TITLE: Impacts of DEQ Rule changes for Small Wood Fired Boilers

FROM: Paul Fouch, PE, President of Save Our Rural Oregon
8017 Hwy 66
Klamath Falls, Or 97601
pmfouch@gmail.com 541-884-4324

TO: Jill Inahara, Program Director
Air Quality Division
Dept. of Environmental Quality
2020 SW 4th Ave.
Portland, Or 97201
inahara.jill@deq.state.or.us

SORO RESEARCH REPORT--COST EVALUATION IMPACT FOR NEW DEQ OPACITY AND GRAIN LOADING RULES

Executive Summary

Based on a reputable research reports and the expert opinions of several PE's, SORO concludes:

a Most mechanical collection devices using centrifugal forces can easily control opacity and grain loading to the proposed .15gr/ dscf and 20% opacity for up to 80 MMBtu/hr. heat input sources for capital costs of less than 10% of boiler costs and minimal annual operating costs. (in fact low end controls only run 3% or $30-40,000)

b) Actual conversion cost estimates appear to be significantly lower than DEQ estimates for small boilers with heat inputs under 80 MMBtu/hr. and DEQ data appears incomplete with no boiler size cost relationships presented.

c) SORO feels that COMs are necessary for larger boilers greater than 30MMBtu to assure compliance and digital on line logs are necessary for smaller boilers.

Coverage:

1) Specification's of control devices for retrofitting old boilers and the resultant retrofitting costs.

2) Comparison of Oregon state opacity and grain loading rules to several neighboring state and northeast state rules

3) Review of some literature on the well know negative health impacts resulting for wood fired boiler pollution

4) Outlines several strategies to fund the conversion of small boilers

5) Proposes alternative implementation strategies (BART)

6) Proposed future more stringent rules.

1) Evaluating the cost impacts of retrofitting small wood fired biomass boilers

The following give some examples of the costs to retrofit some smaller boilers with new pollution control equipment

a) Add on retrofit control costs from a 2010 study

Figure 1

Capital Cost	ESP Dry	ESP Wet	Separator	Multiclone	Cyclone
Equipment	$170,769	$183,386	$19,875	$18,315	$7,600
Site and Facilities	$13,969	$13,969	$2,000	$2,000	$2,000
Installation	$114,415	$122,868	$6,956	$7,365	$6,000
Total costs	**$299,153**	**$320,223**	**$28,831**	**$27,680**	**$15,600**
Percentage of original boiler cost	**30%**	**32%**	**2.9%**	**2.9%**	**1.6%**

Source: Att 1.0, An evaluation of Air Pollution Control Technologies for Small Wood-fired Boilers, prepared by Resource Systems Group for Massachusetts, New Hampshire and Vermont environmental agencies, May 2010.

Assume:

--Particulate Control Systems Cost Analysis (ER =0.71 Lb/MM Btu, Cap Factor =30%)

--7.5 MMBtu

--$1 million original boiler cost (see attachment 2 –Biomass conversion technolgies report and Refer on line to Chiptech boiler costs for Montpelier biomass plant for derivation of boiler costs

b) Add on retrofit control costs from a 2001 study. Table 2 below shows add on control costs for a broader spectrum of controls

Figure 2

As mentioned, there are many factors which cause variability in capital and operating costs. In addition, cost effectiveness (especially in mechanical collectors) is also affected by particle size distribution.[2] Therefore, actual costs could vary considerably from what is quoted below.

Table 12: Cost Effectiveness for Controlling PM10 Emissions[3]

Pollution Control Device	Control Efficiency	PM10 Emissions Removed (tons/year)	Installed Capital Cost of Equipment	Annual Operating Costs	Total Annual Costs	Total Cost per Ton Removed
Cyclone	50%	0.9	$2,243	$580	$791	$930
Multicyclone	75%	1.3	$9,424	$580	$1,469	$1,151
HE Multicyclone	99%	1.3	$62,878	$800	$6,980	$4,159
HE Multicyclone (valved)	99%	1.7	$125,756	$800	$12,915	$7,695
Core Separator (12")	94%	1.7	$111,709	$1,239	$12,350	$7,685
Core Separator (24")	72%	1.2	$63,337	$1,459	$8,004	$6,519
Cyclone + Baghouse	99%	1.7	$109,878	$3,920	$14,291	$8,483
ESP	95%	1.6	$138,005	$1,867	$14,894	$9,213

Table 13: Cost Effectiveness for Controlling PM2.5 Emissions[4]

Pollution Control Device	Control Efficiency	PM2.5 Emissions Removed (tons/year)	Installed Capital Cost of Equipment	Annual Operating Costs	Total Annual Costs	Total Cost per Ton Removed
Cyclone	5%	0.9	$ 2,243	$580	$791	$11,534
Multicyclone	10%	1.3	$9,424	$580	$1,469	$10,707
HE Multicyclone	86%	1.2	$65,478	$800	$6,980	$5,884
HE Multicyclone (valved)	86%	1.2	$128,356	$800	$12,915	$10,887
Core Separator (12")	56%	0.8	$117,709	$1,239	$12,350	$16,105
Core Separator (24")	29%	0.4	$69,337	$1,459	$8,004	$19,939
Cyclone + Baghouse	99%	1.7	$109,878	$3,920	$14,291	$10,519
ESP	90%	1.6	$138,005	$1,867	$14,894	$12,059

The total cost per ton of pollutant removed is calculated by dividing the total annual costs by the total amount of pollutant removed. Pollutant removal costs of PM2.5 with cyclones and multicyclones are significantly higher than for PM10 because the values for the tons of PM2.5 removed are less than one. This significant increase in pollutant removal cost demonstrates the relative ineffectiveness of conventional cyclones and multicyclones.

Source: Att 4.0 , Emission Controls for Small Wood-Fired Boiler prepared by Resource Systems Group for the US forest Service, July 2001

Assume:

--5.0 MMBtu boiler input level

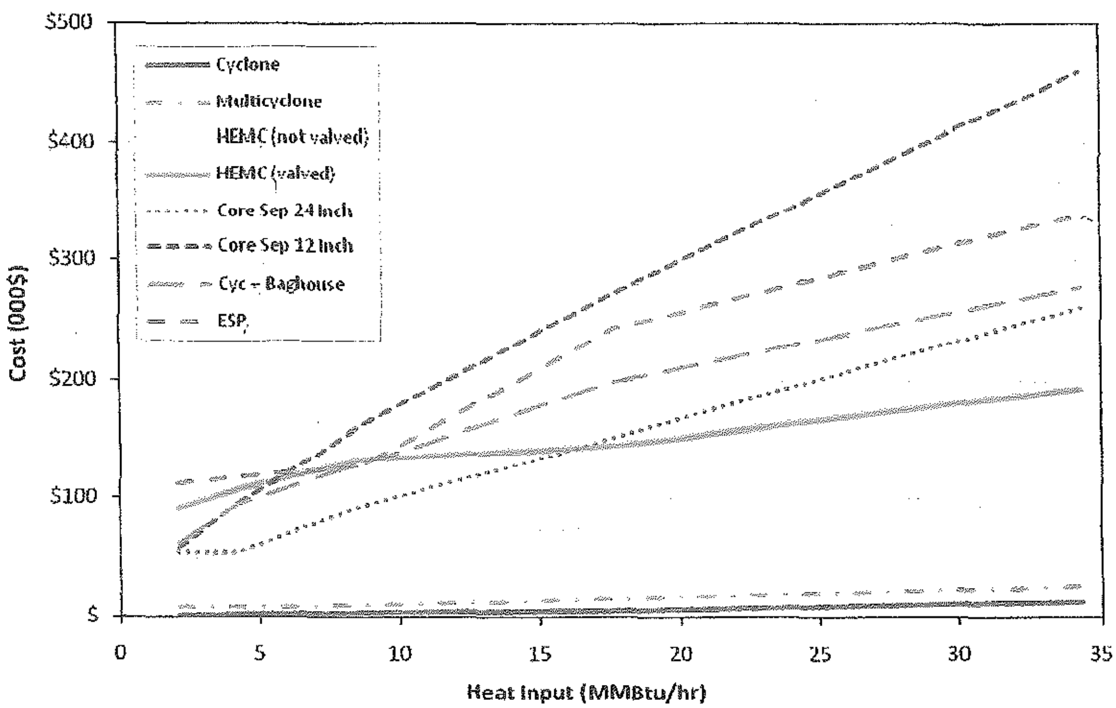
--Costs from the 2010 study show a decrease in capital cost which might be attributed to: 1) improvements in design and manufacturing, 2) the fact that the heat input size for the 2010 study was 5.0 MMBtu while the input for the 2001 study was 7.5 MMBtu.

Figure 3.0

shows equipment cost relationships for boiler input sizes between 2 and 35 MMBtu

Estimated capital costs for add-on particulate matter controls are shown below for a single cyclone, multicyclone, high efficiency multicyclone (not valved), high efficiency multicyclone (valved),[2] Core Separator™ (with 24 inch diameter separators), Core Separator™ (with 12 inch diameter separators), cyclone coupled with baghouse[3], and an electrostatic precipitator. Approximate costs are shown for systems from approximately 2 MMBtu/hour to 34 MMBtu/hour heat input in Figure 1. These costs are subject to the variability caused by the bulleted items discussed above. They are also a best estimate of installed cost.

Figure 1: Particulate Matter Add-On Emission Control Costs



Source: Att 1.0 An evaluation of Air Pollution Control Technologies for Small Wood-fired Boilers, prepares by Resource Systems Group for Massachusetts, New Hampshire and Vermont environmental agencies, May 2010.

Note: Extrapolation of cost size relationships between 40 MMBtu and 80 MMBtu may not be reliable using this graph

Some conclusions outlined in above reports

SORO contends that it is extremely important to install controls on all stationary point sources such as small biomass boilers, because they may be a major contributor to the particulate inventory. Reports attached in attachments Att1.0 and Att 2.0 show that small wood fueled boilers are a major contributor to particulate air pollution in states like Penn, Vermont, etc.. In addition systems to control emission to near future tighter control such as the EPA grain loading standard of .03 gr/dscf for boilers of greater than 30 MMBtu's will soon to required in Oregon. Source of some expert opinions: AFS Energy Systems, Inc. 420 Oak Street - PO Box 170 Lemoyne, PA 17043 www.AFSEnergy.com

--**The types of controls** primarily depend on the grain loading standard requirements.

1) ESPs can control grain loading to as low as .011 gr/dscf but run as much as 25% of the original boiler costs (Fig. 1 shows that EPSs for 7.5 MMBtu plant cost as much as $300,000. This would be very expensive for small boiler businesses especially the ones that produce steam only. The advantage of the ESPs are that they not only control PM10 with 99.9% efficiency but also control PM2.5 with 99% efficiency and new designs in ESPs have reduced capital costs for some system sizes and made them more attractive to small businesses. ESPs have lower per unit operating costs for PM2.5 and lower energy demand and can meet all stricter emission limits. --ESP's are the only control systems that have a guaranteed grain loading output by the manufacturer.

2) Mechanical add on controls can easily control grain loading to .15 gr/dcf and opacity to 20% limits. Mechanical controls are not as expensive as ESPs being less than 10% of the original boiler costs and running between $30,000-$100,000 Some systems are 90% efficient at controlling PM10. But they are not very efficient at controlling PM2.5 as can be seen from Fig. 2. In Att 3.0 (a link to The BC ministry of the environment report: Emissions from Wood Fired combustion equipment evaluates the cost and efficiency of various control systems in detail.

--Expert opinions on mechanical control devises meeting Oregon grain loading Standard.
An expert Environmental Engineer from the NW said: "If the wood waste fueled boiler uses OK fuel (not too wet, does not contain seasalt, etc) and has good combustion, a good multiclone separator installed correctly (i.e. has balanced gas flow such that the gas velocity profile at the multiclone entrance and exit is balanced, does not have gas leaks in the particle hopper, etc.), then it should be easy to meet the opacity, grain loading, and lb/million Btu regulations."

Experts from the NE made following comments on small biomass control systems: "Table 1 - Page 31* in eCFR —Code of Federal Regulations shows the PM for new biomass boilers. The new rule you listed on your email (.15 grains per standard cubic foot) is only 0.4 pounds / MM BTU input. This can be easily be accomplished with a mechanical control device without the need for an ESP. (20% opacity should be easily meet with any good combustion system.) We need to meet 10% in a lot of States.

As promised, I went back through our costs on the Montpelier, Vermont project. On this project we had to meet 0.03 pounds / MM BTU input (0.011 gr/dscf). This required a dry ESP. This control device added 25% to the boiler system costs v/s using only a mechanical device. The boiler system costs did not include the material receiving, screening, storage and material transfer equipment. The boiler system cost did included valves, deaerator, installation, jobsite electrical, start-up, etc. ". For a 7.5 MMBtu or 15,250 lbs/hr plant, if an ESP costs $300,000 its represents 25% of the original boiler costs. Therefore, a new boiler would cost nearly $1million.

Older boilers such as pre-1970 boilers need not be replaced to withstand additional back pressure and other demands caused by new add on control systems if they have be maintained per boiler code specs. All that might be necessary proper to retrofitting might be a tune up

Success story: A small one million MMbtu boiler in the NE equipped with a simple multicone control was still making the 20% opacity standard 20 years later by using proper record keeping and logs and following a proper maintenance procedure. (inlet input:.40 lb/ 1 million MMBtu.

Final Note: To achieve lower grain loading and opacity standards projects often use multi stages of mechanical controls along with other control devices.

<u>3. COMs—Continuous Opacity Monitors to assure compliance.</u>
The public is worried that the history of non compliance will continue after new laws are implemented and boilers retrofitted. SORO has previously submitted affidavits to the DEQ noting infractions such as disconnecting scrubbers, and ESPs, after DEQ inspections. Therefore, the public is requesting that COM's be installed on all boilers with heat inputs of 30 MMBtu's or more and power plants with greater than 10MW output. Experts from the NE states say that this is the demand put on their boilers there. They say that their projects of 30 MMBtu's or more require continuous Opacity Monitors mounted in the stack with real time digital records kept. They are required to be calibrated per EPA standards. (Frequent calibration is required because of the coating of pollution from the stack deposited on the devices) They devices generally cost about $25,000 for capital costs and less than $5,000 for annual maintenance costs. Note: SORO worries that without COMs compliance cannot be assured. But on smaller boilers daily on line digital logs of will help assure compliance and can be crosschecked to records of the volume of fuel burned, stack gas temperature, etc. (This detection of tampering can be verified.))
Note: Small boilers in some state account for the majority of air pollution.

Cost data gathering procedure and data validity
1) Research data was gathered from reports made reputable renewable energy resources groups. Data was selected from reports to ascertain costs relationships between boiler sizes in MMBtus/hr. and equipment costs.

2) The validity of the data should be high because the reports are recent (made in the last 5 years). Various reports provide a cross check of the data. In addition experts have validated a sample of the data. Experts also state that production costs for equipment should be stable and have only increased a few percent in the past 5 years..

3) Because SORO did not have data for boiler sizes between 40MMBtu – 80MMBtu. Extrapolation of the 2010 study curve should yield some estimates of costs for these size ranges that are reliable (The slope of these curves are rather flat) To verify this experts quote a dry ESP for a 60 MMBtu boiler at $500,00 (however they say such an effiecnt system would not be needed to attain the .15 gr/dscf standard. And experts point out that as size of the boiler increases the control cost become a smaller percentage of total system costs. The BC report also yields much additional information on control costs for larger sized boilers .

Weaknesses of DEQ data.

1)There are no relationship between the size of the boiler and control equipment costs or no mathematical formulas to ascertain these relationships

2)Control equipment costs are referenced to no specified boiler size or efficiency.

3) The DEQ implied that a boiler tune up could be used to meet the new grain loading standard. Experts disagree with this approach and say that the standard could only be met for a short time because the boiler frequently gets out of adjustment and has corrosion, mineral and other buildups in the input water system and the fuel quality varies so much and stack gas temperatures are continually in need of balancing.

Notes on larger biomass boilers

Controls for larger biomass plants are a much smaller % of total capital cost for the plant and emission levels are much less because of the use of more sophisticated control systems and the large investment required for boilers--The largest component of capital costs for the larger systems is for the boiler itself and associated equipment—making up 60 to 70 percent of the total plant cost. Thus the cost of emission controls is not a large percentage of total capital costs and updating control systems may not be as much burden on the projects as for the smaller biomass boilers. Refer on line to EPA report for a capital cost analysis of larger biomass boilers. "7. Representative Biomass CHP System Cost and Performance Profiles "

2) Grain loading and opacity standards for other states:

It is noted that not all states have not currently implement EPA standards for grain loading and opacity and other emissions and Oregon has the highest level per SORO's research. The EPA NSPS standard^^ for grain loading is:

.20 for boilers less than 10MMBtu
.07 for boilers between 10-30MMBtu
.03 for boilers greater than 30MMBtu

Below are current standards for various states:

State	grain loading	opacity
Vermont*	.08 gr/dscf	10%
Idaho**	08 gr/dscf	10%
Oregon	.20 gr/dscf	40%
Washington***	.10 grain/dscf	20%
BC		10%+
Sample of NE states	.05 gr/dscf	10%
Massachusetts****		5%

*Montpelier Project engineer quote

**See on line-- Moscow, Idaho project report to reference Idaho laws.

*** See Att 4.0 except, for an emissions unit combusting wood derived fuels for the production of steam. No person shall allow the emission of particulate matter in excess of 0.46 gram per dry cubic meter at standard conditions (0.2 grain/dscf)

****See attachments and for a discussion of grain loading and opacity standards for some other states and referenced state laws (attachment 5.0 covers Massachusetts standards)

+ BC requires COMs for boilers exceeding 25MW

Note: In many cases to make comparisons it is essential to use the mathematical relationship between plume opacity and grain loading and stack diameter).

^^eCFR —Code of Federal Regulations Title 40: Protection of Environment

3) Health impacts

Health impacts from biomass incineration located close to humans is well know and the impacts are well documents by many reliable medical research studies and the EPA. The most dangerous of particulates is of course small particulates--PM2.5 SORO medical advisor Dr. Sammons says that: These toxics have not be accounted for nor regulated in the permitting processes so permits are not protective of human health. Public health risks in response to increases in PM2.5 are enormous and led to the mortality of tens of thousands of people in the US alone. Therefore The EPA has developed new thresholds of PM2.5 control in the past several years. Refer to Att 6.0 the NAAQS study and Att 7.0 the SILS study—Sierra Club v the EPA. Also refer on line to the signed off referendum by 77,000 doctors to congress who are against biomass incineration.

Additional studies also reveal that long term exposure to PM 10 can cause severe lung and heart health problems. It is also noted that studies (see link in Att 13 "Air quality guidelines for Europe" have been published that permit evaluation of the health effects of PM10 alone, either because exposure to other pollutants was low or because adequate adjustment was possible. It emphasizes studies that permit direct evaluation of associations with PM10, sulfate ion ($SO_4^{=}$), PM2.5, and hydrogen ion (H^+). The need to revise existing air quality guidelines and standards is widely felt, as many of the recent studies have suggested that significant effects on health occur at levels below those that were seen as "thresholds" in the recent past.

