence indicates that there are significant human health hazards associated with exposure to diesel exhaust.[34] EPA recently concluded that diesel exhaust is a chronic respiratory hazard and a probable human lung carcinogen.[35] Documented short-term responses to exposure to diesel exhaust include pulmonary resistance (i.e. difficulty breathing due to airway constriction), acute irritation (e.g. eye, throat, bronchial), neurophysiological symptoms (e.g. lightheadedness, nausea and slowed reaction time, as well as difficulty with balance, verbal recall and color perception), and respiratory symptoms (cough, phlegm). Epidemiological studies indicate that occupational exposure to diesel exhaust can result in increased frequency of bronchitic symptoms, cough and phlegm, wheezing, and decrement in lung function. Other studies have documented health effects in children exposed to diesel particulates at school and in people who live within 100 meters of highways that are heavily traveled by diesel trucks. Children with bronchial hyper-reactivity or susceptibility to other allergens appear to be particularly sensitive to adverse effects. These findings are supported by studies of laboratory animals which have demonstrated that the inhalation or direct application of diesel into the respiratory tract – over both chronic and short-term exposures – induces inflammatory airway changes, lung function changes, and increased susceptibility of exposed animals to lung infection.

Committee Act (FACA) process (at http://www.epa.gov/ttnatw01/iccr/engine/em97rice.pdf) and from a study published by the Western States Petroleum Association and the American Petroleum Institute titled *Air Toxic Emission Factors for Combustion Sources Using Petroleum-Based Fuels* (October 17, 1997).

[33] See Footnote 29 for an explanation of the term "$PM_{2.5}$".

[34] For further detail and additional references see, for example: *Health Assessment Document for Diesel Engine Exhaust*. U.S. Environmental Protection Agency. Washington DC, 2002; Lloyd A.C. and Cackette T.A. Diesel engines: environmental impact and control; *Journal of the Air & Waste Management Association* [*J. Air & Waste Manage. Assoc.*] 2001, 51:809-847; or *Staff Report: Initial Statement of Reasons for Rulemaking—Proposed Identification of Diesel Exhaust as a Toxic Air Contaminant.* California Air Resources Board: Sacramento, CA, 1998.

[35] The potential cancer-causing (carcinogenic) effects of exposure to diesel exhaust have been the subject of numerous studies, involving both human subjects and in vitro laboratory investigations. These studies have provided compelling qualitative evidence for the carcinogenic effects of diesel exhaust, though cancer risks have proved difficult to quantify.

Finally, there are a number of review articles which postulate that air pollutants generally – and diesel exhaust in particular – play a role in the increasing prevalence of asthma and other allergic respiratory diseases. In studies with human volunteers, diesel exhaust particles made people with allergies more susceptible to allergens such as dust and pollen. Exposure to diesel exhaust also causes inflammation in the lungs, which may aggravate chronic respiratory symptoms and increase the frequency or intensity of asthma attacks. The potential relevance of these immunological endpoints to public health is very high, due the high incidence of respiratory allergies and asthma in many urban areas.

B. Emissions Analysis for New York City and Fairfield County, CT Using PSR Telephone Survey Results

This section describes an initial analysis of emissions impacts from distributed generators in New York City and Fairfield County, Connecticut using the results of the PSR telephone survey and city or state permitting records for these areas (see Chapter IV). Because of the enormous uncertainties associated with the more general estimates of engine population presented in Chapter III and because information on actual engine operation is simply not available for the broader region, the analysis is confined to those areas covered by PSR's detailed telephone surveys. However, even these data contain significant uncertainties with respect to total populations and operating hours. Given these uncertainties, and the fact that the electricity markets in both New York City and Fairfield County are likely to be somewhat unique – in terms of their transmission and supply situation, certainly, and perhaps for other reasons as well – the applicability of these results to other parts of the Northeast is uncertain.

1. Methodology for Emissions Impact Analysis

Engine owners contacted in the PSR telephone survey were asked to estimate actual hours of operation per year for each of their units. Their responses were compiled to estimate annual generation totals for each survey area (in MWh), aggregated by fuel type and engine size. To reflect the fact that the telephone surveys captured only a subset of the total engine population, engines identified in state or city databases – and not identified in the surveys – were added to those identified through the telephone surveys and were assumed to operate for a number of hours comparable to surveyed engines used for the same application. The resulting adjusted generation totals were then combined with emissions factors published by the Sacramento Metropolitan Air Quality Management District (SMAQMD), which primarily cites EPA's AP-42 values (see Table V-1).[36] The AP-42 emissions factors are from engine tests performed as many as 15 years

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[36] The emissions factors in Table V-1 are taken from the SMAQMD *Internal Combustion Engine Policy Manual*, September 2002. The SMAQMD Manuel largely relies on EPA's Compilation of Pollutant Emission Factors, AP-42, Fifth Edition, Volume I: *Stationary Point and Area Sources* (located at http://www.epa.gov/ttn/chief/ap42/index.html) except where emissions testing performed by the state of California for purposes of BACT determinations revealed higher emissions rates than the AP-42 factors. Additional sources of information on NOx emission factors and control costs include an Ozone Transport Commission study conducted in support of its model rule for distributed generation (*Control Measure*

ago, and therefore do not necessarily reflect the performance of today's engines. Given that the average age of units identified in the telephone surveys was 12-14 years, the use of emissions factors typical of new engines would likely understate actual emissions impacts.

Compared to the emissions factors in Table V-1 for diesel engines larger than 600 hp, the use of emissions factors typical of new diesel engines would reduce estimated NOx emissions by approximately 30% and estimated PM_{10} by nearly 20%. Information on emissions factors characteristic of new engines is available from the Regulatory Assistance Project's (RAP) Distributed Generation Emission Model Rule.[37] While emissions factors for new engines are readily available through emissions testing and regulations, those for older engines more representative of the existing population are more difficult to determine. The IC engine emissions factors used for this analysis are in agreement with a recent Natural Resource Defense Council (NRDC) report, which cites a range of emissions rates from 10 – 41 lb/MWh for NOx and 0.4 – 3 lb/MWh for PM_{10}.[38] Because uncontrolled diesel engines are at the high end of emissions rates for IC engines generally, the NRDC figures are consistent with the emissions factors shown in Table V-1. Additionally, historical emissions information from Caterpillar indicates that NOx emissions rates for engines manufactured in the late 1980s and early 1990s averaged 32 lb/MWh.[39] Finally, emissions data compiled by the state of New Hampshire from 45 stack tests on IC engines show NOx emissions rates varying from a low of 11.4 lb/MWh to a high of 42.5 lb/MWh.

Table V-1
Distributed Generator NOx, PM_{10} and VOC Emissions Factors

Engine Type	NOx		PM_{10}		VOC	
	g/hp-hr	lb/MWh	g/hp-hr	lb/MWh	g/hp-hr	lb/MWh
Diesel < 600 hp	14.06	41.47	1.00	2.95	1.14	3.36
Diesel > 600 hp	10.86	32.04	0.32	0.94	1.00[b]	2.95[b]
Natural Gas[a]	10.89[b]	32.12[b]	0.15[b]	0.45[b]	0.43[b]	1.27[b]
Gasoline	5.00	14.72	0.33	0.97	9.79	28.88

a Emissions factors represent an average for three types of natural gas engines. Additional detail in Table VI-2.
b SMAQMD emission factors used in place of AP-42, see Footnote 36.

Development Support Analysis of OTC Model Rules, 2001 available at: http://www.sso.org/otc/Publications/pub2.htm) and NESCAUM's December 2000 report: *Status of NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers and IC Engines.*

37 This information – which was compiled by Joel Bluestein – can be accessed online at: http://www.raponline.org/ProjDocs/DREmsRul/Collfile/DGEmissionsMay2001.PDF.

38 From the NRDC article: "Small and Clean is Beautiful: Exploring the Emissions from Distributed Generation and Pollution Prevention Policies," Nathanael Greene and Roel Hammerschlag, *Electricity Journal*, June 2000.

39 This is the average for all diesel engines at the time of manufacture and does not account for the effect of normal wear and tear.

2. Estimated Emissions Impact for New York City

Survey results for New York City indicate that the units identified by PSR produce a total of approximately 489,400 MWh in a typical year (as shown in Table IV-3), based on reported hours of operation and individual unit capacities. Owners of emergency engines contacted through the survey indicated that their engines typically operated about 150 hours per year. Assuming the same hours of operation apply to those 512 units in the City's list of emergency engines that were *not* captured in the telephone survey, results in an additional 42,300 MWh of estimated electrical output. Combining these generation totals with the emissions factors shown in Table V-1, yields the emissions estimates shown in Table V-2. It should be emphasized, however, that considerable uncertainties are embedded in these estimates. For example, PSR's survey identified a number of engines that were also included in the City's list of emergency engines (even though these engines were not identified as emergency engines in the survey), that seemed to operate, according to the owners' survey responses, well beyond the limits theoretically applicable to emergency engines. Specifically, reported hours of operation for the subset of units common to both lists averaged approximately 450 hours per year, which – if accurate – suggests either that the City's list includes some non-emergency engines or that some emergency engines are being operated beyond their permit limits. If one assumed that all 512 un-surveyed units in the City list operated 450 hours per year (rather than the 150 hours per year assumed for emergency engines in Table V-2), our estimate of total generation would increase by more than 84,700 MWh, while associated annual emissions would increase by 1,430 tons for NOx, by 50 tons for PM_{10} and by 100 tons for VOC.

Table V-2
Estimated New York City Emissions from Surveyed and Permitted Engines According to PSR Survey Results

	Engines	MWh/yr	NOx (tons/yr)	PM_{10} (tons/yr)	VOC (tons/yr)
Diesel	1,652	379,620	6,480	260	580
Natural Gas	549	144,720	2,320	30	90
Gasoline	35	7,360	50	5	110
Total	2,236	531,700	8,850	295	780

3. Estimated Emissions Impact for Fairfield County, Connecticut

Based on owner-reported hours of operation, the engines surveyed by PSR in Fairfield County generate a total of approximately 9,300 MWh per year (as reported in Table IV-6). Total generation is relatively modest because most of the engines identified in the Fairfield County survey were designated for emergency use only and were estimated by their owners to operate, on average, only 42 hours per year. As discussed in Chapter IV, an additional 266 engines (beyond those captured in PSR's telephone survey) are identified in state permitting records. Of these, 184 are designated for emergency use and were assumed to operate for the same average of 42 hours per year. The remaining 82 non-emergency engines identified in state permitting records were assumed to operate for an average of 3,790 hours per year, consistent with the estimated hours of operation reported by owners of non-emergency engines in PSR's survey. The results of these assumptions, applied to the combined population of engines identified in the telephone survey *and* in state permitting records, are shown in Table V-3. The table indicates a total of nearly 320,000 MWh per year of generation by distributed generators in Fairfield County and estimated annual emissions impacts of over 5,000 tons for NOx, almost 200 tons for PM_{10} and more than 500 tons for VOCs. It should be emphasized that these figures assume that the high level of utilization (nearly 3,800 hrs/yr) reported by owners of non-emergency engines contacted in PSR's survey apply equally to all non-emergency engines included in state permit records for Fairfield County. As such, these estimates are quite uncertain and may substantially overstate actual generation and emissions totals for southwest Connecticut.

Table V-3
Estimated Fairfield County Emissions from Surveyed and Permitted Engines According to PSR Survey Results

	Engines	MWh/yr	NOx (tons/yr)	PM_{10} (tons/yr)	VOC (tons/yr)
Diesel	447	313,040	5,220	190	470
Natural Gas	90	3,700	60	0.80	2.5
Gasoline	23	2,820	20	1.4	40
Total	560	319,560	5,300	192	513

4. Estimated Summertime Emissions Impact

The above estimates of total electrical output and associated emissions for distributed generators in New York City and Fairfield County are presented on an annual basis. For reasons discussed elsewhere in this report, actual output from distributed generators, and associated emissions, are unlikely to be evenly distributed throughout the year. In particular, both output and emissions from engines operated for peak shaving purposes or as part of emergency or price-based demand response programs are likely to be concentrated during the summer months. These are also the months when emissions are likely to be of greatest concern from an air quality and public health perspective. By contrast, operation of baseload units, as well as any operation of emergency back-up generators for routine maintenance and testing purposes is likely to be distributed more evenly throughout the year. To estimate summer-only emissions in New York City and Fairfield County we assumed that all operation by baseload units, plus up to 50 hours per year of operation reported for emergency units, is distributed evenly throughout the year. In addition, all operation by peak-shaving engines and any operation above 50 hours per year by emergency engines are assumed to occur during the 5 month period from May to September. The resulting estimated summertime (or "ozone season") emissions for New York City and Fairfield County are 53% and 42% of the total annual emissions estimates, respectively. The proportion of summer emissions in Fairfield County is very close to 5/12. This reflects the dominance of non-emergency engines from the state's permit files in the estimated generation totals. The permits do not make a distinction between peak and baseload engines, so to estimate summer emissions all non-emergency engines were assumed to operate as baseload units – that is to say, consistently throughout the year.

C. Emissions Estimates for ISO-Sponsored Demand Response Programs

As noted elsewhere in this report, the Independent System Operators (ISOs) for both New York and New England have instituted formal demand response programs in the last few years to help address system adequacy and reliability concerns during summer peak demand periods. In general, these programs provide incentives for customers to voluntarily reduce their demand for grid-supplied electricity during periods of high prices and/or when reserve margins (the difference between available grid-connected generating capacity and load) become critically low. These conditions can occur system-wide or in particular transmission-constrained "load pockets" within the ISO region. An individual customer's demand response capability can include the ability to curtail load (e.g. by turning off equipment) or the ability to self-generate using an on-site generator, or a combination of both.

1. New York ISO Program

During the summer of 2002, the New York ISO invoked its price-responsive load program on a total of four days. This program is activated when the ISO forecasts a day-ahead operating reserve deficiency. Compensation for participating in the program is a minimum of $500/MWh, but may be higher if the locational market price per marginal MWh rises higher. For the summer of 2002, the New York ISO signed up 1,702 customers, who registered 1,480 MW of collective demand response capability in the form of both on-site generation and load curtailment. These totals included an unknown number of residential customers who registered a combined demand response capability of 20 MW through a third party aggregator.

Data for the four price-responsive load program events in New York during the summer of 2002 are summarized in Table V-4. All four events included New York City along with other areas of the state, but only data for participation in New York City are shown. The two events in April occurred on unusually hot days, when two major transmission lines were out of service. Because these events occurred before the usual start of the season, program coordinators relied on customers who had signed up the previous year. For this reason, statewide participation in the April events was smaller than during the later events in July and August, though the demand response in New York City was still substantial. Because of the unexpected nature of the April event, there was little advance notice to allow participating customers to plan load curtailment activities. Hence, it is estimated that the demand response elicited on April 17 and 18 was mostly attributable to on-site generation. For the later price-responsive events, NY-ISO's record of the contribution of on-site generation (as opposed to load curtailment) is shown in Table V-4.

Unfortunately, information about the specific engines that supplied on-site generation during NY ISO's 2002 price-responsive load program events is not available. Table V-4 provides emissions estimates calculated by applying emissions factors typical of a larger than 600 hp diesel engine. These emissions factors were used because the average size of load reduction that customers signed up for under this program was 870 kW. Cumulative emissions for the four price response events using this assumption total almost 14 tons of NOx and 0.4 tons of PM_{10}. If emissions factors for diesel engines smaller than 600 hp were used, estimated NOx emissions would increase by 37% and estimated PM_{10} emissions would increase by 68%. The average compensation paid to demand response participants during these events was the ISO's floor price of $500 per MWh (market prices did not exceed this minimum during any of the 2002 events).

Table V-4
Emissions Estimates for 2002 New York ISO Price-Responsive Load Program in New York City

Date	MWh Generated	NOx (tons)	PM_{10} (tons)	VOC (tons)
04/17/02	154.6*	2.48	0.07	0.23
04/18/02	191.5*	3.07	0.09	0.28
07/30/02	267.7	4.29	0.13	0.39
08/14/02	251.3	4.03	0.12	0.37
Total	**865.1**	**13.86**	**0.41**	**1.28**

*No data on generation vs. curtailment were available for the April events. The response is assumed to be from generation due to the unexpectedness of the events, which occurred before the start of summer.

2. New England ISO Programs

The New England ISO sponsors two demand response programs: an emergency demand response program and a price response program. As its name implies, the emergency demand response program is designed to reduce system loads at times when demand threatens to exceed supply and brown-outs or black-outs are imminent. This program is triggered when the ISO begins calling for voltage reductions (technically, Step 12 of the ISO's Operating Procedure Number 4). By contrast, the ISO's price response program is designed to elicit voluntary demand response at any time when the power pool's hourly forecast "Energy Clearing Price" (ECP) rises above $100 per MWh. Compensation for both programs is a minimum of $100/MWh and is a maximum of $100 above the forecast ECP, depending on other factors such as transmission congestion impacts.

Results for Summer 2001

In a report released in August 2002, the New England ISO presented an assessment of emissions impacts associated with its summer 2001 demand response programs.[40] Table

[40] The report, initially prepared by Boston-based EFI, a consulting firm, was released by ISO-NE in August 2002 under the title: *Summer 2001 NEPOOL Load Response Program: Emissions Impacts & Associated Discussions.*

V-5 summarizes the results of the ISO's analysis; it also includes NESCAUM's estimates of NOx and PM_{10} emissions using the emissions factors for diesel engines larger than 600 hp shown in Table V-1. The ISO analysis does not provide an estimate of particulate emissions, and assumes a NOx emissions factor of 21.8 lb/MWh – approximately 32% lower than the 32 lb/MWh emissions factor for diesel engines larger than 600 hp used for these calculations, cited in Table V-1.[41] As indicated by Table V-5, participation in ISO-New England's formal demand response programs was relatively modest in 2001, eliciting only 24 MWh of curtailment and 479 MWh of on-site generation. All of the generation occurred in Massachusetts over a period of 6 days.

Table V-5
Emissions Estimates for 2001 New England ISO Demand Response Programs

State	MWh Curtailed	MWh Generated	NOx (tons)*	PM_{10} (tons)	VOC (tons)
Connecticut	17.78				
Massachusetts		478.99	7.67	0.23	0.71
Maine	6.48				
Total	24.26	478.99	7.67	0.23	0.71

* New England ISO's August 2002 Report (see Footnote 40) uses a lower NOx emissions factor of 21.8 lb/MWh, resulting in total NOx emissions of 5.22 tons.

Results for Summer 2002

Between 2001 and 2002, the New England ISO substantially expanded participation in its demand response programs, particularly with respect to the contribution from load curtailment which grew from 24 MWh in the summer of 2001 to more than 430 MWh in the summer of 2002. However, distributed generation also increased by more than 25%, from 479 MWh in 2001 to more than 600 MWh in 2002. All of this curtailment and generation was provided under the price response program, which was triggered for a total of 166 hours on 12 different days during 2002 when market clearing prices rose above $100/MWh. However, the ISO never found it necessary to call for voltage reductions in 2002, so the conditions necessary to trigger the emergency demand response program did not occur.

Table V-6 summarizes data on the number of customers who signed up to participate in the New England ISO's two demand response programs in 2002. Overall, 221 customers enlisted in one or the other of these programs, providing a combined demand response capability of 185 MW. Note that this figure for total demand response capability includes both load curtailment capacity and on-site generation capacity (information on the generator component of total capability was not readily discernible from the 2002 data provided by the ISO). Because the ISO made a particular effort to enlist participants in

[41] Note that the ISO analysis also accounts for offsetting emissions reductions at grid-connected peaking units, based on the assumption that these units operated less as a result of customer-based demand response. These or other potentially offsetting emissions benefits of on-site generation (such as reduced demand for central-station generators to be operating in a stand-by capacity for system reliability purposes) were not evaluated as part of this study. These issues *are* being addressed in the more detailed emissions impact analysis being sponsored by EPA and conducted by Synapse Energy Economics (see Footnote 31).

the transmission-constrained southwest Connecticut load pocket, a disproportionate percentage of the overall demand response capability signed up for these programs was concentrated in that part of New England.[42] As Table V-6 indicates, more customers (and more MW) were enrolled in the emergency demand response program in southwest Connecticut; whereas there was greater participation in the price response program compared to the emergency program elsewhere in New England. The average demand response capacity signed up by participants in southwest Connecticut was also significantly greater than elsewhere in the region (an average of 2.5 MW compared to 0.5 MW).

Table V-6
New England ISO 2002 Program Enrollment[43]

Program Enrollment	Southwest CT		Other New England		Total	
	Customers	MW	Customers	MW	Customers	MW
Emergency Response	39	91	38	21	77	112
Price Response	13	7	131	66	144	73
Total	52	98	169	87	221	185

Table V-7 summarizes estimated emissions associated with the 2002 price response program using information provided by the New England ISO and the emissions factors for larger than 600 hp diesel engines shown in Table V-1. Table V-8 shows how on-site generation and emissions were distributed over the 12 individual price response events in 2002, and the share of total generation and emissions attributable to participants in different states for each event. Unlike 2001, most of the on-site generation that occurred under the New England ISO's formal demand response programs in 2002 occurred in Connecticut. Finally, Table V-9 shows emissions impacts associated with on-site generation in 2002 by price response program participants in southwestern Connecticut, specifically.

[42] Note that "southwest Connecticut" in the context of the ISO-New England programs encompasses a somewhat larger area than Fairfield County, where PSR conducted detailed telephone surveys. However, Fairfield County covers a large portion of southwest Connecticut, including 22 towns out of the 51 towns that are considered to be within the transmission-constrained southwest Connecticut load pocket.
[43] This table was a part of a presentation "Making Demand Response Work in New England" by Henry Yoshimura of NE ISO in January, 2003, for the Northeast Energy and Commerce Association, available at: http://www.ksg.harvard.edu/hepg/Papers/Yoshimura_NE.Demand.Response_01-09-2003.pdf.

Table V-7
Emissions Estimates for 2002 New England ISO Price Response Program

State	MWh Curtailed	MWh Generated	NOx (tons)*	PM_{10} (tons)	VOC (tons)
Connecticut	272.25	421.97	6.76	0.20	0.62
Massachusetts	88.38	27.07	0.43	0.01	0.04
Maine	62.55	81.82	1.31	0.04	0.12
New Hampshire	7.48	0.00	0.00	0.00	0.00
Rhode Island	3.44	0.00	0.00	0.00	0.00
Vermont	0.04	72.53	1.16	0.03	0.11
Total	**434.13**	**603.39**	**9.67**	**0.28**	**0.89**

* As noted in Table V-5, the New England ISO used a lower NOx emission factor in its analysis of the 2001 programs.

Table V-8
Distribution of 2002 NE ISO Price Response Events and Emissions, by State

Date	MWh On-Site Generation	NOx (tons)	PM_{10} (tons)	VOC (tons)	% of Gen in CT	% of Gen in MA	% of Gen in ME	% of Gen in VT
6/26/2002	3.32	0.05	0.00	0.00	27%	62%	11%	0%
7/3/2002	4.9	0.08	0.00	0.01	93%	3%	4%	0%
7/23/2002	60.91	0.98	0.03	0.09	16%	12%	12%	60%
7/30/2002	37.05	0.59	0.02	0.05	17%	7%	34%	42%
7/31/2002	16.12	0.26	0.01	0.02	48%	0%	50%	2%
8/5/2002	31.33	0.50	0.01	0.05	67%	7%	23%	3%
8/13/2002	11.06	0.18	0.01	0.02	54%	12%	26%	8%
8/14/2002	130.34	2.09	0.06	0.19	82%	1%	15%	2%
8/15/2002	221.71	3.55	0.10	0.33	91%	1%	6%	2%
8/19/2002	13.61	0.22	0.01	0.02	50%	11%	16%	23%
9/10/2002	47.88	0.77	0.02	0.07	83%	9%	7%	0%
9/16/2002	25.16	0.40	0.01	0.04	38%	10%	15%	38%
Total	603.4	9.67	0.28	0.89	70%	4%	14%	12%

Table V-9
Generation and Estimated Emissions for 2002 NE ISO Price Response Program in Southwest CT

Date	MWh Generated	NOx (tons)	PM_{10} (tons)	VOC (tons)
06/26/02	0.29	0.0046	0.0001	0.0004
07/03/02	2.52	0.0404	0.0012	0.0037
07/23/02	6.99	0.1124	0.0033	0.0103
07/30/02	4.57	0.0734	0.0021	0.0067
07/31/02	0.37	0.0060	0.0002	0.0006
08/05/02	2.91	0.0468	0.0014	0.0043
08/13/02	2.02	0.0325	0.0009	0.0030
08/14/02	2.16	0.0347	0.0010	0.0032
08/15/02	2.14	0.0344	0.0010	0.0032
08/19/02	1.47	0.0236	0.0007	0.0022
09/10/02	0.80	0.0128	0.0004	0.0012
09/16/02	2.14	0.0345	0.0010	0.0032
Total	**28.36**	**0.456**	**0.013**	**0.042**

The price response program in New England is relatively new and hence participation to date has been modest. However, New England ISO has indicated that it hopes to significantly expand participation in this program in the future, while also continuing a robust emergency demand response program. Ultimately, the ISO's objective is to increase the total demand response capability available to the pool in emergency or high price situations to as much as 600 MW. Achieving this objective amounts to tripling the current capacity enlisted in these programs. If that were achieved and if the price response and/or emergency response programs were triggered more frequently in future summers, the associated emissions impacts could increase accordingly. This could also be compounded by an increase in participation from customers who are already signed up for the price response program. During 2001 and 2002, many customers were signed up but chose to not officially operate their engines under the program.

In general, this preliminary analysis suggests that additional emissions impacts associated with the use of stationary diesel generators *in recently introduced formal demand response programs* have to date been small – on an annual basis – relative to state and local inventories of emissions from all pollutant sources. Moreover, emissions from the existing operation of larger, non-emergency engines for peak-shaving and baseload purposes (as described in Section B of this chapter) are likely to dwarf any near-term increase in emissions associated with the use of diesel generators under the formal demand response programs being introduced or augmented by grid operators. In New Hampshire, for example, no new generation occurred under the New England ISO's formal price response program in 2002. However, the New Hampshire Department of Environmental Services had documented a significant increase in NOx emissions from stationary IC engines in the 1990s, presumably as the result of the increased operation of non-emergency engines in response to other market factors.[44]

D. Potential Impact of Real-Time Pricing on Future Emissions from On–Site Generators

Another source of impetus for increased reliance on distributed generators in coming years – and one which may prove much more difficult to track than participation in formal demand response programs[45] – is the potential exposure of growing numbers of

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[44] Specifically, NOx emissions from fossil-fuel fired IC engines grew from 1.4% to 14% of New Hampshire's total ozone season NOx inventory from electric generating units between 1993 and 1999. In just the 3 years between 1996 and 1999, estimated NOx emissions from these engines more than doubled – from 243 tons in the 1996 ozone season to 576 tons in the 1999 ozone season. Moreover, the NH Department of Environmental Services was aware of at least two instances where multiple IC engines were installed to reduce electricity costs. These developments prompted NH to adopt new emissions rules for IC engines in 2001.