--Mortality: acute effects as suggested by time-series studies
Many recent studies have addressed the relationship between daily variations in particulate air pollution and mortality at low levels of exposure were generally greatest for deaths due to respiratory or cardiovascular causes. They were also generally greater among the elderly than among younger subjects. An in-depth analysis of mortality occurring on low- and high-pollution days conducted on the data from Philadelphia showed a disproportionate increase in mortality

Effects of PM2.5 on mortality.
Recently, an analysis from the Harvard Six Cities study (a large, prospective study on the health effects of air pollution conducted in six different communities in the USA) was published addressing the of question whether fine particulate mass (PM2.5) is a better predictor of mortality than coarse particulate mass (the difference between PM10 and PM2.5) *(89)*. The results indicate that mortality is strongly associated with PM2.5 but not with coarse mass. Because of the high correlation between PM2.5 and PM10, mortality was also strongly associated with PM10, and the results of this particular analysis suggest that the associations between PM10 and mortality observed in other studies may very well be due to the effects of fine rather than coarse particulate mass. Table 2 provides a summary of this recent analysis. The pooled estimate was a relative risk of 1.015 (95%

confidence limits 1.011–1.019) for each 10µg/m3 increase in PM2.5.Estimated effects on mortality in these studies were generally greatest for deaths due to respiratory or cardiovascular causes. They were also generally greater among the elderly than among younger subjects. An in-depth analysis of mortality occurring on low- and high-pollution days conducted on the data from Philadelphia showed a disproportionate increase in mortality among the elderly (103). Mortality due to chronic lung disease and cardiovascular disease was also disproportionally increased. Interestingly, respiratory conditions were also more often mentioned on death certificates as contributing causes to cardiovascular deaths on high pollution days. An analysis of location of death revealed that deaths outside the hospital were disproportionally increased as compared to death of hospitalized patients. This pattern is very similar to the pattern of mortality seen during and following the 1952 London smog.

4) Strategies to reduce costs of conversion and operations

--**The goal should be to make it attractive** or even profitable for small businesses to convert to new pollution control equipment to reduce opacity

--Allow a tax break (not taxing funds small business need to set aside for conversion to cover capital costs—sort of like a sinking fund to lower net income and not be taxed until after conversion—say after 2020. (even then the funds should not be fully taxed because of tax credits to be allowed*) "A **sinking fund** is a fund established by an economic entity by setting aside revenue over a period of time to fund a future capital expense, or repayment of a long-term debt."

--Give State subsidies or grants for conversion to cover capital costs of conversion

--*Allow tax credits for businesses that convert (like ODOE tax credits for renewable energy). This would cover increased operating costs for the new systems.

--Natural business operation will dampen operating costs for new air quality systems

- -Operating efficiencies will reduce the cost of operations for new air quality systems designs
- -Taxes will be reduced due to amortization of the new equipment and the time value of money

Financing help for small business.

There are basically 2 choices to finances help for small business: 1) using taxpayers funds from the state coffer to lessen the burden on small businesses or having large corporations who cause the bulk of pollution emissions pay their fair share. 2) Another way to accomplish this is to collect an annual pollution fee for industry based on their volume of pollution—tons of toxics emitted. (This would not be a burden on small business that only emitted a few tons/ per year. And the tax would be regressive for larger polluters but so minimal it would have no impact on them) Funds could be allocated back to business in reverse order, i.e., Thus small businesses would get a larger

proportionate share of the pollution tax fund. The fund could be even used for financing CEM's for small businesses in special control areas or nonattainment areas.
Note: Title V projects already pay penalties if the choose not to upgrade their equipment. Refer to attached north eastern states report which includes financing of renewable energy. (Att 8.0)

5) Alternative implementation strategy—similar to using the EPA BART process for retrofitting larger boilers. BART is the Best Available Retrofitting Technology and requires among other things in its process:
-Identification of all retrofitting technologies
-Specifying technological feasible technologies for the project
-Evaluation of the cost effectiveness of feasible technologies

Setting up and certifying the most effective systems
Because there are so many variables in retrofitting small boilers by owner operators it might be wise to consider the DEQ giving a subsidy of say $5,000 to each business to hire a PE to follow a BART like process to certify that the best technology and cost alternative for the project was used and certify proper installation. Most of the installation could be performed by certified DEQ technicians. Note: Experts say that controls must have balanced gas flow such that the gas velocity profile at the multiclone entrance and exit is balanced, does not have gas leaks in the particle hopper, etc) The should certify all conversions with his stamp.
Note: Experts state that in no case should an exception be allowed for financial hardship because the cost of low end mechanical controls would only be a few percent of the system cost and could be covered with a grant. Besides there would be no way of assuring compliance for the exception in the future.

Assuring Compliance
The PE or certified technican can also setup the required record keeping to assure proper maintenance processes and schedules and compliance to the new rule. A daily digital on line log will help assure compliance and can be crosschecked to records of the volume of fuel burned, stack gas temperature, etc. (This detection of tampering can be verified.)

6) Future proposal for implementing overall adequate air quality laws to protect the public

SORO feels that the current rule changes maybe be too lenient and are not properly time phased to prepare Oregon for massive increased pollution due to Sen. Wyden's logging bill and trying to make Oregon the Saudi Arabia of biomass. SORO and the public would like the DEQ to investigate the following:

--Phase I
Lower Oregon's grain loading and opacity standards to .08gr/drcf and opacity to 10% to comply with the EPA standard. The current proposal of 20% and .15 gr/drcf will do little to reduce pollution in the long run because the only industry requiring changes will be small boilers. With the technology as it is today most good combustion technology

incorporated into boiler designs equipped with exhaust controls can easily reach .05 gr/dscf and 10% opacity, even for small boilers down to 2MMBtu heat inputs.

To assure compliance COMs should be required for all boilers with 20 MMBtu or greater heat input.

--Phase 2
Implement new EPA laws fully into the SIP to adequately protect human health and livability:
--Accounting for all project emissions not just site or stack emissions. Require that truck emissions, chip pile emissions, etc. be accounted for.
--Assure the accuracy of emissions estimating by requiring actual empirical emissions verifications from similar facilities (include confidence intervals for estimates)
--Justify why a federal PSD is required using verified estimates from above and present findings to the public for public evaluation and comments.
--Reduce PM2.5 emissions level to meet the Dec. 2012 new NAAQS standards by:
-Implementing the DEQ IMD to account for condensibles as required by the EPA directive in 2011 and implemented by the DEQ in March of 2013.
-Implementing LEAR standards
-Implementing SILS requirement to prevent significant incremental degradation of air quality (Sierra Club v EPA 2013)
--Require CEM's on all facilities that emit greater than 15 tons/yr. of PM2.5 to assure compliance to adequately protect public health.

--Conduct location analyses to consider air shed and human impacts The BC Environment requires:
" Populated settings or sensitive air sheds may require special consideration. Thus, it may be necessary to require limits stricter than the proposed economically achievable levels, even for smaller units. In such cases the economics may then require subsidies, without which the wood- fired projects may be abandoned in these areas" See att 5.0 for an on line link to the detailed discussion.
Note: This fits within the DEQ designation of special control areas. But non attainment and maintenance areas are the highest priority areas for this analysis.

Attachments

Att 1.0 Systems Research Group –2010 study on Small Wood Fired Boilers
Att 2.0 Systems Research Group –2001 study on Small Wood Fired Boilers
Att 3.0 Link to BC study on wood fired boilers
Att 4.0 Wash St. Opacity rules for small boilers
Att 5.0 Massachusetts emissions laws and limits
Att 6.0 NAAQS 2012 Rules
Att 7.0 SILS rules --Sierra Club v EPA case
Att 8.0 Financial Incentives for renewable energy in the NE states
Att 9.0 Mathematical relationship between opacity, grain loading and stack diameter.

Technical notes

Grain size v opacity relationship

To accurately define design specification for controls and estimate their costs grain loading specifications are needed. In many cases that would require determining the relationship between plume opacity and grain loading. There is a rather simple relationship between plume opacity (or light transmittance through a plume), plume diameter (ie stack diameter), grain loading, and an optical factor (takes into account the particle size distribution and particle refractive index). Being as the stack diameter, plume opacity, and grain loading have been measured for many hog fuel boilers (note that this is mandatory at most installations), this relationship of plume opacity to grain loading and stack diameter is well established with measured parameters.

Figure 1 below graphically represents the relationship. The basic theory of the relationship and its mathematical derivation follows. For a more detailed explanation see Att 13.0

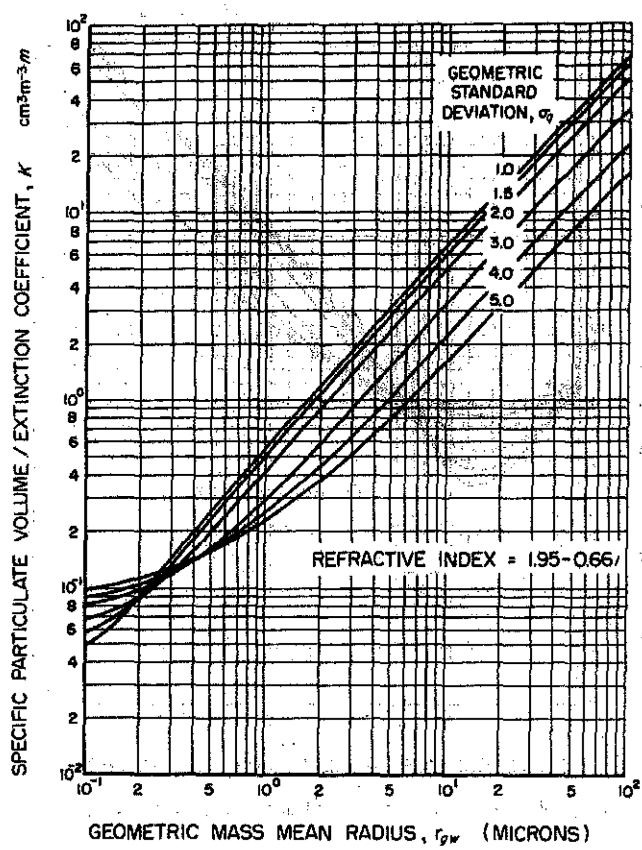


Fig. 2. Relationship of *K* to particle size distribution parameters for a black aerosol.

C. *Comparison of calculated K with previously reported relationships*

The theoretical results for *K* presented in Figs. 1 and 2 are in good agreement with the relationships reported by Hawksley *et al.* (1961). Equation 1 is for light absorbing particles smaller than the wavelength of light and of density 2 g cm^{-3}. Assuming a mass mean radius of 0.2 μm and a standard deviation of 1.0 (monodisperse) a *K* of 0.09 is obtained from Fig. 2. Substituting these magnitudes for *K* and ρ into (20) gives

$$\ln(I/I_0) = -5.55\, WL, \qquad (26)$$

which is approximately the same as (1).

Equation 2 is for light absorbing particles larger than the wavelength of light having an average specific surface area diameter (i.e. diameter of a sphere with a surface

2. THEORY

(a). *Development of equation relating plume opacity to particle properties*

A general relationship can be developed between plume opacity (I/I_0), the plume path length, and the particle properties (particle size distribution, density, mass concentration, and refractive index). The transmission of light through a volume containing an aerosol is described by the Lambert–Beer law

$$I/I_0 = \exp(-B_E L), \tag{4}$$

where L is the illumination path length and B_E is the extinction coefficient. Assuming that the light extinction in the volume is entirely due to aerosol particles of constant concentration throughout the illumination path length, B_E can be defined in terms of the extinction cross-section per particle S_E and $n(r)$, the particle number frequency distribution (number of particles/volume of air between r and $r+dr$).

$$B_E = \int_0^\infty S_E(r, \lambda, m)\, n(r)\, dr. \tag{5}$$

The extinction cross-section per particle S_E is related to the extinction efficiency factor Q_E (total light flux scattered and absorbed by a particle divided by the light flux incident on the particle) and the projected cross-sectional area of a spherical particle by

$$S_E = \pi r^2 Q_E. \tag{6}$$

Therefore the extinction coefficient of a polydisperse aerosol is given by

$$B_E = \int_0^\infty Q_E(r, \lambda, m)\, \pi r^2\, n(r)\, dr. \tag{7}$$

The extinction efficiency factor Q_E can be computed using the Mie equations (VAN DER HULST, 1957).

$$Q_E = \frac{2}{\alpha^2} \sum_{t=1}^{\infty} (2t+1)\, Re(a_t + b_t) \tag{8}$$

The term *Re* means a real part of the complex number in parenthesis and α is the size parameter $2\pi r/\lambda$.

The complex Mie amplitude coefficients a_t and b_t are defined as:

$$a_t = \frac{\eta_t^{(1)}(m\alpha)\, Z_t^{(1)}(\alpha) - m\, Z_t^{(1)}(m\alpha)\, \eta_t^{(1)}(\alpha)}{\eta_t^{(1)}(m\alpha)\, Z_t^{(3)}(\alpha) - m\, Z_t^{(1)}(m\alpha)\, \eta_t^{(3)}(\alpha)}, \tag{9}$$

$$b_t = \frac{m\, \eta_t^{(1)}(m\alpha)\, Z_t^{(1)}(\alpha) - Z_t^{(1)}(m\alpha)\, \eta_t^{(1)}(\alpha)}{m\, \eta_t^{(1)})m\alpha(\, Z_t^{(3)}(\alpha) - Z_t^{(1)}(m\alpha)\, \eta_t^{(3)}(\alpha)}. \tag{10}$$

Attachments

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ATT 1.0

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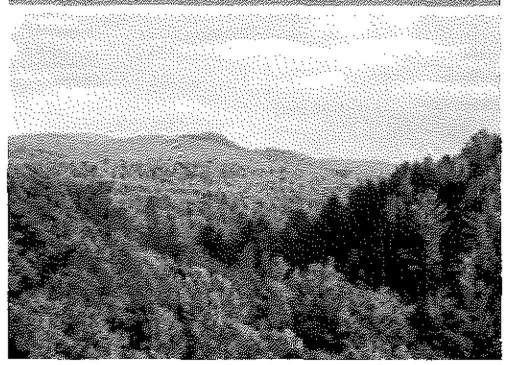

Emission Controls for Small Wood-Fired Boilers

Prepared for:

United States Forest Service,
Western Forestry Leadership Coalition

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DATA ■ ANALYSIS ■ SOLUTIONS

REPORT PREPARER

John Hinckley, Q.E.P.
Senior Consultant
Resource Systems Group, Inc.
55 Railroad Row
White River Junction, VT 05001
Email: jhinckley@rsginc.com
Voice: 802/295-4999

Kamalesh Doshi
Program Director
Biomass Energy Resource Center
43 State Street
Montpelier, VT 05601
Email: kdoshi@biomasscenter.org
Voice: 802/223-7770

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GLOSSARY OF TERMS

Particulate matter (PM) - all sizes of filterable and condensable particles.

Filterable particulate matter – solid particles of all sizes (PM10, PM2.5, etc.) which can be collected on a filter.

Condensable particulate matter – particles which form as organic vapors in combustion exhaust cool and condense into liquid droplets or condense onto the surface of solid particles.

PM10 - particles equal to or less than ten micrometers in aerodynamic diameter, also referred to as "coarse particles" or "PM coarse." Can include filterable and condensable particles.

PM2.5 - particles less than or equal to 2.5 micrometers in aerodynamic diameter, also referred to as "fine particles" or "PM fine." Can include filterable and condensable particles.

CCG – close coupled gasifier or a combustion system which utilizes two separate combustion chambers in series.

SA – a stoker combustor where the fuel is fed to a grate in the combustor with an auger.

SP – a stoker combustor where the fuel is fed to a grate in the combustor pneumatically.

CS - core separator.™

HEMC – high efficiency multicylone.

MC – conventional multicyclone.

FF – fabric filter or baghouse.

ESP – electrostatic precipitator.

Whole tree chips – wood chips created by chipping the entire tree (stem, top, leaves/needles, branches).

Bole tree chips – wood chips created by chipping the tree stem.

Mill chips – wood chips from sawmill residue and contain no bark.

1.0 INTRODUCTION

In 2001, Resource Systems Group, Inc. (RSG) produced an emission control report for a consortium of northeastern government agencies called "An Evaluation of Air Pollution Control Technologies for Small Wood-Fired Boilers."[1] While the study identified and evaluated many ways to reduce emissions, it did select a single add-on control technology (the Core Separator™) as "BACT" or Best Available Control Technology for controlling particulate matter emissions. While the conclusions of this report were accepted by the consortium of northeastern state agencies, they did not translate into a formal BACT determination at the federal level.

According to the Environmental Protection Agency (EPA), "BACT is an emissions limitation which is based on the maximum degree of control that can be achieved. It is a case-by-case decision that considers energy, environmental, and economic impacts. BACT can be add-on control equipment or modification of the production processes or methods. This includes fuel cleaning or treatment and innovative fuel combustion techniques. BACT may be a design, equipment, work practice, or operational standard if imposition of an emissions standard is infeasible."[2]

For the purposes of this report, the best available control technology (BACT) may simply be defined as the highest performing control technology for a specific pollutant that is available commercially for a general class and size of emission source. This is usually defined as resulting in the lowest emission rate although differences in available fuel specifications may complicate the issue. Other environmental, health, safety and energy consumption factors should be considered in making a BACT determination. The operation of a specific control technology applied to a comparable source anywhere in the US is usually considered sufficient evidence that the technology is BACT. In principle, the search for BACT should be worldwide, although local conditions make comparability complicated and in practice, a control technology usually needs a US based customer support system to make it truly available.

Costs are also a consideration in defining BACT for a specific application. Total cost per unit of pollutant removed decline with increasing size of the facility; therefore, a technology may be BACT for a large plant but not for a smaller one. Wood-fired boilers in the size range of 3 to 10 MMBtu/hour have not been subject to formal federal BACT review for criteria pollutants given the comparatively high and therefore challenging cost of control technologies in this size range. However, state air pollution control permits are often required for this size range, which often require a number of technical analyses, including emissions estimation, air quality modeling and some degree of informal economic analysis for pollution control costs.

The EPA BACT process follows a top down procedure. It begins with the most effective control technology available that will result in the lowest emission rate and then reviewing that technology to determine if there are technical, safety, health or other environmental factors which would make it impractical or undesirable. If the technology is not rejected because of any of these factors, then a cost analysis is conducted to determine the absolute costs and per unit costs of implementation. The cost analysis follows guidelines established by EPA. If it is relevant, the analysis may include special costs associated with retrofitting the technology in an existing plant. The cost analysis is then reviewed to determine if the technology is economically feasible in the specific case. If the first technology choice is rejected for technical, environmental, safety or costs reasons, then the analysis proceeds to the second best performing technology and so on until a feasible technology is accepted or all available options are

[1] An Evaluation of Air Pollution Control Technologies for Small Wood-Fired Boilers." Prepared for Vermont Department of Public Service; Vermont Department of Environmental Conservation, Air pollution Control Division; New Hampshire Governor's Office of Energy Resources and Community Services; and the Massachusetts Division of Energy Resources. Resource Systems Group, Inc., White River Junction, VT. Revised, September 2001.

[2] US EPA. http://www.epa.gov/nsr/psd.html

exhausted. This process may include not only add-on technology but combustion process modifications and changes in fuel specifications.

The study described by this report builds upon the 2001 report, but differs in that its goal was not to identify a single Best Available Control Technology (BACT). Rather, its goal was to identify multiple emission controls in order to provide more flexibility in the design process for biomass combustion systems. This is because there are many factors affecting the degree of control needed to meet the National Ambient Air Quality Standards (NAAQS), which were promulgated by EPA to protect human health and welfare.

Regarding the NAAQS, we note EPA significantly strengthened the NAAQS for PM2.5 (aka fine particulate matter or particles less than 2.5 micrometers in aerodynamic diameter) in 2006. PM2.5 consists of solid particles and liquid droplets less than 2.5 microns in aerodynamic diameter and is widely held to be the most critical pollutant resulting from biomass combustion. For comparison, the average period at the end of a sentence is approximately 500 microns in diameter.[1] Concern for health impacts from PM2.5 exposure coupled with the strengthened PM2.5 NAAQS has led to a much greater emphasis on emission control than in previous years.

The need to develop environmentally beneficial uses of low grade timber, improve forest health, mitigate climate change, offset rising fossil fuel oil prices and reduce foreign oil dependence have increased demand for biomass energy systems. Given frequent budget limitations, biomass developers are pressed to find cost-effective ways to reduce emissions of PM2.5 and other pollutants. In addition to being affordable, emission controls must be practical and easily implementable, otherwise they will not be effective. This study was commissioned by the U.S. Forest Service (USFS) to identify and evaluate such emission controls.

This report contains the following sections:

- Scope of study
- Emissions overview
- Best Management Practices (BMPs)
- Add-on pollution controls
- Summary of European emission control practices
- Capital costs for particulate matter control
- Cost effectiveness of add-on emission controls for particulate matter
- Overview of emission controls for other relevant pollutants
- Summary
- Conclusion
- Recommendations

The use of trade or firm names is for information only and does not imply endorsement by the authors or this study's sponsor.

[1] "Health Effects of Wood Smoke." Washington State Department of Ecology. http://www.ecy.wa.gov/biblio/92046.html

2.0 Scope of Study

The scope of this study was to update and expand the RSG 2001 report as follows:

1) **Identify and Evaluate Best Management Practices (BMPs).** BMPs, also called "work practice standards" and "inherently lower emitting processes and practices," are used to control emissions upstream of add-on control technologies such as mechanical collectors (cyclones, multicyclones), baghouses (fabric filters), electrostatic precipitators (ESPs), etc. Attention is typically directed toward add-on emission control selection. These solutions are typically more costly. While not as effective as most add-on controls, BMPs can substantially reduce emissions, improve system efficiency and improve system performance; therefore, this report will focus on BMPs in addition to add-on controls. This said, BMPs alone will not likely satisfy the requirements for "LAER" or lowest achievable emission rate, which is typically required in non-attainment areas. Non-attainment areas are areas where one or more of the National Ambient Air Quality Standards (NAAQS) are not met.

2) **Expand the original size range evaluated from 3 MMBtu/hr - 10 MMBtu/hr to 3 MM Btu/hr - 30 MM Btu/hr (heat input).**[1] This report will still focus on small (less than 10 MMBtu/hr) wood boilers. However, there is new information available from recently constructed wood boilers smaller than 3MMBtu/hr and larger than 10 MMBtu/hr that can be extrapolated to the 3 to 10 MMBtu/hr size range. This information was evaluated for the purposes of this report.

3) **Include emissions control information for PM2.5 and a number of hazardous air pollutants (HAPs) including Mercury.** This is primarily in response to EPA's strengthening of the PM2.5 NAAQS and due to recent availability of stack emission test data for PM2.5 and HAPs.

4) **Include pellet boiler emission information.** Many new pellet boilers and pellet production plants (pellet mills) have been constructed in recent years in response to demand for this fuel. In addition, a number of stack emission tests have been completed for pellet boilers in the United States. This report will discuss this new information.

3.0 Emissions Overview

When evaluating emission controls for biomass boilers, it is important to first develop an understanding of current actual emissions from biomass boilers. The most current and descriptive emissions information is obtained from exhaust stack emission tests performed according to EPA reference methods. These tests are typically performed to fulfill air pollution control permit requirements requiring a demonstration that emission limits are being met. In addition to compliance emission tests, many voluntary tests have been sponsored by interested parties given the level of interest in knowing actual emissions and effectiveness of emission controls. These tests were completed throughout the United States, with different fuel characteristics, different firing rates and different emission controls.

This study focused on particulate matter emissions. There are many terms used to characterize particulate matter. For the purposes of this report, the term particulate matter includes all sizes of solid particles and liquid particles (droplets). Solid particles are referred to as "filterable" particulate matter because they can be measured with a filter. Liquid particles are also called "condensable" particulate

[1] 30 MMBtu/hr is the threshold level at which the federal PM emission limit drops to 0.030 lb/MMBtu. This emission limit cannot be achieved with a mechanical collector. See 40 CFR Part 60, Subpart Dc. – Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units.

matter because they are formed by vapors in the combustion exhaust which cool and condense into particles. These vapors can also condense onto the surface of solid particles.

Filterable and condensable particulate matter is grouped into three size classes. "Particulate matter" (PM) includes all sizes of filterable and condensable particles. The next smallest size class is PM10 or filterable and condensable particles equal to or less than ten micrometers in aerodynamic diameter. PM10 particles are also called "coarse particles." PM2.5 is the smallest particle size class currently regulated. PM2.5 particles, also called "fine particles," include all filterable and condensable particles less than or equal to 2.5 micrometers in aerodynamic diameter. For the purposes of this report, it was assumed all condensable particulate matter falls is less than 2.5 microns in diameter.

Condensable particulate matter is reported separately from filterable PM2.5 because it is controlled differently. Some of the "condensables" will condense on filterable particles. Hence, anything controlling filterable particulate matter will inherently control some portion of the total condensables. Good combustion practices are the primary means for controlling condensables from small wood boilers without add-on controls.

Unless stated otherwise, the terms PM10 and PM2.5 will refer to filterable particulate matter only. This is because the methods used to measure the PM10 and PM2.5 emissions listed in this report measured filterable particulate matter only.

RSG reviewed 24 recent stack emission tests to develop an understanding of existing emissions (see Appendix A for supporting stack test reports available for public consumption). All but one of these tests was completed after the 2001 RSG report. These stack tests were performed in Idaho, Montana, New Hampshire, North Dakota, Rhode Island and Vermont. Twenty-two of the tests were performed on wood chip boilers and two tests were performed on wood pellet boilers. All tests measured some form of particulate matter emissions (filterable PM10, filterable PM2.5 and condensable PM). Some of the tests included other pollutants such as carbon monoxide (CO) and a selected number of Hazardous Air Pollutants (HAPs). Fuels burned included sawmill residue chips, bole chips, whole tree chips, bark chips, sawdust and municipal vegetative waste combined with ground pallets. Add-on emission controls included cyclones, multicyclones, high efficiency multicyclones (HEMCs), core separators and baghouses.

This study did not identify any stack emission data for ESPs on small wood-fired boilers in the United States. However, according to the EPA "RACT-BACT-LAER Clearinghouse", the lowest emission limit listed for PM and PM10 for large wood-fired boilers controlled with ESPs is 0.02 lb/MMBtu (PM2.5 was not listed).[1] Given this limit is based on demonstrated technology, it is technically possible that small wood-fired boilers could meet this limit. However, the economic analysis on which this limit is based is for significantly larger systems (100 MMBtu/hour or greater), where the total cost per ton of pollutant removed is significantly lower. This is why the economic analysis performed for this report was based on outlet emissions not exceeding 0.045 lb/MMBtu of all filterable particulate matter.

It should also be noted that the larger facilities subject to the limit of 0.02 lb/MMBtu have the potential to emit more than an order magnitude more emissions and therefore must meet stringent emission limits in order to meet federal ambient air quality requirements.

Table 1 summarizes the 24 particulate matter stack test results. Emissions are grouped into the three categories: filterable PM10, filterable PM2.5 and condensable PM. Table 2 through Table 4 summarize emissions by the following heat input categories:

- Less than 30 MMBtu/hour and greater than 10 MMBtu/hour (based on seven stack tests).
- Less than or equal to 10 MMBtu/hour (based on 18 stack tests).
- Less than or equal to 5 MMBtu/hour (based on nine stack tests).

A more detailed summary of all 24 tests is shown in Table 5.

[1] This emission limit applies to a utility sized boiler whose heat input exceeds 100 MMBtu/hour.

As shown below in Table 1, there is a large difference between the maximum and minimum values measured. The difference was as much as two orders of magnitude for PM10. The maximum PM10 value of 0.506 lb/MMBtu resulted from a facility burning a low quality fuel - whole tree chips produced by a grinder and having notable quantities of dirt and rock. The fuel was burned in a stoker combustor with no add-on emission control. The lowest PM10 value of 0.06 lb/MMBtu resulted from burning a high quality mill chip (no bark and no soil/rock impurities) in a close-coupled gasifier controlled with a high efficiency multicyclone (HEMC).[1]

Table 1: Summary of all Stack Emission Test Results

Category	PM10 Emissions (lb/MMBtu)	PM2.5 Emissions (lb/MMBtu)	Condensable PM (lb/MMBtu)
Average[2]	0.178	0.111	0.021
Median	0.140	0.122	0.014
Maximum	0.506	0.267	0.039
Minimum	0.016	0.014	0.006

Table 2: Stack Test Summary for Heat Input Less than 30 MMBtu/hour and Greater than 10 MMBtu/hour

Category	PM10 Emissions (lb/MMBtu)	PM2.5 Emissions (lb/MMBtu)	Condensable PM Emissions (lb/MMBtu)
Average	0.230	0.164	0.011
Median	0.101	0.188	0.014
Maximum	0.382	0.267	0.014
Minimum	0.019	0.062	0.006

Table 3: Stack Test Summary for Heat Input Less Than or Equal to 10 MMBtu/hr

Category	PM10 Emissions (lb/MMBtu)	PM2.5 Emissions (lb/MMBtu)	Condensable PM Emissions (lb/MMBtu)
Average	0.175	0.107	0.018
Median	0.156	0.104	0.014
Maximum	0.506	0.179	0.039
Minimum	0.016	0.014	0.007

Table 4: Stack Test Summary for Heat Input Less Than or Equal to 5 MMBtu/hour

Category	PM10 Emissions (lb/MMBtu)	PM2.5 Emissions (lb/MMBtu)	Condensable PM Emissions (lb/MMBtu)
Average	0.231	0.114	0.025
Median	0.161	0.110	0.026
Maximum	0.506	0.179	0.039
Minimum	0.016	0.014	0.009

[1] The HEMC was determined to be BACT for small wood-fired boilers in Rhode Island in a 2006 BACT study completed by Resource Systems Group. BACT for PM10 and PM2.5 were determined to be 0.20 lb/MMBtu and 0.18 lb/MMBtu respectively.

[2] Average values represent the average of instances when both PM10 and PM2.5 were measured at the same site.

0.090 gr/dscf

0.081 gr/dscf

Table 5 provides more information for each stack test than the tables above. Information is provided in ascending order of measured PM10 emissions for each of the 24 tests. Table cells were left blank to represent instances when PM2.5 and condensable PM data were not available. Also shown is the type of fuel burned and type of emission control. The following combustion technologies are listed: close-coupled gasifier (CCG), auger fed stoker (SA), pneumatically fed stoker (SP).

Table 5: Summary of 24 Particulate Matter Stack Emission Tests

Location	Design Heat Input (MMBtu/hr)	Comb. Type	Fuel Burned	Emission Control	PM10 Emissions (lb/MMBtu)	PM2.5 Emissions (lb/MMBtu)	Condens. PM Emissions (lb/MMBtu)
Glocester, RI	4.6	CCG	Mill chips	HEMC	0.016	0.014	
Middlebury, VT	29.0	CCG	Bole chips	MC + FF	0.019		
Dillon, MT	19.0	CCG	Bole chips	MC	0.052		
N. Scituate, RI	9.1	CCG	Mill chips	HEMC	0.058	0.054	0.007
N. Scituate, RI	9.1	CCG	Mill chips	HEMC	0.066	0.066	
Thompson Falls, MT	2.2	CCG	Bole tree chips	Cyclone	0.070		
Brattleboro, VT	6.9	CCG	Wood chips	Core Sep.	0.078		
Greenfield, NH	5.7 & 11.4	SA	Bole chips	MC + FF	0.078	0.062	0.014
Newport, VT	15.6	CCG	Bole chips	MC	0.101		0.006
Peterborough, NH	2.8	SA	Pellets	MC	0.101		
Bennington, VT	16.8	SP	Whole tree chips	2 MC	0.140		
Darby, MT	3.3	SA	Bole chips	None	0.156		
Victor, MT	2.6	SA	Bole chips	None	0.166	0.098	0.009
Springfield, NH	15.5	SA	Sawdust	None	0.168		
Hinesburg, VT	6.5	SA	Bole chips	Cyclone	0.171	0.147	0.012
Brattleboro, VT	10.0	SA	Mill chips	Core Sep.	0.172	0.162	0.012
Burlington, VT	10.0	SA	Mill chips	MC	0.187		0.015
Darby, MT	3.3	SA	Bole chips	None	0.192	0.110	0.015
Bismarck, ND	1.0	SA	Muni. veg. & pallets	None	0.199	0.151	0.077
Burlington, VT	10.0	SA	Bole chips	MC	0.257		0.017
Townsend, MT	0.75	SA	Pellets	None	0.305	0.133	0.036
Bennington, VT	16.8	SP	Whole tree chips	2 MC	0.382	0.267	0.014
Council, ID	1.9	SA	Whole tree chips	None	0.506	0.179	0.039
Dillon, MT	19.0	CCG	Bole chips	MC		0.188	

The following were observed:

- Close-coupled gasifiers emitted the lowest levels of emissions. This may be due to less carry-over of filterable particles from the combustion chambers into the exhaust.
- There is limited PM2.5 emissions data. This is partially because PM2.5 is still not officially enforced by most state air quality agencies; therefore, state agencies are requiring compliance stack testing for PM10 only.
- The lowest PM10/PM2.5 emissions were produced by a close coupled gasifier burning a relatively high quality wood chip, with emissions controlled by a HEMC.
- PM10 emissions from baghouses were surprisingly not the lowest for all tests. They were the third and eighth lowest emissions of all tests. The lower than expected control efficiency for the

Greenfield, NH site is likely due to a portion of the boiler exhaust gases circumventing the bag house via a leaking damper into a bypass duct.

- PM10 emissions were equal to or less than 0.20 lb/MMBtu for 19 of the 24 tests (79%) and less than 0.10 lb/MMBtu for 10 of the 24 tests (41%).
- All but one of the PM2.5 tests was less than 0.20 lb/MMBtu. Five of the 13 PM2.5 tests were less than 0.10 lb/MMBtu.
- Bark can increase PM emissions. For example, the two results from Burlington, Vermont, where mill and bole chips were tested, indicate bark can increase PM emissions. PM10 emissions were 0.187 lb/MMBtu and 0.257 lb/MMBtu for mill and bole chips respectively.
- There are two stack test results for pellet fired systems. PM10 emissions from these systems ranged from 0.101 lb/MMBtu to 0.305 lb/MMBtu. The higher number corresponds to a much older system with no add-on emission controls. The lower number corresponds to a new system with a multicyclone. Average PM2.5 emissions from the older system were 0.133 lb/MMBtu. PM2.5 emissions were not measured for the newer system.

The EPA has developed emission factors for wood boilers. These emission factors are included in a document called "AP 42", which is a compilation of emission factors.[1] Comparable emission factors from the AP 42 are summarized for reference below. Note these emission factors represent an average for a group of emission tests. These emission factors were published in September, 2003 and likely correspond to systems larger than most of those considered for this report. The majority of the stack test data used to develop these emission factors was collected in the early to mid 1990's.

Table 6: Comparable EPA AP 42 Emission Factors

Fuel Type	Control Device	PM10 Emissions (lb/MMBtu)	PM2.5 Emissions (lb/MMBtu)	Condensable PM Emissions (lb/MMBtu)
Bark & wet wood	None	0.50	0.43	0.017
Bark & wet wood	Mechanical collector	0.32	0.19	0.017
Wet wood	None	0.29	0.25	0.017
Wet wood	Mechanical collector	0.20	0.12	0.017
All fuel types	Fabric filter (baghouse)	0.074	0.065	0.017
All fuel types	Electrostatic Precipitator (ESP)	0.04	0.035	0.017

3.1 Vermont APCD Emission Study

The Vermont Agency of Natural Resources (ANR) recently completed an emission study focusing on air pollutant control efficiency for a number of add-on pollution controls. The study evaluated inlet and outlet particulate matter emissions (or the emissions entering and exiting a given pollution control device) from five wood chip fired boilers in the Northeast. These boilers are located at Crochet Mountain Rehabilitation Center (Greenfield, NH), Bennington College (Bennington, VT), Brattleboro Union High School (Brattleboro, VT), Ponaganset High School (North Scituate, RI) and Champlain Valley Union High School (Hinesburg, VT). Emissions data and design heat inputs for these boilers are provided previously in Table 5.

[1] Can be accessed at http://www.epa.gov/ttn/chief/ap42/ch01/index.html

Table 7 shows approximate PM2.5, PM10 and PM control efficiency for the five sites.[1] The control efficiencies listed below refer to the percent of filterable particulate matter removed by the add-on pollution control device. Control efficiencies for different add-on pollution controls are further discussed later in this report.

Table 7: Vermont ANR Emission Study Approximate Control Efficiencies

Location	PM Control	PM2.5 Control Efficiency	PM10 Control Efficiency	PM Control Efficiency
Greenfield, NH	Multicyclone + baghouse	74%	74%	83%
Bennington, VT	Two multicyclones in series	14%	22%	61%
Brattleboro, VT	Core separator (24")	24%	32%	60%
North Scituate, RI	High efficiency multicyclone	15%	21%	23%
Hinesburg, VT	Cyclone	3%	6%	4%

The following observations were made from these results:

- **Bennington and Brattleboro, VT.** The PM control efficiencies are typically significantly higher than the PM2.5 and PM10 efficiencies because there were significant quantities of particles larger than PM10 (ten microns in aerodynamic diameter) emitted during the stack tests.
- **Greenfield, NH.** The control efficiency is relatively low for a multicyclone followed by a baghouse. Baghouses are widely thought to achieve 99% control efficiency for PM2.5 and smaller filterable particles. As mentioned, the low control efficiency is suspected to be due to a portion of the boiler exhaust gases circumventing the bag house via a damper which was not closed completely. This allowed a small portion of the boiler exhaust into a bypass duct around the baghouse and into the stack.
- **Bennington, VT.** While this is the highest control efficiency value of all mechanical collectors tested, the actual emissions were higher than all other five sites (0.382 for PM10 and 0.267 lb/MMBtu for PM2.5). The higher emissions may be due to carry over of large particles from the combustion chamber caused by pneumatic feeding of fuel into the combustion chamber.

  It was discovered after this testing that some of the underfire air passages were obstructed by a buildup of boiler bottom ash. This ash was subsequently cleaned out, the boiler combustion air was adjusted and an improved ash management procedure was implemented. The retesting which occurred after these measures were implemented indicated the total PM emission rate dropped to 0.14 lb/MMBtu (approximately a 63% reduction).
- **Brattleboro, VT.** The PM collection efficiency was nearly the same as at Bennington, but the PM10 and PM2.5 collection efficiencies were higher. This shows the Core Separator™ is more effective at removing smaller particles than conventional multicyclones, even conventional multicyclones in series.

  The Core Separator™ operating at Brattleboro was designed for the exhaust volume from a 400 horsepower (hp) boiler. However, the boiler size was reduced to 332 hp during project development. So while a smaller "2-core" unit would have worked, a "3 core" unit was operating. The result is that during emission testing, the Core Separator™ was operating at half it's design pressure drop. A higher collection efficiency would likely have resulted if it was operating at its design pressure drop.

[1] The PM2.5 and PM10 control efficiencies were calculated using the inlet and outlet emission factors (in lb/MMBtu) from the control device. The PM control efficiency was taken directly from the study report.

- **North Scituate, RI.** The outlet emissions were the lowest of all sites (0.0662 MMBtu/hr for PM10 and 0.0660 MMBtu/hr for PM2.5) despite one of the lowest collection efficiencies measured (23%). Similar to the Brattleboro, this is because the system was operating at low capacity (30% load) which led to a low pressure drop (approximately 0.7 inches of WC). The design pressure drop for this system is 4" of WC. At this pressure drop it is conceivable that the collection efficiency would have been 75% or greater. Vendor calculations suggested a PM collection efficiency of 80% or greater at design load/pressure drop. It should also be noted that the vast majority of the inlet loading was PM2.5 (88.7%). Therefore, the control efficiency is relatively high for a mechanical collector operating at low pressure drop.
- **Hinesburg, VT.** Single cyclones have the lowest collection efficiency of all mechanical collectors. This is evidenced by the collection efficiency measured, which is due to a considerably higher portion of PM2.5 in the inlet exhaust. Despite the type of control device, the outlet emissions were relatively low (0.171 for PM10 and 0.147 lb/MMBtu for PM2.5). Similar to North Scituate, this boiler operated at relatively low load and consequently there was relatively low pressure drop across the cyclone.