[45] Because participants in formal demand response programs are typically offered incentives or capacity payments, or in some cases may participate like conventional generators in day-ahead or real-time electricity markets, the ISO will generally have, at a minimum, a record of the total demand response provided and who provided it. By contrast, the ISO would not necessarily have information on customers who simply choose on their own initiative to avoid high prices or capacity charges by reducing consumption of grid-supplied electricity during peak demand periods.

customers to real-time electricity prices. The desirability of moving more customers to real-time pricing in the interests of promoting a more robust and efficient electricity market is widely recognized among analysts and economic regulators (including FERC).[46] That option is most likely to be feasible for (and attractive to) large commercial or industrial electricity users that are in a position to respond to temporal price fluctuations by either curtailing load or by self-generating. How much on-site generation might occur in direct response to price signals depends on the relative economics of operating an on-site generator versus purchasing electricity off the grid. Generally, the costs of conventional distributed generation have been estimated to range from 7 to 15 cents per kilowatt-hour. Within that range, diesel engines tend to be among the cheapest options for on-site generation, with combined operation and maintenance costs ranging from approximately 6 cents/kWh for larger engines, up to 7.25 cents/kWh for smaller engines (i.e. below 500kW).[47] Though these costs are well above the average wholesale cost of grid-supplied electricity in most parts of the country, they are well *below* the spot market price spikes that have occurred with some regularity during peak demand periods in the Northeast and elsewhere during recent years.

To get some sense of how often it might be economic to operate on-site diesel generators instead of purchasing centrally generated electricity,[48] NESCAUM examined recent spot market prices posted by the New England and New York ISOs. The results, in terms of the numbers of hours when each pool's prices rose above certain levels in 2002 and in the first three months of 2003, are presented in Table V-10.[49] Figure V-1 presents the number of hours when the price of electricity exceeded 8 cents/kWh and 10 cents/kWh in the two regions, for each month in 2002. In New England, the hourly energy clearing price (ECP) rose above 8 cents/kWh for 77 hours in 2002; in New York, the figure was 136 hours. In 2001, the ECP rose above 8 cents/kWh for 215 hours in New England, and for 146 hours in New York. Interestingly, the record for January and February of 2003 shows a surprising number of high-price hours in both ISOs for these months. This may be an isolated phenomenon attributable to the region's unusually cold weather and high energy prices in other sectors during these months, but it does suggest that both power control

[46] At present, the vast majority of customers – and nearly all small customers – pay a flat, fixed rate for each kilowatt-hour regardless of when they consume that kilowatt-hour. As such they are impervious to the fact that the real cost of supplying a marginal kilowatt-hour can fluctuate dramatically from hour to hour. The non-existence of any real-time price signal that would allow demand to respond to supply has been identified as a major shortcoming of many current electricity markets.

[47] The 7-15 ¢/kWh cost range for all forms of conventional distributed generation is taken from an Arthur D. Little White Paper: *Distributed Generation: Understanding the Economics*, 1999. The cost figures cited for large versus small diesel generators come from an NRDC report, *Distributed Resources and Their Emissions: Modeling the Impacts*, Greene, Hammerschlag, and Keith, 2001.

[48] Of course, operating costs will vary with individual engines, as well as with fuel costs. In addition, a number of other factors can shift the economic calculation or otherwise influence the decision to operate an on-site generator. For example, utilities sometimes charge high "stand-by" rates precisely to discourage on-site generation, or permit restrictions may apply, or there may be an additional hassle factor (to the facility operator) involved in switching to on-site generation.

[49] Historically, the New England ISO has recorded a pool-wide Energy Clearing Price or ECP (although it has recently also introduced location-based marginal pricing). In Table V-10, the Location Based Marginal Price (LBMP) represents the real time prices of electricity in the New York City area.

areas may be subject to wintertime, as well as summertime price spikes under certain conditions.

Table V-10
New England Energy Clearing Price (ECP) New York City Location Based Marginal Price (LBMP) Data

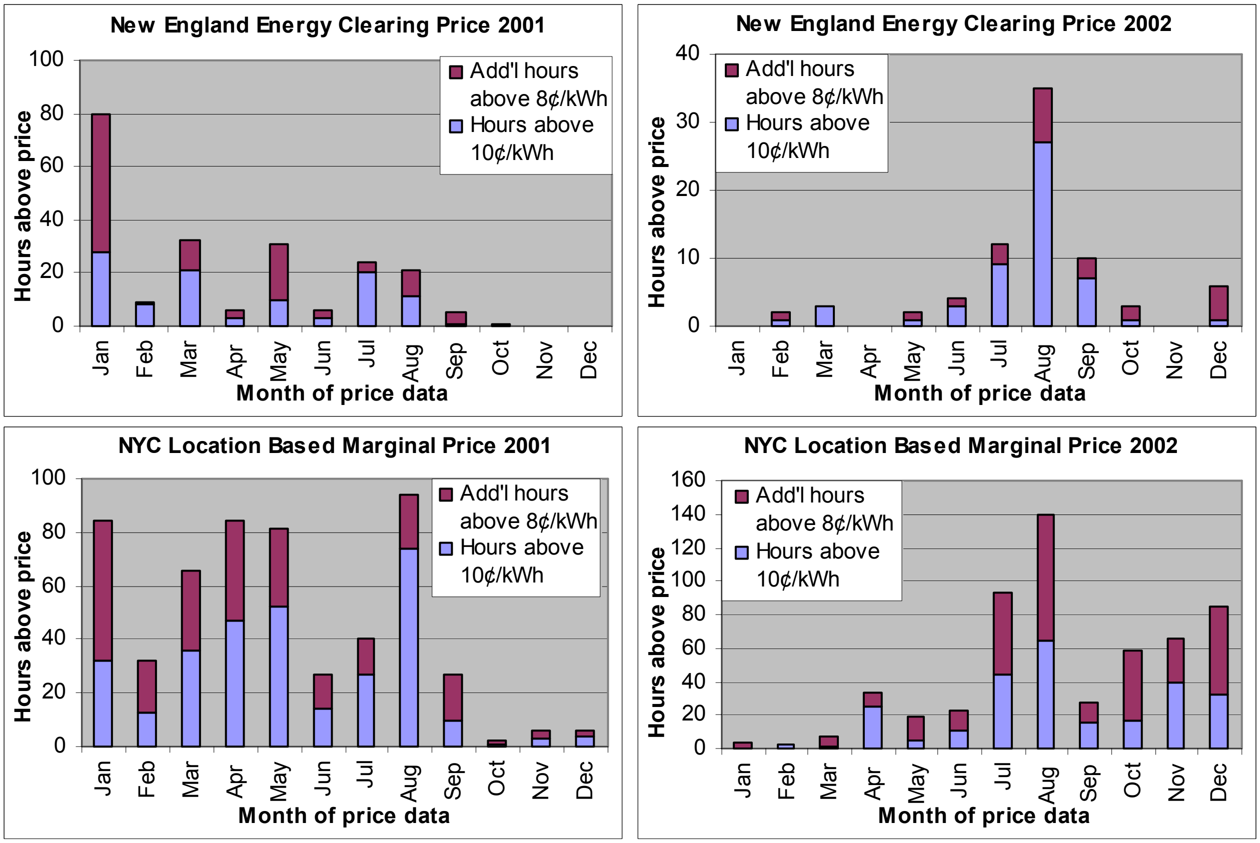
Electricity Prices		Hours above 10¢/kWh	Hours above 8¢/kWh	Hours above 7¢/kWh	Hours above 6¢/kWh	Average Prices
2001	New England ECP	106	215	381	787	3.99¢
	New York City LBMP	313	549	739	1066	4.47¢
2002	New England ECP	53	77	133	299	3.54¢
	New York City LBMP	256	557	890	1643	4.47¢
January 2003	New England ECP	87	87	141	324	6.02¢
	New York City LBMP	154	269	392	505	7.95¢
February 2003	New England ECP	78	179	278	401	6.94¢
	New York City LBMP	161	316	444	508	8.60¢
March 2003	New England ECP	N/A[a]	N/A[a]	N/A[a]	N/A[a]	N/A[a]
	New York City LBMP	166	286	369	470	8.16¢

[a] value not available at the time of publication

Assuming, for example, that an additional 600 MW of diesel engine capacity in New England or New York were to operate an average of 100 hours per year simply in response to high short-term prices, the additional generation (60,000 MWh) and emissions would substantially exceed – by as much as two orders of magnitude – the amounts estimated in connection with formal demand response programs sponsored by the NY and NE ISOs to date. Whether the above calculation grossly overstates or understates the potential impact of real-time pricing on engine operation in New England or New York is, of course, a different question, and one that was outside the scope of this study to evaluate. To put the same (essentially arbitrary) figure of 60,000 MWh in a different perspective, however, it may also be useful to point out that it is much *lower* than the output estimated in earlier sections of this chapter for generators either surveyed or registered in New York City and Fairfield County. The results of PSR's telephone surveys in these areas suggest that current engine output – when one includes the non-emergency peak shaving and baseload generators that account for most hours of operation – is already on the order of hundreds of thousands of MWh per year. Whether the (typically larger) non-emergency units are in a position to substantially increase their output in response to stronger price signals would therefore be an important question to investigate.[50]

[50] At present, emergency engines in the Northeast are almost without exception precluded from operating in response to real-time price signals by current permitting restrictions. Whether these permitting restrictions are always respected, and how effectively they can be enforced, is a separate but important question for state regulators and policymakers.

Figure V-1
Hours that Electricity Prices Exceeded 8¢ and 10¢/kWh in 2001 and 2002



VI. Emission Control Technologies for Stationary Diesel Generators

The operation of all internal combustion (IC) engines results in the emission of hydrocarbons (HC or VOC[51]), carbon monoxide (CO), nitrogen oxides (NOx), and particulate matter (PM). The actual concentrations of these pollutants in engine exhaust vary from engine to engine, depend on the mode of operation and are strongly related to the type of fuel used. An important emissions control priority for diesel engines (compared to stationary IC engines using other fuels such as natural gas, propane or gasoline) is particulate matter. Indeed, for the reasons discussed in the previous chapter, particulate emissions pose perhaps the most serious public health risks associated with diesel exhaust.

Various emission control technologies exist for IC engines, which can afford substantial reductions in all four pollutants listed above. Uncontrolled emissions and achievable emissions reductions depend on fuel characteristics, on whether the engine is being run rich, lean, or stoichiometrically[52] and on the emission control technology being used. The most important control options include oxidation catalysts, which can be used to control HC, CO and PM emissions; selective catalytic reduction or SCR, which is very effective for NOx control; and particulate filters, which can achieve high levels of particulate control. Other emissions control options discussed in this chapter include lean-NOx catalysts, ignition timing adjustments and exhaust gas recirculation (EGR). Importantly, both filter and catalyst controls can provide significant (80-90%) reductions in HC emissions – including emissions of toxic HC – in addition to PM and CO reductions. Filters can also help eliminate the characteristic odor of diesel engine exhaust. Finally, an important issue in assessing control options for diesel IC engines is fuel quality, and sulfur content in particular. All of the major control options discussed in this report perform significantly better with – and in some cases require – lower sulfur fuel.

The discussion of stationary IC engine control technologies in this chapter was prepared by ESI International, Inc. for NESCAUM as a complement to the engine inventory and related efforts described elsewhere in this report. It begins by providing some additional background on the status and market for distributed generation technology generally. (Additional background information on stationary generator engines is provided in Appendix D.) This introductory section is followed by a summary of emissions factors for uncontrolled engines and a review of available control options for diesel and natural gas-powered stationary engines used as distributed power generation resources. Chapter

[51] The acronyms correspond to "hydrocarbons" (HC) and "volatile organic compounds" (VOC). See additional explanation for these terms in Footnote 27.

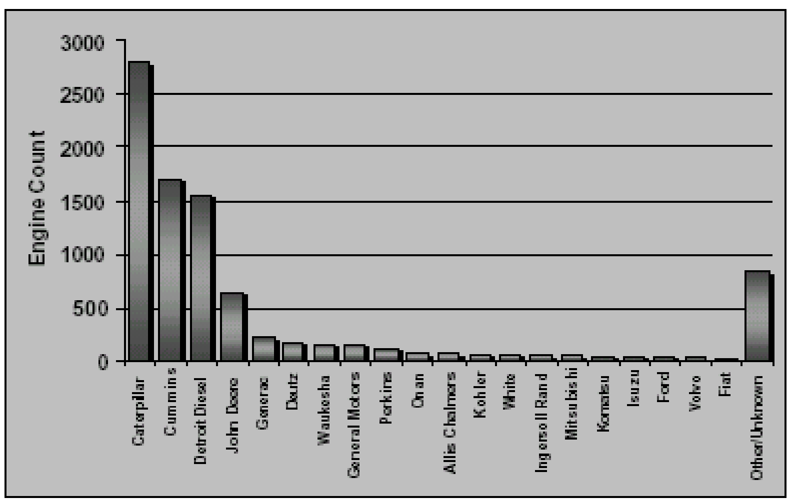
[52] In stoichiometric combustion, the air-fuel mixture is theoretically balanced such that there is exactly enough oxygen to allow for complete oxidation of the fuel. In an engine running rich, the air-fuel ratio is tipped toward relatively more fuel and less air, whereas in an engine running lean the ratio is tipped toward relatively less fuel and more air. All diesel engines inherently operate lean, whereas natural gas fired engines, for example, can operate in all three modes.

VII, also prepared by ESI International, Inc., provides six detailed case studies of actual control technology installations on diesel generators.

A. Distributed Generation Market Status and Outlook

As noted elsewhere in this report, stationary reciprocating IC engines are the most common and most technically mature of all distributed generation technologies. They are available from small sizes (e.g. 5 kW for residential back-up generation) to large generators (e.g. 7 MW). Stationary diesel engines are, by a large margin, the most commonly used engines for distributed generation. In fact, over 90% of distributed generators are powered by diesel fuel.[53] In 2001, the California Air Resources Board (CARB) surveyed stationary IC engines throughout California and found that diesel-powered Caterpillar engines were by far the most commonly used engine, as shown in Figure VI-1.

Figure VI-1
Permitted Stationary Diesel Engine Database Manufacturer Listing



Source: California Air Resources Board "Permitted Stationary Diesel Engine Database." January 16, 2002.

In recent years, the convergence of a number of factors has led to a growing national interest in distributed generation generally. They are:

- A need for the existing electric power infrastructure to keep pace with demand for high-quality, reliable power;
- Dramatic reduction in large electric generating plant investment due to regulatory, capital, environmental and political constraints;

[53] U.S. Department of Energy, Office of Distributed Energy Resources. Web Site: Distributed Energy Resources, www.eren.doe.gov/der.

- Restructuring of the power industry leading to competitive markets and reduced incentives for utilities to invest in new generating facilities; and
- Technological advancements in small-scale power generating equipment with greater efficiencies, improved environmental performance and lower costs.

1. National Market

Nationally, many large industrial customers have already embraced distributed generation. The largest potential new markets for distributed generation in the near term therefore lie with commercial and small to medium-sized industrial customers. Currently, there are more than 60,000 MW of distributed power installed in North America in the form of IC engines and gas turbines.[54] Their use in providing back-up power continues to grow steadily at 7% per year. Other distributed generation applications for meeting baseload and peaking requirements are growing at 11% and 17% respectively.[55]

A number of trends in distributed generation markets are now becoming evident. There is increasing use of:

- On-site power for cost and reliability reasons.
- Combined heat and power (CHP) or cogeneration applications.
- Combinations of CHP with thermal energy storage systems.
- Fuel cells.
- Uninterruptible power systems to ride through brief power disturbances and outages.
- Increased use of natural gas for distributed generation. (In fact, DOE has estimated that distributed generation using natural gas could account for as much as 20% of all power generation nationwide by the year 2020.)

2. Small Commercial and Residential Markets

Advances in new generating technologies have been moving in the direction of smaller equipment with increased output, making on-site generation increasingly feasible for commercial establishments and even residential energy users. Small manufacturing plants and medium-sized buildings can now be powered by cost-effective combustion turbines as small as 500 kW, while IC engines have become cost-effective for systems down to 50 kW, making them suitable for small office buildings and even for free-standing commercial establishments such as restaurants.

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[54] As indicated in the Introduction to this report, other estimates of installed distributed generation capacity nationwide are even higher, ranging up to 127,000 MW using PSR's estimation methodology.

[55] U.S. Department of Energy, Office of Distributed Energy Resources. Web Site: Distributed Energy Resources, www.eren.doe.gov/der.

In the residential market, utilization of distributed generation technologies is growing among affluent U.S. consumers. A recent national survey found measurable interest in customer-site generation within this group:[56]

- More than half reported their power usage had increased over the past five years.
- 31% expressed interest in generating on-site power.
- Nearly 10% had purchased or leased an emergency or back-up generator for their primary residence.
- 16% used such equipment in weekend or vacation homes.
- 40% were considering purchasing a generator.
- Congress is also becoming interested in this issue. The Home Energy Generation Act, introduced in 1999, is aimed at setting standards to encourage the development of residential distributed energy technologies.

3. Combined Heat & Power Market

A thriving U.S. market exists for IC engine-based combined heat and power (CHP) applications (see Footnote 11). The top twelve states with CHP sites using stationary IC engines are shown in Table VI-1 below.

Table VI-1
Top Twelve States with Combined Heat & Power Sites Using Stationary IC Engines

State	Number of Sites	Percent of U.S. Market
California	493	42.0
New York	136	11.6
New Jersey	117	10.0
Massachusetts	46	3.9
Illinois	44	3.7
Pennsylvania	44	3.7
Connecticut	43	3.7
Michigan	28	2.4
Texas	23	2.0
Virginia	17	1.4
Florida	16	1.4
Arizona	15	1.3
Total	*1022*	*87.1*

Source: Resource Dynamics Corporation. Web Site: Distributed Generation Information Center, www.distributed-generation.com.

[56] Resource Dynamics Corporation. Web Site: Distributed Generation Information Center, www.distributed-generation.com.

4. Utility Market

Across the nation, the use of distributed generating resources among utility companies is gaining momentum. Some recent examples include:

- Tacoma Public Utilities in Washington State installed 30 diesel-fired engines for a combined capacity of 48 MW.
- GPU Energy proposed a program to New Jersey regulators for the dispatch of customer-owned diesel stand-by generators, with the aim of overcoming delivery system bottlenecks in certain counties.
- PacifiCorp leased and installed five 22 MW gas turbines adjacent to the main office of its subsidiary, Utah Power, in Salt Lake City.
- The New York Power Authority is seeking regulatory approval to install eleven gas turbines (with a collective capacity of 444 MW) at six sites in New York City boroughs and on Long Island.
- Long Island Power Authority has added a new supplemental service rate to on-site generators that will provide lower demand charges during the summer and lower energy charges throughout the year.
- Transmission grid operators (Independent System Operators or ISOs) are establishing programs to reward energy users who shed utility load by using on-site generators. Programs established by PJM,[57] ISO-New England and the New York ISO are the most favorable to distributed generation.

Note that utility sites for distributed generation often use several large engines in parallel to produce larger amounts of electricity, as illustrated in Figure VI-2.

Figure VI-2
An Example of Multiple Engine Usage (Tacoma Power, CAT 3516B Diesel Engines with SCR)

SCR Catalyst

Engine Housing

[57] See description of PJM in Footnote 8.

B. Emissions Factors for Stationary IC Engines

As noted previously, emissions vary from engine to engine and model to model and depend on mode of operation as well as fuel qualities. Nonetheless, the values shown in Table VI-2 are representative of what may be expected for typical engines. Note that the NOx and PM_{10} emissions factors shown in Table VI-2 are consistent with those used to estimate emissions impacts in Chapter V of this report (see Table V-1).

Table VI-2
Typical Emissions Factors for Stationary IC Engines

Fuel Type	Engine Type	Emission Factor (g/hp-hr)				
		NOx	CO	VOC	SOx	PM_{10}[a]
Diesel	Up to 600 hp	14.06	8.5	1.14	0.1645	1.00
	Greater than 600 hp	10.86	8.5	1.0[b]	0.1645	0.318
Gasoline	All	4.99	199.13	9.79	0.1645	0.327
Natural Gas	2-Cycle Lean Burn	10.89[b]	1.5	0.43	0.002	0.152[b]
	4-Cycle Lean Burn	11.79[b]	1.6	0.721[b]	0.002	0.152[b]
	4-Cycle Rich Burn	9.98[b]	8.62	0.14[b]	0.002	0.152[b]

[a] Although measured as PM_{10}, particles smaller than 2.5 microns ($PM_{2.5}$) account for most of the overall PM emissions from IC engines.
[b] These emission factors were published by the SMAQMD based on results obtained on existing engines in the course of testing for BACT determinations. They reflect higher emissions rates than the AP-42 factors (see Footnote 36).

Emissions factors such as those summarized in Table VI-2 are important for developing emission control strategies, determining applicability of permitting and control programs, understanding the effects of sources and appropriate mitigation strategies, and a number of other related applications by various users, including federal, state and local agencies, and industry. For obvious reasons, data from source-specific emission tests or continuous emission monitors are generally preferred for estimating actual emissions from individual sources. Unfortunately, source-specific test data are not always available; hence, emission factors are frequently used to estimate emissions, in spite of their limitations.

C. Emission Control Technologies for Diesel and Natural Gas Stationary IC Engines Used in Distributed Power Generation

Most engines used for distributed power generation are powered by either diesel or natural gas. The main emissions control priority for diesel-powered engines has been PM and NOx emissions. For natural gas-powered engines, the control priority has been NOx emissions.

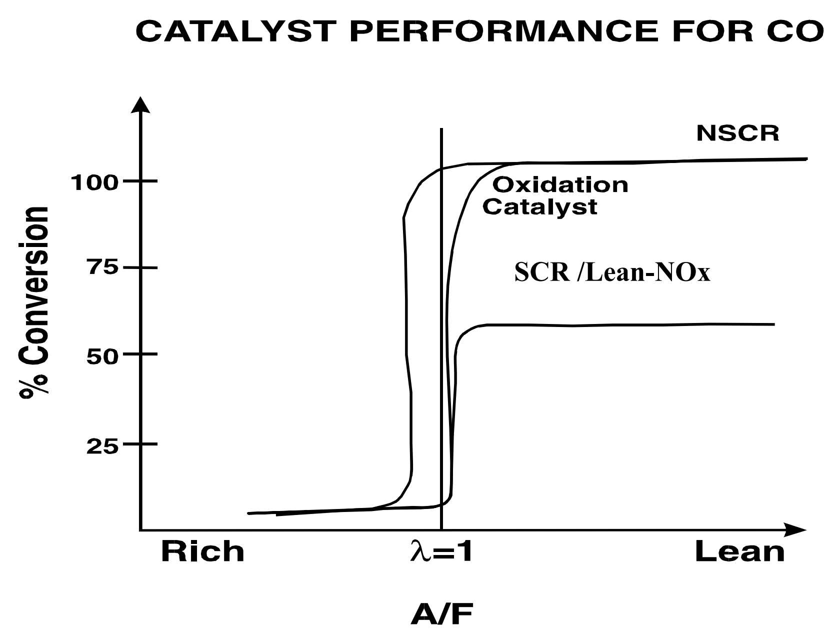
As noted in the introduction to this chapter, PM emissions from diesel-powered engines can be controlled with both diesel particulate filters (DPFs) – which provide very high (>80%) reductions – and diesel oxidation catalysts (DOCs) for more modest (>25%)

reductions. Both DPFs and DOCs can also provide significant reductions in HC, CO and toxic HC emissions. They also serve to eliminate the characteristic odor of diesel engines. NOx emissions, from both diesel and lean-burn natural gas-powered stationary IC engines, have traditionally been controlled using SCR. Here, a reagent – typically ammonia or urea – is added to the oxygen-rich exhaust environment and reacted over a catalyst with the NOx present in the exhaust gases. SCR systems commonly achieve NOx control efficiencies in excess of 90%. Lean-NOx catalysts can also be used for more modest control (15-25%) of NOx emissions from IC engines. Incorporating an oxidation catalytic function with these technologies also allows for the simultaneous control of CO, HC and toxic HC emissions.

Emissions from rich-burn natural gas powered engines can be controlled using non-selective catalytic reduction (NSCR) which can achieve NOx reductions in excess of 90% as well as significant HC reductions. Three-way catalyst (TWC) technology – similar to automotive catalyst technology – can be used on stoichiometrically calibrated natural gas engines for the simultaneous control of NOx, CO, HC and toxic HC emissions.

Figure VI-3 illustrates typical gaseous emissions control performance at various air/fuel ratios for the above mentioned catalysts with respect to CO, NOx and non-methane hydrocarbon (NMHC)[58] emissions.