3.2 Hazardous Air Pollutant Information

3.2.1 HAP Stack Emission Test Information

In addition to PM2.5, there is growing interest in Hazardous Air Pollutant (HAPs) emissions from wood combustion. The EPA publishes HAP emission factors in Section 1.6 of the AP 42, which was last updated in September, 2001 and, as mentioned, is based on emission tests conducted before that date. Since that time, there have been advances in combustion technology and practices, which suggest HAP emissions have and will likely continue to decline with time.

This study compared a number of AP 42 HAP emission factor values with measured emissions from five test sites. Both gaseous and particulate HAPs were evaluated. A full list of the HAPs evaluated is provided in the appendix. HAP emissions were not weighted according to their respective toxicity level.

The information provided in this report is intended to establish a starting point for understanding HAP emissions. Firm conclusions should not be drawn from the information provided as it is based on a limited number of stack emission tests.

Not all 188 federal HAPs were measured at each of the five test sites. Each HAP measured at each site was compared with its AP 42 equivalent.

The comparisons made showed actual emissions of individual HAPs were both higher and lower than AP 42 equivalents. They also showed total HAPs measured at each site were lower than the total AP 42 HAP equivalent for all but one site. The average actual total HAP emission from all sites was 68% lower than the AP 42 total HAP equivalent. The comparisons are summarized below. Detailed information is provided in the appendix.

Table 8: Summary of HAP Test Sites

Location	Design Heat Input (MMBtu/hr)	Combustion Type	Emission Control	Emission Test Date	Number of HAPs Compared	Total Measured HAP Percent of AP 42 Total HAP
North Scituate, RI	9.1	CCG	HEMC	2009	24	13%
Glocester, RI	4.6	CCG	HEMC	2009	24	8%
Council, ID	1.9	SA	Uncontrolled	2007	22	23%
Green Acres, VT	2.2	SA	Uncontrolled	1996	24	123%
Hazen Union, VT	2.8	CCG	MC	1996	24	26%

3.2.2 Mercury Emissions

Mercury emissions are typically considered with coal projects. Mercury emissions have been considered for wood combustion projects, but to a lesser extent. There is much information about mercury control from coal fired power plants via fuel and exhaust cleaning. Unlike NO_2 emissions, Mercury emissions are a function of fuel mercury content. Therefore, a fuel analysis provides a good indication of potential mercury emissions.

Mentz et al, describes work performed to measure mercury content of bark and stemwood in 30 locations throughout the country.[1] The average bark and stemwood concentrations at the 30 sites were 1.42 lb/10^{12} Btu and 0.28 lb/10^{12} Btu for bark and stemwood respectively. The mean mercury content for each of the 30 sites ranged from 0.57 lb/10^{12} Btu to 3.14 lb/10^{12} Btu in bark and from 0.12 lb/10^{12} Btu to 0.46 lb/10^{12} Btu in stemwood.

These numbers are based on the assumption that the entire quantify of mercury is released from the fuel into a vapor form and does not combine with any other constituents in the exhaust gas or is removed by some form of emission control.

Pease et al, describes research performed to evaluate the potential for flue gas cooling, flue gas humidification, pulsed energization, and sorbent injection in wet and dry ESPs to reduce mercury emissions. This study found that all of these measures are effective. It also found that some mercury will attach to fly ash thereby increasing the potential for mercury removal.

4.0 Best Management Practices (BMPs)

BMPs range from physical equipment such as oxygen sensors to operational practices such as visual observations of plume opacity. Properly implemented, BMPs will optimize combustion conditions thereby helping maximize energy efficiency and minimize emissions from any system.

4.1 Fuel Quality

The first step in implementing BMPs is to obtain the highest quality fuel possible. There are many factors affecting fuel quality. Fuel quality is an important consideration as improved fuel quality improves combustion conditions, increases efficiency and reduces emissions. Fuel quality is a function of fuel moisture content, bark content, uniformity, size, and purity. These factors are described in detail later in this report.

There are no formally established grades of wood chips. However, there are four basic types of wood chips, whose quality and corresponding emissions are fairly well understood. For the purposes of this report, the term "high quality" describes a chip which has minimal ash content, is of uniform and proper size and results in the least possible emissions.

1. **Sawmill residue chips (mill chips).** This chip is thought to be the highest quality in that it contains no bark. The availability of this chip is limited due to the decline in U.S. sawmills coupled with the demand for higher value products from those chips such as pulp, wood composite products and wood pellets.
2. **Bole tree chips (bole chips).** Are produced by chipping the tree stem (trunk). This is a moderate to high quality chip as it contains relatively minimal quantities of bark and are relatively uniform in size.

[1] Karen Mentz, John Pinkerton, and Jeff Louch."Potential Mercury and Hydrochloric Acid Emissions from Wood Fuels." Forest Products Journal, 55(2): 46-50. Received for publication in August, 2004. Article No. 9919.

3. **Whole tree chips.** Are produced by chipping the entire tree and therefore include the tops, leaves and branches/needles in addition to the trunk. This category would also include municipal vegetative waste in addition to trees removed from a given forest. These are a moderate to low quality chip as they are less uniform in size/shape and have higher ash content than bole tree chips.
4. **Bark chips.** These chips consist primarily of bark and are the lowest quality chip given the high ash content of bark. In addition to its mineral content, bark can have higher ash content because it may have impurities adhered to it from harvesting and transport.

Wood chips can be produced with chippers and grinders. Grinders can handle more dirt and rocks and therefore have greater potential for contaminating wood chips with those impurities. Grinders also produce chips with greater size variation than chippers. As is discussed later in this section, fuel homogeneity is important for effective fuel handling and combustion.

In 2007, the Biomass Energy Resource Center (BERC) published a report for the South Dakota Department of Agriculture, Resource Conservation & Forestry Division entitled "Woodchip Fuel Specifications and Procurement Strategies for the Black Hills."[1] While this document is intended for a specific geographic area, the overall principles can be applied throughout the United States. This document characterizes four grades of wood chip quality and provides guidelines for obtaining each of those four grades.

The information in the BERC report was combined with the author of this report's working knowledge to develop the fuel quality BMPs summarized in the table below below. Any number of these BMPs can be applied to planned as well as existing facilities.

Table 9: Summary of Fuel Quality BMPs for Wood Chips (Continued on Next Page)

BMP Category	Description	Fuel Quality Improvement	Combustion Improvements / Emission Reductions
Bark content	Minimize bark content. Mill chips and sawdust based pellets do not contain bark.	Reduces ash content.	Reduces clinker formation on grates thereby maintaining proper airflow through the grates. Reduces emissions associated with fly ash carry over. Increases combustion efficiency.
Moisture content	Moisture content must be within range meeting combustion system design requirements.	Ensures design fuel heat content met.	Energy loss occurs when excess moisture is vaporized. Fugitive dust and excess PM emissions occur when fuel is excessively dry.
Storage surface	Minimize/prevent storage on ground surfaces. Store on concrete or other type of clean paved surface.	Prevents transfer of soil, rocks, salts and other impurities from the ground surface to the fuel.	Improves combustion efficiency by reducing clinker and ash formation. Minimizes particulate matter emissions.
Storage time for trees with needles	When dry, needles fall off tree when fallen tree mechanically shaken.	Reduces ash content. Increases fuel uniformity.	Lower ash content and reduced potential for clinker formation and increases combustion efficiency. Reduced PM emissions from reduced fly ash carry over.

[1] Biomass Energy Resource Center (BERC). "Woodchip Fuel Specifications and Procurement Strategies for the Black Hills." Prepared for the South Dakota Department of Agriculture, Resource Conservation & Forestry Division. May 15, 2007. www.biomasscenter.org

BMP Category	Description	Fuel Quality Improvement	Combustion Improvements / Emission Reductions
Storage coverage	Store in covered area.	Ensures design moisture content met. Maximizes heat content of fuel.	Ensures design combustion efficiency met by preventing energy loss associated with excess moisture vaporization. This minimizes excess fuel consumption.
Method of chip production	Sharp and properly adjusted equipment is critical for grinders and chippers. Chipping typically produces better chip than grinder.	Maximizes wood chip uniformity. "Stringer" formation minimized.	Promotes uniform combustion thereby maximizing combustion efficiency. Prevents system interruptions (upset conditions) caused by stringers in metering bins.
Chipping/grinding equipment. Operation and maintenance.	Manufacturer's operation and maintenance requirements should be adhered to.	Ensures chip uniformity.	Promotes uniform combustion thereby maximizing combustion efficiency.
Uniformity of fuel input to chipper or grinder	Uniform size material fed to chipper or grinder.	Increases chip uniformity.	Promotes uniform combustion thereby maximizing combustion efficiency.
Chip screening	Mechanical screening (sizing) of chips.	Increases chip uniformity, removes oversized material and removes fines. Has potential to separate and remove some portion of bark from raw chips.	Promotes uniform combustion thereby maximizing combustion efficiency and reducing overall emissions. PM emissions potentially reduced as carry over of fines into exhaust eliminated. PM emissions reduced through reduced bark content.
Long term fuel supply contracts	Encourages investment in wood chip production equipment producing higher quality chip.	Optimal fuel characteristics developed.	Promotes optimal combustion conditions which maximizes energy efficiency and minimizes emissions.
Fuel supply testing	Visually inspect fuel geometry, uniformity, moisture content prior to fuel being dumped into storage bin. Retain grab samples if need for future fuel measurements anticipated.	Ensures design fuel specifications are met.	Ensures optimal combustion conditions.

There are a number of grades of wood pellets defined by the Pellet Fuel Institute (PFI). They are super premium, premium, standard and utility. As shown in Table 10, grades are a function of bulk density, diameter, pellet durability index, percent of fines, inorganic ash content, length, moisture content, chloride content, ash fusion and heating value. These categories are further described on the PFI Internet Site.[1] There are no legal factors necessitating use of any particular grade of wood pellets. However, it is useful to know the pellet grade for purposes of meeting air quality requirements for a given area.

[1] http://www.pelletheat.org/3/institute/standards/PFI%20Standards.pdf

While not depicted in the table below, the PFI is proposing standards for pellet manufacturers to disclose on the bag surface if non-natural additives were used to form the pellets. This is because additives have the potential to increase the relative toxicity of pellet combustion exhaust.

Table 10: Values used for Classifying Residential Grades of Pellets according to the Pellet Fuels Institute

Fuel Property	PFI Super Premium	PFI Premium	PFI Standard	PFI Utility
Bulk Density, lb./cubic foot	40.0-46.0	40.0-46.0	38.0-46.0	38.0-46.0
Diameter, inches	0.250- 0.285	0.250- 0.285	0.250- 0.285	0.250- 0.285
Diameter, mm	6.35-7.25	6.35-7.25	6.35-7.25	6.35-7.25
Pellet Durability Index	>97.5	>97.5	> 95.0	>95.0
Fines, % (at the mill gate)	<0.50	<0.50	<0.50	<0.50
Inorganic Ash, % - See Note 1	<0.50	< 1.0	<2.0	<6.0
Length, % greater than 1.50 inches	< 1.0	< 1.0	< 1.0	< 1.0
Moisture, %	<6.0	<8.0	<8.0	< 10.0
Chloride, ppm	< 300	< 300	< 300	< 300
Ash Fusion	NA	NA	NA	NA
Heating Value	As-Rec. ± 2SD	As-Rec. ± 2SD	As-Rec. ± 2SD	As-Rec. ± 2SD

4.2 Operation and Maintenance Plan

An operation and maintenance plan (O&M Plan) is a document describing the equipment and work practices that will take place to ensure optimal combustion conditions and compliance with applicable emission limits. These plans also specify the frequency that all work practices will be completed. Consequently, they may include daily, weekly, monthly and annual checklists to ensure all work practices (BMPs) are completed. Facilities are oftentimes required to record and maintain this information for a period of time as part of a permit condition. O&M plans are developed in concert by the boiler operator, wood boiler equipment vendor and state regulatory office. O&M plans should be flexible to allow for improved O&M measures if/when they are identified for a given facility. Ideally, all O&M plans are written and approved within a few months after start-up.

Here is a sample list of O&M components as specified in a Vermont air pollution control permit:

- Descriptions of routine maintenance and inspection procedures.
- Description of procedure for and frequency of ash removal from the boiler and the particulate matter emission control device.
- Provisions for maintaining records of maintenance and inspection procedures, including both routine activities and actions taken in response to observations of low combustion efficiency.
- Provisions for calibration and maintenance of any testing instruments and/or equipment used to measure the concentrations of CO_2 and CO in the boiler exhaust gases.

4.3 Boiler Operator Training

Boiler operator training is essential to proper operation and maintenance. This is typically provided by the vendor prior to and shortly after start-up. There are currently no standardized training programs for acquiring boiler operator certification.

There are occasions when the boiler operator who was trained by the vendor upon start-up leaves for a new job. In these situations, it is critical to ensure the replacement operator has sufficient training and experience.

4.4 Equipment Sensors

Many wood boilers are equipped with internal sensors that provide real time information about some aspect of the combustion process to an automated control system. Information from these sensors helps the system self-regulate with the intelligence they provide. Sensors are frequently used to measure pressure drop across a mechanical collector or baghouse, opacity in the exhaust stack (with smoke density meters), oxygen level in the combustion chamber and/or exhaust stack, and temperature in the combustion chamber and/or exhaust stack.

4.5 Automatic Ash Removal

Bottom ash, or ash collected at the bottom of the combustion chamber, can become re-suspended and carry over into the exhaust, thereby increasing particulate matter emissions. Automatic ash removal can ensure frequent bottom ash removal. This may be especially useful if burning a high ash content fuel.

4.6 Raking Grates as Needed

In most direct burn combustion systems, biomass is combusted on grates. Ash will accumulate on these grates. If left to accumulate, this can lead to clinker formation and limit under-fire airflow thereby reducing combustion efficiency. Raking the grates reduces this problem.

4.7 Combustion Efficiency Testing

Combustion efficiency testing is a way to quantify the degree of combustion completeness, not the overall thermal efficiency (heat input divided by heat output). One method for measuring combustion efficiency is by measuring carbon monoxide (CO) and carbon dioxide (CO_2) concentrations in the boiler exhaust with a hand-held portable analyzer.

CO is an indicator of the level of gaseous air toxics in boiler exhaust and therefore a good surrogate for gaseous air toxics. The relationship between CO and carbon dioxide (CO_2) concentrations provides an indication of the degree combustion completeness and is therefore appropriate for the levels of all emissions in boiler exhaust.

Vermont and Rhode Island implemented a permit condition requiring measurement of both CO and CO_2 in the exhaust gas to determine combustion efficiency. Combustion efficiency is determined using this equation, taken from a Vermont air pollution control permit:

Equation 1

$$CE(\%) = \frac{CO_2}{CO_2 + CO} \times 100$$

Where:

CE = Combustion efficiency,

CO_2 = % by volume of carbon dioxide in the flue gas, and

CO = % by volume of carbon monoxide in the flue gas.

Compliance is demonstrated when the combustion efficiency is calculated to be equal to or greater than 99%. A representative number of measurements should be taken given the broad range of operating conditions that can occur in a given biomass boiler.

4.8 Visual Plume Observations

Visually observing the exhaust plume is a way to confirm good combustion conditions are occurring. EPA publishes two methods for visually evaluating plume opacity. The first one, Method 22, is mostly qualitative and does not require formal training.[1] The second, Method 9, is more quantitative and requires the observer be re-certified every six months.[2] If the plume characteristics pass a Method 22 test, then the observation is complete. If the Method 22 test is not passed, then the observer can perform a Method 9 test to quantify the plume characteristics, if necessary. At minimum, steps should be taken to correct combustion conditions if a Method 22 test is not passed.

4.9 Recordkeeping

Consistent and thorough record keeping is another means to ensure ongoing optimal combustion conditions. Record keeping is therefore considered a means for demonstrating ongoing compliance with pollutant emission limits. Record keeping is required in the areas of fuel use, equipment maintenance and equipment monitoring. Record keeping has been required for the items below. These requirements listed are directly quoted or derived from recent permits issued in Vermont and New Hampshire.

- Track fuel use on a monthly basis if heat input equal to or greater than 10 MMBtu/hr. Track fuel use on an annual basis if heat input less than 10 MMBtu/hr.
- Measure and record oxygen in percent volume, in the exhaust gas and permanently record the output in a log book.
- Maintain records of the results of the combustion efficiency testing conducted on the Facility's boiler. These records shall at least include the test date, identification of boiler tested, a measurement of the load on the boiler (such as fuel feed rate or steam production rate), the concentrations of oxygen, carbon monoxide and carbon dioxide in the exhaust gas as well as the calculated combustion efficiency.
- Install and maintain a temperature sensor to measure the wood-fired boiler's exhaust exit temperature and permanently record the output in the log book.
- Observe visible emissions (via EPA Method 22) once a day on normal business days. Record the date, time, duration of excursion, and corrective actions taken if visible emissions are not typical of good operation.
- Inspect the differential pressure across the cyclone (once per shift).
- Visually inspect the cyclone shell, piping, and ducts for leaks; inspect the ash collection equipment and check for abnormal noise or hot spots (once per shift).
- Clean the boiler grates once a day on normal business days.
- Inspect the cyclone/multicyclone at least once per year or if conditions indicate it may need maintenance. Clean the boot and vanes if possible on the annual inspection.
- Empty the cyclone/multicyclone ash collection vessel as necessary, but not less than once per week, in accordance with the manufacturer's recommendations.[3]

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[1] More information can be accessed at http://www.epa.gov/ttn/emc/methods/method22.html

[2] More information can be accessed at http://www.epa.gov/ttn/emc/methods/method9.html

[3] This would also suffice for any other add-on control device.

4.10 Annual Tune Up

Annual tune ups are typically performed on wood boilers. The annual tune up includes a comprehensive inspection of the combustor, boiler and pollution control system components. Adjustments/improvements to system components are performed as needed. Combustion efficiency is typically measured when the annual tune up is performed.

5.0 Add-On Pollution Controls

Add-on pollution controls are emission control devices which remove pollutants from the exhaust gas stream somewhere between the boiler combustion chamber and the exhaust stack. They are installed when the combustion equipment cannot reduce emissions to a desired level. In the absence of a fixed BACT requirement,[1] emission controls are determined on a case by case basis and are a function of the following: level of uncontrolled emissions, applicable state/federal emission limits, existing ambient pollutant concentrations (background concentrations), stack height and stack proximity of stack to sensitive populations. Potential add-on controls reviewed for this study include cyclones, multicyclones, high efficiency multicyclones (HEMCs), core separators, electrostatic precipitators (ESPs) and baghouses (fabric filters). The Core Separator™ was determined in the 2001 emission control report by Resource Systems Group as the Best Available Control Technology (BACT) for small wood-fired boilers burning a wood chip type fuel and capable of limiting PM10 emissions to 0.1 lb/MMBtu.[2] The Core Separator™ will be discussed in further detail later in this section. Again, the conclusions of this report were accepted by a consortium of New England states, they did not translate into a formal BACT determination at the federal level.

This section will focus on add-on controls for reducing filterable particulate matter because for the boiler size range considered in this study, combustion controls are used to limit emissions of other pollutants such as condensable particulate matter, nitrogen oxides (NOx), carbon monoxide (CO), volatile organic compounds (VOCs) and most hazardous air pollutants (HAPs or "air toxics"). Add-on controls are not discussed for sulfur dioxide (SO_2) given the low sulfur content of biomass. Combustion controls for pollutants other than particulate matter are summarized later in this report.

5.1 Mechanical Collectors

Mechanical collectors use centrifugal forces to separate particulate matter from an exhaust gas stream. Mechanical collectors include single cyclones, multicyclones, high efficiency multicyclones (HEMCs) and core separators. They are often used as exhaust gas pre-cleaners for other control devices, such as baghouses or ESPs.

The exhaust gas flow rate is directly proportional to the operating load of the boiler. Pressure drop, an indicator of centrifugal separation force which removes particles from exhaust, is directly proportional to the exhaust gas flow rate. Therefore, mechanical collectors work best when operating at their respective design (maximum) pressure drop.

[1] Massachusetts currently requires all wood boilers meeting the state permit applicability threshold meet a PM10 emission limit of 0.10 lb/MMBtu.