Figure VI-3
Control Capabilities of Catalyst Control Technology vs. A/F Ratio



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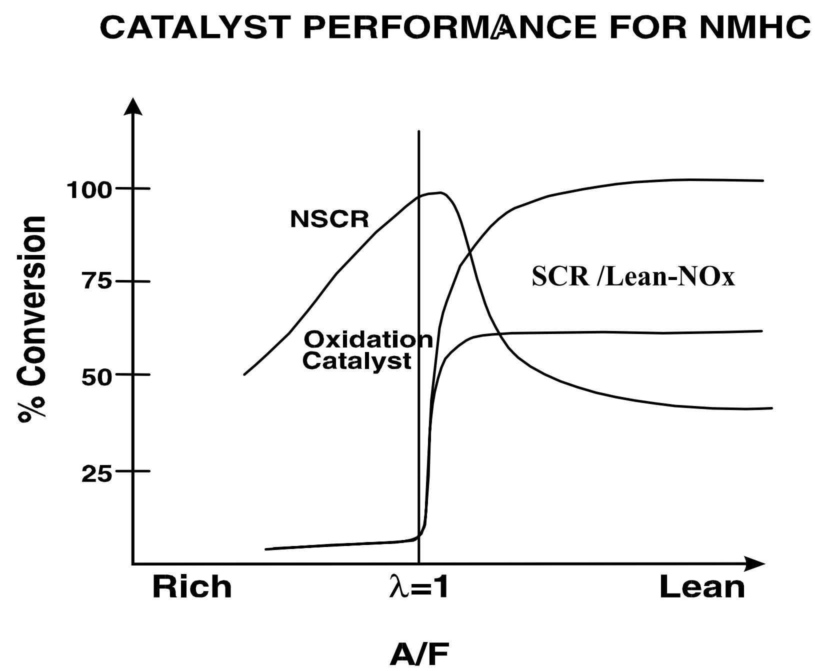
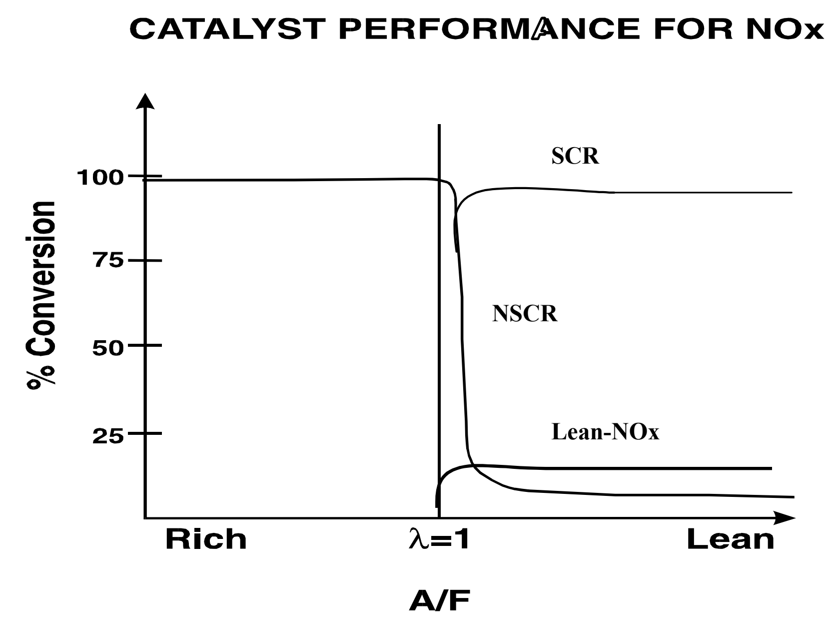
[58] See Footnote 27 for further discussion of the term NMHC.

Figure VI-3 (cont.)
Control Capabilities of Catalyst Control Technology vs. A/F Ratio





Source: Manufacturers of Emission Controls Association, "Emission Control Technology for Stationary Internal Combustion Engines – Status Report," July 1997.

Where diesel particulate filters are used for PM control, an oxidizing catalyst function is often included. When this function is incorporated into a diesel particulate filter, CO and hydrocarbon emissions can be controlled as shown above for oxidation catalysts.

The vast majority of stationary IC engines used for distributed power generation are lean-burn diesel engines. Hence, the rest of this chapter focuses on the following technologies:

- Diesel particulate filters for control of PM and other gaseous emissions from diesel engines,
- Oxidation catalysts for control of PM and other gaseous emissions from diesel engines, and
- Selective catalytic reduction (SCR) for the control of NOx and other gaseous emissions from diesel engines.

To date, the use of emission control technology on stationary diesel engines has been limited. Nevertheless, hundreds of control technology installations exist, with most involving retrofits to existing engines. In addition, control technologies have been demonstrated at installations in Europe, Korea, and Taiwan.

Other emissions control options applicable to diesel engines – such as crankcase emission control, EGR and lean-NOx catalysts – are described later in this chapter.

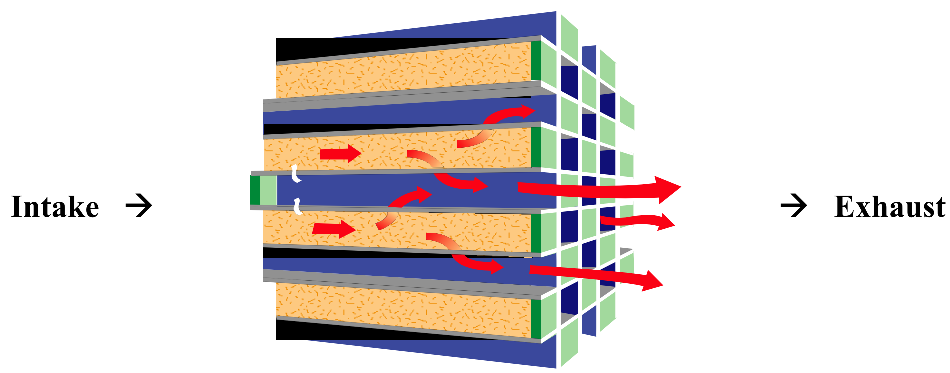
1. Diesel Particulate Filters (DPFs)

As the name implies, diesel particulate filters remove particulate matter in diesel exhaust by filtering exhaust from the engine. They can be installed on both stationary and mobile engines (e.g. diesel vehicles). Since a filter can fill up over time, these systems must provide a means of burning off or removing accumulated particulate matter. A convenient means of accomplishing this is to burn or oxidize accumulated particulate matter on the filter when exhaust temperatures are adequate. By burning off trapped material, the filter is cleaned or "regenerated." Filters that regenerate in this fashion cannot be used in all situations. Both exhaust gas temperature and fuel sulfur level must be taken into consideration.

In some non-road applications, disposable filter systems have been used. A disposable filter is sized to collect particulates for a working shift or some other predetermined period of time. After a prescribed amount of time, or when backpressure limits are approached, the filter is removed and cleaned or discarded. To ensure proper operation, disposable filter systems must be designed for specific engines and engine applications. In many cases, the use of these types of filters on stationary diesel engines for distributed power generation may not be practical.

A number of filter materials have been used in diesel particulate filters, including: ceramic and silicon carbide materials, fiber wound cartridges, knitted silica fiber coils, ceramic foam, wire mesh, sintered metal substrates and temperature resistant paper in the case of disposable filters. Collection efficiencies of these filters range from 50% to over 90 %. Filter materials capture particulate matter by interception, impaction and diffusion. Filter efficiency has rarely been a problem with the filter materials listed above, but work has continued to: (1) optimize filter efficiency and minimize back pressure, (2) improve the radial flow of oxidation in the filter during regeneration, and (3) improve the mechanical strength of filter designs. Figure VI-4 provides a diagram of a typical wallflow-type filter system.

Figure VI-4
Mechanical Filtration of a Wallflow DPF



As shown in Figure VI-4, particulate-laden exhaust enters the filter from the left. Because the cells of the filter are capped at the downstream end, exhaust cannot exit the cell directly. Instead, exhaust gas passes through the porous walls of the filter cells. In the process, particulate matter is deposited on the upstream side of the cell wall. Cleaned exhaust gas exits the filter to the right.

Many techniques can be used to regenerate a diesel particulate filter. Some of these techniques are used together in the same filter system to achieve efficient regeneration. Both on- and off-board regeneration systems exist. The major regeneration techniques are listed below.

- *Catalyst-based regeneration using a catalyst applied to the surfaces of the filter*. A base or precious metal coating applied to the surface of the filter reduces the ignition temperature necessary to oxidize accumulated particulate matter.

- *Catalyst-based regeneration using an upstream oxidation catalyst*. In this technique, an oxidation catalyst is placed upstream of the filter to facilitate oxidation of nitric oxide (NO) to nitrogen dioxide (NO_2). The nitrogen dioxide adsorbs on the collected particulate, substantially reducing the temperature required to regenerate the filter.

- *Fuel-borne catalysts*. Fuel-borne catalysts reduce the temperature required for ignition of trapped particulate matter.

- *Air-intake throttling*. Throttling the air intake to one or more of the engine cylinders can increase the exhaust temperature and facilitate filter regeneration.

- *Post top-dead-center fuel injection*. Injecting small amounts of fuel in the cylinders of a diesel engine after pistons have reached the top-dead-center position introduces a small amount of unburned fuel in the engine's exhaust gases. This unburned fuel can then be oxidized in the particulate filter to combust accumulated particulate matter.

- *On-board fuel burners or electrical heaters*. Fuel burners or electrical heaters upstream of the filter can provide sufficient exhaust temperatures to ignite accumulated particulate matter and regenerate the filter.

- *Off-board electrical heaters*. Off-board regeneration stations combust trapped particulate matter by blowing hot air through the filter system.

Experience with catalyst-based filters indicates that they can achieve a virtually complete reduction in odor and in the soluble organic fraction of particulate emissions. However, some catalysts may also increase sulfate emissions.

Sulfur in diesel fuel affects the reliability, durability and emissions performance of catalyst-based diesel particulate filters. The degree of the impact is dependent both on the technology being applied and the operation of the engine. Sulfur affects filter performance by inhibiting the performance of catalytic materials upstream of, or on the filter. Sulfur also competes with chemical reactions intended to reduce pollutant emissions and creates particulate matter through catalytic sulfate formation. In general, the less sulfur in the fuel, the better the control technology performs. Therefore, when using diesel particulate filter technology, a careful assessment of its suitability should be made based on fuel sulfur content, engine type, filter system, operating conditions and desired control levels.

Filter systems do not appear to cause any additional engine wear or affect engine maintenance. The systems are designed with engine displacement as a key parameter in order to ensure that appropriate backpressures are encountered during engine operation. Concerning maintenance of the filter system itself, manufacturers are designing systems to minimize maintenance requirements during the useful life of the engine. In some cases, however, accumulated lubricating oil ash may have to be periodically removed. Generally, manufacturers provide the end-user with appropriate removal procedures.

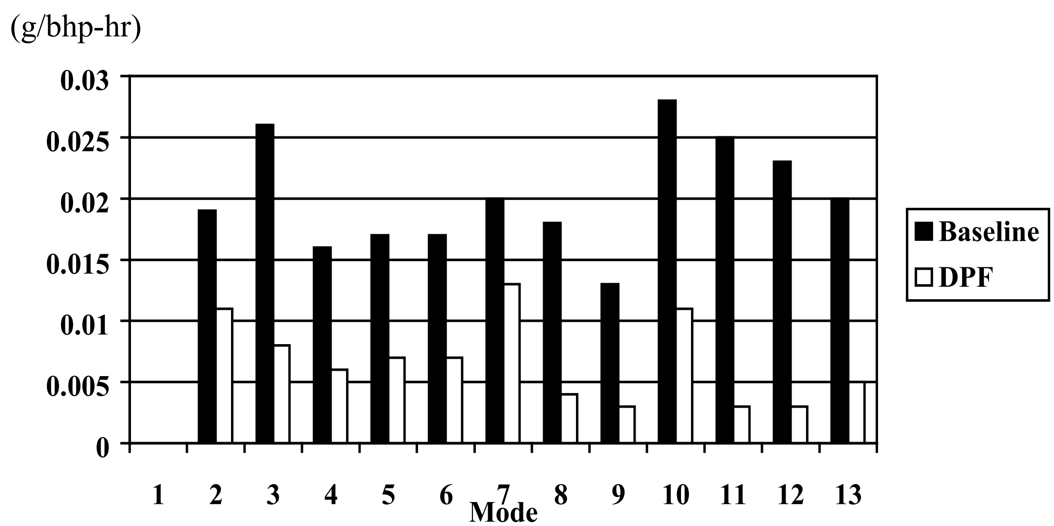
Determining whether a given filter system is appropriate for a given engine in a specific distributed power generation application depends on fuel sulfur level and exhaust gas temperature during operation. The steady-state operation of these engines makes this determination relatively simple. For example, a manufacturer may specify that, when using diesel fuel containing 50 ppm of sulfur, regeneration of the filter will occur at temperatures in excess of 300^{o}C. Running the engine at the load condition in which it will be used to generate electricity and measuring the exhaust gas temperature will indicate whether the filter system is suitable.

Generally, the emissions control performance of diesel particulate filters is well established. While most emissions testing has been performed on transient test cycles, steady state test data also exist.[59] Figure VI-5 shows control performance for a diesel particulate filter applied to a 1998 model year, 400 hp engine under the 13 different operating modes described in Table VI-3. The sulfur content of the fuel used in these tests was 54 ppm (parts per million). As can be seen in Figure VI-5, significant PM reductions were achieved in all operating modes.

Table VI-3
Specifications of a 13-Mode Engine Test Cycle

Mode	Speed, rpm	Torque, %
1	600	0
2	840	50
3	840	100
4	1080	50
5	1080	100
6	1380	50
7	1380	100
8	1560	50
9	1560	75
10	1560	100
11	1800	50
12	1800	75
13	1800	100

Figure VI-5
13-Mode Steady-State Test Cycle for DPF PM Emissions Reduction



[59] Manufacturers of Emission Controls Association, *Stationary Engine Emission Control*, May 2002.

The use of ultra-low (e.g. <15 ppm) sulfur fuel would have resulted in even more dramatic reductions by virtually eliminating the catalytic production of sulfuric acid. Also, formulating the catalyst to minimize the production of sulfuric acid would have further enhanced its control capabilities.

Another advantage of applying particulate filters to diesel-powered stationary IC engines is their ability to dramatically reduce toxic hydrocarbon emissions. As part of the same test program used to generate the results shown in Figure VI-5, the control capability of two separate, catalyst-based DPF systems was evaluated with respect to 18 distinct polycyclic aromatic hydrocarbons (PAHs). The results are shown in Table VI-4. As indicated, average PAH emissions were reduced by 89% and 84% for the systems tested. In this case, the testing was performed over the U.S. Federal Test Procedure (FTP), a transient test cycle used for motor vehicles. Test results would likely be similar, or better, on a steady-state test cycle more representative of a stationary IC engine because of the relatively low load associated with parts of the FTP and correspondingly low exhaust gas temperatures (the catalyst function of the filter performs better at elevated temperatures).

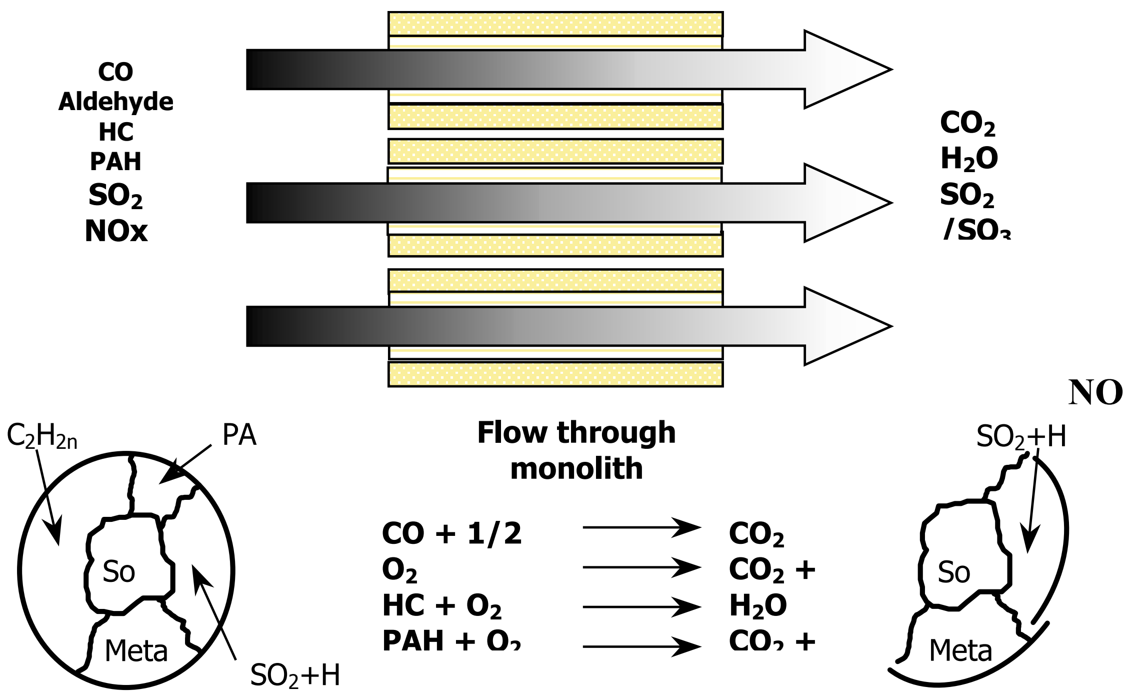
Table VI-4
Reductions in PAH Emissions for Two DPF Systems (micrograms per bhp-hr)

Compound	Baseline	DPF-A	DPF-B	% Red DPF-A	% Red DPF-B
Napthalene	295	50	0	83.0%	100.0%
2-Methylnapthalene	635	108	68	83.0%	89.3%
Acenapthalene	40	0.8	1	98.0%	97.5%
Acenapthene	46	6.7	11	85.4%	76.1%
Fluorene	72	29	12	59.7%	83.3%
Phenanthrene	169	33	26	80.5%	84.6%
Anthracene	10	1	1	90.0%	90.0%
Fluoranthene	7.7	0	2	100.0%	74.0%
Pyrene	14	0	2	100.0%	85.7%
Benzo(a)anthracene	0.22	0	0.01	100.0%	95.4%
Chrysene	0.51	0	0	100.0%	100.0%
Benzo(b)fluoranthene	0.26	0	0	100.0%	100.0%
Benzo(k)fluoranthene	0.15	0	0	100.0%	100.0%
Benzo(e)pyrene	0.26	0	0	100.0%	100.0%
Perylene	0.01	0	0	100.0%	100.0%
Indeno(123-cd)pyrene	0.13	0	0	100.0%	100.0%
Dibenz(ah)anthracene	0.01	0	0	100.0%	100.0%
Benzo(ghi)perylene	0.32	0	0	100.0%	100.0%
Average Reduction				**89%**	**84%**

2. Diesel Oxidation Catalysts (DOCs)

The principle behind oxidation catalysts is that they reduce emissions by causing chemical reactions without themselves being changed or consumed. A DOC system typically consists of a steel housing that contains a metal or ceramic structure which acts as a catalyst support or substrate. The size of the catalyst system depends on the size of engine to which it is being applied. There are no moving parts, just acres of interior surfaces on the substrate coated with either base or precious catalytic metals such as platinum (Pt), rhodium (Rh) and palladium (Pd). Catalysts transform pollutants into harmless gases by causing chemical reactions in the exhaust stream. Diesel oxidation catalysts serve to reduce PM, CO, HC and toxic HC emissions. PM emissions are reduced by the chemical transformation of their soluble organic fraction to carbon dioxide and water. Figure VI-6 outlines the functionality of a diesel oxidation catalyst.

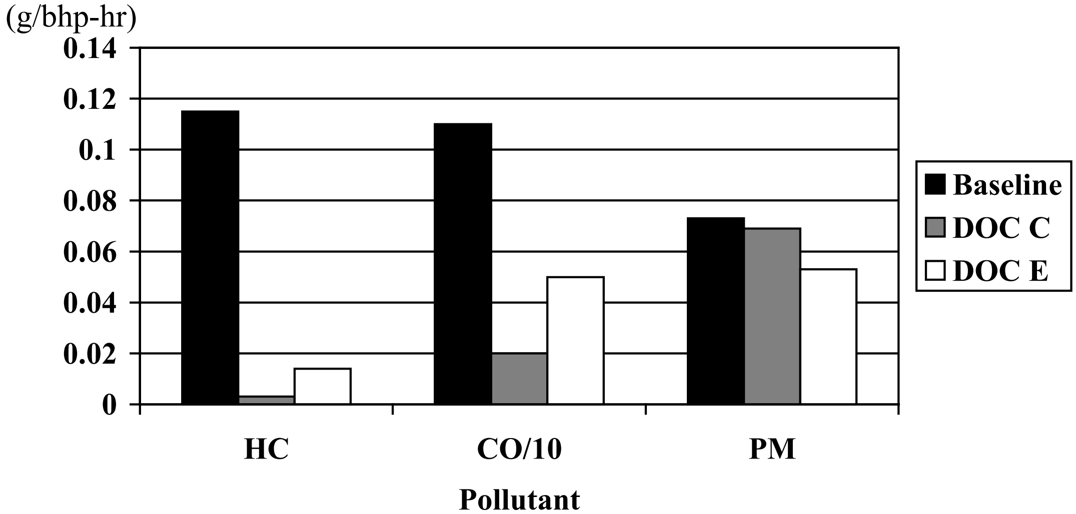
Figure VI-6
Diesel Oxidation Catalysts



Different catalyst formulations can be used to target different pollutants more aggressively than others, as illustrated by a comparison of different catalyst formulations ("C" & "E", respectively) as part of the previously-referenced test program. The results of this comparison over the FTP test cycle are graphed in Figure VI-7.

As indicated by Figure VI-7, catalyst formulation "C" was designed to aggressively reduce both HC and CO, whereas it achieved only modest PM reductions. On the other hand, formulation "E" reduced PM emissions significantly more at the expense of some HC and CO control. These results illustrate why it is important to select an oxidation catalyst knowing which pollutants are of most concern.

Figure VI-7
DOC Performance

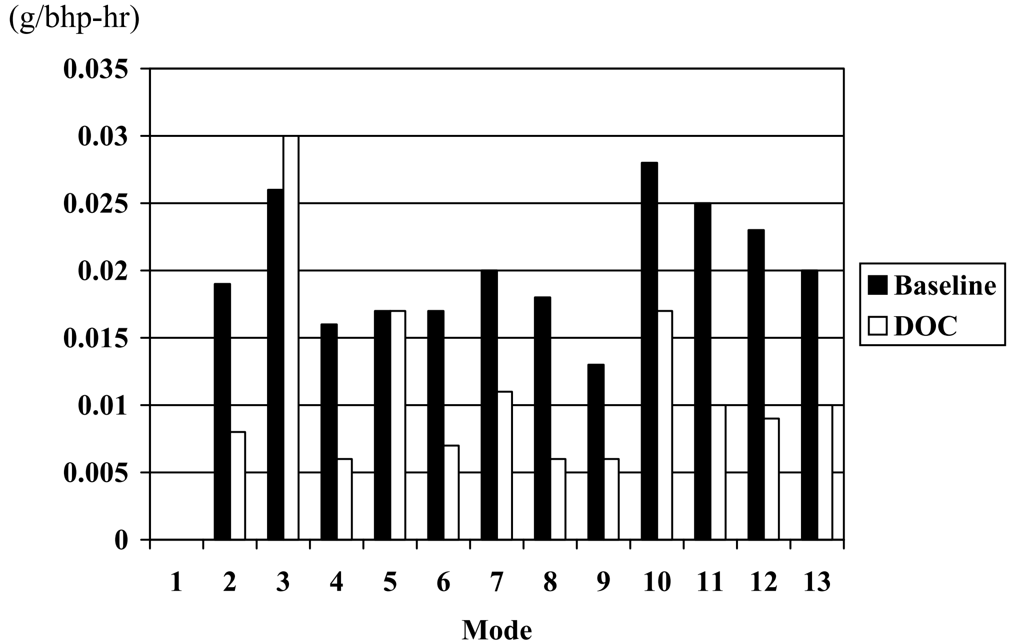


As part of the same test program, different oxidation catalysts were also tested over the steady-state test cycle outlined in Table VI-3. The results of these tests are shown in Figure VI-8. It indicates that the oxidation catalyst was effective in reducing PM emissions in all modes except mode 5 (no change) and mode 3 where there was a slight increase in PM emissions. Significant reductions were found in all other modes – in some instances exceeding 50%. This testing was performed using fuel with a sulfur content of 368 ppm. As is the case with catalyst-based particulate filters, the use of ultra-low (e.g. <15 ppm) sulfur fuel would have resulted in greater reductions and certainly would have eliminated the PM emissions increase found in mode 3 operation.

Like catalyst-based DPFs, oxidation catalysts are effective in controlling toxic HC emissions. Table VI-5 outlines the control capabilities of two DOCs on the same 18 distinct PAHs included in Table VI-4. As indicated, reductions in excess of 50% are readily achieved using the FTP, with reductions approaching 70% for some compounds. For the reasons indicated above, similar or better results can be expected on steady-state test cycles.

Diesel oxidation catalysts are virtually maintenance-free. Periodic inspection to ensure that cell plugging is not occurring is advisable. This would only occur in the case of engine malfunction (e.g. a faulty injector or two) and in that event, the catalysts can easily be cleaned and reinstalled.

Figure VI-8
13-Mode Steady-State Test Cycle for DOC PM Emissions Reductions



Like diesel particulate filters, diesel oxidation catalysts are also affected by sulfur. Hence, the sulfur content of diesel fuel is critical to applying catalyst technology. Catalysts used to oxidize the soluble organic fraction of particulate emissions can also oxidize sulfur dioxide to form sulfates, which are counted as part of total particulate emissions. This reaction is not only dependent on the level of sulfur in the fuel, but also on the temperature of the exhaust gases. Catalyst formulations have been developed which selectively oxidize the soluble organic fraction while minimizing oxidation of the sulfur dioxide. However, the lower the sulfur content in the fuel, the greater the opportunity to maximize the effectiveness of oxidation catalyst technology for both better total control of PM and greater control of toxic hydrocarbons. The lower, 500 ppm sulfur fuel that was introduced in 1993 throughout the U.S. has thus facilitated the application of catalyst technology to diesel-powered vehicles. Furthermore, the very low fuel sulfur content (30 ppm) available in several European countries, and more recently in the U.S., has further enhanced catalyst performance.

Catalysts have also been installed on engines using higher sulfur fuel (e.g. >500 ppm sulfur). The performance of an oxidation catalyst on such fuel will vary with catalyst formulation, engine type and duty cycle. In all cases, however, catalyst performance is adversely affected by the presence of sulfur in the fuel.