[2] An Evaluation of Air Pollution Control Technologies for Small Wood-Fired Boilers," Prepared for Vermont Department of Public Service; Vermont Department of Environmental Conservation, Air pollution Control Division; New Hampshire Governor's Office of Energy Resources and Community Services; and the Massachusetts Division of Energy Resources. Resource Systems Group, Inc., White River Junction, VT. Revised, September 2001.

5.1.1 Cyclones and Multicyclones

Single and multicyclones can remove a large percentage (approximately 90%) of large particles (PM10 and larger) and remove a small percentage (less than 10%) of fine particles (PM2.5). HEMCs and core separators will collect higher percentages of PM10 and PM2.5.

5.1.2 High Efficiency Multicyclones

The high efficiency multicyclone (HEMC) is similar to a conventional multicyclone, but has higher collection efficiency due to use of a higher pressure drop. Conversely, the additional pressure drop has a higher energy demand. The HEMC was found to be the Best Available Control Technology (BACT) in a 2006 permit application to the Rhode Island Department of Environmental Management (RI DEM) for new institutional wood boilers with heat input less than 10 MMBtu/hour. The BACT study translated into emission limits of 0.20 lb/MMBtu and 0.18 lb/MMBtu for PM10 and PM2.5 respectively (these limits include both filterable and condensable particulate matter).

Inlet-outlet testing was performed for the Vermont APCD study at the HEMC installed at the Ponaganset Middle School in North Scituate, RI. Two, one-hour tests were completed for a single wood boiler. The HEMC there is designed to operate most effectively at four inches of pressure drop. During testing, the wood boiler operated at low load (30% capacity) which created a pressure drop of approximately only 0.7 inches of water. The HEMC collected 23% of the particulate matter in the boiler exhaust despite the low pressure drop and a very high percentage of fine particles in the inlet exhaust gas stream (approximately 90%).

A collection efficiency of 23% is a relatively low number in comparison with other add-on controls. However, it is approximately 10% higher than what a conventional multicyclone can achieve for PM2.5 removal under design (maximum) pressure drop conditions. Furthermore, design calculations provided by the vendor indicate the PM2.5 collection efficiency would have been approximately four times higher at design pressure drop.

HEMC's can be designed to maintain a high pressure drop at low loads. This can be achieved by using valves to regulate the number of cyclones through which exhaust gas passes. For example, at high load, all valves would open thereby allowing exhaust gas to distribute among all the cyclones. As load decreased, valves would close causing exhaust gas to be distributed among a smaller number of cyclones.

5.1.3 Core Separator™

The Core Separator™ was previously determined as BACT for particulate mater, in a 2001 report written by Resource Systems Group.[1] This technology became commercially unavailable after the report was issued, when LSR Technologies stopped operating. Since that time, the rights to the patent were transferred to Easom Corporation, from whom core separators can currently be purchased.

Unlike conventional cyclone/multicyclones and the HEMCs in Rhode Island, the Core Separator™ design will maintain a relatively high pressure drop at all operating loads. Therefore, this technology's collection efficiency will not deteriorate with reduced operating loads. Stack test results indicate it has a PM collection efficiency of approximately 60% and outlet PM2.5 emissions of less than 0.1 lb/MMBtu with close coupled gasifiers and approximately 0.15 lb/MMBtu with stoker combustors.

5.2 Dry Electrostatic Precipitators

Dry Electrostatic precipitators (ESPs) work on the principle of electrostatic attraction. In this, particles in an exhaust gas stream are charged as they pass through the ESP and are pulled out of the exhaust gas stream by oppositely charged plates on the side of the ESP. This technology is widely used in Europe to

[1] An Evaluation of Air Pollution Control Technologies for Small Wood-Fired Boilers. Resource Systems Group, 55 Railroad Row, White River Junction, Vermont 05001. September 2001.

control particulate emissions from biomass systems. The control efficiency of PM10 and PM2.5 appears to be 99% or greater, making this control technology very compelling.[1] There are no demonstrated applications of ESPs on small wood boilers in the United States. The pervasiveness of ESPs in Europe is due to stricter emission limits and higher subsidies.[2] There is one demonstrated ESP on a small coal fired boiler in North Carolina. At least two ESPs are slated for construction for small wood fired boilers in New England this year.

Until recently, it has been commonly held that ESPs have significantly higher capital costs than baghouses. Given changes in ESP design and recent cost analyses, it is now thought that ESPs have comparable capital costs to baghouses for certain boiler sizes as they require less ancillary equipment (such as insulated ductwork, multicyclone for exhaust pre-cleaning) than baghouses. This finding coupled with significantly lower operating costs and smaller spatial requirements than baghouses, have helped ESPs become especially attractive when advanced emission control is necessary.

Significant pressure drops do not occur in ESPs; therefore, they do not require the extra energy to run fans to overcome the pressure drop. This means ESPs potentially will have a lower energy demand than all other add-on controls.

5.3 Baghouses (Fabric Filters)

Baghouses utilize fabric filtration to remove particles from an exhaust gas stream. They are thought to provide the highest degree of control of all add-on controls (99%+ of filterable PM2.5 emissions).[3] This is higher than the control efficiency measured in Greenfield, NH or 74%. Again, this lower value was likely due to tramp air flowing through a bypass during the stack test there.

Cyclone/multicyclones are used to pre-clean exhaust gas upstream of baghouses to reduce fire hazard. As with mechanical collectors, there is pressure drop across this control device caused by the exhaust gas passing through fabric. Therefore, energy is required to draw exhaust through the fabric.

The 2001 RSG report determined baghouses were technically infeasible due to threat of fire. A 2006 RSG BACT study also found them technically infeasible due to fire hazard and due to potential for filter bag clogging, a condition which occurs when the exhaust gas cools to the dew point causing moisture to condense on the particulate "cake" on the side of the bag walls. The end product is impermeable and can cause bags to rupture.

It should be noted that filter clogging has the potential to occur in systems burning a wet fuel (approximately 25% to 50% moisture content) with variable firing rates. Filter clogging is not likely to occur in systems burning a dry fuel (approximately 15% or less moisture content) and operating consistently at a high firing rate, which prevents the exhaust from cooling and reaching its dew point.

Historically in New England, baghouses have not been selected for systems with design inputs less than 10 MMBtu/hour because the facilities which they would serve determined they did not have the financial or technical resources to purchase and service them. For example, this size boiler would serve a small school, which would typically not have a large and experienced facilities staff who could service the baghouse. In the absence of a significant subsidy, a small school would typically not have the financial resources to purchase a baghouse.

There are now three demonstrated applications of baghouses on relatively small wood fired boilers in New England. These installations are not experiencing filter bag clogging problem because the vendors developed a design to avoid this problem. However, there was one fire which occurred in one of the systems which required the bags to be replaced. A multicyclone was installed after the fire. No fires have been reported since that time. These systems are described below:

[1] Compilation of Emission Factors, AP 42, Chapter 1.6, US EPA, revised September, 2003

[2] Personal communication with Biomass Energy Resource Center. September, 2009.

[3] Compilation of Emission Factors. AP 42 Chapter 1.6. Revised September, 2003

- Mount Wachusett College, Gardiner, MA - 10 MMBtu/hour wood chip boiler.
- Crochet Mountain Rehabilitation Center, Greenfield, NH – 5.7 and 11.4 MMBtu/hour wood chip boilers.
- Middlebury College, Middlebury, VT – 29 MMBtu/hour wood chip boiler.

These applications indicate baghouses are technically feasible, provided they are designed to avoid fire and filter clogging.

Baghouses have the highest operating cost of all add on controls discussed in this report. This is largely due to the cost of replacement bags and to the amount of time required to keep baghouses in proper working order. At this time, it is not known exactly how frequently bags need to be replaced on small wood boilers. The rule of thumb is to replace a given bag every three years, which means replacing one third of all the bags every year. However, this may not be applicable to wood boilers operating only during the heating season. Bag replacement for these boilers could equate to approximately one sixth of the bags every year.

6.0 Summary of European Emission Control Practices

The Biomass Energy Resource Center (BERC) recently completed a research trip to Europe to learn more about their biomass facilities. Here is a synopsis of their findings.

- There are larger economic incentives for bioenergy in Europe as compared to the US. For example, electricity from biomass power plants can be sold to utilities for approximately 30 euro cents/kwh (40 US dollar cents/kWh), which is approximately three times higher than the price the utility will charge to its customer base. This means a subsidy of approximately 20 euro cents/kwh is paid to the utility. For comparison, in Vermont, biomass electricity is sold to utilities for approximately 12.5 cents/kwh and in turn sold by utilities for approximately 13 to 14 cents/kwh.
- Most of the biomass systems in Europe deploy the following energy efficiency measures (unless noted otherwise, the following list of energy efficiency measures are also used in the US):
  - High combustion temperature 1013°C (1855 F);
  - Low excess air (approximately 50 to 75%);
  - Continuous oxygen content monitoring (%O_2) to achieve target content in flue of approximately about 7 to 9%;
  - Setting target CO_2 exhaust content (not used in the US). The target of the CO_2 in the flue gas is 13%. If less than 10%, the secondary air is adjusted. Even for the small wood pellet boilers (residential scale) the O_2 % in the flue gases is monitored continuously and the excess air is modulated based on the % O_2 content;
  - Pre-heating of both the primary and the secondary air using an economizer;
  - A heat recovery system using the hot air from the upper level of the boiler room is used to dry the woodchips;
  - Water preheated using the flue gas, cooling the flue gases from 900°C (1652 °F) to 180°C (356°F)[1] before the ESP; and
  - Variable speed drives on the hot water distribution pumps.
- Emissions control equipment normally used is a multicyclone and ESP in series. ESP's are frequently installed outside of buildings.

[1] This temperature is maintained to prevent condensation.

- Some projects have condensers to remove the moisture from the flue gases simultaneously recovering some additional thermal energy.
- The average ash content is about 2-5% of the biomass and reflects burning lower quality biomass (in some cases). The ash streams are collected separately and utilized where appropriate. The ash from the multi-cyclone and the combustion chamber of the boiler may be used as fertilizer in farm operations. The ash from ESP (fine ash) is land filled, as it may contain heavy metals.
- The capital cost of a typical ESP for a new power plant of 5 to 10 MW capacity range was typically about 12-14% of the cost of the project. This percent may be more for smaller capacity plants producing only heat.
- The quality of woodchips is not considered to be very critical. This is likely attributable to the widespread use of ESPs.

7.0 Capital Costs of Emission Controls for Particulate Matter

Capital and operating costs were estimated with quotes from and personal communication with equipment vendors as well as the equations and methods presented in the "EPA Cost Control Manual."[1] Information used to generate costs is detailed in the appendix. In addition to the size of the biomass combustor, there are a number of other factors which cause variability in the capital costs. Here is a selected list of factors affecting price variability:

- **Change in the price of steel.** This change had a significant affect on the price of the Core Separator™ and other mechanical collectors.
- **Foreign exchange rates.** For equipment purchased overseas, specifically Europe, the cost is significantly affected by the exchange rate, which now increases price for US installations. The two high efficiency multicyclones featured in this report were purchased from a European vendor.
- **Pollution control device design.** Capital costs are also affected by the pollution control equipment design. For example, the price of electrostatic precipitators is sensitive to the size of the particle collection plates. Collection efficiency is related to collection plate size; therefore, projects requiring relatively high collection efficiency will result in larger collection plates and a more expenive electrostatic precipitator.
- **Fuel characteristics.** As mentioned systems having variable firing rates burning wet fuels are susceptible to filter clogging if a baghouse is installed. As a result, baghouses are now typically designed with additional components which mitigate the problem, but significantly increase price.
- **Space requirements.** The amount of horizontal and vertical space required for a given control can affect the installation cost. For examples, baghouses can require more space than electrostatic precipitators. The additional space required can increase the footprint and/or height of the building housing the equipment, thereby increasing construction costs.
- **Ancillary equipment.** For example, baghouses require more ancillary equipment, such as insulated ductwork and a mechanical collector (to reduce fire risk), than an ESP.

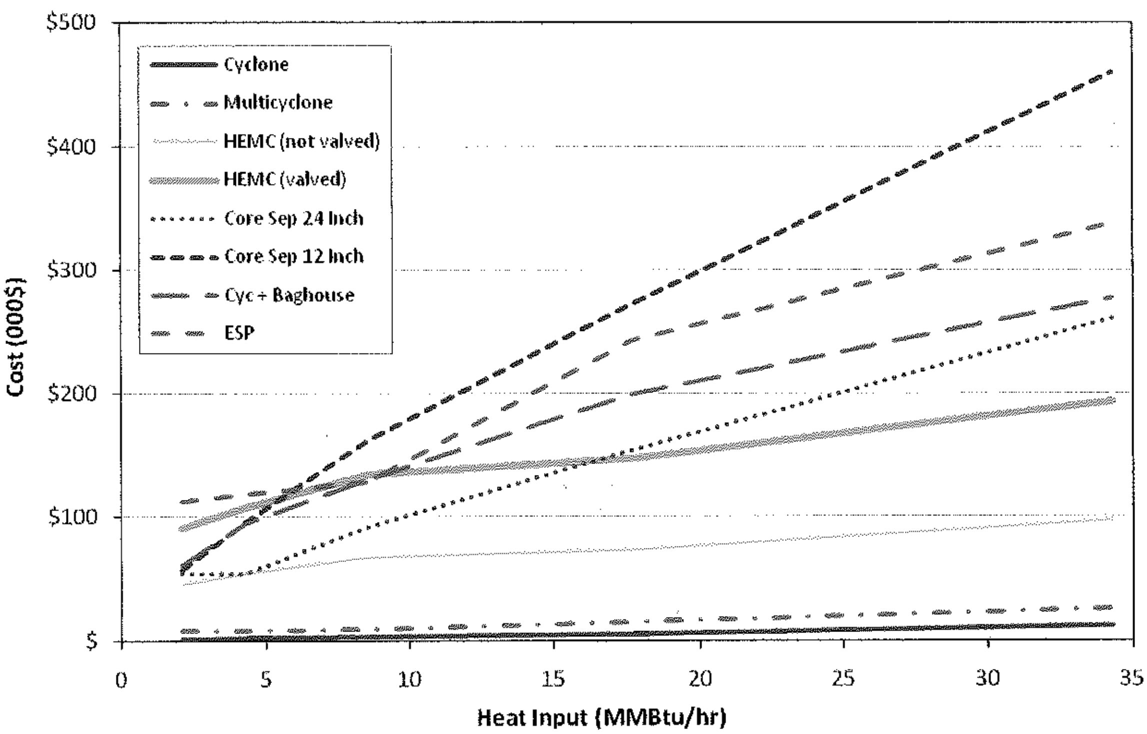
[1] EPA Cost Control Manual, Sixth Edition. U.S EPA report #EPA/452/B-02-001. January, 2002. Available at: http://www.epa.gov/ttn/catc/dir1/c_allchs.pdf.

- **Shipping costs.** The proximity of the location to major transportation hubs as well as the equipment production location can affect costs.
- **Duplicated equipment & services.** In some cases, the wood boiler vendor and emission control vendor may inadvertently include a number of similar equipment items and services in their quotes. This can significantly increase costs if overlapping equipment items are not identified and re-allocated.[1]

  Examples of duplicated equipment and services could include the support stand, draft fan, sensors, dampers, control panel with plc, vfd for draft fan, inlet and outlet expansion/isolation joints, rotary air lock, duct work, engineering services, assembling and commissioning.

Estimated capital costs for add-on particulate matter controls are shown below for a single cyclone, multicyclone, high efficiency multicyclone (not valved), high efficiency multicyclone (valved),[2] Core Separator™ (with 24 inch diameter separators), Core Separator™ (with 12 inch diameter separators), cyclone coupled with baghouse[3], and an electrostatic precipitator. Approximate costs are shown for systems from approximately 2 MMBtu/hour to 34 MMBtu/hour heat input in Figure 1. These costs are subject to the variability caused by the bulleted items discussed above. They are also a best estimate of installed cost.

Figure 1: Particulate Matter Add-On Emission Control Costs



[1] Duplicated costs were identified for a project RSG participated in which included an HEMC, and where it was determined that the price of the HEMC could be substantially reduced because the wood boiler vendor had already specified the equipment and services in its quote.

[2] As previously mentioned, the term "valved" refers to the use of valves to maintain pressure drop over a range of firing rates.

[3] Baghouse costs reflect baghouses with multiple cells to prevent filter clogging.

All capital costs shown above except those for "cyclone + baghouse" were derived exclusively with vendor quotes. This category was calculated by inputting the cost of the bags into an equation listed in Table 1.9 of the EPA Cost Control Manual, which calculated remaining costs based on the price of the bags. They are intended to represent all costs leading up to and including installation.

8.0 COST EFFECTIVENESS OF PARTICULATE MATTER EMISSION CONTROLS

Cost effectiveness was estimated for the same particulate matter add-on controls. For the purposes of this report, the term "cost effectiveness" refers to the dollars spent to remove one ton of a given pollutant in a given year and are a function of the capital and operating costs. Costs were estimated using the methodology in the EPA Air Pollution Cost Control Manual and with price quotes and personal communication with equipment vendors and other technology experts.[1] Cost effectiveness is linearly related to the:

1) Design heat input of the system,
2) Annual fuel consumption rate (annual capacity factor),
3) Pollutant inlet loading of the pollution control device and
4) Size of particle being controlled (PM10 and PM2.5).

This means the cost effectiveness values listed later in this section can be scaled upward or downward, given the linear relationship of the aforementioned factors with cost effectiveness,

Cost effectiveness was estimated for PM10 and PM2.5. Table 11 summarizes the assumed parameter values used to model cost effectiveness. The values used are intended to help portray a small institutional wood boiler operating approximately half the year to provide heat and hot water. The inlet loading values were taken from AP 42 and correspond to the "wet wood" category. These values were deemed as being generally representative for a stoker combustion system. Actual numbers may be lower for "stokers" and are likely lower for close coupled gasifiers.

Table 11: Assumed Parameter Values for Cost Effectiveness Analysis

Wood boiler design heat input	5.0 MMBtu/hour
PM10 Inlet loading	0.31 lb/MMBtu
PM2.5 inlet loading	0.25 lb/MMBtu
Operating hours per year	4380 (half the year)
Average daily operating capacity	50%
Annual capacity factor	25%
Fuel heat content at 40% MC	5,013 btu/lb
Annual fuel consumption	1,095 tons/year
Annual uncontrolled PM10 emissions (tons/yr)	2.7
Annual uncontrolled PM2.5 emissions (tons/yr)	2.4

Table 12 and Table 13 show estimated cost effectiveness PM10 and PM2.5 removal respectively, from the system summarized in Table 11. A best estimate has been made to assign control efficiencies, capital costs and operating costs. Control efficiencies were estimated with the emission test information reviewed for this report, AP 42 uncontrolled and controlled emission factors, the RSG 2001 BACT report,

[1] EPA Air Pollution Control Cost Manual, Sixth Edition. EPA/452/B-02-001. United States Environmental Protection Agency, Office of Air Quality Planning and Standards. Research Triangle Park, North Carolina. January, 2002

personal communication with equipment vendors, and a draft report written by the Northeast States for Coordinated Air Use Management (NESCAUM).[1] Assumed control efficiency values reflect optimal operating conditions are occurring for both the combustor and the control equipment. It should be noted that both HEMCs listed and only the 12" Core Separator control efficiencies are based on vendor calculations, not actual performance. Furthermore, as evidenced by the stack test in Rhode Island, actual control efficiency will be lower for "un-valved" HEMC's whose wood boiler is operating below full load.

As mentioned, there are many factors which cause variability in capital and operating costs. In addition, cost effectiveness (especially in mechanical collectors) is also affected by particle size distribution.[2] Therefore, actual costs could vary considerably from what is quoted below.

Table 12: Cost Effectiveness for Controlling PM10 Emissions[3]

Pollution Control Device	Control Efficiency	PM10 Emissions Removed (tons/year)	Installed Capital Cost of Equipment	Annual Operating Costs	Total Annual Costs	Total Cost per Ton Removed
Cyclone	50%	0.9	$2,243	$580	$791	$930
Multicyclone	75%	1.3	$9,424	$580	$1,469	$1,151
HE Multicyclone	99%	1.3	$62,878	$800	$6,980	$4,159
HE Multicyclone (valved)	99%	1.7	$125,756	$800	$12,915	$7,695
Core Separator (12")	94%	1.7	$111,709	$1,239	$12,350	$7,685
Core Separator (24")	72%	1.2	$63,337	$1,459	$8,004	$6,519
Cyclone + Baghouse	99%	1.7	$109,878	$3,920	$14,291	$8,483
ESP	95%	1.6	$138,005	$1,867	$14,894	$9,213

Table 13: Cost Effectiveness for Controlling PM2.5 Emissions[4]

Pollution Control Device	Control Efficiency	PM2.5 Emissions Removed (tons/year)	Installed Capital Cost of Equipment	Annual Operating Costs	Total Annual Costs	Total Cost per Ton Removed
Cyclone	5%	0.9	$ 2,243	$580	$791	$11,534
Multicyclone	10%	1.3	$9,424	$580	$1,469	$10,707
HE Multicyclone	86%	1.2	$65,478	$800	$6,980	$5,884
HE Multicyclone (valved)	86%	1.2	$128,356	$800	$12,915	$10,887
Core Separator (12")	56%	0.8	$117,709	$1,239	$12,350	$16,105
Core Separator (24")	29%	0.4	$69,337	$1,459	$8,004	$19,939
Cyclone + Baghouse	99%	1.7	$109,878	$3,920	$14,291	$10,519
ESP	90%	1.6	$138,005	$1,867	$14,894	$12,059

The total cost per ton of pollutant removed is calculated by dividing the total annual costs by the total amount of pollutant removed. Pollutant removal costs of PM2.5 with cyclones and multicyclones are significantly higher than for PM10 because the values for the tons of PM2.5 removed are less than one. This significant increase in pollutant removal cost demonstrates the relative ineffectiveness of conventional cyclones and multicyclones.

[1] "Controlling Emissions from Wood Boilers." Northeast States for Coordinated Air Use Management (NESCAUM). October, 2008. Available at: http://www.nescaum.org/topics/commercial-wood-boilers.

[2] The particle size distribution corresponds to the collective percentages of each particle size.

[3] The quantity of emissions controlled is a function of the particle size distribution. The values in this table assume 100% of the inlet emissions are evenly distributed from 2.5 microns up to 10 microns.

[4] The quantity of emissions controlled is a function of the particle size distribution. The values in this table assume 100% of the inlet emissions are evenly distributed from 1 to 2.5 microns.

9.0 Overview of Emission Controls for Other Relevant Pollutants

9.1 Nitrogen Oxides (NOx)

There are two major sources of NOx emissions. The first, "fuel NOx" is NOx produced by the oxidation of fuel bound nitrogen during combustion. The second, "thermal NOx" is NOx produced by the oxidation of nitrogen in the combustion air. The latter is produced at temperatures typically much higher than those occurring during biomass combustion. Therefore, the total NOx is most influenced by the fuel nitrogen content.

Combustion controls are the only way NOx emissions are controlled apart from add-on controls such as selective catalytic reduction (SCR) or selective noncatalytic reduction (SNCR).

Increasing excess air can help control thermal NOx emissions by reducing flame temperature. Oxygen concentration is an indicator of the amount of excess air; therefore, monitoring oxygen concentration and linking oxygen measurements with automated controls establish the appropriate quantity of excess air on a continual basis and prevent excess thermal NOx emissions.

Staged combustion is another means for controlling thermal NOx emissions.

9.2 Sulfur Dioxide (SO_2)

SO_2 emissions from wood combustion are negligible given very low sulfur content in biomass.

9.3 Carbon Monoxide (CO)

Carbon monoxide emissions are minimized by good combustion conditions, specifically, maintaining the proper air to fuel ratio. Plume opacity observation, proper operation and maintenance, periodic combustion efficiency testing, and in-situ oxygen concentration monitoring are ways to ensure ongoing good combustion conditions. A combustion chamber designed with staged combustion increases the degree of combustion completeness and is therefore useful for minimizing CO emissions.

9.4 Volatile Organic Compounds (VOCs)

The same measures for minimizing CO emissions will minimize VOC emissions.

9.5 Hazardous Air Pollutants (HAPs)

Hazardous air pollutants include both gaseous and particulate based pollutants. The aforementioned controls for CO and are also effective at controlling HAPs, but most effective at controlling gaseous HAPs. Particulate HAPs are also controlled with an add-on control device.

10.0 Conclusions

The following conclusions were drawn from the study completed for this report:

1. New stack test emission information is providing additional insights into how fuel characteristics and add-on controls affect particulate emission levels.
2. Limited information is available for pellet combustion emissions, high efficiency multicyclone (HEMC) control efficiency, fabric filter, and electrostatic precipitator (ESPs) control efficiency for small wood boilers.
3. While the quantity of emissions information for wood boilers approximately 10 MMBtu/hour and smaller is growing to a level on which generally meaningful interpretations can be made, this quantity of information is not available to make meaningful interpretations for wood boilers smaller than 5.0 MMBtu/hour.
4. There are many Best Management Practices (BMPs), also called work practice standards, which can be implemented to characterize, enhance and preserve fuel quality. Implementing these measures improves fuel handling and combustion conditions, increases energy efficiency and reduces emissions.
5. The increased combustion completeness resulting from BMPs not only helps reduce particulate matter emissions, but also helps reduce emissions of gaseous pollutants, including carbon monoxide, nitrogen oxides, volatile organic compounds (VOCs) and hazardous air pollutants (HAPs).
6. BMPs help prevent upset combustion conditions which will reduce nuisance episodes accompanied by excessive plume opacity.
7. Particle size has a large affect on collection efficiency in <u>conventional</u> mechanical collectors (mechanical collectors with a relatively low pressure drop). Substantially smaller quantities of fine particles (PM2.5) than coarse particles (PM10) can be collected in conventional mechanical collectors.
8. Pressure drop has a large affect on mechanical collector collection efficiency. Core separators collect substantially larger quantities of fine particles than conventional mechanical collectors, at all firing rates, as they are designed to maintain a high pressure drop at all firing rates.
9. New baghouse designs are safer and technically feasible. These conclusions are demonstrated by three relatively new baghouse installations in the northeast.
10. Potential exists for implementing an HEMC design which maintains a relatively high pressure drop at a range of firing rates using valves.
11. The Core Separator™ was commercially unavailable, but is now commercially available. While not field tested, laboratory tests and engineering calculations indicate the 12" Core Separator has potential to collect more particulate matter than the 24" model.
12. ESPs and baghouses have near comparable capital costs for some system sizes. ESPs have lower operating costs and lower energy demand.
13. Recent experience in Europe indicates greater prevalence of ESPs due to greater financial incentives and stricter emission limits.
14. Baghouses and ESPs are the add-on controls providing the highest degree of control of PM2.5 for all firing rates.
15. For small systems less than 2.0 MMBtu/hr, the annual operating cost of all add-on emission controls except cyclones, multicyclones and "non-valved" high efficiency multicyclones are likely to be substantially higher than for larger systems.

11.0 Recommendations for Future Research

A number of factors affect emission rates, such as geographic location, type of fuel burned, firing rate characteristics, type of combustion technology, and type of add-on emission control. Additional emission tests will improve understanding of how these factors affect emission levels. Future emission tests could be structured for wood chip and wood pellet systems as follows:

1. Inlet-outlet testing for particulate emissions (PM10, PM2.5) controlled by ESPs, baghouses and HEMCs. Particle size distribution should also be measured at the inlet and outlet, in addition to measuring mass emission rates.
2. HAP emissions in concert with CO and PM2.5. Inlet and outlet testing should be performed for particulate HAPs. PM2.5 should be tested because it is considered a surrogate for particulate HAPs. CO should be tested (outlet testing only) because it is considered a surrogate for gaseous HAPs.
3. Stack testing for any given site should be expanded to include emissions from the following:
    a. Low, medium and high firing rates
    b. At least two fuels, such as, wood with bark (bole chips or whole tree chips) and wood without bark (mill chips).

Attention should also be given to the following:

1. Development of a voluntary universal boiler operator training program for obtaining boiler operator certification.
2. Further development of fuel quality specifications to further establish grades of wood fuels.

12.0 Summary

A number of emission controls for small wood-fired boilers have been evaluated. This study evaluated a number of Best Management Practices (BMPs – also called work practice standards) and add-on controls. While these controls are focused on particulate matter control, their implementation will control emissions of all types of pollutants, including carbon monoxide, sulfur dioxide, nitrogen oxides, volatile organic compounds and hazardous air pollutants. Maximizing fuel quality, optimizing combustion conditions and selecting a well designed add-on pollution control are the three main categories for controlling emissions. Control efficiency and cost effectiveness vary by boiler size, particle size distribution and type of add-on pollution control.

APPENDIX A

STACK TEST REPORTS

APPENDIX B

EMISSION CALCULATIONS

Hazardous Air Pollutant Synopsis

Pollutant Category	System Information / Pollutant	Ponaganset MS Result (lb/MMBtu)	Ponaganset HS Result (lb/MMBtu)	Council Result (lb/MMBtu)	Green Acres Result (lb/MMBtu)	Hazen Union Result (lb/MMBtu)	Overall Average Result (lb/MMBtu)	AP 42 Emission Factor (lb/MMBtu)	% of AP 42	Ponaganset % of Others
	Design Heat Input	9.1	4.6	1.9	2.2	2.8				
	Combustion type	CCG	CCG	SA	SA	CCG				
	Emission control	HEMC	HEMC	Uncontrolled	Uncontrolled	Multicyclone				
Metals	Arsenic	1.54E-06	8.40E-07	4.54E-06	2.66E-06	5.71E-07	2.03E-06	2.20E-05	9%	46%
	Cadmium			2.15E-05	1.78E-05	3.93E-06	1.44E-05	4.10E-06	352%	
	Chromium			2.34E-05	2.64E-05	6.51E-06	1.88E-05	2.10E-05	89%	
	Chromium VI	4.83E-06	1.31E-06		1.31E-06	8.37E-07	2.07E-06	3.50E-06	59%	286%
	Nickel	9.87E-06	3.29E-06	2.20E-05	2.11E-05	3.57E-06	1.20E-05	3.30E-05	36%	42%
	Manganese	9.58E-05	8.66E-05				9.12E-05	1.60E-03	6%	
	Phosporus	1.00E-04	1.29E-04				1.15E-04	2.70E-05	425%	
Organics	Formaldehyde	9.30E-04	4.77E-04	9.50E-04	1.05E-02	1.38E-03	2.84E-03	4.40E-03	65%	16%
	Benzene	1.50E-04	4.11E-06		4.49E-05	5.80E-05	6.43E-05	4.20E-03	2%	150%
PAHs	Acenapthene	4.27E-08	5.05E-08	0.00E+00	7.53E-07	4.65E-07	2.62245E-07	9.10E-07	29%	11%
	Acenapthylene	4.80E-06	4.81E-06	0.00E+00	3.33E-05	2.04E-04	4.93813E-05	5.00E-06	988%	6%
	Anthracene	1.82E-06	1.41E-06	0.00E+00	2.44E-06	1.42E-05	3.97491E-06	3.00E-06	132%	29%
	Benz(a)anthracene	2.38E-05	2.84E-05	0.00E+00	1.54E-06	1.63E-05	1.40124E-05	6.50E-08	21,558%	439%
	Benzo(b)fluoranthene	2.18E-05	1.83E-05	0.00E+00	3.66E-06	2.51E-05	1.37725E-05	1.00E-07	13,772%	209%
	Benzo(ghi)perylene	2.82E-06	2.57E-06	2.52E-07	1.93E-06	1.44E-05	4.39315E-06	9.30E-08	4,724%	49%
	Benzo(e)pyrene	1.50E-05	9.65E-06	0.00E+00	2.38E-06	1.57E-05	8.5388E-06	2.60E-09	328,416%	204%
	Benzo(a)pyrene	4.56E-06	5.50E-06	0.00E+00	9.91E-07	1.34E-05	4.88928E-06	2.60E-06	188%	105%
	Chrysene	4.91E-05	4.46E-05	0.00E+00	3.15E-06	2.43E-05	2.42272E-05	3.80E-08	63,756%	512%
	Dibenz(a,h)anthracene	3.73E-07	4.15E-07	0.00E+00	1.33E-07	6.97E-06	1.57829E-06	9.10E-09	17,344%	17%
	Fluoranthene	2.82E-05	9.15E-05	1.31E-06	1.08E-05	9.51E-05	4.53915E-05	1.60E-06	2,837%	168%
	Fluorene	1.17E-07	1.39E-07	1.43E-06	6.22E-07	2.90E-06	1.04166E-06	3.40E-06	31%	8%
	Ideno(1,2,3-cd)pyrene	2.22E-06	1.98E-06	0.00E+00	1.28E-06	2.77E-06	1.65057E-06	8.70E-08	1,897%	156%
	2-methylnapthalene	1.02E-06	9.51E-07	0.00E+00	1.32E-05	1.32E-05	5.67378E-06	1.60E-07	3,546%	11%
	Napthalene	2.85E-05	2.57E-05	6.55E-06	1.26E-04	7.47E-05	5.2285E-05	9.70E-05	54%	39%
	Phenanthrene	2.46E-05	2.05E-05	3.17E-06	2.67E-05	2.64E-04	6.77896E-05	7.00E-06	968%	23%
	Pyrene	3.05E-05	3.22E-05	4.69E-06	9.38E-06	8.12E-05	3.15871E-05	3.70E-06	854%	99%
AP 42 Comparison	Ponaganset Total HAPs	1.53E-03	9.91E-04					1.04E-02		
	Ponaganset % of AP 42	15%	10%							
	Council Total HAPs			1.04E-03				4.60E-03		
	Council % of AP 42			23%						
	Green Acres Total HAPs				1.08E-02			8.81E-03		
	Green Acres % of AP 42				123%					
	Hazen Total HAPs					2.32E-03		8.81E-03		
	Hazen % of AP 42					26%				
	Green Acres & Hazen Total HAPs						3.29E-03	8.81E-03		
	Green Acres & Hazen % of AP 42						37%			

Hazardous Air Pollutant Synopsis

Pollutant Category	System Information / Pollutant	Ponaganset MS Result (lb/MMBtu)	Ponaganset HS Result (lb/MMBtu)	Council Result (lb/MMBtu)	Green Acres Result (lb/MMBtu)	Hazen Union Result (lb/MMBtu)	Overall Average Result (lb/MMBtu)	AP 42 Emission Factor (lb/MMBtu)	% of AP 42	Ponaganset % of Others
	Design Heat Input	9.1	4.6	1.9	2.2	2.8				
	Combustion type	CCG	CCG	SA	SA	CCG				
	Emission control	HEMC	HEMC	Uncontrolled	Uncontrolled	Multicyclone				
Metals	Arsenic	1.54E-06	8.40E-07	4.54E-06	2.66E-06	5.71E-07	2.03E-06	2.20E-05	9%	46%
	Cadmium			2.15E-05	1.78E-05	3.93E-06	1.44E-05	4.10E-06	352%	
	Chromium			2.34E-05	2.64E-05	6.51E-06	1.88E-05	2.10E-05	89%	
	Chromium VI	4.83E-06	1.31E-06		1.31E-06	8.37E-07	2.07E-06	3.50E-06	59%	286%
	Nickel	9.87E-06	3.29E-06	2.20E-05	2.11E-05	3.57E-06	1.20E-05	3.30E-05	36%	42%
	Manganese	9.58E-05	8.66E-05				9.12E-05	1.60E-03	6%	
	Phosporus	1.00E-04	1.29E-04				1.15E-04	2.70E-05	425%	
Organics	Formaldehyde	9.30E-04	4.77E-04	9.50E-04	1.05E-02	1.38E-03	2.84E-03	4.40E-03	65%	16%
	Benzene	1.50E-04	4.11E-06		4.49E-05	5.80E-05	6.43E-05	4.20E-03	2%	150%
PAHs	Acenapthene	4.27E-08	5.05E-08	0.00E+00	7.53E-07	4.65E-07	2.62245E-07	9.10E-07	29%	11%
	Acenapthylene	4.80E-06	4.81E-06	0.00E+00	3.33E-05	2.04E-04	4.93813E-05	5.00E-06	988%	6%
	Anthracene	1.82E-06	1.41E-06	0.00E+00	2.44E-06	1.42E-05	3.97491E-06	3.00E-06	132%	29%
	Benz(a)anthracene	2.38E-05	2.84E-05	0.00E+00	1.54E-06	1.63E-05	1.40124E-05	6.50E-08	21,558%	439%
	Benzo(b)fluoranthene	2.18E-05	1.83E-05	0.00E+00	3.66E-06	2.51E-05	1.37725E-05	1.00E-07	13,772%	209%
	Benzo(ghi)perylene	2.82E-06	2.57E-06	2.52E-07	1.93E-06	1.44E-05	4.39315E-06	9.30E-08	4,724%	49%
	Benzo(e)pyrene	1.50E-05	9.65E-06	0.00E+00	2.38E-06	1.57E-05	8.5388E-06	2.60E-09	328,416%	204%
	Benzo(a)pyrene	4.56E-06	5.50E-06	0.00E+00	9.91E-07	1.34E-05	4.88928E-06	2.60E-06	188%	105%
	Chrysene	4.91E-05	4.46E-05	0.00E+00	3.15E-06	2.43E-05	2.42272E-05	3.80E-08	63,756%	512%
	Dibenz(a,h)anthracene	3.73E-07	4.15E-07	0.00E+00	1.33E-07	6.97E-06	1.57829E-06	9.10E-09	17,344%	17%
	Fluoranthene	2.82E-05	9.15E-05	1.31E-06	1.08E-05	9.51E-05	4.53915E-05	1.60E-06	2,837%	168%
	Fluorene	1.17E-07	1.39E-07	1.43E-06	6.22E-07	2.90E-06	1.04166E-06	3.40E-06	31%	8%
	Ideno(1,2,3-cd)pyrene	2.22E-06	1.98E-06	0.00E+00	1.28E-06	2.77E-06	1.65057E-06	8.70E-08	1,897%	156%
	2-methylnapthalene	1.02E-06	9.51E-07	0.00E+00	1.32E-05	1.32E-05	5.67378E-06	1.60E-07	3,546%	11%
	Napthalene	2.85E-05	2.57E-05	6.55E-06	1.26E-04	7.47E-05	5.2285E-05	9.70E-05	54%	39%
	Phenanthrene	2.46E-05	2.05E-05	3.17E-06	2.67E-05	2.64E-04	6.77896E-05	7.00E-06	968%	23%
	Pyrene	3.05E-05	3.22E-05	4.69E-06	9.38E-06	8.12E-05	3.15871E-05	3.70E-06	854%	99%
AP 42 Comparison	Ponaganset Total HAPs	1.53E-03	9.91E-04					1.04E-02		
	Ponaganset % of AP 42	15%	10%							
	Council Total HAPs			1.04E-03				4.60E-03		
	Council % of AP 42			23%						
	Green Acres Total HAPs				1.08E-02			8.81E-03		
	Green Acres % of AP 42				123%					
	Hazen Total HAPs					2.32E-03		8.81E-03		
	Hazen % of AP 42					26%				
	Green Acres & Hazen Total HAPs						3.29E-03	8.81E-03		
	Green Acres & Hazen % of AP 42						37%			

APPENDIX C

OPERATING COST CALCULATIONS

PM10 Operating Cost Calculation Values & References

GENERAL INPUTS

Category	Value	Notes
Interest rate (%)	0.07	Default value from EPA Cost Control Manual
Economic life (years)	20	Default value from EPA Cost Control Manual
Capital Recovery Factor (CRF)	9%	Equation 2.8a from EPA Cost Control Manual