Table VI-5
Reductions in PAH Emissions for DOCs (micrograms per bhp-hr)

Compound	Baseline	Cat B	Cat D	% Red Cat B	% Red Cat D
Napthalene	295	159	182	46.1%	38.3%
2-Methylnapthalene	635	278	277	56.2%	56.4%
Acenapthalene	40	13	13.6	67.5%	66.0%
Acenapthene	46	25	24.4	45.7%	47.0%
Fluorene	72	29	28.9	59.7%	59.9%
Phenanthrene	169	54	56	68.0%	66.9%
Anthracene	10	2.6	2.8	74.0%	72.0%
Fluoranthene	7.7	2.6	4.9	66.2%	36.4%
Pyrene	14	5	6.4	64.3%	54.3%
Benzo(a)anthracene	0.22	0.05	0.18	77.3%	18.2%
Chrysene	0.51	0.16	0.33	68.6%	35.3%
Benzo(b)fluoranthene	0.26	0.09	0.12	65.4%	53.8%
Benzo(k)fluoranthene	0.15	0.05	0.08	66.7%	46.7%
Benzo(e)pyrene	0.26	0.08	0.14	69.2%	46.2%
Perylene	0.01	0	0	100.0%	100.0%
Indeno(123-cd)pyrene	0.13	0.04	0.07	69.2%	46.2%
Dibenz(ah)anthracene	0.01	0	0	100.0%	100.0%
Benzo(ghi)perylene	0.32	0.1	0.22	68.8%	31.3%
Total	**1290.57**	**568.77**	**597.14**	**55.9%**	**53.7%**
Average Reduction				**68.5%**	**54.1%**

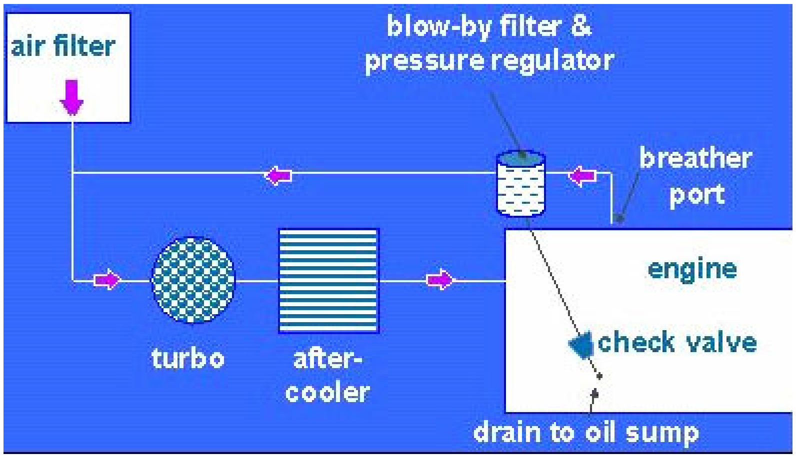
3. Crankcase Emission Controls

In most existing turbocharged diesel engines, the crankcase breather is vented to the atmosphere – often using a downward directed draft tube to prevent fouling of the turbocharger and the resultant maintenance. While a rudimentary filter is often installed on the crankcase breather (the vent for the oil reservoir), a substantial amount of particulate matter is often released to the atmosphere. For diesel engines used in motor vehicle applications, emissions through the breather may exceed 0.7 g/bhp-hr during idle conditions, even on recent model year engines.

One solution to this problem is the use of a multi-stage filter designed to collect, coalesce and return the emitted lube oil to the engine's sump.[60] Filtered gases are returned to the intake system, balancing the differential pressures involved. Typical systems consist of a filter housing, a pressure regulator, a pressure relief valve and an oil check valve. These systems greatly reduce crankcase emissions.

[60] *NOx and PM Control from Heavy-Duty Diesel Engines Using a Combination of Low Pressure EGR and Continuously Regenerating Diesel Particulate Filter*, S. Chatterjee, R. Conway, S. Viswanathan, Johnson Matthey; M. Blomquist, S. Andersson, STT Emtec. SAE Paper No. 2003-01-0048.

Figure VI-9
Schematic of Crankcase Emission Control

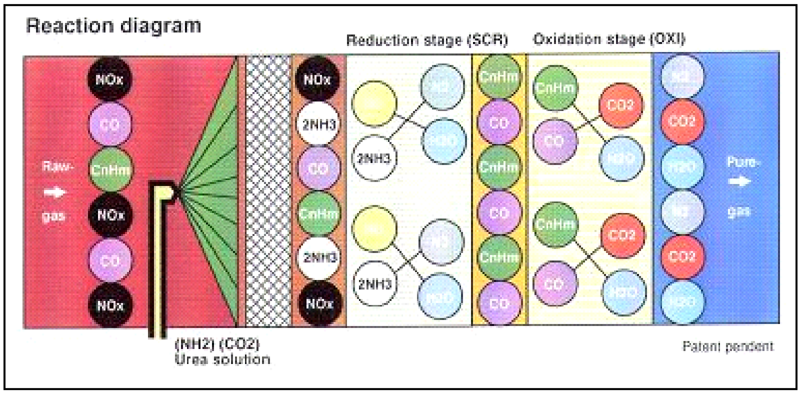


4. Selective Catalytic Reduction (SCR)

SCR has been used to control NOx emissions from stationary sources for over 15 years. More recently, it has been applied to select mobile sources including trucks, marine vessels, and locomotives. Applying SCR to diesel-powered engines provides substantial reductions of NOx emissions.

Like an oxidation catalyst, the catalyst in an SCR system allows chemical reactions to take place that would not take place during normal engine operation. Again, like an oxidation catalyst, the SCR catalyst enables chemical reactions without being consumed itself. Unlike an oxidation catalyst, however, a SCR system needs a chemical reagent – or "reductant" – to convert nitrogen oxides to molecular nitrogen and oxygen in the exhaust stream. The reductant is typically ammonia (NH_3) or urea. It is added at a rate calculated from an algorithm that estimates the amount of NOx present in the exhaust stream. The algorithm relates NOx emissions to engine operating conditions, for example engine revolutions per minute and load. As exhaust gases and reductant pass over the SCR catalyst, chemical reactions occur that reduce NOx emissions from 65% to more than 90%. Where an additional oxidation function is included, HC emissions (including toxic emissions) can be reduced from 50-90% and PM emissions can be reduced 30-50%. Like all catalyst-based emission control technologies, SCR performance is enhanced by the use of low sulfur fuel. Figure VI-10 is a schematic of the functionality of an SCR system.

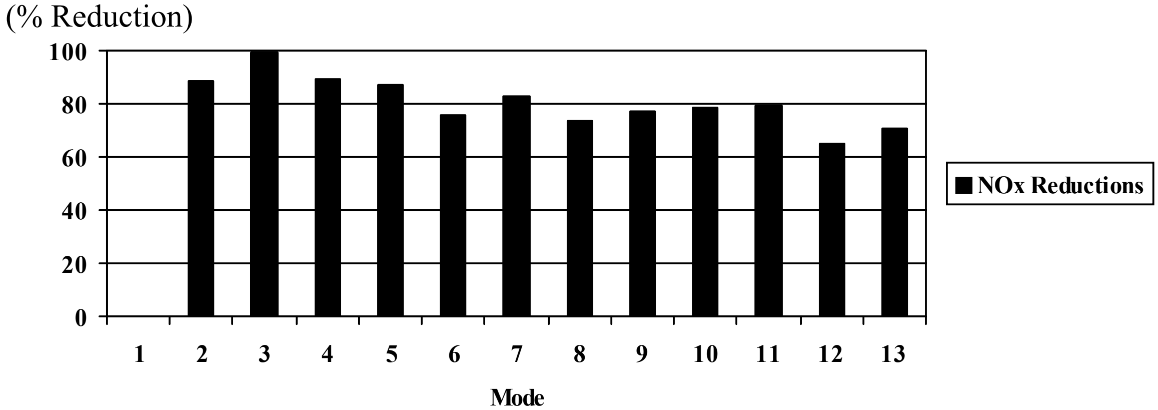
Figure VI-10
Selective Catalytic Reduction



Both precious metal and base metal catalysts have been used in SCR systems. Base metal catalysts, typically vanadium and titanium, are used for exhaust gas temperatures between 450^{o}F and 800^{o}F. For higher temperatures (675^{o}F to 1100^{o}F), zeolite catalysts may be used. Precious metal SCR catalysts are also useful for low temperatures (350^{-} 550^{o}F). Note that the benefits of low sulfur fuel and the potential for sulfuric acid formation apply also to SCR systems that use precious metals.

The same 13-mode steady-state test cycle outlined in Table VI-3 was used to test NOx control performance for an SCR system. The results, shown in Figure VI-11, suggest achievable reductions ranging from 65% (in mode 12) to nearly 100% (in mode 2).

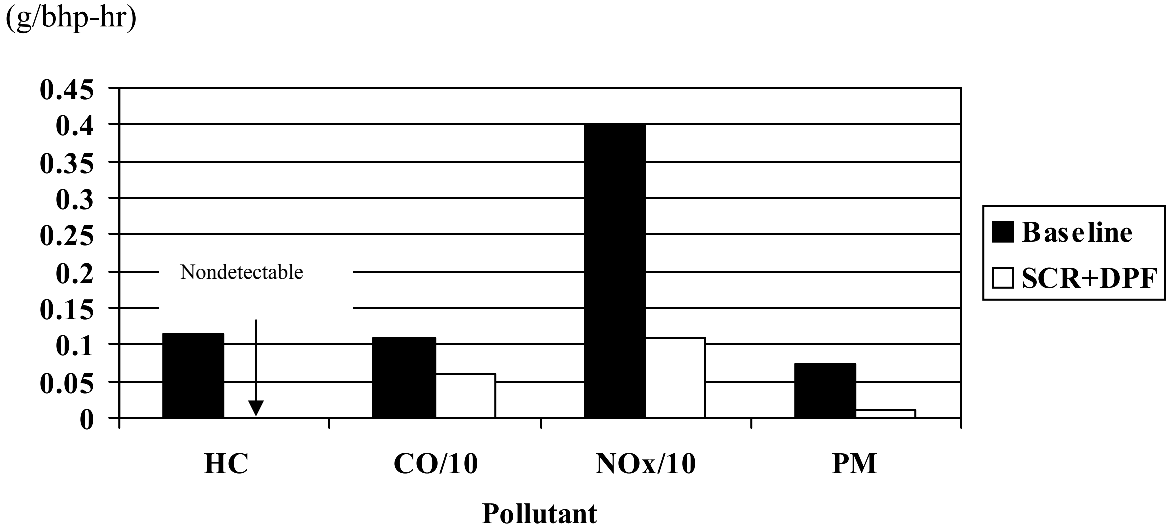
Figure VI-11
13-Mode Steady-State Test Cycle for SCR NOx Emissions Reductions



5. Diesel Particulate Filters Combined with SCR

Recently in the U.S., stationary diesel engines used for distributed power generation have begun to be equipped with a combination of diesel particulate filters and SCR. This combination of control technologies was also investigated as part of the aforementioned test program. In this instance, a fuel-borne catalyst was used with the particulate filters. The testing was performed over the FTP with fuel containing 368 ppm sulfur. The results are shown in Figure VI-12. Again, it is likely that similar results could be achieved under steady-state conditions. As the figure indicates, HC and PM emissions were virtually eliminated, while NOx emissions were reduced by approximately 75% and CO emissions were reduced by almost half.

Figure VI-12
Control Performance of a Combined DPF/SCR System



6. <u>Exhaust Gas Recirculation (EGR)</u>

EGR on a diesel engine offers an effective means of reducing NOx emissions. Both low-pressure and high-pressure EGR systems exist, but low-pressure EGR is most suitable for retrofit applications because it does not require engine modifications.

As the name implies, EGR involves re-circulating a portion of the engine's exhaust back to the turbocharger inlet or, in the case of a naturally aspirated engines, to the intake manifold. In most systems, an intercooler lowers the temperature of the re-circulated gases. The cooled re-circulated gases, which have a higher heat capacity than air and contain less oxygen than air, lower combustion temperature in the engine and reduce NOx formation. Diesel particulate filters are an integral part of any low-pressure EGR system because they are needed to ensure that large amounts of particulate matter are not re-circulated to the engine. In mobile source applications, NOx reductions of approximately 40% have been reported. Figure VI-13 depicts a low-pressure EGR system for diesel engines.[61]

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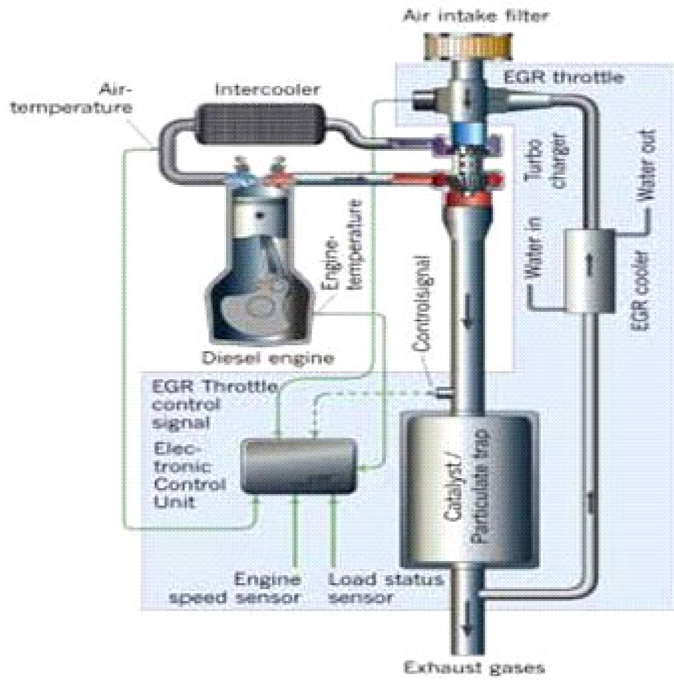
[61] "Closed Crankcase Filtration - The Next Step in Diesel Engine Emissions Reduction," Marty Barris, Donaldson Company, Inc. (as printed in the Summer 2000 edition of the *Clean Air Technology News*, a joint publication of the Manufacturers of Emission Controls Association and the Institute of Clean Air Companies. Washington, DC, September 2000.)

Figure VI-13
Exhaust Gas Recirculation



7. <u>Other NOx Control Technologies and Strategies for Lean-Burn Engines</u>

Lean NOx catalyst systems have also been used on lean-burn engines. Some lean NOx catalysts rely on the injection of a small amount of diesel fuel or other reductant into the exhaust. The fuel or other hydrocarbon reductant serves as a reducing agent for the catalytic conversion of NOx to N_2. Other systems operate passively at reduced NOx conversion rates. The catalyst substrate is a porous material often made of zeolite. The substrate provides microscopic sites that are fuel/hydrocarbon rich where reduction reactions can take place. Without the added fuel and catalyst, reduction reactions that convert NOx to N_2 would not take place because of the excess oxygen present in the exhaust. An HC to NOx ratio of up to 6:1 is needed to achieve optimal NOx reductions. Since the fuel used to reduce NOx does not produce mechanical energy, lean NOx catalysts typically operate with a fuel penalty of about 3%. Currently, peak NOx conversion efficiencies are typically around 10-20%.

Two types of lean NOx catalyst formulations have emerged: a low temperature catalyst based on platinum and a high temperature catalyst utilizing base metals, usually copper. Each catalyst is capable of controlling NOx over a narrow temperature range. Combining high and low temperature lean NOx catalyst systems broadens the temperature range over which they convert NOx, making them more suitable for practical applications.

Engine timing retard has also been demonstrated to provide NOx reductions in the range of 15-30% for stationary diesel IC engines.[62] This is achieved by retarding the timing by four degrees top dead center. The retarded timing provides lower combustion temperatures which results in lower NOx emissions. However, CO and PM emissions typically increase. This increase could be more than offset with the combined use of a diesel particulate filter or oxidation catalyst.

NOx adsorber catalysts are currently undergoing extensive research and development in anticipation of the new federal on-road heavy-duty diesel engine regulations scheduled to take effect in 2007. NOx adsorbers act to store NOx emissions during lean engine operation and release the stored NOx by periodically creating a rich exhaust environment, either through engine operation or by injecting a reductant in the exhaust stream. When released, the NOx is converted to N_2 by a three-way catalytic reaction. Although the use of NOx adsorber catalysts presently is not feasible on stationary diesel engines, NOx adsorber technology may be available for use on stationary engines in the future.

8. Ultra-Low Sulfur Fuel as a Control Option for Particulate Matter

The use of low sulfur fuel can also be used as a strategy to reduce engine-out particulate emissions from stationary diesel engines. In a recent manufacturers' study, switching from 368 ppm sulfur fuel to 54 ppm sulfur fuel reduced engine-out PM emissions from 0.073 g/bhp-hr to 0.063 g/bhp-hr, or by almost 14% as measured over the FTP.[63]

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[62] U.S. Environmental Protection Agency, OAQPS. *EPA Air Pollution Cost Manual, Sixth Edition*. EPA-452-02-001, January 2002.
[63] Manufacturers of Emission Controls Association, *Stationary Engine Emission Control*, May 2002.

VII. Control Technology Case Studies

To provide better information on the “real-world” cost, operation and performance of potential control technologies for stationary diesel IC engines, ESI International prepared case studies of six actual control technology installations. The case studies use data obtained from engine operators to develop cost and cost-effectiveness data on various control technology options. Since stationary IC engines equipped with emission controls are not summarized in a national database, several means were used to identify likely study participants. Most study participants were identified through state air pollution control agencies. Attempts were also made to identify study participants by contacting emission control suppliers and by searching the U.S. EPA’s RACT/BACT/LAER (RBL) Clearinghouse. The RBL Clearinghouse contains information concerning air permits issued by state and local air pollution control agencies in the United States. A rigorous statistical method was not used to select a sample of case study participants because the universe of engines equipped with emission controls is not well defined and the principal reason for “selecting” a facility was its willingness to participate in a study.

The case studies were performed in close cooperation with the facility owners. In each case the facility owners filled out a questionnaire that requested pertinent information. (included as Appendix E). After information was gathered from the owners, a case study was prepared and then sent to the facility owners for review and comment. Completed questionnaires along with cost data, maintenance information and other documentation were used to make calculations of emissions, cost and cost-effectiveness.

Table VII-1 summarizes the case studies developed for this report. Four of the case studies examine the use of particulate filters, one analyzes the combined application of particulate filters and SCR, and one involves a control installation that employed oxidation catalysts. More detailed descriptions of each case study including specific engine, cost and contact information follow. However, this is preceded by a description of the methodology used to develop cost figures for each of the case studies.

Table VII-1
Summary of Case Study Facilities

Facility	Location	Engine	Control Technology	Emissions Controlled
Kings County Dept. of Public Works	Kings County, CA	Caterpillar 3516B: 2848 hp @ 1800 rpm	Particulate Filter	PM, CO, and HC
National Steel and Shipping Company	San Diego, CA	Cummins QST30 G1: 1030 hp @ 1800 rpm	Particulate Filter and SCR	PM, NOx, CO, and HC
Pacific Bell-SBC	San Francisco, CA	Caterpillar 3516: 2841 hp @ 1800 rpm	Particulate Filter	PM, CO, and HC
Pacific Bell-SBC	San Jose, CA	Cummins KTA50-64: 2200 hp @ 1800 rpm	Oxidation Catalysts	PM, CO, and HC
Santa Clara County Building Operations	Santa Clara County, CA	Cummins KTA50 G2: 2200 hp @ 1800 rpm	Particulate Filter	PM, CO, and HC
Sierra Nevada Brewing Co.	Chico, CA	Caterpillar 3412: 1109 hp @ 1800 rpm	Particulate Filter	PM, NOx,[a] CO, and HC

[a] As discussed in the case study.

A. Cost Methodology

With the exception of a few modified assumptions, this study used cost estimating procedures developed by EPA's Office of Air Quality Planning and Standards (OAQPS) and described in the OAQPS Control Cost Manual.[64] Generally, these procedures allow costs to be analyzed on an annual basis assuming equal end-of-year costs, including direct and indirect annual costs and costs associated with recovering capital expenditures for purchased air pollution control equipment. Annual capital recovery costs were determined by multiplying the total capital cost of the emission control equipment by a capital recovery factor (CRF). This factor, explained in detail in the OAQPS document, uses assumptions regarding the annual pretax marginal rate of return on private investment, and expected project life to create a stream of equal payments (capital recovery costs) that recoup capital costs over the life of the project.

In following the OAQPS procedure, participants were asked to provide accurate cost information for the major capital and annual cost categories listed below.

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[64] U.S. Environmental Protection Agency, OAQPS, *EPA Air Pollution Cost Manual, Sixth Edition*. EPA-452-02-001, January 2002.

- Capital Costs
    - Purchase equipment costs
    - Direct installation costs
    - Indirect installation costs
    - Contingencies
- Annual Costs
    - Direct annual costs
    - Indirect annual costs

In many cases, participants provided aggregate costs (e.g. total capital costs that included purchase equipment costs, direct installation costs, indirect costs and contingencies). When this type of cost information was provided, no attempt was made to disaggregate the costs into subordinate costs.

Since the following operation and maintenance costs can contribute strongly to annual costs, an effort was made to collect detailed cost information for these items.

- Utilities
- Operating labor
- Operating materials (e.g. reagent use)
- Maintenance labor
- Maintenance materials
- Cost of an annual compliance test
- Catalyst replacement

While more elaborate techniques can be used to estimate the costs of purchasing and operating emission control equipment, the procedure developed by OAQPS provides reasonably accurate cost data for regulatory purposes. The procedure has been used by EPA and other organizations to evaluate the costs of many different types of control equipment.

B. Case Study Assumptions

The following assumptions were made in all of the case studies presented:

1. The annual pretax marginal rate of return on private investment was assumed to be 8%. The OAQPS cost estimating procedure, last updated in 1990, uses a 10% return on investment. More recent studies have used a rate of return of 8%.[65] Because 8% better captures return on investment under current economic conditions, this figure was used in calculating the capital recovery factor (CRF).

[65] See, for example, NESCAUM's *Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines – Technologies & Cost Effectiveness.* December 2000.

2. A 10-year project life was used in this collection of case studies to be consistent with previous studies.

3. Emissions reductions were calculated using source test data when available. When source test data were not available, emissions reductions were based on:

   - the performance claims of the emission control manufacturers,
   - reductions demonstrated on similar equipment under similar operating conditions, and
   - engineering judgment.

4. When a case study participant provided aggregate capital costs for both NOx and PM controls, costs were disaggregated by estimating the cost of the PM control system and then subtracting PM control costs from total costs to derive an estimate of NOx control costs. PM control costs were estimated using a cost factor of $22 per horsepower derived from current diesel retrofits in California.

5. When a study participant provided aggregate operating or maintenance costs for NOx and PM controls, annual operating costs for each pollutant were disaggregated by multiplying total annual costs by the ratio of NOx capital costs to total capital costs and PM capital cost to total capital costs, respectively.

6. Annual overhead costs were estimated to be 15% of annual labor costs.

C. Case Study Descriptions

1. Kings County, Department of Public Works, CA

Facility Description
Kings County is located in California's San Joaquin Valley about halfway between Los Angeles and San Francisco. Hanford, the county seat, is located about 210 miles southeast of San Francisco. To save on electricity costs, the County subscribes to an interruptible power program with the local utility. As a program participant, the County gets a 25% lower rate on electricity but must disconnect from utility grid after being given 30-minute notice. If the County fails to disconnect in 30 minutes, it must pay a large penalty. During interruptions in prior years, the County would shed all load and run essential services on small local generators. After a period of frequent interruptions during the winter of 2000/2001, the County Council authorized the installation of a large generator to supply backup power to most facilities located at Government Center in Hanford. The 2 MW generator that was installed supplies backup power to essential services including the jails, juvenile detention facilities, emergency dispatch (911) center and the mainframe computer system. The generator also provides backup power for the County Courts, the Department of Human Services, the Department of Health Services and other government offices.

A Caterpillar 3516B engine powers the backup generator. The turbocharged and aftercooled engine produces 2,848 hp at 1,800 rpm. To comply with air quality regulations for diesel generators that run during voluntary power interruptions, the County installed a diesel particulate filter system on the engine. Installation of the filter system was a joint effort involving the County, the system supplier, and the filter installer. The filter system supplier benefited from the project in that it gave them the opportunity to certify their filter system with the California Air Resources Board (CARB) under CARB's Diesel Emission Control Strategy Verification Program. The generator engine burns ultra-low sulfur diesel fuel, fuel that contains less than 15 ppm sulfur. The engine operated by the Kings County Department of Public Works is summarized in Table VII-2.

Table VII-2
Case Study 1: Engine and Emission Control Summary

Engine	Caterpillar 3516B
Horsepower	2,848 hp @ 1,800 rpm
Engine Age	1 year
Fuel	Ultra low sulfur diesel fuel
Emission Controls	Diesel particulate filter

Emissions

Engine emissions before and after installation of the particulate filters are summarized in Table VII-3. Emissions before installation of the filter system were provided by Caterpillar, Inc. and represent emissions for the engine operating at 50% load, the average load the engine carries at the Government Center. Engine-out emissions for particulate matter were also reduced by 25% as suggested by Caterpillar, Inc. to account for the use of cleaner burning California diesel fuel. Since Kings County runs their engine on ultra-low sulfur diesel fuel, a fuel with lower sulfur content than California diesel fuel, actual particulate matter emissions may be even lower than those reported in this case study. Emissions reductions were calculated from percent reduction information obtained by the filter manufacturer. The percent reduction information was based on actual source test data.

Table VII-3
Case Study 1: Emissions Reduction Summary

Pollutant	Emission Rate Before Controls (g/bhp-hr)	Emission Rate After Controls (g/bhp-hr)	Percent Reduction
Carbon Monoxide	0.84	0.084	90
Hydrocarbons	0.33	0.033	90
Particulate Matter	0.179[a]	0.027[a]	85
Nitrogen Oxides	6.51	NA[b]	NA[b]

[a] PM emission rate reduced 25% per Caterpillar, Inc. to account for lower PM emissions from CARB diesel fuel
[b] not applicable

The air quality permit for this engine limits its operations to 614 hours per year. Emissions calculations were based on this maximum number of operating hours. Emissions were estimated using a load factor of 50%. The 50% load factor was based on actual data provided by Kings County for average weekday summer load.

Costs

The total capital cost of the filter system was estimated at $121,153 in year 2000 dollars. This cost includes the cost of the filters and direct and indirect installation costs. Both the particulate filter supplier and Kings County provided purchased equipment cost information from which this total capital costs were derived.

Kings County does not expect to incur annual operation and maintenance (O&M) costs for the filter system because the engine operates at sufficient load to generate the exhaust gas temperatures to hot enough to oxidize accumulated particulate matter in the filter system. To date, the filter system has been maintenance free. The County is not required to conduct periodic compliance tests, so compliance test costs were not included in annual costs. Since O&M costs for the filter system are expected to be negligible, overhead – which is estimated from annual labor costs – was estimated to be negligible. Annual costs for the filter system are summarized in Table VII-4.

Table VII-4
Case Study 1: Annual DPF Costs and Emissions

Annual Costs	Costs[a]
Direct Costs	
Labor and Materials	$0
Compliance Test	$0
Total Direct Costs	$0
Indirect Costs	
Overhead	$0
Capital Recovery Cost	$18,055
Total Indirect Costs	$18,055
Total Annual Costs	$18,055
Annual Emissions	Tons per Year
PM Emissions Before Installation of Controls	0.173
PM Emissions After Installation of Controls	0.026
Annual Tons of PM Removed	0.147
Percent Reduction	85%
CO Emissions Before Installation of Controls	0.810
CO Emissions After Installation of Controls	0.081
Annual Tons of CO Removed	0.729
Percent Reduction	90%
HC Emissions Before Installation of Controls	0.318
HC Emissions After Installation of Controls	0.033
Annual Tons of HC Removed	0.032
Percent Reduction	90%
Total Annual Tons of Pollution Reduced	0.908

[a] year 2000 dollars

Facility and Contact Information
Kings County Department of Public Works
1400 W. Lacey Boulevard
Hanford, CA 93230

Mr. Harry W. Verheul
(559) 582-3211 ext. 2698

2. National Steel and Shipbuilding Company (NASSCO)

Facility Description

NASSCO is the largest shipyard engaged in new ship construction on the West Coast. The shipyard, which is located on San Diego Bay, builds commercial ships including oil tankers, ferries, container ships and research vessels. It also builds U.S. Navy support ships.

In 2001, the shipyard purchased a Cummins QST30-G1 diesel engine and generator to power Crane Number 16, a 300-ton gantry crane. The engine, rated at 1,135 hp at 1,800 rpm, is turbocharged and aftercooled. To meet air quality requirements, the engine was equipped with Best Available Control Technology (BACT). The air pollution control equipment installed on the engine included a diesel particulate filter to control particulate matter and a selective catalytic reduction (SCR) unit to reduce NOx emissions. The reagent used in the unit is a 40% aqueous solution of urea. The reagent is consumed at a rate of about 2.7 pints per hour (0.34 gallons per hour). The San Diego County Air Pollution Control District limits ammonia emissions (ammonia slip) to less than 10 ppm. The NASSCO SCR unit operates within that limit.

To keep the exhaust gas temperatures hot enough for proper operation of the particulate filter and SCR system, exhaust gas heaters are installed ahead of the emission control system. Exhaust gas temperatures are maintained above 715º F to oxidize accumulated particulate matter in the filter system. The SCR system needs temperatures above 570º F to maintain NO_x conversion efficiency.

NASSCO operates Crane Number 16 on California #2 diesel fuel. Table VII-5 summarizes the equipment installed at NASSCO.

Table VII-5
Case Study 2: Engine and Emission Control Summary

Engines	Cummins QST30-G1
Horsepower	1,030 hp @ 1,800 rpm
Engine Age	2 years
Fuel	CARB #2 diesel fuel
Emission Controls	Selective catalytic reduction (SCR) & Diesel particulate filter (DPF) system

Emissions

Engine emissions before and after installation of emission controls are summarized in Table VII-6. The emissions rates for the engine before the installation of emission controls are from Cummins, Inc. The NASSCO crane engine usually operates at low load, or approximately 11-15% capacity. Calculated loads for the case study were 12.8%. Since emissions data were not available for the Cummins QST30 engine at low load, Cummins provided emissions data for a similar 1,525 hp engine operating at 10% load.

Emissions rates at the 10% power point for the 1,525 hp engine approximate emissions rates for the 1,135 hp engine operating at 13.5% load, roughly the load observed at NASSCO.

Emissions reductions are based on the performance claims of the emission control manufacturer and reflect typical values observed in similar applications. The emission control installer estimates the diesel particulate filter achieves an 85% reduction of particulate matter and the SCR unit achieves a 90% reduction of NOx. Source tests were conducted on the crane by World Environmental, Inc. on March 14, 2002. Preliminary source test data confirm the SCR system achieves a >90% reduction of NOx. However, PM emissions appeared to increase. This is still under investigation and may be due to a sampling anomaly. Because the control efficiency of diesel particulate filters is well known, an 85% reduction is assumed.

Table VII-6
Case Study 2: Emissions Reduction Summary

Pollutant	Emission Rate Before Controls (g/bhp-hr)	Emission Rate After Controls (g/bhp-hr)	Percent Reduction
Carbon Monoxide	0.2	0.85	85
Hydrocarbons	1.1	0.10	85
Particulate Matter	0.03[a]	0.045[a]	85
Nitrogen Oxides	8.1[b]	0.69[b]	93

[a] PM emission rates reduced 25% per Caterpillar, Inc. to account for lower PM emissions from California diesel fuel
[b] NOx emission rates reduced 7% per Caterpillar, Inc. to account for lower NOx emissions from California diesel fuel

NASSCO operates Crane Number 16 two eight-hour shifts per day, six days a week, 50 weeks per year. Thus, the crane operates about 4,800 hours per year. An engine load factor of 0.12 was calculated from fuel consumption data provided by NASSCO. The load factor appears reasonable given that the crane spends large amounts of time at idle. The 0.12 load factor was used in all annual emissions calculations.

Costs
NASSCO estimated the capital cost of the SCR and DPF control system for the engine as $289,900 in year 2000 dollars. This cost included purchase equipment costs and direct and indirect installation costs. The capital cost for the filter system, including the exhaust gas heaters, was approximately $111,020. The capital cost of the SCR system was $178,880.

Annual costs for the diesel particulate filter system included maintenance labor, prorated costs for a semiannual compliance test, overhead and recovery of capital. No filter replacement costs were assumed for the ten-year life of the filter system. The most significant annual cost associated with the filter system was the cost of recovering capital. Cost information for the filter system is summarized in Table VII-7.

Table VII-7
Case Study 2: Annual DPF Costs and Emissions

Annual Costs	Costs[a]
Direct Costs	
Labor	$2,930
Compliance Test	$1,862
Total Direct Costs	$4,791
Indirect Costs	
Overhead	$439
Capital Recovery Cost	$16,545
Total Indirect Costs	$16,985
Total Annual Costs	$21,776
Annual Emissions	Tons per Year
PM Emissions Before Installation of Controls	0.023
PM Emissions After Installation of Controls	0.003
Annual Tons of PM Removed	0.020
Percent Reduction	85%
CO Emissions Before Installation of Controls	0.154
CO Emissions After Installation of Controls	0.015
Annual Tons of CO Removed	0.139
Percent Reduction	90%
HC Emissions Before Installation of Controls	0.848
HC Emissions After Installation of Controls	0.085
Annual Tons of HC Removed	0.763
Percent Reduction	90%
Total Annual Tons of Pollution Reduced	0.922

[a] year 2000 dollars

Annual O&M costs for the SCR system include the cost of urea reagent, maintenance labor, prorated costs for a semiannual compliance test and the levelized cost of replacing the SCR catalyst. Urea is purchased at $2.71 per gallon and supplied to the SCR system at a dosing rate of 0.34 gallons per hour. The SCR supplier has recommended that NASSCO follow a phased replacement schedule for the SCR catalyst replacing one of the three SCR catalyst layers every 20,000 operating hours. Each layer costs $2,600. Under NASSCO's current operating scenario, the levelized cost of SCR catalyst replacement is $624 per year. Cost information for the SCR system is summarized in Table VII-8.

Table VII-8
Case Study 2: Annual SCR Costs and Emissions

Annual Costs	Costs[a]
Direct Costs	
Reagent	$4,390
Labor	$4,720
Compliance Test	$3,000
Catalyst Replacement Costs	$624
Total Direct Costs	$12,734
Indirect Costs	
Overhead	$4,720
Capital Recovery Cost	$26,658
Total Indirect Costs	$31,379
Total Annual Costs	$44,113
Emissions	Tons per Year
NOx Emissions Before Installation of Controls	6.24
NOx Emissions After Installation of Controls	0.67
Annual Tons of NOx Removed	5.57
Percent Reduction	90%

[a] year 2000 dollars

Facility and Contact Information
National Steel & Shipbuilding Company
Harbor Drive & 28th Street
P.O. Box 85278
San Diego, CA 92186-5278

Mr. Dina Ahmed
(619) 544-8764

3. Pacific Bell-SBC Telecommunications Facility, San Francisco, CA

Facility Description
In 1994, Pacific Bell-SBC installed two emergency generators at their high-rise telecommunications facility at 611 Folsom Way, San Francisco, CA. Originally at this location, Pacific Bell operated a turbine to provide emergency backup power. To accommodate growth, Pacific Bell replaced the turbine with two Caterpillar 3516 engines and their associated generators. Each engine produces 2,841 horsepower at 1,800 rpm.

Operation of the earlier turbine had resulted in several nuisance complaints concerning smoke and odors. To avoid future complaints, Pacific Bell installed diesel particulate filter systems on the new Caterpillar engines. The installed filter systems are capable of reducing particulate matter emissions by 85% and carbon monoxide and hydrocarbon emissions by 90%. The engines burn regular #2 diesel fuel. Equipment installed at Pacific Bell's telecommunications facility at 611 Folsom Way is summarized in Table VII-9.

Table VII-9
Case Study 3: Engine and Emission Control Summary

Engine	Caterpillar 3516
Horsepower	2,841 hp @ 1,800 rpm
Engine Age	8 years
Fuel	#2 diesel fuel
Emission Controls	Diesel particulate filter

Emissions
Engine emissions before and after installation of the particulate filters are summarized in Table VII-10. Emissions reductions are based on the emissions reduction claims of the control system manufacturer.

Table VII-10
Case Study 3: Emissions Reduction Summary

Pollutant	Emission Rate Before Controls (g/bhp-hr)	Emission Rate After Controls (g/bhp-hr)	Percent Reduction
Carbon Monoxide	1.17	0.12	90
Hydrocarbons	0.50	0.05	90
Particulate Matter	0.239	0.036	85
Nitrogen Oxides	17.04	NA[a]	NA[a]

[a] not applicable

Electricity service is quite reliable in the San Francisco area and as a result, the engines are operated only about 20 hours per year. Pacific Bell runs the engines about one hour every month to ensure they will be able to carry building load in an emergency. Once a year, the engines are run for longer periods to test transfer switchgear and other equipment.

Actual load data were not available to estimate a load factor for the engine. A load factor of 0.15, a typical load factor for maintenance-type operation, was used to make emissions estimates.

Costs
The total capital cost of a filter system for one of the engines was $95,860 in year 2000 dollars. This cost included the cost of the filters, electric heaters, structural supports,

exhaust system piping and insulation, controls and instrumentation, and other direct and indirect installation costs.

Pacific Bell estimates the annual cost of operating and maintaining a single filter system is about $5,000. Pacific Bell is not required to conduct periodic compliance tests, so no compliance test costs were included in annual costs. Overhead, which is estimated from annual labor costs, was estimated to be about $750 per year. Costs for a single filter system are summarized in Table VII-11.

Table VII-11
Case Study 3: Annual DPF Costs and Emissions

Annual Costs	Costs[a]
Direct Costs	
Labor and Materials	$5,000
Compliance Test	$0
Total Direct Costs	$5,000
Indirect Costs	
Overhead	$750
Capital Recovery Cost	$14,286
Total Indirect Costs	$15,036
Total Annual Costs	$20,036
Annual Emissions	Tons per Year
PM Emissions Before Installation of Controls	0.002
PM Emissions After Installation of Controls	0.000
Annual Tons of PM Removed	0.002
Percent Reduction	85%
CO Emissions Before Installation of Controls	0.009
CO Emissions After Installation of Controls	0.001
Annual Tons of CO Removed	0.008
Percent Reduction	90%
HC Emissions Before Installation of Controls	0.004
HC Emissions After Installation of Controls	0.0004
Annual Tons of HC Removed	0.0036
Percent Reduction	90%
Total Annual Tons of Pollution Reduced	0.0014

[a] year 2000 dollars

Facility and Contact Information
Pacific Bell-SBC
95 Almaden Street
Room 316
San Jose, CA 95113

Ms. Lynn Bowers
(408) 491-2402

4. Pacific Bell-SBC Telecommunications Facility, San Jose, CA

Facility Description
In 2000, Pacific Bell-SBC installed an emergency generator at their telecommunications facility in a rural area near San Jose, CA. The telecommunications center, located at 6245 Dial Way, serves as a dial tone, high-speed data and interconnection facility. The engine installed at the site is a Cummins KTA50-G9 producing 2,220 horsepower at 1,800 rpm. It is turbocharged and aftercooled. When the engine was installed, Pacific Bell equipped the engine with a diesel oxidation catalyst to control exhaust odors. The exhaust stack for the engine is near air intakes for a neighboring building and there was concern that exhaust could find its way into the neighboring building. The engine operates on a mixture of #1 and #2 diesel fuel. Equipment installed at Pacific Bell's telecommunications facility is summarized in Table VII-12.

Table VII-12
Case Study 4: Engine and Emission Control Summary

Engine	Cummins KTA50-G9
Horsepower	2,220 hp @ 1,800 rpm
Engine Age	2 years
Fuel	#1 and #2 diesel fuel
Emission Controls	Diesel Oxidation Catalyst

Emissions
Engine emissions before and after installation of the oxidation catalyst are summarized in Table VII-13. Emissions reductions are based on the emissions reduction claims of the control device manufacturer.

Table VII-13
Case Study 4: Emissions Reduction Summary

Pollutant	Emission Rate Before Controls (g/bhp-hr)	Emission Rate After Controls (g/bhp-hr)	Percent Reduction
Carbon Monoxide	8.5	0.22	90
Hydrocarbons	1.0	0.01	90
Particulate Matter	0.4	0.01	25
Nitrogen Oxides	6.9	NA[a]	NA[a]

[a] not applicable

The emergency backup generator is only operated about 20 hours per year. Pacific Bell runs the engine about one hour every month to exercise it. Once a year, the engine is run for a longer period to test transfer switchgear and other equipment. The electrical grid is stable in this area of California and the engine is rarely used to generate electricity in a power outage.

Actual load data were not available to estimate a load factor for the engine. A load factor of 0.15, a typical load factor for maintenance-type operation, was used to make emissions estimates.

<u>*Costs*</u>
The total capital cost of the diesel oxidation catalyst in year 2000 dollars was $24,895. This cost includes the cost of the emission control device, $12,950 in year 2000 dollars, plus sales taxes, freight, direct and indirect installation costs.

Annual costs for the catalyst were minimal involving only the recovery of capital. Since the engine operates infrequently, labor costs were estimated to be negligible. Pacific Bell is not required to conduct periodic compliance tests, so no compliance test costs were included in annual costs. Overhead, which is estimated from annual labor costs, is also negligible in this case study. Cost information for the catalyst is summarized in Table VII-14.

Table VII-14
Case Study 4: Annual DOC Costs and Emissions

Annual Costs	Costs[a]
Direct Costs	
Labor	$0
Compliance Test	$0
Total Direct Costs	$0
Indirect Costs	
Overhead	$0
Capital Recovery Cost	$3,710
Total Indirect Costs	$3,710
Total Annual Costs	$3,710
Annual Emissions	Tons per Year
PM Emissions Before Installation of Controls	0.003
PM Emissions After Installation of Controls	0.002
Annual Tons of PM Removed	0.001
Percent Reduction	25%
CO Emissions Before Installation of Controls	0.062
CO Emissions After Installation of Controls	0.006
Annual Tons of CO Removed	0.056
Percent Reduction	90%
HC Emissions Before Installation of Controls	0.007
HC Emissions After Installation of Controls	0.001
Annual Tons of HC Removed	0.007
Percent Reduction	90%
Total Annual Tons of Pollution Reduced	0.064

[a] year 2000 dollars

Facility and Contact Information
Pacific Bell-SBC
95 Almaden Street
Room 316
San Jose, CA 95113

Ms. Lynn Bowers
(408) 491-2402

5. Santa Clara County Building Operations

Facility Description

Santa Clara County operates a back-up generator at 1555 Berger Drive in San Jose, CA. The generator is located in the basement of Building 2 of the County Service Center. The generator provides emergency back-up power to three buildings in the Service Center. These buildings house the Departments of Agriculture, Information Services and Revenue, the General Services Administration, the Registrar of Voters, the District Attorney's Crime Lab, Telephone Services, Property Management, Purchasing and other government offices.

In 1998, Santa Clara County purchased the Cummins KTTA50-G2 diesel engine and generator to provide emergency power for the County Service Center. The engine is rated at 2,220 hp at 1,800 rpm. It is turbocharged and aftercooled. To avoid complaints concerning smoke and odors, and to be a "good neighbor" to nearby building occupants, Santa Clara County installed two catalyzed diesel particulate filters on the engine exhaust system at the time the engine was installed. The filters significantly reduce CO, HC and PM emissions. They were not installed to meet the requirement of an air quality permit. The engine operates on CARB Diesel Fuel #2. Equipment installed at Santa Clara County is summarized in Table VII-15.

Table VII-15
Case Study 5: Engine and Emission Control Summary

Engine	Cummins KTTA50-G2
Horsepower	2,220 hp @ 1,800 rpm
Engine Age	4 years
Fuel	CARB #2 Diesel Fuel
Emission Controls	Diesel Particulate Filter (DPF) system

Emissions

Engine emissions before and after installation of the filter system on the engine are summarized in Table VII-16. Emissions reductions are based on preliminary source test results provided by the emission control manufacturer for a similar emission control system installed at another facility. The engine and control system at Santa Clara County's Service Center was emission tested by the California Air Resources Board (CARB), however the test results were not available at the time this case study was prepared.

Table VII-16
Case Study 5: Emissions Reduction Summary

Pollutant	Emission Rate Before Controls (g/bhp-hr)	Emission Rate After Controls (g/bhp-hr)	Percent Reduction
Carbon Monoxide	2.17	0.22	90
Hydrocarbons	0.14	0.01	90
Particulate Matter	0.083[a]	0.012[a]	85
Nitrogen Oxides	12.8	NA[b]	NA[b]

[a] PM emission rate reduced 25% per Caterpillar, Inc. to account for lower PM emissions from CARB diesel fuel.
[b] not applicable

The number of hours the engine has been operated per year has varied since its installation. Before the engine was issued an air quality permit, the engine operated hundreds of hours per year when the local utility, Pacific Gas and Electric, instituted "load curtailment." During load curtailment, periods of high electricity demand and/or limited electricity supply, PG&E would ask local generators to come on-line to reduce load on the grid. Now, the air quality permit limits the County's generator operations to only 100 hours per year over actual emergency operations. Emergency operations are minimal involving only one or two events per year of about two to three hours per event. Santa Clara County estimates the engine now operates only about 70 hours per year.

Actual load data were not available to estimate a load factor for the engine. Given the lack of actual data, a load factor of 0.15 was used to make emissions estimates. This load factor represents the typical load standby engines carry when they are exercised monthly or weekly under minimal load.

Costs
The total capital cost of the DPF system, $45,834 in year 2000 dollars, includes the actual cost of the DPF system, $24,000, plus additional amounts for installation and other costs.

Annual costs for the filter system were minimal involving only the recovery of capital. Since the engine operates infrequently, labor costs were estimated to be negligible. Santa Clara County is not required to conduct periodic compliance tests, so no compliance test costs were included in annual costs. Overhead, which is estimated from annual labor costs, is also negligible in this case study. Cost information for a filter system is summarized in Table VII-17.

Table VII-17
Case Study 5: Annual DPF Costs and Emissions

Annual Costs	Costs[a]
Direct Costs	
Labor	$0
Compliance Test	$0
Total Direct Costs	$0
Indirect Costs	
Overhead	$0
Capital Recovery Cost	$6,831
Total Indirect Costs	$6,831
Total Annual Costs	$6,831
Annual Emissions	Tons per Year
PM Emissions Before Installation of Controls	0.003
PM Emissions After Installation of Controls	0.001
Annual Tons of PM Removed	0.002
Percent Reduction	85%
CO Emissions Before Installation of Controls	0.056
CO Emissions After Installation of Controls	0.006
Annual Tons of CO Removed	0.005
Percent Reduction	90%
HC Emissions Before Installation of Controls	0.004
HC Emissions After Installation of Controls	0.0004
Annual Tons of HC Removed	0.0036
Percent Reduction	90%
Total Annual Tons of Pollution Reduced	0.0536

[a] year 2000 dollars

Facility and Contact Information

Santa Clara County
Building Operations – GSA
1555 Berger Drive
San Jose, CA 95112

Ms. Alana Crary
(408) 299-4181 ext. 2156

6. Sierra Nevada Brewing Company, Chico, CA

Facility Description

Sierra Nevada Brewing Company (SNBC) is a brewery that produces ales, stouts and beers in Chico, CA. In 1997 and 1999, the brewery purchased two 750 kW generators to provide emergency backup power for brewery operations. Both generators are powered by Caterpillar 3412 diesel engines. Each turbocharged engine produces 1,109 hp at 1,800 rpm. To meet air quality requirements, SNBC installed diesel particulate filters on the engines in 1999 and 2000. Two catalyzed diesel particulate filters are installed in parallel on each engine. The engines run on CARB diesel fuel. The engines operated by SNBC are summarized in Table VII-18.

Table VII-18
Case Study 6: Engine and Emission Control Summary

Engines	Caterpillar 3412
Horsepower	1,109 hp @ 1,800 rpm
Engine Ages	3 years and 5 years
Fuel	CARB diesel fuel
Emission Controls	Diesel particulate filters

Emissions

Engine emissions before and after installation of the particulate filters are summarized in Table VII-19. Emissions before installation of the filter system were provided by Caterpillar, Inc. and are emissions for the engine operating at 75% load. SNBC typically operates their engines at about 80% load. Emissions data at 80% load were not available from Caterpillar, Inc. Uncontrolled engine emissions for NOx and PM were reduced by 7% and 25%, respectively, as suggested by Caterpillar, Inc. to account for the use of cleaner burning CARB diesel fuel. Occasionally, SNBC runs their engines on a diesel fuel that contains less sulfur than CARB diesel fuel. When this lower sulfur fuel is used, actual PM emissions may be even lower than those reported in this case study.

CARB performed source tests on SNBC's engines on March 20-24, 2000. To the extent data were available, Caterpillar engine emissions data and CARB source test data were used to calculate emissions reductions. Average source test emissions for NOx, converted to grams per brake horsepower, were subtracted from Caterpillar engine-out emissions to calculate the 12.3% drop in NOx emissions reported below. The CARB source test report concluded PM test results should be viewed as only "qualitative in nature" because of testing anomalies. PM emissions reductions calculated from CARB source test data agree well, however, with reductions observed in other similar applications of diesel particulate filter technology. Average source test emissions for PM, converted to grams per brake horsepower, subtracted from Caterpillar engine-out emissions resulted in an emissions reduction of 85%. Reductions of this magnitude are often observed when diesel particulate filters are installed on stationary diesel engines.

Table VII-19
Case Study 6: Emissions Reduction Summary

Pollutant	Emission Rate Before Controls (g/bhp-hr)	Emission Rate After Controls (g/bhp-hr)	Percent Reduction
Carbon Monoxide	0.84	0.084	90
Hydrocarbons	0.33	0.033	90
Particulate Matter	0.164[a]	0.025[a]	85
Nitrogen Oxides	6.69[b]	5.85	12

[a] PM emission rate reduced 25% per Caterpillar, Inc. to account for lower PM emissions from CARB diesel fuel.
[b] NOx emission rate reduced 7% per Caterpillar, Inc. to account for lower NOx emissions from CARB diesel fuel.

SNBC's air quality permit limits engine operations and each engine operates only 100 to 150 hours per year. Most operating hours are devoted to exercising the engines to ensure they are ready to come on-line in an emergency. Emission calculations were based on one engine operating 150 hours per year. Emissions were estimated using a load factor of 80 percent. SNBC exercises their engines under load to achieve the engine exhaust temperatures needed to oxidize the accumulated particulate matter on their diesel particulate filters.

<u>Costs</u>
The total capital cost for a single filter system was estimated to be $40,655 in year 2000 dollars. This cost includes the cost of the filters and direct and indirect installation costs. The cost of the initial compliance test for an engine, $1,500, was included in indirect costs.

SNBC does not expect to incur annual operation and maintenance (O&M) costs for the filter systems because the generator engines are exercised at sufficient load to generate the exhaust gas temperatures hot enough to oxidize accumulated particulate matter in the filter system. To date, the filter system has been maintenance-free. SNBC is not required to perform periodic compliance tests so compliance test costs were not included in annual costs. Because O&M costs for the filter systems are negligible, overhead, which is estimated from annual labor costs, was assumed to be negligible. Annual costs for the filter system are summarized in Table VII-20.

Table VII-20
Case Study 6: Annual DPF Costs and Emissions

Annual Costs	Costs[a]
Direct Costs	
Labor and Materials	$0
Compliance Test	$0
Total Direct Costs	$0
Indirect Costs	
Overhead	$0
Capital Recovery Cost	$6,059
Total Indirect Costs	$6,059
Total Annual Costs	$6,059
Annual Emissions	Tons per Year
NO_x Emissions Before Installation of Controls	0.981
NO_x Emissions After Installation of Controls	0.860
Annual Tons of NO_x Removed	0.121
Percent Reduction	12%
PM Emissions Before Installation of Controls	0.024
PM Emissions After Installation of Controls	0.004
Annual Tons of PM Removed	0.020
Percent Reduction	85%
CO Emissions Before Installation of Controls	0.173
CO Emissions After Installation of Controls	0.021
Annual Tons of CO Removed	0.161
Percent Reduction	93%
HC Emissions Before Installation of Controls	0.026
HC Emissions After Installation of Controls	0.003
Annual Tons of HC Removed	0.024
Percent Reduction	90%
Total Annual Tons of Pollution Reduced	0.335

[a] year 2000 dollars

Facility and Contact Information
Sierra Nevada Brewing Company
1075 East 20th Street
Chico, CA 95928

Mr. Ken Grossman
(530) 893-3520

D. Cost-Effectiveness Analysis

Based on the case studies described above, the capital cost of a filter system ranges from about $45,000 to about $120,000. The sole diesel oxidation catalyst installation, by contrast, had a more modest capital cost of $25,000. The capital cost of the SCR installation was estimated to be just under $180,000.

The cost effectiveness of a control technology is typically measured in terms of control costs incurred for a given amount of pollution removed (e.g. $/ton), where control costs include the annual levelized capital costs of the technology as well as fixed and variable operating and maintenance costs. Because this metric takes into account the amount of pollution removed, it is dependent on engine operation (fuel consumption and load) and hours of operation, as well as on the control technology used and the levels of pollution reduction achieved. If an engine runs for only a few tens or hundreds of hours in a year, a given control technology will likely remove only relatively small amounts of emissions (say, compared to a central-station power plant) for a given capital cost.