CYCLONE / MULTICYCLONE OPERATING COSTS

Category	Value	Notes
total ash disposal cost	$0.00	all ash land applied for soil enhancement
electricity price ($/kwh)	0.1	av'g commercial elec. cost in 2009 (http://www.eia.doe.gov/cneaf/electricity/epm/table5_3.html
waste gas flow rate (acfm)	2562	from review of recent stack test reports in Vermont
static pressure drop (in wc)	2	based on project experience
combined fan-motor efficiency	60%	from EPA Cost Control Manual
hours per year	2,190	operating half the year at average operating capacity of 50% loac
incremental electricity cost	$219.76	EPA Cost Control Manual, Equation 1.46.
labor hours per year	12	regular inspections, unexpected maintenance and annual inspection of the interior
labor rate	$30.00	personal communication with wood boiler vendor
labor costs	$360.00	
total annual costs	$579.76	

HIGH EFF MULTICYCLONE

Category	Value	Notes
total ash disposal cost	$0.00	all ash land applied for soil enhancement
electricity price ($/kwh)	0.1	av'g commercial elec. cost in 2009 (http://www.eia.doe.gov/cneaf/electricity/epm/table5_3.html)
waste gas flow rate (acfm)	2,562	from review of recent stack test reports in Vermont
static pressure drop (in wc)	4	from vendor quote
combined fan-motor efficiency	60%	from EPA Cost Control Manual
hours per year	2,190	operating half the year at average operating capacity of 50% loac
incremental electricity cost	$439.52	EPA Cost Control Manual, Equation 1.46.
labor hours per year	12	regular inspections, unexpected maintenance and annual inspection of the interior
labor rate	$30.00	personal communication with wood boiler vendor
labor costs	$360.00	
total annual costs	$799.52	

CORE SEPARATOR (24 INCH)

Category	Value	Notes
total ash disposal cost	$0.00	all ash land applied for soil enhancement
electricity price ($/kwh)	0.1	av'g commercial elec. cost in 2009 (http://www.eia.doe.gov/cneaf/electricity/epm/table5_3.html)
waste gas flow rate (acfm)	2,562	from review of recent stack test reports in Vermont
static pressure drop (in wc)	8	personal communication with vendor
combined fan-motor efficiency	60%	from EPA Cost Control Manual
hours per year	2,190	operating half the year at average operating capacity of 50% loac
incremental electricity cost	$879.03	EPA Cost Control Manual, Equation 1.46.
labor hours per year	12	regular inspections, unexpected maintenance and annual inspection of the interior
labor rate	$30.00	personal communication with wood boiler vendor
labor costs	$360.00	
total annual costs	$1,239.03	

CORE SEPARATOR (12 INCH)

Category	Value	Notes
total ash disposal cost	$0.00	all ash land applied for soil enhancement
electricity price ($/kwh)	0.1	av'g commercial elec. cost in 2009 (http://www.eia.doe.gov/cneaf/electricity/epm/table5_3.html
waste gas flow rate (acfm)	2,562	from review of recent stack test reports in Vermont
static pressure drop (in wc)	10	personal communication with vendor
combined fan-motor efficiency	60%	from EPA Cost Control Manual
hours per year	2,190	operating half the year at average operating capacity of 50% loac
incremental electricity cost	$1,098.79	EPA Cost Control Manual, Equation 1.46.
labor hours per year	12	regular inspections, unexpected maintenance and annual inspection of the interior
labor rate	$30.00	personal communication with wood boiler vendor
labor costs	$360.00	
total annual costs	$1,458.79	

BAGHOUSE OPERATING COSTS

Category	Value	Notes
total ash disposal cost	$0.00	all ash land applied for soil enhancement
total bag cost	$4,250.00	vendor quote for coated bags
% of bags replaced annually	8%	1/12 of bags replaced every year assuming 50% annual capacity factor
bag replacement cost ($/yr)	$350.63	
electricity price ($/kwh)	0.1	av'g commercial elec. cost in 2009 (http://www.eia.doe.gov/cneaf/electricity/epm/table5_3.html
waste gas flow rate (acfm)	2,562	from review of recent stack test reports in Vermont
static pressure drop (in wc)	5	from permit application for new wood boiler in central Massachusetts
combined fan-motor efficiency	60%	from EPA Cost Control Manual
hours per year	2190	operating half the year at average operating capacity of 50% loac
incremental electricity cost	$549.40	EPA Cost Control Manual, Equation 1.46.
labor rate	$30.00	personal communication with wood boiler vendor
labor hours per year	81	1 hr/wk general maint., 80 hours to replace all bags, 8 hours for black light testing at 2x per year
labor costs	$2,440.00	
total annual costs	$3,340.02	

ESP OPERATING COSTS

Category	Value	Notes
total ash disposal cost	$ -	all ash land applied for soil enhancement
pressure drop (in. water)	0.04	page 3-34 in EPA Cost Control Manual
operating time (h/yr)	2,190	operating half the year at average operating capacity of 50% loac
system flow rate (acfm)	2,562	from review of recent stack test reports in Vermont
fan power req. (kWh/yr)	41	EPA Cost Control Manual, equation 3.46
electricity req. (kWh/yr)	2431	personal communication with vendor
electricity price ($/kwh)	0.1	av'g commercial elec. cost in 2009 (http://www.eia.doe.gov/cneaf/electricity/epm/table5_3.html
total electricity demand	569.4	sum of fan and other electricity requirements
total power cost	$ 247.20	
labor hours per year	8	personal communication with vendor. Open, inspect and clean ESP.
labor rate	$ 30.00	personal communication with wood boiler vendor
labor costs	$ 240.00	
maintenance costs	$ 1,021.59	page of EPA Cost Control Manual, equation 3-45
total annual costs	$ 1,508.79	

PM 2.5 Operating Cost Calculation Values & References

GENERAL INPUTS

Category	Value	Notes
Interest rate (%)	0.07	Default value from EPA Cost Control Manual
Economic life (years)	20	Default value from EPA Cost Control Manual
Capital Recovery Factor (CRF)	9%	Equation 2.8a from EPA Cost Control Manual

CYCLONE / MULTICYCLONE OPERATING COSTS

Category	Value	Notes
total ash disposal cost	$0.00	all ash land applied for soil enhancement
electricity price ($/kwh)	0.1	av'g commercial elec. cost in 2009 (http://www.eia.doe.gov/cneaf/electricity/epm/table5_3.html
waste gas flow rate (acfm)	2562	from review of recent stack test reports in Vermont
static pressure drop (in wc)	2	based on project experience
combined fan-motor efficiency	60%	from EPA Cost Control Manual
hours per year	2,190	operating half the year at average operating capacity of 50% loac
incremental electricity cost	$219.76	EPA Cost Control Manual, Equation 1.46.
labor hours per year	12	regular inspections, unexpected maintenance and annual inspection of the interior
labor rate	$30.00	personal communication with wood boiler vendor
labor costs	$360.00	
total annual costs	$579.76	

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Category	Value	Notes
total ash disposal cost	$0.00	all ash land applied for soil enhancement
electricity price ($/kwh)	0.1	av'g commercial elec. cost in 2009 (http://www.eia.doe.gov/cneaf/electricity/epm/table5_3.html)
waste gas flow rate (acfm)	2,562	from review of recent stack test reports in Vermont
static pressure drop (in wc)	4	from vendor quote
combined fan-motor efficiency	60%	from EPA Cost Control Manual
hours per year	2,190	operating half the year at average operating capacity of 50% loac
incremental electricity cost	$439.52	EPA Cost Control Manual, Equation 1.46.
labor hours per year	12	regular inspections, unexpected maintenance and annual inspection of the interior
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labor hours per year	12	regular inspections, unexpected maintenance and annual inspection of the interior
labor rate	$30.00	personal communication with wood boiler vendor
labor costs	$360.00	
total annual costs	$1,239.03	

CORE SEPARATOR (12 INCH)

Category	Value	Notes
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static pressure drop (in wc)	5	from permit application for new wood boiler in central Massachusetts
combined fan-motor efficiency	60%	from EPA Cost Control Manual
hours per year	2190	operating half the year at average operating capacity of 50% loac
incremental electricity cost	$549.40	EPA Cost Control Manual, Equation 1.46.
labor rate	$30.00	personal communication with wood boiler vendor
labor hours per year	81	1 hr/wk general maint., 80 hours to replace all bags, 8 hours for black light testing at 2x per year
labor costs	$2,440.00	
total annual costs	$3,340.02	

ESP OPERATING COSTS

Category	Value	Notes
total ash disposal cost	$ -	all ash land applied for soil enhancement
pressure drop (in. water)	0.04	page 3-34 in EPA Cost Control Manual
operating time (h/yr)	2,190	operating half the year at average operating capacity of 50% loac
system flow rate (acfm)	2,562	from review of recent stack test reports in Vermont
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labor costs	$ 240.00	
maintenance costs	$ 1,021.59	page of EPA Cost Control Manual, equation 3-45
total annual costs	$ 1,508.79	

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RESOURCE
SYSTEMS GROUP
INCORPORATED

AN EVALUATION OF AIR POLLUTION CONTROL TECHNOLOGIES FOR SMALL WOOD-FIRED BOILERS

Prepared for:

Vermont Department of Public Service

Vermont Department of Environmental Conservation, Air Pollution Control Division

New Hampshire Governor's Office of Energy Resources and Community Services

Massachusetts Division of Energy Resources

July 2001

331 Olcott Drive, White River Junction, Vermont 05001

TABLE OF CONTENTS

EXECUTIVE SUMMARY

Resource Systems Group, Inc, has undertaken An Evaluation of Air Pollution Control Technologies for Small Wood-Fired Boilers. This is focused on boilers in the size range of approximately 3 to 10 MM Btu/ hour heat output although reference is made to boilers slightly smaller and considerably larger in obtaining data for the analysis. The analysis is generic in that it is applicable to any manufacturer or type of wood-fired boiler in this size range for any location. Attention has been given to boilers in this size range manufactured by the companies that are active in marketing boilers in the northeastern states.

The conclusions of the study are that small wood-fired boilers using staged combustion or gasifier designs are able to achieve lower emission rates for particulate matter when compared to many larger wood-fired boilers and small units with older designs. However, the analysis has demonstrated that lower PM10 emissions can be achieved with appropriate add on control systems at reasonable cost. The best available control for PM10 is an LSR Core Separator with an emission rate of less than 0.1 lb/MM Btu. This technology will also bring about some reduction in particulate toxic emissions.

A review of control technologies for other criteria pollutants concluded that there was no economically practical control technology available that could bring about a reduction of emissions from wood-fired boilers in this size category especially when these boilers would be primarily used for space heating in institution or commercial situations.

A comparison of boiler emissions fired by wood, distillate oil, natural gas and propane shows that wood has lower sulfur dioxide and net greenhouse gas emissions than distillate oil. Nitrogen oxide emission rates from wood are close to the emission rates from distillate oil. Particulate matter, carbon monoxide and total organic compound emissions are higher than oil.

INTRODUCTION

Resource Systems Group, Inc. under contract to the Vermont Department of Public Service, the Vermont Department of Environmental Conservation, Air Pollution Control Division, the Massachusetts Division of Energy Resources and the New Hampshire Governor's Office of Energy Resources and Community Services, has undertaken "An Evaluation of Air Pollution Control Technologies for Small Wood-Fired Boilers." The study is intended for research and informational purposes by state agencies in Vermont, Massachusetts, New Hampshire and elsewhere and by energy planners and others with an interest in biomass energy systems. The conclusions and the opinions are those of the principal author Dr. Colin J. High and do not necessarily reflect the opinion of the sponsoring agencies. Although the study has been guided by the methods used in the EPA Best Available Control Technology (BACT) analysis process, it is not intended to define BACT for regulatory purposes or to imply that any of the sponsoring states intends to establish a BACT requirement for wood-fired boilers of this class. Reference to manufacturers names and the performance characteristics of specific equipment is for informational purposes. Neither the author nor the sponsoring agencies endorse these products or performance claims.

This study is focused on boilers in the size range of approximately 3 to 10 MM Btu/hour heat output, although reference is made to boilers slightly smaller and considerably larger in obtaining data for the analysis. The analysis is generic in that it is applicable to any manufacturer or type of wood-fired boiler in this size range for any location. Attention has been given to boilers in this size range manufactured by companies that are active in marketing boilers in the northeastern states. The analysis is also guided by the regulatory requirements in the states of Massachusetts, New Hampshire and Vermont. The results are however, relevant beyond these specific terms of reference.

Formal BACT analysis for wood-fired boilers in this size range is somewhat uncharted territory because typically, smaller wood-fired boilers have not needed to demonstrate BACT, and they rarely use state-of-the-art control technologies. In consequence, the control engineering and costs for this size range are not well demonstrated. Therefore in some cases it has been necessary to use technology and cost information for somewhat larger systems and then use general engineering principles to scale the appropriate control systems to this size of boiler.

The second component of this study is to make a comparison between wood-fired systems and comparably sized systems burning fuel oil, natural gas or propane in terms of emissions and control technology for relevant pollutants. This comparison will provide the basis for making overall comparisons that may provide input to public policy decisions. It should be recognized that the second part of the analysis is inherently more difficult because it involves comparisons among pollutants that the existing regulatory frameworks do not consider.

METHOD AND SCOPE OF THE STUDY

APPROACH

The approach to the first part of this study has been to conduct the type of investigation that would normally be made in a control technology analysis. This involves collection of data from manufacturers, independent research sources, the EPA and state agencies on existing emission rates from actual equipment in the field and on the control technologies available commercially. The RACT/BACT/LAER Clearinghouse (RBLC) database was also searched for wood combustion systems in all sizes. This investigation covered US and Canadian sources of information in detail and in addition reviewed, as far as possible, information from European sources. North American importers of European and Japanese combustion systems and control technologies were also contacted.

The results of this research are described in the analysis and summary tables that follow. In general European biomass combustion technologies and control systems are the same as those available in North America. Some of the wood combustion systems currently available in North America are based on European designs. Reported particulate emission rates for biomass-fired boilers in Denmark, where there is a well-developed biomass energy industry, are similar to comparable systems available in the North America. In the application of SCR systems to NOx control, at least one European manufacturer has more experience with installations on smaller oil-fired boilers and internal combustion engines but none of this experience extends to wood fired combustion. None of the recommendations requires the import of technology or would be affected by technology exclusively in use in Europe.

SELECTION OF THE BEST AVAILABLE CONTROL TECHNOLOGY

Best available control technology (BACT)[1] may simply be defined as the highest performing control technology for a specific pollutant that is available commercially for a general class and size of emission source. This is usually defined as resulting in the lowest emission rate although differences in available fuel specifications may complicate the issue. In making the determination other environmental, health, safety and energy consumption factors should be considered. The operation of a specific control technology applied to a comparable source anywhere in the US is usually considered to provide evidence that the technology is BACT. In principle the search for BACT should be worldwide, although local conditions make comparability complicated and in practice a control technology usually needs a US based customer support system to make it truly available.

Costs are also a consideration in defining BACT for a specific application. Total cost per unit of pollutant removed decline with increasing size of the facility and therefore a technology may be BACT for a large plant but not for a smaller one. Typically wood-fired boilers in the size range 3 – 10 MM Btu/hour have not been subject to a regulatory BACT review for criteria pollutants in recognition of the comparatively

[1] Unless stated otherwise BACT is used throughout the report without regulatory implications.

high cost of most of the control technologies in this size range. Wood-fired boilers in this size range have been subject to hazardous air emissions controls in Vermont[1] and therefore some have been subject to comparable technology review. In the federal BACT process and in Vermont's Hazardous Most Stringent Emission Rate (HMSER) process, costs are taken into consideration.

An informal statement of the practice is that if the absolute costs are so high that they make the enterprise uncompetitive and therefore not viable and the costs per unit of pollutant removed are above the range that is typically paid by other enterprises, then a case can be made that the technology is not a realistically available option. Because the federal BACT decision process for criteria pollutants does not extend to wood-fired boilers of this size there are not specific precedents. In order to form opinions on what may be BACT, this study has been guided by the EPA process but the results should not be treated as recommendations for regulation.

The EPA BACT process[2] follows a top-down procedure. It begins with the most effective control technology available that will result in the lowest emission rate and then reviewing that technology to determine if their are technical, safety, health or other environmental factors which would make it impractical or undesirable. If the technology is not rejected because of any of these factors then a cost analysis is conducted to determine the absolute costs and per unit costs of implementation. The cost analysis follows the guidelines established by EPA. If it is relevant, the analysis may include special costs associated with retrofitting the technology in an existing plant. The cost analysis is then reviewed to determine if the technology is economically feasible in the specific case.

If the first technology choice is rejected for technical, environmental, safety or costs reasons, then the analysis proceeds to the second best performing technology and so on until a feasible technology is accepted or all available options are exhausted. This process may include not only add-on technology but combustion process modifications and changes in fuel specifications. However, specifying a different fuel changes, such as gas to replace wood, is not considered here as part of the BACT analysis. The second part of the report makes comparisons between fuels to provide a comparative background in which to consider wood fuels.

In this study it is assumed that the boilers are new, not retrofitted and that there are no site-specific factors that increase or reduce costs. In addition it is assumed that the potential application for wood-fired boilers in this size range will include institutional and commercial, as well as small industrial uses.

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[1] Vermont Air Pollution Control Regulations, Section 5-261.

[2] EPA, New Source Review Workshop Manual, Draft October 1990 and 40 CFR 52.21 (j).

Therefore, environmental and safety issues associated with those applications need to be considered in a generic BACT analysis.

EMISSIONS FROM SMALL WOOD –FIRED BOILERS: AN OVERVIEW

Compared with distillate fuel oil, natural gas or propane, wood is a very variable fuel with respect to heat content, moisture content, density and combustion characteristics. In consequence emissions rates tend to be quite variable depending not only on the fuel but also on the conditions of combustion and the load of the boiler. Table 1: provides a range of emission factors for wood-fired boilers. The table includes boilers that span the size range of units as well as some larger and smaller units. Emission rates in this and other tables are standardized to lb/MM Btu for comparison. This removes the factor of moisture content and the differences between softwood and hardwood that affect emission rates reported on a volume or weight basis. These emission rates are for clean natural wood in the form of chips, hogged fuel or saw dust. Fuel that includes large quantities of bark will have different and generally less predictable emission rates[1]. Fuel containing demolition material, painted or treated wood may have higher particulate and toxic air emissions.

Table 1: Emission Rates for Small Wood-Fired Boilers[2]

Manufacturer	Chiptec	Messersmith	BCS	KMW	AP 42	AP 42
Model	85-90T	na	na	1800KW	na	na
Heat Input MMBtu	2.2	2.8	various	6	na	na
Control	Cyclone	None	Cyclone	Cyclone	None	Mechanical
Emissions	lb/MMBtu	lb/MMBtu	lb/MMBtu	lb/MMBtu	lb/MMBtu	lb/MMBtu
NOx	0.211	0.146	-	-	0.165	0.165
CO	0.902	2.123	-	-	1.496	1.496
Particulate PM10	0.097	0.12	0.29	0.12	0.968	0.286
SO2	-	-	-	-	0.00825	0.00825
TOC	-	-	-	-	0.0242	0.0242

[1] US EPA, Compilation of Air Pollution Emission Factors Fifth Edition Revised. (AP-42) Section 1.6

[2] The emission rates are provided by the manufacturers or other parties from actual tests. Chiptec and Messersmith tests are reported in CONEG Report "Wood-Chip Fired Furnaces Testing Project Air Analysis Testing and Public Health" April 1996, CONEG, Washington DC., BCS tests are averaged and include tests of former G& S Mill units that were provide by the manufacturer Biomass Combustion Systems Inc., KMW tests are from Braaten, R.W., and T.G. Sellers , "Prince Edward Island Wood-Chip Fired Boiler Performance Report", Energy Research Laboratories, Ottawa, Ontario Canada April 1993. Mechanical or cyclone collectors only control particulate. The blanks indicate that no data are available. Chiptec, Messersmith, BCS and KMW are manufacturers of wood-fired combustion systems. AP-42 emission rates are from the EPA reference (1) cited above.