To illustrate this relationship, data obtained from the case studies for both control systems costs and emission control performance were used to determine cost-effectiveness per ton of pollutant reduced compared to annual operating hours and type of operation as reflected by different load factors. In calculating cost-effectiveness, all pollutant reductions being achieved at the case study facilities were included. In other words, the calculation includes PM, CO and HC reductions for the Kings County, Santa Clara County and Pacific Bell (San Francisco and San Jose) installations and PM, NOx, CO and HC for the NASSCO and Sierra Nevada installations.

To calculate engine-out emissions per year for each case study, the following equation was used:

Mass Emission Rate x Load Factor x Horsepower x Operating Hours per Year = Mass Emissions per Year

An example calculation is shown below:

$$6.9 \text{ g/bhp-hr} \times 0.12 \text{ load factor} \times 1{,}030 \text{ bhp} \times 4{,}800 \text{ hr/yr} = 4.1\times10^{6} \text{ g/yr}$$

where:

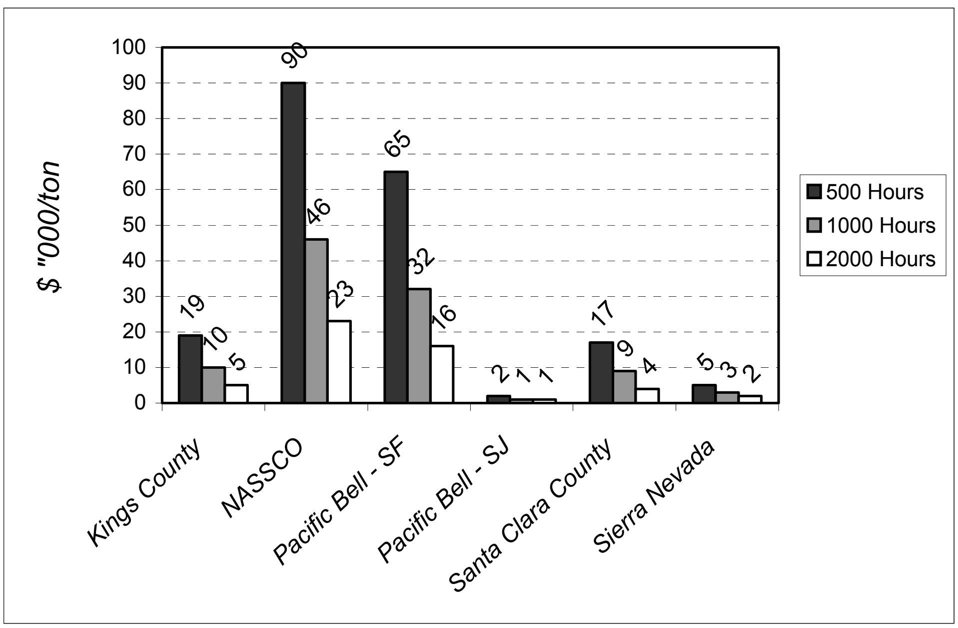
g/bhp-hr = grams per brake horsepower hour
bhp = brake horsepower
hr = hours
yr = year

Converting grams to tons yields annual emissions in tons per year:

$$(4.1x10^{6} \text{ g/yr}) / (453.59 \text{ g/lb x } 2{,}000 \text{ lb/ton}) = 4.5 \text{ tons/yr}$$

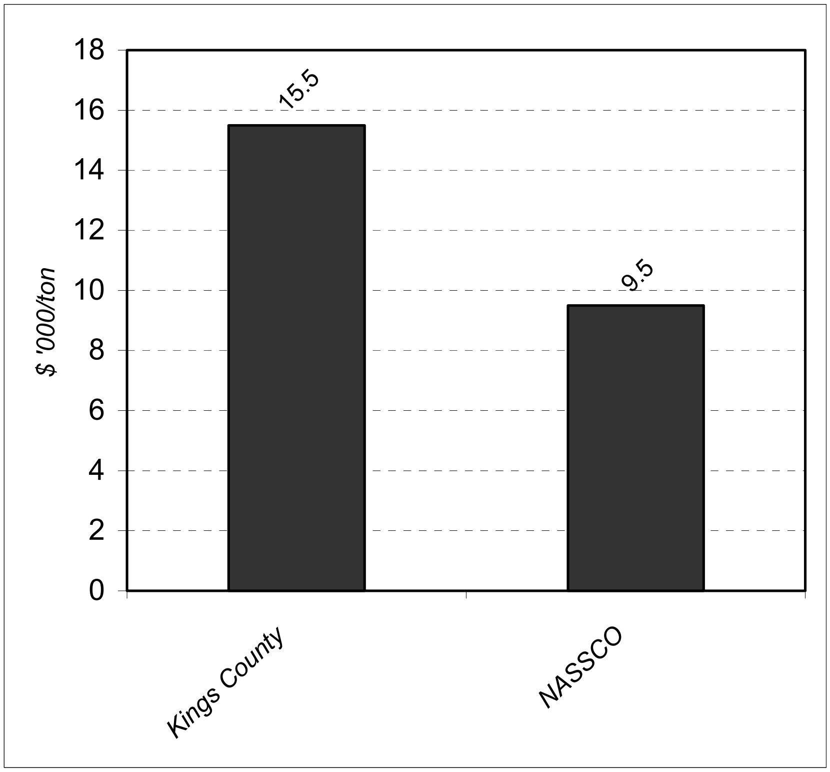
Figure VII-1 shows how cost-effectiveness varies depending on operating hours for each of the case studies analyzed. At 500 annual operating hours, for example, cost-effectiveness ranges from approximately $2,000/ton in the case of the Pacific Bell installation in San Jose to $90,000/ton at National Steel and Shipbuilding Company (NASSCO), with an average cost-effectiveness of $36,000 per ton of pollution controlled. If the engines are assumed to operate for 2000 hours per year, these values change to a low of less than $1,000/ton to a maximum of $23,000/ton. Average cost-effectiveness at 2000 hours of potential operation annually is $8,500 per ton of pollution reduced, based on information provided by the case studies.

Figure VII-1
Cost-Effectiveness Versus Annual Operating Hours



Of the case studies presented in this report, however, only two involve engines that are operated for other than emergency or back-up purposes – Kings County and NASSCO. The others are operated predominantly to insure they will be available if needed and hence operate even less frequently than the 500 hour minimum shown in Figure VII-1. The installation at Kings County is operated to provide electricity with a 50% load factor for up to 614 hours per year. At NASSCO, the engine is used to power a 300-ton gantry crane for 4,800 hours per year at a load factor of only 12% because the engine spends a great deal of time at idle. The Kings County installation is equipped with a diesel particulate filter system for the control of PM, CO, and HC emissions. The NASSCO facility has a combined diesel particulate filter/SCR system for the control of PM, CO, HC, and NOx. The cost-effectiveness of controlling emissions from these two installations using their actual operating hours is shown in Figure VII-2.

Figure VII-2
Control Cost-Effectiveness for Actual Operation at Kings County and NASSCO



As shown, the cost-effectiveness of emission control technologies for these two operations ranges from approximately $9,500 to $15,500 per ton of pollution reduced annually.

Cost-effectiveness is far less favorable for the other four case studies if actual operating hours are assumed. At the Pacific Bell facilities, the subject engines are operated at low load for only 20 hours per year. The Santa Clara County installation is operated for 70 hours annually with over 90% of the operation for testing and routine maintenance. Similarly, the Sierra Nevada Brewing Company operates its engines at 80% load predominantly for testing and maintenance for up to 150 hours per year. As a result, costs per ton of pollution removed are at least an order of magnitude higher for the particulate filter control systems installed at the Pacific Bell, Santa Clara County, and Sierra Nevada Brewing Company facilities compared to the Kings County and NASSCO installations, if actual operating hours are assumed. Costs per ton are somewhat lower, at $58,000/ton, for the oxidation catalyst system installed at the Pacific Bell San Jose facility, even taking into account its similarly low annual hours of operation.

Finally, the case studies indicate that cost-effectiveness also varies with the size of the engine involved. For example, they suggest that current capital costs for retrofitting an existing diesel engine with a particulate filter system are in the range of $20 to $45 per horsepower. Thus, the capital cost of retrofitting a midsize, 1000 hp diesel engine (equivalent to 750 kW), would be in the range of $20,000 to $45,000. It should be emphasized that the relatively high capital costs associated with these control systems can be expected to decline substantially with manufacturing economies of scale and as more engines are retrofitted, creating a more competitive market for vendors.

VIII. Conclusions and Policy Recommendations

As noted in the Introduction and in subsequent chapters, two broad questions and concerns motivated this study. The first was a recognition that environmental regulators lack reliable and accurate information on the current population and emissions characteristics of stationary diesel engines in the Northeast. A second, closely related concern was the lack of information on how rapidly developing demand response and real-time pricing programs – coupled with metering, interconnection and other technology advances – might impact air emissions associated with diesel engines, the most common form of distributed generation capacity available at the present time.

The findings presented elsewhere in this report suggest a number of things about the existing stationary diesel generator population in the Northeast. First, while it is difficult to develop reliable population and size distribution estimates for all such engines, the total number of units distributed throughout the eight-state NESCAUM region is significant and likely ranges from well over 12,000 units to as many as 35,000 units. Diesel internal combustion (IC) engines clearly account for the vast majority of stationary distributed generators installed at commercial and industrial facilities in the Northeast. Within the diesel IC engine population, most (80%) are intended exclusively or primarily for emergency use. Finally, a comparison of the inventory estimates and telephone surveys conducted for this study suggests that state agencies lack permit records or other unit-specific information on large numbers of individual engines in the region.

Available information further suggests that the impact of formal demand response programs sponsored by New York and New England Independent System Operators (ISOs) to date has been modest, both in terms of the total amount of customer-based electricity generated and in terms of the pollution added to state and regional inventories.[66] In fact, the telephone surveys conducted in New York City and Fairfield County, Connecticut, suggest that current levels of diesel generation outside formal demand response programs are much more significant. Presumably, most of that generation is being provided by units permitted to operate for peak-shaving and baseload – rather than strictly emergency – purposes. At present, emergency generators are generally precluded by state regulation from operating under all but a very limited set of conditions. The potential for an increase in emissions from the current base of distributed diesel generators is therefore largely driven by the following three factors:

- The potential for increased capacity utilization of existing baseload or peak-shaving units;
- The potential for increased eligibility of – and use of – emergency engines in emergency demand response programs, which allow for operation before an actual outage occurs; and

[66] Of course, as discussed in Chapter V, the health risks and environmental impacts of diesel generators are perhaps more appropriately viewed from a local impacts standpoint – taking into account the unique characteristics of diesel exhaust – than from the more traditional emissions inventory/attainment planning standpoint in which cumulative emissions from multiple sources are often aggregated over larger areas.

- The potential for increasing numbers of generators to operate to the limits of – and perhaps in some cases even beyond – applicable air permit restrictions if changing market signals or incentive programs provide stronger economic reasons to do so.

At least in New England, the recent addition of substantial new central-station combined-cycle gas turbine capacity is likely to substantially ameliorate the first two, if not all, of these potential drivers in the near term by making capacity shortfalls and high prices less common. However, as regional demand continues to grow and investment in new central-station capacity slows down due to a shortage of capital and loss of investor confidence in the energy sector more broadly, shortage situations and high prices may begin to re-emerge, especially in transmission-constrained load pockets. It is therefore important that air quality management officials respond now by updating permitting and other regulatory requirements and by ensuring that mechanisms are in place to collect the data needed to assess and manage potential impacts in the future. In updating regulatory requirements, states should consider the importance of limiting harmful impacts from the existing base of stationary diesel generators, while also (ideally) promoting the transition to a new generation of cleaner alternatives.

This chapter reviews a number of policy initiatives currently being undertaken by states and other organizations to update existing regulatory requirements for distributed generators and to institute better data collection practices, particularly in cooperation with northeastern ISOs. The state summaries are followed by a brief discussion of some of the control technology options available to diesel generators and their costs. Finally, the chapter closes with a discussion of a number of recommendations aimed at promoting regional policies for the use of diesel engines and other distributed generation technologies that are protective of the environment and at the same time, provide fuel diversity and supply reliability.

A. Emissions Standards and Model Rules for Distributed Generators

Model rules for distributed generation have been proposed by the Northeast Ozone Transport Commission (OTC), a regional organization created under the Clean Air Act Amendments of 1990 to address the regional transport of ozone and its precursors in the Northeast and Mid-Atlantic states, and by the Regulatory Assistance Project (RAP), a non-profit organization that aims to assist state and federal regulators in addressing a wide range of electric sector issues. Both organizations solicited input from numerous stakeholders in developing their model rules. The OTC model rule recommends fuel-specific emissions standards (for NOx only) for all non-emergency natural gas and diesel engines.[67] In addition, the OTC model rule recommends a number of requirements for emergency engines, including requirements to (1) set and maintain engine ignition and injection timing at specified levels; (2) inspect and adjust timing every 3 years; (3) avoid operation on days with high ozone levels; and (4) promote record-keeping on engine operation, including the installation of meters that can record monthly hours of operation.

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[67] As an alternative, the OTC model rule also allows for requirements to be met by achieving engine-specific percentage reductions from current baseline NOx emissions or by purchasing NOx allowances.

In contrast to the OTC model rule, the RAP model rule is aimed at new engines only and recommends the phased introduction of progressively more stringent output-based emissions standards for several pollutants (including particulate matter, carbon monoxide and nitrogen oxides, as well as carbon dioxide). The emissions standards proposed in the RAP model rule are independent of fuel type. In addition, new regulations governing emissions from distributed generators have recently been adopted in California and Texas. All of these efforts provide a potential source of guidance for Northeast states looking to update their regulatory requirements for distributed generators. Table VIII-1 summarizes the specific emissions standards proposed by the OTC and RAP model rules as well as emissions standards adopted in California and Texas.

Table VIII-1
Summary of Recommended/Adopted Distributed Generation Emissions Standards

	Emission Limits (lb/MWh)					
Regulation	**NOx (Ozone Attainment Areas)**	**NOx (Ozone Non-Attainment Areas)**	**CO**	**VOCs**	**PM**	**CO_2**
OTC Model Rule[a] - new and in use engines (emissions factors converted from g/bhp-hr)						
Natural Gas (except emergency)	4.4	4.4				
Diesel (except emergency)	6.8	6.8				
RAP Model Rule - new engines						
After January 1, 2004	4	0.6	10		0.7	1900
After January 1, 2008	1.5	0.3	2		0.07	1900
After January 1, 2012	0.15	0.15	1		0.03	1650
California Air Resources Board						
Distributed Generation Certification Rule for New Non-Emergency Engines						
After January 1, 2003	0.5	0.5	6	1	fuel req.[b]	
After January 1, 2007	0.07	0.07	0.1	0.02	fuel req.[b]	
Airborne Toxics Control Measure for New and In-Use Stationary IC Engines (DRAFT 6/5/03)						
New diesel engines > 50 hp				(converted from g/bhp-hr)		
Baseload power	off-road standards apply[c]				0.03	
Emergency power	off-road standards apply[c]				0.44[d]	
Exisiting diesel engines > 50 hp						
Baseload power	NOx, CO and VOCs not to increase > 10% to meet PM limits[e]				0.03[f]	
Emergency power	NOx, CO and VOCs not to increase > 10% to meet PM limits[e]				1.48[d]	
Texas - new engines						
Before January 1, 2005						
less than 300 hrs/yr	21	1.65				
more than 300 hrs/yr	3.11	0.47				
After January 1, 2005						
less than 300 hrs/yr	21	0.47				
more than 300 hrs/yr	3.11	0.14				

[a] The OTC Model Rule offers three compliance options: 1) meet the NOx emission limit specified above, 2) meet a percentage reduction of NOx emissions specific to the type of engine, and 3) purchase of NOx allowances.

[b] PM emission limit corresponding to natural gas with fuel sulfur content of no more than 1 grain/100 standard cubic foot.

[c] Engine must meet model year off-road compression-ignition engine standards, or Tier 1 off-road certification standards.

[d] Allowable hours of operation increase as the emissions factor of an engine decreases.

[e] Many engines may require control technology to meet the PM limits set in this rule, and these technologies must not increase the emisisons of NOx, CO or VOC by more than 10%.

[f] Engines can meet this standard or reduce PM emissions by 85%.

B. New England Demand Response Initiative and Efforts to Improve Data Collection and Coordination with ISOs

Launched in 2001, the New England Demand Response Initiative (NEDRI) has provided a useful venue for exploring environmental concerns associated with current federal and regional efforts to promote more robust demand response capabilities in deregulated wholesale electricity markets. NEDRI itself was designed as a multi-stakeholder process that aimed to develop specific policy recommendations on a whole host of demand response issues. While this effort was targeted from the outset to the needs and concerns of the New England region specifically, the Federal Energy Regulatory Commission (FERC) has since indicated that it will look to NEDRI for policy guidance in developing demand response provisions in its forthcoming rulemaking on Standard Market Design for competitive wholesale markets nationwide. NEDRI's recommendations are expected to be released in a final report due for completion during the summer of 2003. Meanwhile, a number of specific recommendations concerning eligibility for participation and information collection requirements in the context of the New England ISO's summer 2003 demand response programs have already been finalized by participating stakeholders and submitted to FERC for review.

Recognizing that states will need to update current air permitting requirements to handle a greatly expanded reliance on distributed generators, and indeed, that many are already in the process of doing so, the NEDRI recommendations essentially create two new types of requirements. First, they establish more explicitly that compliance with current air permitting requirements is a necessary pre-condition for eligibility to participate in ISO-sponsored demand response programs.[68] Accordingly, the New England ISO will begin requiring demand response providers (including third-party aggregators) to affirm that, to the best of their knowledge, applicable permits are on file for any on-site generators expected to operate as part of the demand response capability being registered. If an engine does not require an air permit, the owner is obligated to obtain a waiver from the state permitting authority and to provide basic information about the engine (e.g. size, age, model, rated fuel input, etc.).

The second type of requirement endorsed by NEDRI relates to information collection and coordination between the ISO and state air agencies. Specifically, the New England ISO has committed to providing state air agencies with a summary report on the number of hours and dates that participating units actually ran and the megawatt hours of electricity produced during demand response events at the end of each summer season. To allow a full and detailed assessment of environmental impacts from these programs, future reports of this nature will ideally include specific information about ownership, type, size, and location of engines, control technologies in place and estimated emissions, type of fuel used (including sulfur content), amount of electricity produced, and hours/dates of demand response events. As discussed at length in the NEDRI process, improved information is crucial for state air programs to evaluate what kinds of control

[68] Note that this basic approach has already been adopted by PJM – the ISO that serves much of the Mid-Atlantic region (see Footnote 8) – with FERC approval.

technologies and strategies (including perhaps an allowance-based market based approach such as the OTC NOx Budget program) may be needed to ensure that adequate and cost-effective environmental protection accompanies the increased use of demand response resources. Enhancing and formalizing information exchange between the ISO and air regulators can go a long way toward addressing and resolving lingering concerns about the environmental impacts of distributed generation and toward ensuring that state permitting and enforcement programs are providing effective protection against unwanted environmental outcomes.

C. Current State Activities Related to the Environmental Regulation of Distributed Generators in the Northeast

As noted earlier in this chapter a number of Northeast states have already begun efforts to update permitting requirements and other regulations pertaining to distributed generators, including diesel engines. A short summary of each state's activities (updated as of May 2003) is presented below.

1. <u>Connecticut</u>

As described in Chapter II and elsewhere, Connecticut in 2002 introduced a new General Permit for Distributed Generation – applicable to all engines over 50 hp (37 kW) – to help respond to resource adequacy concerns in the southwest Connecticut load pocket. This permit expires at the end of 2003 and Connecticut is currently developing a separate regulation to be in place in spring 2004. This new regulation is likely to be a self-implementing permit-by-rule applicable to distributed generators in the entire state, and will likely set technology-neutral emissions limitations that become more stringent over time. The Connecticut air bureau also co-chaired the RAP collaborative that developed the model emissions rule described earlier in this chapter. The RAP model rule is being used for guidance in Connecticut's current development of new regulations for distributed generation. Meanwhile, the state currently prohibits emergency engines from participating in the New England ISO price response program.

2. <u>Maine</u>

In Maine, emergency engines are licensed to operate during "sudden and reasonably unforeseeable events beyond the control of the source" for a maximum of 500 hours per year. Non-emergency engines over 500 kW in Maine must be licensed and all diesel engines are required to use on-road fuel. Regulators in Maine do not currently view distributed generation as a significant problem, but they are experiencing an increase in the number of companies requesting permits to install engines for primary power. Thus, peak and baseload engines represent a greater source of potential emissions increases than emergency engines in Maine. Accordingly, the Maine Department of Environmental Protection has stated that it will require selective catalytic reduction (SCR) controls for any engine with potential NOx emissions in excess of 20 tons per year. At this time, no generator has triggered this requirement. Currently, regulators in Maine are beginning a process to develop a rule that will address distributed generation.

3. Massachusetts

Air quality officials in Massachusetts are developing new regulations to include a larger number of distributed generators in the state's permitting system. At the same time, the state is considering streamlining the pre-construction review process – which is currently conducted on a case-by-case basis for all engines above particular size thresholds – to introduce a certification and permit-by-rule compliance option for non-emergency engines. Certification requirements will also be added to the existing permit-by-rule program for emergency engines. Together with Connecticut, Massachusetts air officials co-chaired the RAP model rule collaborative. They are now considering adoption of regulations based on the RAP model rule, including the extension of permit requirements to smaller engines.

Massachusetts anticipates that emissions requirements for non-emergency engines will continue to be more stringent than those for emergency engines and that only engines meeting the more stringent non-emergency requirements will be eligible to participate in the New England ISO's price response programs. In general, Massachusetts considers the widespread use of emergency engines for stand-alone generation to be quite limited, given the unfavorable economics of operating these units as a substitute for grid-supplied electricity. Finally, the Massachusetts Department of Telecommunications and Energy recently concluded a stakeholder process to recommend new interconnection standards, policies and procedures to support greater development of distributed generation resources. Those policies are now being considered for adoption by the state.

4. New Hampshire

As described in the next section (Section D) of this chapter, New Hampshire introduced an emissions fee system in 2001 to promote reduced NOx emissions from non-emergency generators. The fees do not apply to very small generators or to emergency generators. They range in magnitude from $400-$800 per ton of NOx emissions, depending on whether emissions occur during the summer ozone season (May 1 to September 30), and are scheduled to increase to $500-$1,000 per ton in the next few years. At this time, New Hampshire is not working on additional regulations to address distributed generation.

5. New Jersey

New Jersey plans to propose tighter NOx restrictions for non-emergency reciprocating IC engines, consistent with the OTC model rule. Accordingly, new or modified engines larger than 50 hp (about 37 kW) will require a permit and will need to meet more stringent state-of-the-art emissions limits for NOx and particulate emissions. At the same time, New Jersey plans to raise the permitting size thresholds for clean distributed generators, as proposed in the OTC Model Rule for Distributed Generation, so that only larger units of this type will need to obtain permits.[69]

New Jersey's current permitting restrictions preclude the operation of emergency generators in anything but outage situations (i.e. "only when the primary source of energy has been rendered inoperable by circumstances beyond the control of the owner or operator of the facility"). However, the state is considering proposing changes that would allow emergency generators to operate to avert imminent outages – for example, when a voltage reduction alert is called by PJM. This would be similar to the emergency demand response exceptions that have been introduced in New York and some parts of New England.

6. New York

Since the summer of 2002, the New York DEC has prohibited the use of all diesel engines and all emergency engines in the New York ISO's price responsive program. However, emergency engines are eligible to participate in the NY ISO's emergency demand response program, subject to certain requirements including limits on total operating hours.

The NY DEC began a stakeholder process as part of its Distributed Generation Rulemaking Project in 2001. The proposed rule includes RACT-level output-based limits for NOx and CO emissions from new distributed generation sources. The proposed PM emissions standards are input-based and have been in place for all oil-fired engines since 1972. The PM emissions standards will apply to existing engines in 2007, and the NOx and CO standards will apply to existing engines in 2008. Finally, the state is proposing to require the use of ultra-low sulfur fuel in diesel generators and to phase in new emissions standards over the next three years. New York air officials hope to have a rule finalized by early 2004.

7. Rhode Island

Rhode Island has plans to propose a new "general permit" or "permit-by-rule" for emergency generators in 2004. This may include engines smaller than the current 500 kW threshold. For other non-emergency engines, the state has considered options such as including smaller engines or adopting the RAP model rule, but has not yet made a final decision. Rhode Island air officials are also interested in observing other states' experience with adopting the OTC model rule before determining a final course of action.

Currently, emergency engines in Rhode Island are allowed to operate only "when the primary power source is inoperable." As such they are precluded from participating in any interruptible power service agreements, including the New England ISO demand

[69] The OTC Model Rule for Distributed Generation recommends exempting the following engines from permitting requirements: All fuel cells fueled by hydrogen, fuel cells smaller than 5 MW fueled by methane, all remaining fuel cells smaller than 500 kW, and microturbines smaller than 500 kW fueled by natural gas and certified to emit less than 0.4 lb/MWh of NOx.

response programs. To become eligible for participation, any engine over applicable permitting size thresholds would be required to utilize Best Available Control Technology (BACT). BACT performance requirements for a given unit would vary depending on expected hours of operation, but would at a minimum require the use of ultra-low sulfur fuel for diesel engines.

8. Vermont

Currently, Vermont allows emergency engines to operate only for testing (maximum of 200 hrs/yr) or in true emergency situations (i.e. outages). There is no restriction on hours of operation in the event of a true emergency. The state has no plans at present to allow emergency engines to operate to avoid emergencies (e.g. through emergency demand response programs). Non-emergency engines may, of course, participate subject to NSR requirements and any other state-imposed fuel or operational restrictions. Meanwhile, the state is planning to revise its emissions standards for both emergency and non-emergency diesel generators to bring them in line with federal standards for non-road diesel engines. Requiring SCR NOx control for some high-use engines is also an option being considered, particularly for engines used in ski areas.

D. Control Technology, Cost and Other Policy Considerations

As discussed at length in Chapter VI, a number of control technologies exist that can substantially reduce diesel engine emissions of pollutants such as nitrogen oxides (NOx), carbon monoxide (CO), particulate matter (PM) and hydrocarbons or volatile organic compounds (VOCs). The primary control options include diesel particulate filters, oxidation catalysts and selective catalytic reduction (SCR) for NOx control. Generally, these technologies are well developed and have been successfully demonstrated. Thus the chief issues when evaluating emissions control policies for diesel IC generators – particularly in the case of smaller engines – are likely to be issues of cost and cost-effectiveness, rather than technical feasibility. If an engine runs for only a few tens of hours in a year, a given control technology will likely remove only relatively small amounts of emissions (say, compared to a central-station power plant) for a given capital cost.[70] Not surprisingly, data from the case studies described in Chapter VII indicate that cost effectiveness – as measured by the conventional metric of tons removed per dollar of control cost – improves as operating hours increase.

In this context, innovative regulatory approaches can provide attractive alternatives to mandating end-of-the-pipe emissions control technologies. For example, in late 2001, New Hampshire imposed NOx emissions fees (in dollars per ton) on small diesel generators in the state in an effort to reduce NOx emissions from these sources. The fees apply only to NOx emissions; in addition, small engines (with NOx emissions below 5 tons per year) and emergency generators are exempted. New Hampshire's current fees

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[70] It should be emphasized that the relatively high capital costs currently associated with many available control systems can be expected to decline substantially with manufacturing economies of scale and as more engines are retrofitted, creating a more competitive market for vendors.

range from $400 per ton of NOx emissions in the non-ozone season up to $800 per ton during the ozone season. They are scheduled to increase to $500 per ton and $1,000 per ton, respectively, in 2005. Similar emissions incentive programs could be applied elsewhere in the Northeast to promote less polluting engines. The resulting revenue stream could be used for control technology development or demonstration programs, retrofit efforts, or to support more advanced distributed generation options including inherently low or zero emission renewable and fuel cell alternatives. Finally, another option would be to require distributed generators participating in ISO or utility-sponsored demand response programs to obtain pollution allowances. This approach is most readily implemented where an allowance trading program already exists for other sources, as in the case of the existing OTC NOx budget program which caps ozone-season NOx emissions from power plants and large industrial boilers in the Northeast.

In developing future emissions standards and permitting requirements for diesel generators, states should consider the new federal standards recently introduced for non-road diesel engines used in farming, construction, and industrial activities.[71] The standards require substantial reductions in NOx and PM emissions (on the order of 90% from current levels) to be achieved in new engines by 2014. In addition, they establish fuel content requirements (i.e. sulfur caps).[72] New fuel requirements are necessary because the control technologies necessary to meet more stringent emissions standards (e.g. diesel particle filters for PM and NOx adsorbers[73] for NOx control) require low-sulfur fuel. Importantly, low-sulfur fuel will provide immediate emissions reductions in the existing engine fleet, in addition to any reductions that are gradually achieved by the introduction of new and cleaner engine models. In addition, emulsified diesel fuel[74] holds considerable promise as a cost-effective strategy for reducing both PM and NOx emissions. Some recent commercial diesel products utilizing an emulsion formulation with 20% water content have been verified by the California Air Resources Board to provide average PM and NOx emissions reductions of 63% and 14%, respectively, when used in on-highway vehicles.[75] The transferability of this fuel-based control option to stationary diesel engines needs to be investigated. Meanwhile, fuel standards (especially related to sulfur content) could be adopted for stationary diesel generators to achieve near-term emissions reductions – and indeed a number of northeastern states have already taken this step.

As in the case of stationary engines used to generate electricity, emissions standards for new non-road engines will take considerable time to penetrate, given the slow turnover of

[71] EPA promulgated its rule *Control of Emissions of Air Pollution from Nonroad Diesel Engines and Fuel* on April 15, 2003 (40 CFR Parts 69, 80, 89, 1039, 1065, and 1068). The rule was published in the Federal Register on May 23, 2003 (http://www.epa.gov/fedrgstr/EPA-AIR/2003/May/Day-23/a9737a.htm).

[72] Specifically, EPA is requiring that the allowable sulfur levels in nonroad diesel fuel be reduced by more than 99% (from 3400 ppm to about 15 ppm by the year 2010).

[73] NOx adsorber technology is applicable to new engines, but not as a retrofit option for existing engines.

[74] Generically, the term emulsion refers to the suspension of small globules of one liquid in a second liquid with which the first will not mix. In this case, the emulsion would consist of diesel globules suspended in water.

[75] Information on emulsified diesel is taken from NESCAUM's Draft White Paper *Status Report on Clean Mobile Source Diesel Initiatives in the Northeast States' and Canadian Provinces*, April 2003.

the existing fleet. As a result, efforts are also underway to develop and apply retrofit emission control technologies for on-road and non-road engines, many of which are likely to be similarly applicable to existing stationary diesel generators.[76] For example, a number of voluntary programs are being used in the Northeast to test the operation of diesel particulate filters and oxidation catalysts in on-road and non-road mobile source applications (e.g. trucks, buses, construction equipment, etc.). There is no technical reason why these options cannot be successfully applied and should not be tested on existing stationary diesel engines.

E. Policy Recommendations for the Northeast States

Based on the findings of this report and other related initiatives, NESCAUM has developed a number of policy recommendations for Northeast states interested in regulating diesel generators specifically and promoting cleaner distributed generation alternatives more broadly. In general, our policy recommendations fall into three categories:

- Updating emissions standards and air permitting requirements
- Regulating use of diesel generators in demand response programs
- Improving regional coordination and data collection

Each of these categories of recommendations is discussed in more detail below.

1. <u>Updating Emissions Standards and Permitting Requirements</u>

State air regulators increasingly recognize that current permitting requirements may need to be updated to manage possible adverse impacts associated with the use of diesel IC engines, whether as part of formal demand response programs or in response to changing market conditions. The need for new regulation may be particularly acute for smaller units that fall below current permitting thresholds. Current exemptions for emergency engines may continue to be appropriate, provided these engines continue to be barred from participation in economic demand response (or "price response") programs. To the extent that emergency generators are allowed to participate in emergency demand response programs, current operational limits or other restrictions may need to be revisited in light of the possibility that such programs may be triggered much more frequently than actual power outages (particularly in existing load pockets and, more broadly, as demand catches up with supply in the Northeast over time). At a minimum, states should consider requiring that emergency generators eligible to participate in emergency demand response programs be operated on "clean diesel" or low sulfur fuel, which can reduce PM emissions (and possibly NOx emissions) by as much as 10-20% at a very reasonable cost. In addition, such fuels can provide substantial sulfur dioxide (SO_2) emissions reductions.

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[76] Note that while states are preempted from regulating mobile onroad and nonroad diesel engines, they are not preempted from setting standards for new and existing stationary engines. Hence, states can move to adopt emissions standards for distributed generators even absent federal action on this issue.

States should also consider whether retrofit requirements can be cost-effectively applied to existing peak-shaving or baseload diesel generators that stand to increase their output under formal price response programs or as a result of real-time pricing and other market signals. Additional retrofit or other requirements (such as those proposed in the OTC model rule) may also be appropriate for otherwise uncontrolled emergency generators that might begin operating more frequently under ISO-sponsored emergency demand response programs. As noted previously, efforts aimed at reducing emissions impacts from the existing generator base can benefit from parallel efforts underway for mobile diesel engines (both on-road and non-road) and from the availability of low-sulfur fuel. In evaluating the need for new emissions control requirements for existing diesel generators, states should consider that the control of particulate emissions may be both more important from a public health perspective and more cost-effective from a control technology perspective. For reasons discussed elsewhere in this report, NOx emissions from small diesel generators are likely to remain relatively modest in the context of states' overall ozone attainment planning obligations in most areas. However, even infrequent short-term increases in particulate emissions from these types of generators can impose substantial health risks on local communities (and especially on susceptible individuals) in the vicinity. In addition, it appears that particulate filters and oxidation catalysts may be relatively inexpensive and easy to retrofit on existing engines compared to NOx controls such as SCR.

To ensure that the region can take advantage of the multiple system benefits of distributed resources in the future, states should consider adopting regulations for new distributed generators. By developing standards that are fuel-independent and output-based (e.g. lb/MWh), states can promote new technologies and improved efficiencies in future distributed generation technologies. In particular, designing regulations to account for useful thermal as well as electrical output can be used to support increased penetration of highly efficient combined heat and power systems in commercial and industrial applications. In developing requirements for new generators, states should consider including, at a minimum, rigorous performance standards for emissions of particulate matter (preferably fine PM or $PM_{2.5}$), NOx, toxics and carbon monoxide (CO). In addition, certification procedures and in-use testing requirements, as well as other provisions, may be needed to promote proper maintenance and ensure effective implementation and enforcement. For example, the new standards adopted by Texas in 2001 require re-certification of engine emissions after 16,000 hours (but not more than once every 3 years).

Finally, states may wish to consider providing incentives for truly advanced, ultra-low or zero-emissions technologies in the permitting process. For example, Texas waives permitting fees for distributed generator units that have certified NOx emissions less than 10% of the required standards, as long as total generating capacity is less than 1 MW. Similar incentives could be used to promote highly efficient, low-emitting fuel cell technologies and zero-emissions renewable options (e.g. wind or solar). Here again, such programs should be designed to account for the increased efficiency of combined heat and power systems, which capture the heat generated by the electricity conversion process to provide useful thermal energy (typically in the form of steam).

2. Regulating Use of Diesel Generators in Demand Response Programs

States should evaluate the need for updated regulations to ensure that the use of diesel generators in demand response programs sponsored by ISOs or by local distribution utilities does not create unintended public health and air quality impacts. In general, it is probably appropriate to draw a clear distinction between economic (price-driven) demand response programs and emergency demand response programs. Different – and more stringent – environmental eligibility criteria may be appropriately applied to economic (price-driven) programs because their potential environmental impacts are substantially greater than those of emergency programs, which, by definition, are invoked only rarely and then usually for short periods of time (i.e. on the order of tens and not hundreds of hours per year). An additional important justification for more stringent environmental controls in price response programs is the fact that participants may receive substantial compensation for any on-site generation they provide on high-demand days when electricity may be valued at prices ten times or more the average price. In light of these payments, additional pollution control investments may be justified, even if their cost-effectiveness – as measured in dollars per ton of pollutant removed – is less favorable than the typical cost-effectiveness for emissions controls applied to central station power plants.

As was noted in the above recommendations concerning permitting requirements and emissions standards, modest retrofit requirements and/or fuel quality standards may also be appropriate for emergency generators participating in emergency demand response programs, particularly if they are likely to accumulate hours of operation at or near current permit limits. In addition, it is important that the definition of what constitutes an emergency be clearly defined (preferably on a consistent basis region-wide, as discussed in the next section). To date, most northeastern state air regulators have defined "emergency" to correspond to a particular step in ISO operations, typically necessitating an actual (as opposed to anticipated) call for voltage reductions.

For economic or price-driven demand response programs, states should consider restricting eligibility to distributed generators that meet minimum emissions performance standards. In addition, further restrictions or requirements specific to diesel engines may be appropriate in some cases, especially in ozone and PM non-attainment areas or in areas with particular local air quality concerns (e.g. environmental justice issues or a high concentration of other diesel exhaust sources). In any case, environmental eligibility requirements for all types of ISO or utility sponsored demand response programs must be clearly communicated to intermediary parties and potential program participants. Ideally, future updates of state emission control requirements and permitting programs should ensure that it is easy to determine and document a given participant's eligibility for different types of demand response programs. For their part, the ISO and distribution utilities should continue to work with state regulators as permitting requirements evolve to ensure that generation owners have accurate, up-to-date information about permitting requirements and reporting obligations.

Meanwhile, the recommendations of the NEDRI process concerning the obligation of demand response providers to check their permit status, to obtain a waiver if they do not require a permit and to provide basic information on any on-site generators (see Section B of this chapter), together with the responsibility of the ISO to provide specific after-the-fact information on program outcomes, provide a useful model for other regions and can serve as an important environmental backstop and source of information as state policies evolve.

3. Improving Regional Coordination and Data Collection

A regional approach to implementing many of the policy recommendations described in this chapter can improve effectiveness, reduce confusion and level the competitive playing field for regulated entities, and minimize regulatory and administrative burdens for states facing formidable resource constraints at this time. At present, state permit requirements vary widely and are perceived as complex and confusing by many economic regulators, system operators and generation owners. More consistency would make it easier for ISOs, the regulated community and other stakeholders to work together in ensuring compliance. Additionally, the adoption of regionally consistent emissions standards for new generators would send a much more powerful signal to manufacturers of distributed generation technologies and would increase the probability that compliant models are brought to market in a timely manner.

In the Northeast, NEDRI has recommended some important initial steps toward greater regional consistency. In the interests of continued progress in this direction, NESCAUM recommends the Northeast states take steps to promote further regional consistency in: (1) regulating the emissions performance of new and existing generators and (2) establishing the eligibility of different generators for various types of demand response programs. In the meantime, efforts already underway to clarify current state requirements and to facilitate permit checking and information collection by state air agencies and the ISO should continue and be strengthened.

In addition to promoting regionally consistent permit rules, demand response eligibility and data collection requirements, the Northeast states should build on this initial effort to develop more reliable and comprehensive inventories of internal combustion engines in the region. Greater regional consistency in state record-keeping practices would be helpful in this regard and could improve states' ability to use available permit information to assess environmental impacts and identify policy priorities. Eventually, the development of a region-wide, user-friendly database of distributed generation resources may be feasible. The ability to query a single database for specific information on large numbers of individual generators would be extremely helpful to state air regulators and to other policy makers interested in promoting environmentally responsible distributed resources more broadly.[77]

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[77] For example, a database could be designed to include key pieces of information, including: (1) permit number, (2) owner name, address and contact information, (3) engine location, (4) make and model of engine, (5) engine size, (6) engine purpose, (7) estimated hours of operation each year, (8) eligibility for demand response programs, (9) fuel type and (10) emissions rates and control technology.

F. Conclusions

This report represents a first and necessarily incomplete effort to develop more comprehensive estimates of the population and associated emissions potential of existing diesel generators in the Northeast. To refine these results in the future, regional data collection mechanisms must be improved. In the meantime, states should consider adopting new requirements and policies aimed at managing any adverse environmental impacts associated with increased reliance on the existing base of distributed generators and promoting a transition to cleaner distributed generation options in the future. The various policy recommendations described in this chapter are re-summarized in Table VIII-2. Most of these recommendations are directly aimed at new and existing generators. However, it is worth emphasizing that a number of other state policies and regulations are likely to directly or indirectly affect the future use and composition of distributed generation options in the Northeast. Examples include utility pricing reforms, interconnection standards and net metering requirements, transmission planning and resource adequacy determinations, information disclosure and emissions portfolio requirements, emissions cap-and-trade programs and other policies. The interaction of these policies and programs with policies more directly related to distributed generation is therefore an important and ongoing consideration for states as they seek to promote a more reliable, less polluting, less costly and more efficient system for meeting the region's electricity needs.

Table VIII-2
Summary of NESCAUM Recommendations

Updating Emissions Standards & Permitting Requirements	• Review adequacy of current permitting size thresholds and requirements, especially in light of new health concerns associated with localized exposure to diesel exhaust. • Update requirements for existing peak, baseload and emergency generators accordingly, especially for those units eligible to participate in ISO or utility-sponsored demand response programs. • Consider additional fuel requirements (e.g. use of low or ultra-low sulfur fuel) for diesel generators, especially for operation in demand response or other non-emergency applications. • Adopt stringent output-based emissions standards for new distributed generators, which – in the case of combined heat and power systems – appropriately account for useful thermal, as well as electrical output.
Regulating Use of Diesel Generators in Demand Response Programs	• Limit participation in *non*-emergency economic (price-driven) demand response programs to generators that meet minimum emissions control requirements (e.g. BACT-level controls, RAP model rule, etc.) • Limit participation of emergency generators to *emergency* demand response programs, subject to additional requirements as deemed appropriate under recommendations above. • Clarify regionally consistent definition of "emergency". • Consider appropriateness of restrictions and/or additional emissions control or operating requirements (e.g. fuel sulfur requirements) for diesel generators participating in demand response programs. • Continue implementing NEDRI recommendations concerning the obligation of demand response participants to verify permit status and provide unit specific information, together with the ISO's obligation to provide detailed information about program outcomes on a regular basis. The information provided must be specific enough to allow air regulators to make a reliable assessment of associated environmental and public health impacts.
Improving Regional Coordination and Data Collection	• Promote more regional consistency in permitting requirements and emissions standards for new and existing distributed generators. • Promote more regional consistency in state record-keeping practices, with the aim of eventually developing integrated, user-friendly information databases. • Continue to develop and refine inventories of generator population and potential emissions impacts. Promote regional consistency in related policies (e.g. interconnection standards, pricing policies, other air regulatory programs, etc.)

Appendix A
Power Systems Research Methodology

PARTSLINK™ METHODOLOGY

BACKGROUND

Over the past 23 years Power Systems Research has maintained a database known as ***PartsLink™***. ***PartsLink™*** utilizes a mathematical model to estimate the number of engine powered products in service in the United States. This model is developed through the use of factual data and survey results developed and compiled by Power Systems Research on a continuing basis. Application populations are distributed geographically based upon selected economic factors from the Bureau of Census, County Business Patterns Survey.

Key elements of the data include:

- A continuing record of shipments from U.S. factories and imports from foreign suppliers
- Exports of U.S. product equipment
- An attrition model utilized to estimate retirement of engine powered products based upon:
    - Estimated engine life
    - Annual hours of utilization
    - Intensity of utilization – load factor

These factors are utilized to calculate retirement rates and estimate the resulting number of products remaining in operation.

Estimated Engine Life

Because accurate data on actual engine life is not available, Power Systems Research has developed an estimating methodology, which incorporates a wide variety of identifiable engine characteristics to predict the useful life of an engine at maximum continuous output. These factors include:

- Engine horsepower
- Rated speed
- Number of cylinders
- Displacement
- Aspiration
- Engine weight
- Configuration
- Bore
- Stroke

These variables combined with constants, developed by Power Systems Research when comparing projected engine life to a few known benchmarks, have been utilized to calculate a projected engine life for every engine in the database. Engine life is expressed in the average number of hours an engine will operate at the maximum continuous rated output for the engine. The product of this horsepower and the number of hours describe life in horsepower hours.

Because normal operation does not involve operation at full output, our assumption says that engine lifetime in actual hours is extended when the engine is operated at less than full output, but the number of horsepower hours will always be constant. We have assumed that this lifetime will be a statistical mean and that a normal distribution can be used to describe all retirements.

Activity Levels

The hours per year experienced by an owner will vary considerably, but generally are similar for any given product application. In our survey, we ask for annual operating hours. In our model we use the mean hours per year for each application, which results from response to this question.

Fuel Consumption

The average output or load factor is typically similar within an application. Because users are usually not able to measure load factor (the average percentage of maximum output at which they are operating), a good indicator is the amount of fuel they consume. Fuel will vary almost directly with the amount of horsepower produced. We ask for annual fuel consumption and then compare that response to fuel which would be consumed at maximum horsepower. The result is load factor. In many cases, respondents are not able to easily estimate annual hours of operation or fuel consumed annually. In those cases we have asked respondents to estimate hours per week and fuel consumed per week. This also required questions to determine if use was seasonal, length of season, and use in off-season. The results were then projected over 52 weeks to get an annual result.

Survey Research

In order to develop reliable parameters for aftermarket indicators, Power Systems Research has developed an on-going survey of owners of engine powered products. The objectives of this survey include development of:

- Mean product lifetime
- Annual hours of operation
- Typical load factor
- Replacement frequency for key components

This survey is conducted among randomly selected owners of each type of engine powered equipment in each market region, and asks users a rather simple set of questions:

- Type of equipment operated
- Equipment manufacturer
- Equipment model
- Age of the equipment
- Cumulative hours
- Hours operated during the past 12 months
- Fuel consumed during the past 12 months
- Engine installed, if available
- Year of manufacture, if known

Typically we have found it necessary to establish these benchmarks through completion of 100 interviews with owners of each type of equipment in each market region. NOTE: “Equipment or Product Type” is denoted by application [see OeLink Product Guide], fuel, and power range.

Over the years we have implemented a number of “rules” to facilitate data processing and storage rather than statistical reliability. Whenever possible, we benchmark our data against widely accepted authoritative sources. Our effort is to establish credible, statistical reliability for the operating characteristics developed during the course of our survey.

Geographic Distribution

The geographic distribution of generator sets in service is accomplished by matching ownership and application norms to economic data provided by the Census Bureau, County Business Patterns database. The ownership and application norms have been developed over the past 20+ years by developing a profile for owners of each type of equipment. These profiles consist of a correlation between any combination of up to 22 economic, geographic, demographic and meteorological factors. For each county or combination of counties selected the profile for owners of equipment in any application and power range is compiled based on Census Data [Standard Industrial Classification (SIC) and employee size] data and the strength of this profile is compared to the national profile for that same application. The proportionate allocation of equipment in that application and power range is then assigned to that county. The association can be made for application, power rating, engine or equipment brand and model, and age distribution. With each level of specificity the statistical reliability deteriorates somewhat. The profile norms are simply tell us the probability that a certain type of business entity or consumer will own a specific type of equipment. We then complete a normal distribution over the profile interval to determine what portion of the national population is located in any specific area.

ADDITONAL NOTES ON THE OWNER SURVEY

Each year, our survey is directed to a random sample of businesses and consumers. In each case we identify engine powered products owned by the respondent. We then collect operating data for that respondent along with demographic and economic data. This information then becomes the basis for projecting the geographic allocation of engine powered products. We look at the distribution of generator sets among businesses by SIC and by employee size as well as location. From this information we are able to establish a correlation from which we can project the population across the entire nation. For example we may find that metal fabricating companies [SIC 331] with between 400 and 600 employees own 14% of the generator sets between 200 and 300 kW. We know from our sales record and attrition that there are 150,000 units nationwide in this power range and thus 21000 units owned by companies of this size and SIC. We can find from Census data that there are 63000 such companies nationwide so we can project that there will be 1 generator in this power range for every three companies of this type. If there are 60 companies of this description in an area, we would then project that there are 20 generators of this size owned among them.

This methodology and completion of more than 200,000 interviews over the past 20 years has allowed us to construct a matrix for SIC vs. Product type. The data contained in this matrix is the nationwide incidence of ownership for each product type by companies within each SIC and employee size or by consumers. Further derivatives of this matrix such as smaller geographic areas [down to the county level] more specific SIC's and/or more specific product specifications can be compiled but of course the statistical reliability declines as the information becomes more granular.

APPLICATION TO THE NESCAUM SURVEY

For the purpose of targeting survey sample, such as in the NESCAUM survey, by type of engine used and product type, we look at the nationwide incidence for each SIC and company size. We compare that to a tabulation of companies by SIC and size in the target area. This comparison gives us a first estimate of how many units we will find in the area and how many owners we will need to contact in order to find those units. In most cases some of the owners we have previously contacted through our normal surveys are found in this area and we supplement the verified owner list by directing our survey first to the highest incidence group and successively to lower probability owners.

The target survey sample is first constructed to draw names from enough combinations of SIC's and employee sizes to reach our quota [in the NESCAUM case identification of 90% of projected population of stationary generator sets]. In this case the estimation was somewhat more difficult because our product types do not delineate between stationary and portable. When we have exhausted our sample and not reached our quota we continue to draw sample from those categories which have demonstrated the best success rate until we have either totally exhausted all sample or reached our quota.

In this case we estimated that in general we should target all SIC's in the target areas for which sample was available and having more than 50 employees. In several cases we exhausted the sample before reaching our quota and thus we continued sampling to companies with less than 50 employees. Our review indicates that there were some deficiencies in the list supplied by American Business Lists. Several SIC's which subsequently were found on the list of installed and permitted generators in the target area were missing from the American Business List information. As a result our compilation is probably over representative in some SIC's and under representative in others. Nonetheless, the results and incidence of ownership in the target areas were similar enough to the national pattern to make statistically valid estimates of the installed generator set population.

One exception is derived from an anomaly in our attrition model. When an engine is projected to have reached two times the mean lifetime expectation for that engine it is dropped from our tabulation – we assume it has been retired. This is often not the case – especially in the case of large stationary generator sets. These gene sets typically are dropped after a lifetime of 30 to 40 years but in fact many survive for much longer because they do not operate for any appreciable amount of time per year.

Among lessons learned from this examination of Fairfield County and the New York City metropolitan area, it appears that the most important is the incompleteness in some sectors of the ABL databank – specifically utilities and government agencies. This is not particularly surprising since the primary source of ABL information is Yellow Pages directories. We have found similar shortcomings with the Dun & Bradstreet listings over the years. A further lesson for us is the importance of creating a correlation to delineate portable and stationary generators.

In the final analysis, the survey methodology was successful in yielding a credible estimation of the size and distribution for active stationary generator sets in the area as well as the pattern of use. It also revealed that with each level of specificity the reliability deteriorates and that, at least in these cases, list of permitted owners will substantially understate the population.

Appendix B
Power Systems Research Population Estimates for Natural Gas Engines

NESCAUM Region

Number Totals	Emergency	Peak	Baseload	Total
25-50 kW	268	-	-	**268**
50-100 kW	364	2	18	**384**
100-250 kW	152	-	-	**152**
250-500 kW	177	-	-	**177**
500-750 kW	182	77	9	**268**
750-1000 kW	-	-	-	**-**
1000-1500 kW	22	30	6	**58**
1500+ kW	26	248	83	**357**
Total	**1,191**	**357**	**116**	**1,664**

Capacity Totals (MW)	Emergency	Peak	Baseload	Total
25-50 kW	7	-	-	**7**
50-100 kW	25	0	1	**26**
100-250 kW	27	-	-	**27**
250-500 kW	59	-	-	**59**
500-750 kW	116	50	6	**173**
750-1000 kW	-	-	-	**-**
1000-1500 kW	27	37	7	**72**
1500+ kW	47	500	114	**661**
Total	**309**	**588**	**129**	**1,026**

Connecticut

Number Totals	Emergency	Peak	Baseload	Total
25-50 kW	29	-	-	**29**
50-100 kW	34	-	-	**34**
100-250 kW	6	-	-	**6**
250-500 kW	8	-	-	**8**
500-750 kW	15	8	-	**23**
750-1000 kW	-	-	-	**-**
1000-1500 kW	-	3	-	**3**
1500+ kW	1	11	14	**26**
Total	**93**	**22**	**14**	**129**

Capacity Totals (MW)	Emergency	Peak	Baseload	Total
25-50 kW	1	-	-	**1**
50-100 kW	2	-	-	**2**
100-250 kW	1	-	-	**1**
250-500 kW	3	-	-	**3**
500-750 kW	10	5	-	**16**
750-1000 kW	-	-	-	**-**
1000-1500 kW	-	4	-	**4**
1500+ kW	2	23	28	**52**
Total	**19**	**32**	**28**	**78**

Maine

Number Totals	Emergency	Peak	Baseload	Total
25-50 kW	1	-	-	**1**
50-100 kW	1	-	-	**1**
100-250 kW	-	-	-	**-**
250-500 kW	-	-	-	**-**
500-750 kW	**-**	-	-	**-**
750-1000 kW	-	-	-	**-**
1000-1500 kW	-	-	-	**-**
1500+ kW	-	2	1	**3**
Total	**2**	**2**	**1**	**5**

Capacity Totals (MW)	Emergency	Peak	Baseload	Total
25-50 kW	0	**-**	**-**	**0**
50-100 kW	0	**-**	**-**	**0**
100-250 kW	**-**	**-**	**-**	**-**
250-500 kW	**-**	**-**	**-**	**-**
500-750 kW	**-**	**-**	**-**	**-**
750-1000 kW	**-**	**-**	**-**	**-**
1000-1500 kW	**-**	**-**	**-**	**-**
1500+ kW	**-**	4	2	**6**
Total	**0**	**4**	**2**	**6**

Massachusetts

Number Totals	Emergency	Peak	Baseload	Total
25-50 kW	41	-		**41**
50-100 kW	59	-	1	**60**
100-250 kW	24	-	-	**24**
250-500 kW	27	-	-	**27**
500-750 kW	23	9	-	**32**
750-1000 kW	-	-	-	**0**
1000-1500 kW	5	5	-	**10**
1500+ kW	3	42	13	**58**
Total	**182**	**56**	**14**	**252**

Capacity Totals (MW)	Emergency	Peak	Baseload	Total
25-50 kW	1	-	-	**1**
50-100 kW	4	-	0	**4**
100-250 kW	4	-	-	**4**
250-500 kW	9	-	-	**9**
500-750 kW	15	6	-	**21**
750-1000 kW	-	-	-	**0**
1000-1500 kW	6	6	-	**12**
1500+ kW	5	83	25	**113**
Total	**45**	**95**	**25**	**165**

New Hampshire

Number Totals	Emergency	Peak	Baseload	Total
25-50 kW	2	-	-	2
50-100 kW	5	-	-	5
100-250 kW	-	-	-	-
250-500 kW	-	-	-	-
500-750 kW	-	-	-	-
750-1000 kW	-	-	-	-
1000-1500 kW	-	-	-	-
1500+ kW	2	11	5	18
Total	9	11	5	25

Capacity Totals (MW)	Emergency	Peak	Baseload	Total
25-50 kW	0	-	-	0
50-100 kW	0	-	-	0
100-250 kW	-	-	-	-
250-500 kW	-	-	-	-
500-750 kW	-	-	-	-
750-1000 kW	-	-	-	-
1000-1500 kW	-	-	-	-
1500+ kW	4	22	10	35
Total	4	22	10	35

New Jersey

Number Totals	Emergency	Peak	Baseload	Total
25-50 kW	70	-	-	70
50-100 kW	94	1	4	99
100-250 kW	37	-	-	37
250-500 kW	48	-	-	48
500-750 kW	49	21	-	70
750-1000 kW	-	-	-	0
1000-1500 kW	6	7	-	13
1500+ kW	11	97	26	134
Total	315	126	30	471

Capacity Totals (MW)	Emergency	Peak	Baseload	Total
25-50 kW	2	-	-	2
50-100 kW	6	0	0	7
100-250 kW	7	-	-	7
250-500 kW	16	-	-	16
500-750 kW	31	14	-	45
750-1000 kW	-	-	-	0
1000-1500 kW	7	9	-	16
1500+ kW	21	198	53	272
Total	89	221	53	362

New York

Number Totals	Emergency	Peak	Baseload	Total
25-50 kW	123	-	-	123
50-100 kW	169	1	13	183
100-250 kW	85	-	-	85
250-500 kW	94	-	-	94
500-750 kW	95	39	9	143
750-1000 kW	-	-	-	-
1000-1500 kW	11	15	6	32
1500+ kW	5	81	21	107
Total	582	136	49	767

Capacity Totals (MW)	Emergency	Peak	Baseload	Total
25-50 kW	3	-	-	3
50-100 kW	11	0	1	12
100-250 kW	15	-	-	15
250-500 kW	32	-	-	32
500-750 kW	60	25	6	91
750-1000 kW	-	-	-	-
1000-1500 kW	14	19	7	40
1500+ kW	9	163	44	216
Total	144	206	59	409

Rhode Island

Number Totals	Emergency	Peak	Baseload	Total
25-50 kW	1	-	-	1
50-100 kW	1	-	-	1
100-250 kW	-	-	-	-
250-500 kW	-	-	-	-
500-750 kW	-	-	-	-
750-1000 kW	-	-	-	-
1000-1500 kW	-	-	-	-
1500+ kW	4	4	3	11
Total	6	4	3	13

Capacity Totals (MW)	Emergency	Peak	Baseload	Total
25-50 kW	0	-	-	0
50-100 kW	0	-	-	0
100-250 kW	-	-	-	-
250-500 kW	-	-	-	-
500-750 kW	-	-	-	-
750-1000 kW	-	-	-	-
1000-1500 kW	-	-	-	-
1500+ kW	7	8	5	20
Total	7	8	5	20

Vermont

Number Totals	Emergency	Peak	Baseload	Total
25-50 kW	1	-	-	1
50-100 kW	1	-	-	1
100-250 kW	-	-	-	-
250-500 kW	-	-	-	-
500-750 kW	-	-	-	-
750-1000 kW	-	-	-	-
1000-1500 kW	-	-	-	-
1500+ kW	-	-	-	-
Total	2	-	-	2

Capacity Totals (MW)	Emergency	Peak	Baseload	Total
25-50 kW	0	-	-	0
50-100 kW	0	-	-	0
100-250 kW	-	-	-	-
250-500 kW	-	-	-	-
500-750 kW	-	-	-	-
750-1000 kW	-	-	-	-
1000-1500 kW	-	-	-	-
1500+ kW	-	-	-	-
Total	0	-	-	<1

Appendix C
Power Systems Research Generator Set Estimator

CALCULATING REGIONAL POPULATIONS

PSR's generator set population estimates are based on an ongoing nationwide survey in which a sampling of each North American Industry Classification System (NAICS) group is made annually. Survey respondents are asked if they own a generator set, its rating, annual hours of service, installation data and other ownership and operating questions. On the basis of their responses over the years we have compiled an incidence factor for each NAICS code. The Census Bureau, Dun & Bradstreet and several other sources can provide the number of establishments within any geographic region (see for example http://www.census.gov/epcd/cbp/view/cbpview.html).

Once data on establishments are entered into column C, the total number of generators estimated to be in service can then be calculated, as shown in the example calculation at the top of the chart. These estimates should be used only for very broad purposes. In addition, it should be noted that because of the similarity between stationary and portable generators the estimates also include portable generator sets (which probably account for 60% or more of the total estimated population and are generally smaller than 300 kW). Each region is different and the incidence of generator sets, which is based upon national results, may not be applicable to a local region due to the average size of establishments within a category, the reliability and cost of the utility electric supply, environmental and other restrictions, as well as generator engine sales and support infrastructure locally.

This chart originated in an Excel spreadsheet. To set up a similar spreadsheet, copy the values in columns A, B and D. Data for column C should be imported from the Census Bureau website. A simple calculation then provides the values for column E (where E = (C x D)/1,000).

NATIONWIDE - U.S.

A 2 Digit NAICS	B INDUSTRIAL CATEGORY	C Number of Establishments	D Gen Set Incidence Gen Sets / 000 Establishments	E Gen Sets In Service
	EXAMPLE CALCULATION	**X**	**Y**	**X*Y/1,000**
01	AGRICULTURAL PRODUCTION-CROPS	31,797	6.4	204
02	AGRICULTURAL PRODUCTION-LIVESTOCK	14,673	23.2	340
07	AGRICULTURAL SERVICES	199,281	8.8	1,754
08	FORESTRY	4,671	20.8	97
09	FISHING HUNTING & TRAPPING	2,407	4.4	11
10	METAL MINING	180	25.2	5
12	COAL MINING	1,114	93.6	104
13	OIL & GAS EXTRACTION	24,425	227.2	5,549
14	MINING & QUARRYING-NONMETALLIC MINERALS	9,002	45.2	407
15	BUILDING CONSTRUCTION-GEN CONTRACTORS	308,604	87.2	26,910

16	HEAVY CONSTRUCTION EXCEPT BUILDING	62,335	15.2	947
17	CONSTRUCTION-SPECIAL TRADE CONTRACTORS	484,515	663.2	321,330
20	FOOD & KINDRED PRODUCTS MFRS	37,214	34.8	1,295
21	TOBACCO PRODUCTS MFRS	889	48.8	43
22	TEXTILE MILL PRODUCTS MFRS	9,927	85.2	846
23	APPAREL & OTHER FINISHED PRODUCTS-MFRS	28,718	14.0	402
24	LUMBER & WOOD PRODS EXCEPT FURNTR MFRS	30,117	74.0	2,229
25	FURNITURE & FIXTURES MFRS	13,586	184.8	2,511
26	PAPER & ALLIED PRODUCTS MFRS	14,236	338.8	4,823
27	PRINTING PUBLISHING & ALLIED INDUSTRIES	131,739	37.2	4,901
28	CHEMICALS & ALLIED PRODUCTS MFRS	24,519	267.2	6,551
29	PETROLEUM REFINING & RELATED INDS MFRS	3,746	394.8	1,479
30	RUBBER & MISCELLANEOUS PLASTICS MFRS	20,446	67.2	1,374
31	LEATHER & LEATHER PRODUCTS MFRS	2,600	46.0	120
32	STONE CLAY GLASS & CONCRETE PRODS MFRS	20,464	65.2	1,334
33	PRIMARY METAL INDUSTRIES MFRS	14,996	35.6	534
34	FABRICATED METAL PRODUCTS MFRS	56,908	60.8	3,460
35	INDUSTRIAL & COMMERCIAL MACHINERY MFRS	93,323	49.2	4,591
36	ELECTRONIC & OTHER ELECTRICAL EQUIP MFR	31,822	34.0	1,082
37	TRANSPORTATION EQUIPMENT MFRS	17,397	92.8	1,614
38	MEASURING & ANALYZING INSTRUMENTS-MFRS	23,383	21.2	496
39	MISCELLANEOUS MANUFACTURING INDS MFRS	60,130	26.8	1,611
40	RAILROAD TRANSPORTATION	3,215	10.0	32
41	LOCAL/SUBURBAN TRANSIT & HWY PASSENGER	42,433	15.2	645
42	MOTOR FREIGHT TRANSPORTATION/WAREHOUSE	144,695	8.8	1,273
43	UNITED STATES POSTAL SERVICE	31,737	12.4	394
44	WATER TRANSPORTATION	22,076	20.8	459
45	TRANSPORTATION BY AIR	15,652	1.4	23
46	PIPELINES EXCEPT NATURAL GAS	3,234	225.6	730
47	TRANSPORTATION SERVICES	69,382	105.2	7,299
48	COMMUNICATIONS	81,301	782.4	63,610
49	ELECTRIC GAS & SANITARY SERVICES	34,700	1,804.8	62,627
50	WHOLESALE TRADE-DURABLE GOODS	454,646	36.8	16,731
51	WHOLESALE TRADE-NONDURABLE GOODS	173,514	45.2	7,843
52	BUILDING MATERIALS & HARDWARE	135,342	48.8	6,605
53	GENERAL MERCHANDISE STORES	57,382	72.8	4,177
54	FOOD STORES	298,820	101.6	30,360
55	AUTOMOTIVE DEALERS & SERVICE STATIONS	285,774	75.6	21,605
56	APPAREL & ACCESSORY STORES	178,884	88.4	15,813
57	HOME FURNITURE & FURNISHINGS STORES	266,800	24.4	6,510
58	EATING & DRINKING PLACES	573,049	45.2	25,902
59	MISCELLANEOUS RETAIL	650,415	34.8	22,634
60	DEPOSITORY INSTITUTIONS	129,374	78.4	10,143
61	NONDEPOSITORY CREDIT INSTITUTIONS	84,012	485.2	40,763
62	SECURITY & COMMODITY BROKERS	95,795	249.6	23,910
63	INSURANCE CARRIERS	27,565	115.6	3,187
64	INSURANCE AGENTS BROKERS & SERVICE	231,299	146.0	33,770
65	REAL ESTATE	437,636	24.4	10,678
67	HOLDING & OTHER INVESTMENT OFFICES	8,434	22.0	186
70	HOTELS ROOMING HOUSES & CAMPS	96,145	88.4	8,499
72	PERSONAL SERVICES	598,420	44.4	26,570
73	BUSINESS SERVICES	546,914	67.2	36,753
75	AUTO REPAIR SERVICES & PARKING	300,181	12.4	3,722
76	MISCELLANEOUS REPAIR SERVICES	108,025	4.8	519
78	MOTION PICTURES	41,281	24.8	1,024

79	AMUSEMENT & RECREATION SERVICES	181,397	125.2	22,711
80	HEALTH SERVICES	1,203,660	456.8	549,832
81	LEGAL SERVICES	505,140	2.5	1,253
82	EDUCATIONAL SERVICES	235,724	342.8	80,806
83	SOCIAL SERVICES	317,856	85.2	27,081
84	MUSEUMS ART GALLERIES & GARDENS	8,831	21.6	191
86	MEMBERSHIP ORGANIZATIONS	526,080	8.4	4,419
87	ENGINEERING & ACCOUNTING & MGMT SVCS	386,323	4.8	1,854
89	MISCELLANEOUS SERVICES NEC	21,719	5.2	113
91	EXECUTIVE LEGISLATIVE & GENERAL GOVT	176,429	85.2	15,032
92	JUSTICE PUBLIC ORDER & SAFETY	82,878	194.8	16,145
93	PUBLIC FINANCE & TAXATION POLICY	15,953	104.8	1,672
94	ADMINISTRATION-HUMAN RESOURCE PROGRAMS	23,520	73.2	1,722
95	ADMIN-ENVIRONMENTAL QUALITY PROGRAMS	18,173	104.8	1,905
96	ADMINISTRATION OF ECONOMIC PROGRAMS	24,162	21.6	522
97	NATIONAL SECURITY & INTERNATL AFFAIRS	15,073	673.6	10,153
99	NONCLASSIFIED ESTABLISHMENTS	586,019	0.1	75
	TOTAL	**12,336,233**		**1,629,436**

Appendix D
Additional Background on Stationary IC Engines and Emissions

Note: the text of this Appendix was developed by ESI as part of its report to NESCAUM on emission control technologies. It is included here in the interests of providing additional background information on stationary IC engines and their emissions.

Internal combustion (IC) engines are used in a variety of stationary applications ranging from power generation to inert gas production. Both spark ignition and compression ignition engines are in wide use. Depending on the application, stationary IC engines range in size from relatively small (~50 hp) for agricultural irrigation purposes to thousands of horsepower for power generation or natural gas transmission. Often when used for power generation, several large engines are used in parallel to meet the load requirements. A variety of fuels can be used for IC engines including diesel, natural gas, and gasoline among others. The actual fuel used depends on the owner or operator preference but can be application dependent as well. IC engines can also be run rich, lean, or stoichiometrically as shown below.

Typical Engine Types and Fuels for Stationary Applications

Rich Burn	Natural Gas Propane Gasoline
Stoichiometric	Natural Gas Propane Gasoline
Lean Burn	Diesel Natural Gas Dual Fuel

The difference between rich, lean, and stoichiometric engine operation lies in the air to fuel ratio. Stoichiometric engine operation is defined as having the chemically correct amount of air in the combustion chamber during combustion. Hence, perfect combustion would result in the production of carbon dioxide (CO_2) and water. However, the fact that perfect combustion is not possible means that even an engine running stoichiometrically produces hydrocarbon (HC or VOC), carbon monoxide (CO), nitrogen oxides (NOx), and particulate matter (PM) emissions. A rich-burn engine is characterized by excess fuel in the combustion chamber during combustion. A lean-burn engine, on the other hand, is characterized by excess air in the combustion chamber during combustion, which results in an oxygen-rich exhaust. Diesel engines inherently operate lean, whereas IC engines that use natural gas, gasoline or propane can be operated in all three modes.

The three primary fuels used for stationary reciprocating IC engines are gasoline, diesel (No. 2) oil, and natural gas. Gasoline is used primarily for mobile and portable engines. Construction sites, farms and households typically use converted mobile engines for stationary applications because their cost is often less than an engine designed specifically for stationary applications. In addition, mobile engine parts and service are readily available, and gasoline is easily transported to the site. Thus, gasoline is an essential fuel for small and medium size stationary engines. Diesel fuel is also easily transported, and therefore is also used in small and medium size engines. In addition, the generally higher efficiencies exhibited by diesel engines makes diesel an ideal fuel for large engines where operating costs must be minimized. Diesel is thus the most versatile fuel for stationary reciprocating engines. Natural gas is used more than any other fuel for large stationary reciprocating or turbine IC engines, typically operating pumps or compressors on gas pipelines. Other fuels are also burned in stationary IC engines, but their use is limited. Some engines burn heavy fuel oils, and a few burn almost any other liquid fuel. Gaseous fuels such as sewer gas are sometimes used at wastewater treatment plants where the gas is available. Stationary IC engines can be modified to burn almost any liquid or gaseous fuel if the engine is properly designed and adjusted.

There are two methods for igniting the fuel in an IC engine. In spark ignition (SI), a spark is introduced into the cylinder (from a spark plug) at the end of the compression stroke. Fast-burning fuels, like gasoline and natural gas, are commonly used in SI engines. In compression ignition (CI), the fuel-air mixture spontaneously ignites when the compression raises it to a sufficiently high temperature. Compression ignition works best with slow-burning fuels, like diesel. Larger engines may last for 20 to 30 years while smaller engines (<1 MW) tend to have shorter life spans.

Stationary IC engines have efficiencies (total output/total input) that range from 25 percent to 45 percent. In general, diesel engines are more efficient than natural gas engines because they operate at higher compression ratios. For future models, engine manufacturers are targeting lower fuel consumption and shaft efficiencies up to 50-55 percent in large engines (>1 MW) by 2010. Efficiencies of natural gas engines, in particular, are expected to improve and approach those of diesel engines.

Appendix E
ESI International Case Study Questionnaire

ESI International, Inc.
Suite 1100, 1660 L Street, NW
Washington, DC 20036
Voice: (202) 296-4797
Fax: (202) 331-1388

ESI International, Inc.

Case Study Questionnaire

Instructions: This questionnaire can be submitted electronically to bgillespie@meca.org or filled out by hand and faxed to (202) 331-1388. Electronic submissions are preferred. If you are preparing an electronic submission, feel free to insert text or data directly into the questionnaire. For assistance, please contact Bill Gillespie at (202) 775-8868.

1. Contact Information

a. Person Preparing the Questionnaire

Name: ____

Address: ____

Telephone number: ____

E-mail address: ____

b. Engine Owner (If different from item 1a.)

Name: ____

Address: ____

Telephone number: ____

E-mail address: ____

c. Engine Operator (If different from item 1a.)

Name: ____

Address: ____

Telephone number: ____

E-mail address: ____

2. Facility Information

a. Describe the business where the engine is installed.

Please attach electronically (or in hardcopy) several paragraphs that generally describe the nature of the business where the engine is installed. This is an opportunity for you to tell us about your company. Please send us company brochures or other information about the firm if they are available.

b. Date engine was purchased: ___________________________________

3. Engine Specifications and Information

a. Make: ____

b. Model number: ____

c. Serial number: ____

d. Displacement: ____

e. Operating horsepower: ____________ horsepower at _____________ revolutions per minute (rpm).

f. Turbocharged or naturally aspirated: _________________________

g. Fuel Consumption (gallons per hour; grams per brake horsepower hour; or other unit of measure): _____________ per ______________

h. Engine load factor: ____

4. Fuel Specifications and Information

a. Type of Fuel:____

b. Fuel sulfur content (specify percent sulfur by weight or parts per million (ppm)): ____

c. Fuel heat content (Btu per gallon for diesel fuel, Btu per cubic foot for natural gas):

____

d. Attach a fuel analysis report if available.

5. Engine Operating Information

a. Describe the engine's principal function (for example, to provide emergency electrical power, to pump water, to operate a ski lift, etc.). Please attach a paragraph electronically or in hardcopy.

____

b. How many hours do you operate the engine per year? ___________ hours per year.

c. Fuel Consumption (gallons per year for diesel fuel; therms or cubic feet per year for natural gas):

Year	1	2	3	4	5
Fuel Consumption (gallons or therms/year)					

Alternative Method for Calculating Fuel Consumption:

If the number of hours the engine operated per year is known, report the total number of hours and a fuel consumption rate (gallons per hour or therms/cubic feet per hour).

Year	1	2	3	4	5
Operating Hours (hours/year)					

Fuel consumption rate (gallons per hour or therms/cubic feet per hour): ____

d. If the engine is used to generate electricity, provide generation per year (kilowatt hours per year (kWhr/yr)):

Year	1	2	3	4	5
Electricity Generation (kWhr/yr)					

e. If the engine provides power to drive a generator, does the engine operate as an emergency back-up unit, a peaking unit, a peak shaving unit, or other unit?

____

f. If the engine provides mechanical energy, please quantify, if possible the mechanical work done (for example, gallons of water pumped, etc.)

____

g. Describe engine operating problems if any:

____

6. Emission Control System Information and Specifications

a. Describe the installed emission control system:

____

Note: the emission control system may include the following devices: diesel oxidation catalyst (DOC), diesel particulate filter (DPF), exhaust gas recirculation (EGR), selective catalytic reduction (SCR), or some other device. Please describe the types of control equipment installed.

b. Why was the emission control system installed? (For example, to meet state or federal permit requirements, etc.)

____

c. For each emission control system installed, provide:

Date installed: ____

Make: ____

Model: ____

Serial number: ____

Reagent (for SCR systems for example): ____________________

____

7. Emission Control System Costs

Note: If you know the total installed cost of each emissions control system, please provide that total cost here ____________

If you can provide disaggregated costs for each emission control system, please complete items a through f below.

a. Purchased equipment costs:

____

Note: Include the cost of emission control equipment, ancillary equipment, instrumentation, etc.)

b. Sales taxes paid:

____

c. Freight paid:

____

d. Direct installation costs:

____

For installation of the emission control system, include direct costs such as the costs of foundations and supports; equipment handling and erection; providing electrical service, piping, insulation, painting, etc. Indicate if any of these costs were included in the purchased equipment costs, Item 7a above.

e. Indirect installation costs:

____

Note: For installation of the emission control system, include indirect installation costs such as the costs of engineering, construction and field expenses, contractor fees, start-up tests, performance tests, studies and training. Indicate if any of these costs were included in the purchased equipment cost, Item 7a, or direct installation costs, Item 7d above.

f. Contingency Costs:

____

Note: Include costs for equipment redesign and modifications, cost escalations, delays in start-up, etc.

8. Emission Control System Operating Information

a. Describe the operation of the emission control system:

____

b. Engine Emission Rates (before installation of the emission control system):

	Emission Rate				
Pollutant	g/bhp-hr	lb/MMBtu	lbs/kWh	g/gal	ppm
Carbon Monoxide CO)					
Hydrocarbons (HC)					
Particulate Matter (PM)					
Nitrogen Oxides (NOx)					

Reporting units:
g/bhp-hr = grams per brake horsepower hour
lbs/MMBtu = pounds per million British thermal units of heat input lbs/kWh = pounds per kilowatt hour of electricity generated
g/gal = grams per gallon of fuel consumed
ppm = parts per million

At a minimum, please provide emission rate information in either g/bhp-hr or lb/MMBtu. Provide emissions in lbs/kWh if available. If you report emissions in units other than those shown above, please define the units you use.

c. Test method used to determine engine emission rates:__________

____

d. Attach engine emission test data if available.

e. Engine emission rates after the emission control system was installed:

	Emission Rate				
Pollutant	g/bhp-hr	lb/MMBtu	lbs/kWh	g/gal	ppm
Carbon Monoxide CO)					
Hydrocarbons (HC)					
Particulate Matter (PM)					
Nitrogen Oxides (NOx)					

Note: At a minimum, please provide emission rate information in either g/bhp-hr or lb/MMBtu. Provide emissions in lbs/kWhr if available. If you report emissions in units other than those shown above, please define the units you use.

f. Percent reduction of air pollutants:

Pollutant	**Percent Reduction**
Carbon Monoxide (CO)	
Hydrocarbons (HC)	
Particulate Matter (PM)	
Nitrogen Oxides (NOx)	

g. Attach or provide the test method used to determine exhaust pipe emission rates.

____

h. If a source testing company or state air quality agency tested the engine after the emission control system was installed, please provide or attach the emission test report.

____

i. Describe any operating problems associated with the emission control system.

____

9. Emission Control System Operating Costs

a. Provide cost information for the operation of the emission control system.

Labor:

Dollars per hour: ____

Hours per year: ____

Total labor costs per year: ___________________________________

Materials:

Describe the materials needed (for example, percent urea for SCR

reagents, etc.): ____

____

Cost of reagent (dollars per gallon): __________________________

Reagent consumption rate (gallons per hour): ____________________

Reagent use (hours per year): ___________________________________

Reagent costs per year: ____

Electricity cost per kilowatt-hour: _____________________________

Electricity hours per year: _____________________________________

Electricity costs per year: _____________________________________

Other material costs per year: __________________________________

Total material costs per year: __________________________________

10. Emission Control System Maintenance

a. Describe the maintenance requirements of the emission control system:

____

b. How often is maintenance of the emission control system performed:

____

11. Emission Control System Maintenance Costs

Labor:

Dollars per hour: ____

Hours per year: ____

Total labor costs per year: _____________________________________

Materials:

Describe the materials needed: __________________________________

____

Expected life of catalyst (years): ______________________________

Cost of catalyst replacement: ___________________________________

Total material costs per year: __________________________________

Thank you for participating in this case study.

Please send the completed questionnaire to:

bgillespie@meca.org

or

Bill Gillespie
ESI International, Inc.
1660 L Street, NW, Suite 1100
Washington, DC 20036-5603

Telephone: (202) 775-8868
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