As can be seen from Table 1 the variability of emissions in PM10 is very large especially when the uncontrolled AP-42 [1] emission rate is considered. The manufacturers emission rates are taken from field tests. In the case of BCS and G&S Mill boilers the rate represents the average of 13 units in operation. Some of these BCS units report emission rates with cyclones close to those of Chiptech and Messersmith. These emission rates are not intended to be used to determine which manufacturer offers the lowest emissions equipment because they are field tests usually under full load and not guaranteed performance. In most cases the guaranteed emission rates are greater by a factor of 2 or 3. Emissions may increase considerably at low loads or under transient conditions.

PARTICULATE EMISSIONS CONTROL TECHNOLOGY

INTRODUCTION

In order to compare the results of specific control technologies for the purpose of determining BACT it is necessary to determine what is the uncontrolled emission rate for particulate matter. The AP-42 uncontrolled PM emission factor is 0.97 lb/MM Btu. The uncontrolled cumulative emission factor for PM10 is 0.71 lb/MM Btu[2]. This is the emission rate used as the base for comparison in some of the tables that follow. However, some uncontrolled small wood-fired boilers of modern design with gasifier[3] or staged combustion have emission rates uncontrolled of between 0.1 and 0.2 lb/MM Btu.[4] However, because of the variability of fuel and combustion conditions, manufacturers will not guarantee these emission rates and therefore they cannot be used for regulatory purposes. It may be possible to obtain a guaranteed emission rate of 0.3 lb/MM Btu. The lower bound sets a comparison basis for incremental controls. In this study we have therefore chosen 0.3 lb/MM Btu as the lower bound and 0.71 lbMM Btu as the upper bound of an uncontrolled emission rate as a basis for unit costs calculations for controlling PM10. Most commonly today's small wood-fired boilers may be expected to have uncontrolled emission rates between these limits but probably more commonly near the lower bound.

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[1] US EPA, Compilation of Air Pollution Emission Factors Fifth Edition Revised. (AP-42) Section 1.6 , tables 1.6.1. 1.6.2, and 1.6.3

[2] AP-42 table 1.6-7.

[3] The term gasifier is used by Chiptec and some other manufacturers for a combustion system where the pyrolysis or gas generation stage is separate from the combustion chamber. This is essentially the same as staged combustion. Use of the term gasifier here differs from the way in which the term is used where gasifiers are used in the context of the production of wood derived liquid or gaseous fuels.

[4] See the Messersmith boiler cited in Table 1 and a Hurst Boiler fitted with a Chiptec gasifier had uncontrolled emission rates averaging 0.17 lb/MM Btu as reported in a Test Report for Allard Lumber Company of Brattleboro Vermont dated February 1997.

PM10 CONTROLS

Fabric Filters or Baghouses

Various types of fabric filters or baghouses have been successfully used for particulate control with solid and liquid fuels. With the correct design and choice of fabric, particulate control efficiencies of over 99% can be achieved even for very small particles (1 micrometer or less). The lowest emission rates for large wood-fired boilers controlled by fabric filters reported in the RBLC database are 0.01 lb/MM Btu. This is consistent with expected control efficiencies close to 99%. Operating experience with baghouses on larger wood-fired boilers indicates that there is a fire risk, due to caking of the filters with unburned wood dust. Although it is possible to control or manage this risk, it is less practical in the small boilers being considered here. This is because small wood-fired boilers are used in small institutions such as schools and hospitals without full time boiler staff. In such situations the fire risk is unacceptable. A review of the RACT/BACT/LAER (RBLC) database shows only two fabric filter systems on wood-fired boilers and none in this size range. Therefore fabric filters are not recommended for the control of particulates in wood-fired boilers for safety reasons.

Electrostatic Precipitators (ESP)

Electrostatic precipitators (ESPs) are widely used for the control of particulates from a variety of combustion sources including wood combustion. An ESP is a particle control device that employs electric fields to collect particles from the gas stream onto collector plates from where they can be removed. There are a number of different designs that achieve very high overall control efficiencies. Control efficiencies typically average over 98% with control efficiencies almost as high for particle sizes of 1 micrometer or less. Overall, ESPs are almost as good as the best fabric filters. The RBLC database reports several large wood-fired boilers with PM10 emission rates in the range 0.02 to 0.03 lb/MM Btu. For small boilers two designs were considered; a dry electrostatic precipitator and a wet electrostatic precipitator. The systems are basically similar except that wet electrostatic precipitators use water to flush the captured particles from the collectors. The advantage of dry systems is that they may have a lower capital cost and reduced waste disposal problems. Wet systems may be less expensive to operate and are probably slightly more efficient at capturing very small particles that may include toxic metals.

Designs for both wet and dry systems were specified and estimates obtained for each system. The summary of costs for a wet ESP and a dry ESP for a boiler of 7.5 MM/Btu are included in Tables 2 through 5. These are for boilers of 7.5 MM Btu heat input. There are four scenarios given.

Table 2: 30% annual capacity and uncontrolled emissions at 0.71 lb/MM Btu

Table 3: 75% annual capacity and uncontrolled emissions at 0.71 lb/MM Btu

Table 4: 30% annual capacity and uncontrolled emissions at 0.3 lb/MM Btu

Table 5: 75% annual capacity and uncontrolled emissions at 0.3 lb/MM Btu

Table 2: Particulate Control Systems Cost Analysis (ER =0.71 Lb/MM Btu, Cap Factor =30%)

Capital Cost	**ESP Dry**	**ESP Wet**	**Core Separator**	**Multiclone**	**Cyclone**
Equipment	$170,769	$183,386	$19,875	$18,315	$7,600
Site and Facilities	$13,969	$13,969	$2,000	$2,000	$2,000
Installation	$114,415	$122,868	$6,956	$7,365	$6,000
Total Direct Capital Cost	**$299,153**	**$320,223**	**$28,831**	**$27,680**	**$15,600**
Annual Cost					
Total Direct	$37,883	$23,414	$4,984	$2,892	$2,838
Capital recovery factor	0.15	0.15	0.15	0.15	0.15
Capital recovery	$44,574	$47,713	$4,296	$4,124	$2,324
Total Annual Cost	**$82,457**	**$71,127**	**$9,280**	**$7,017**	**$5,162**
PM10 Unit Cost of Control At 30% Annual Capacity Factor					
Control Efficiency PM10	99.0%	99.0%	90.0%	73.0%	50.0%
Emission Rate PM10 uncontrolled lb/MM Btu	0.71	0.71	0.71	0.71	0.71
Emission Rate PM10 controlled lb/MM Btu	0.0071	0.0071	0.071	0.1917	0.355
Annual Emissions PM10 uncontrolled tpy	6.997	6.997	6.997	6.997	6.997
Annual Emissions PM 10 after control tpy	0.070	0.070	0.700	1.889	3.499
Annual Emissions PM10 controlled tpy	6.927	6.927	6.297	5.108	3.499
Annual Cost per ton controlled	**$11,903.52**	**$10,267.93**	**$1,473.57**	**$1,373.70**	**$1,475.59**

Table 3: Particulate Control Systems Cost Analysis (ER =0.71 Lb/MM Btu, Cap Factor =75%)

Capital Cost	**ESP Dry**	**ESP Wet**	**Core Separator**	**Multiclone**	**Cyclone**
Equipment	$170,769	$183,386	$19,875	$18,315	$7,600
Site and Facilities	$13,969	$13,969	$2,000	$2,000	$2,000
Installation	$114,415	$122,868	$6,956	$7,365	$6,000
Total Direct Capital Cost	**$299,153**	**$320,223**	**$28,831**	**$27,680**	**$15,600**
Annual Cost					
Total Direct	$94,707	$58,534	$12,459	$7,231	$7,095
Capital recovery factor	0.15	0.15	0.15	0.15	0.15
Capital recovery	$44,574	$47,713	$4,296	$4,124	$2,324
Total Annual Cost	**$139,281**	**$106,247**	**$16,755**	**$11,355**	**$9,419**
PM10 Unit Cost of Control At 75%% Annual Capacity Factor					
Control Efficiency PM10	99.0%	99.0%	90.0%	73.0%	50.0%
Emission Rate PM10 uncontrolled lb/MM Btu	0.71	0.71	0.71	0.71	0.71
Emission Rate PM10 controlled lb/MM Btu	0.0071	0.0071	0.071	0.1917	0.355
Annual Emissions PM10 uncontrolled tpy	17.493	17.493	17.493	17.493	17.493
Annual Emissions PM 10 after control tpy	0.175	0.175	1.749	4.723	8.746
Annual Emissions PM10 controlled tpy	17.318	17.318	15.743	12.770	8.746
Annual Cost per ton controlled	**$8,042.69**	**$6,135.17**	**$1,064.27**	**$889.23**	**$1,076.96**

Table 4: Particulate Control Systems Cost Analysis (ER =0.3 Lb MM/Btu, Cap Factor =30%)

Capital Cost	**ESP Dry**	**ESP Wet**	**Core Separator**	**Multiclone**	**Cyclone**
Equipment	$170,769	$183,386	$19,875	$18,315	$7,600
Site and Facilities	$13,969	$13,969	$2,000	$2,000	$2,000
Installation	$114,415	$122,868	$6,956	$7,365	$6,000
Total Direct Capital Cost	$299,153	$320,223	$28,831	$27,680	$15,600
Annual Cost					
Total Direct	$37,883	$23,414	$4,984	$2,892	$2,838
Capital recovery factor	0.15	0.15	0.15	0.15	0.15
Capital recovery	$44,574	$47,713	$4,296	$4,124	$2,324
Total Annual Cost	**$82,457**	**$71,127**	**$9,280**	**$7,017**	**$5,162**
PM10 Unit Cost of Control At 30% Annual Capacity Factor					
Control Efficiency PM10	99.0%	99.0%	90.0%	73.0%	50.0%
Emission Rate PM10 uncontrolled lb/MM Btu	0.3	0.3	0.3	0.3	0.3
Emission Rate PM10 controlled lb/MM Btu	0.003	0.003	0.03	0.081	0.15
Annual Emissions PM10 uncontrolled tpy	2.957	2.957	2.957	2.957	2.957
Annual Emissions PM 10 after control tpy	0.030	0.030	0.296	0.798	1.478
Annual Emissions PM10 controlled tpy	2.927	2.927	2.661	2.158	1.478
Annual Cost per ton controlled	**$28,171.65**	**$24,300.77**	**$3,487.46**	**$3,251.08**	**$3,492.24**

Table 5: Particulate Control Systems Cost Analysis (ER =0.3 Lb MM Btu Cap Factor =75%)

Capital Cost	**ESP Dry**	**ESP Wet**	**Core Separator**	**Multiclone**	**Cyclone**
Equipment	$170,769	$183,386	$19,875	$18,315	$7,600
Site and Facilities	$13,969	$13,969	$2,000	$2,000	$2,000
Installation	$114,415	$122,868	$6,956	$7,365	$6,000
Total Direct Capital Cost	**$299,153**	**$320,223**	**$28,831**	**$27,680**	**$15,600**
Annual Cost					
Total Direct	$94,707	$58,534	$12,459	$9,641	$7,095
Capital recovery factor	0.15	0.15	0.15	0.15	0.15
Capital recovery	$44,574	$47,713	$4,296	$4,124	$2,324
Total Annual Cost	**$139,281**	**$106,247**	**$16,755**	**$13,765**	**$9,419**
PM10 Unit Cost of Control At 75%% Annual Capacity Factor					
Control Efficiency PM10	98.0%	98.0%	90.0%	73.0%	50.0%
Emission Rate PM10 uncontrolled lb/MM Btu	0.3	0.3	0.3	0.3	0.3
Emission Rate PM10 controlled lb/MM Btu	0.006	0.006	0.03	0.081	0.15
Annual Emissions PM10 uncontrolled tpy	7.391	7.391	7.391	7.391	7.391
Annual Emissions PM 10 after control tpy	0.148	0.148	0.739	1.996	3.696
Annual Emissions PM10 controlled tpy	7.243	7.243	6.652	5.396	3.696
Annual Cost per ton controlled	**$19,228.58**	**$14,668.07**	**$2,518.78**	**$2,551.21**	**$2,548.80**

ESP control costs range from approximately $6,000 to $28,000 per ton controlled. Under all the scenarios in Tables 2 to 5, the costs per ton removed using ESPs far exceed the normal range of costs for PM10 control. Costs for boilers of 3 MM Btu would be even higher. In addition there would be serious concerns about wastewater problems associated with wet ESPs at small commercial and institutional sites. Furthermore, the capital cost of the least expensive system is about 75% of the capital cost of the boiler. This makes the installation of an ESP economically infeasible. A search of the RBLC reveals no ESP in use for wood-fired boilers in the 3 to 10 MM Btu size range. ESPs have been used on solid waste incinerators where they are needed for hazardous air pollutant control. Based on cost and lack of existing installations ESPs are not considered to be feasible for wood-fired boilers in this size range.

The Core Separator[1]

The Core Separator is a relatively new mechanical collector system produced by LSR Technologies. It works on the same general principles as a cyclone but the processes of separation and collection are accomplished separately by two different components: a core separator and a cyclone collector. The Core Separator consists of multiple cylindrical units each with a single inlet and two outlets. One outlet is for the cleaned gas stream and the other contains a concentrated recirculation stream. The recirculation stream is cleaned by being passed through a cyclone, after which it is returned to the separator unit. The core separator has very high collection efficiency, comparable to an ESP, for particles above about 2.5 micrometers but collection efficiency falls to below 50% for particles below 1 micrometer. Its overall performance falls between an ESP or fabric filter and a cyclone. There are several units installed on wood and coal fired boilers and field test results are available for wood-fired applications. In tests on a boiler fired by a wood gasifier with uncontrolled total particulate emission rates that averaged 0.17 lb/MM Btu, the core separator reduced the emissions to an average of 0.07 lb/MM Btu[2]. The overall average collection efficiency was 56%. This collection efficiency reflects the low initial emission rate and resultant particle size distribution. The collection efficiency over the whole range of uncontrolled wood-fired boiler emissions may be as high as 90%

Based on the test results the core separator working on a boiler that is well controlled through good combustion practices can probably achieve controlled emission rates for total particulates of 0.07 lb/MM Btu over a wide range of load conditions. The capital cost and annual operating costs of a core separator are given in Tables 2 through 5. The unit cost for PM10 removed ranges from approximately $1,000 per ton to $3,500 per ton at 30% capacity factor. The cost for a 7.5 MM Btu boiler operating at 75% of annual capacity is about a $1,000 per ton which is within the range of control cost acceptability. At 30% of capacity the control cost of about $3,500 are at the high end for control costs. If this same technology were to be applied to a 3 MM Btu size boiler then capital cost per ton controlled would further increase by at least 12%.

The core separator when operating either on a well controlled or poorly controlled wood-fired boiler can be expected to control PM10 to below 0.1 lb/MM Btu. This would constitute BACT for at least boilers of 7.5 MM Btu and up. For smaller boilers at about 3 MM Btu being used for space heating and operating at an annual capacity factor of 30% or less the control costs rise. An argument could be made that a less expensive cyclone would be acceptable.

Venturi and Wet Scrubbers.

Venturi and other wet scrubbers are more efficient than multicyclones especially in size fractions below 1 micrometer. The AP-42 indicates a control efficiency for wet scrubbers of 93% for PM10. Overall performance across the particle size range is comparable to the LSR Core Separator. No wet scrubbers

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[1] The Core Separator is a registered trademark of LSR Technologies of Acton MA.

[2] Particulate Emission Evaluation Boiler and Core Separator System Exhaust: Report of Tests at Allard Lumber Company Brattleboro Vermont, December 1996 and January 1997. LSR Technologies Inc. 898 Mains St, Acton MA 01720. 1997.

have been reported in use on wood-fired boilers in this size range. A venturi scrubber was installed on a 13.5 MM Btu wood-fired boiler in Hardwick MA. This had a design emission rate at full capacity of 0.13 lb/MM Btu. The best performing venturi scrubber on a wood-fired boiler listed in the RBLC database had an emission rate of 0.15 lb/MM Btu. A combined cyclone plus wet scrubber system on a wood-fired boiler of 35.5 MM Btu/hr capacity at Northampton MA had a design emission rate of 0.1 lb/MM Btu. This is no better than can be achieved by a Core Separator. A combined multicyclone followed by a Fischer Klosterman Spray Scrubber installed on a pair of wood-fired boilers with a combined capacity of 49 MM Btu/hr at Hadley MA, had a stated design emission rate of 0.0093 lb/MM Btu. However, the Massachusetts DEP only set a permit condition emission rate at 0.15 lb/MM Btu so the lower number does not establish a BACT level even if the size range were comparable. Combined multicyclones and wet scrubbers increase the cost well above that of multicylones or an LSR Core Separator. In addition wet scrubbers are problematic in this size range because many applications are likely to be in small institutional or commercial buildings where it would be difficult to handle the waste-water in an environmentally sound manner.

Flue gas condensation systems designed for heat recovery purposes are in use on biomass-fired district heating boilers in Denmark. Claims for pollution control benefits have been made which we have been unable to substantiate. At best these condensation devices could not perform any better than a wet scrubber in which case they would remain as a less desirable option than a core separator for particulate control. The reported use in Denmark combines condensation with a multicyclone to control particulate emissions to less than 0.15 lb/MM Btu[1] which is comparable to the performance of a multicylone alone. Condensation also suffers from some of the same problems of waste-water disposal described for wet scrubbers. Condensation has energy efficiency advantages and may remove some organic compounds but it is not BACT for particulate.

Multicyclones

Multicyclones or multiple tube cyclones are mechanical separators that use the velocity differential across the cyclone to separate particles. A multicyclone uses several smaller diameter cyclones to improve efficiency. Overall efficiency ranges from 65% to 95% but multicyclones, like cyclones, are more efficient in collecting larger particles and their collection efficiency falls off at small particle sizes. The AP-42 lists multicyclone controlled emission rates that indicate a control efficiency of 73% for PM10 when the uncontrolled emission rate is 0.71 lb/MM Btus. The resulting multicyclone controlled emission rate is 0.19 lb/MM Btus. When the uncontrolled emission rate is as low as 0.1 to 0.2 lb/MM Btu the overall control efficiency will be lower. One set of test results for a well controlled Chiptec Gasifier and Hurst Boiler fired at 5.2 MM Btu with a Hurst multicyclone demonstrated emission rates of 0.17 to 0.2 lb/MM Btu. The lowest reported multicyclone controlled wood-fired boiler emission rate in the RBLC database, which was for a 48 MM Btu boiler, was 0.12 lb/MMBtu. Overall the multicyclone is less efficient than the LSR Core Separator in controlling particulate matter, especially in the size range below 0.1 micrometer. This is a disadvantage because many of the hazardous air pollutants are in the very small size

[1] Biomass for Energy; Danish Solutions published by Energistyrelsen, Copenhagen, undated.

categories. On purely technical criteria the multicyclone is not BACT. When cost is taken in to consideration it can be seen from Table 2 that there is relatively little difference in cost between the core separator and the multicyclone. Therefore it should be concluded that the core separator is BACT at least for boilers in the upper part of this size range.

Cyclones

Simple relatively large diameter cyclones are less efficient collectors than multicyclones or the Core Separator and therefore simple cyclones are not BACT. A very well controlled multistage wood combustor or gasifier combined with a cyclone can achieve emission rates below 0.1 lb/MMBtu. However, in all cases we should expect that the same combustion unit would achieve lower emission rates with a core separator or multicyclone. Therefore, a cyclone equipped wood-fired boiler would not be BACT. A cyclone could only be considered to be BACT if the initial cost and per ton removal costs of a Core Separator were too high. That might be the case after conducting a site-specific BACT analysis for a boiler of approximately 3 MM Btu or less with a low capacity factor. In this case a cyclone might be considered to be BACT on economic grounds..

Summary

For wood-fired boilers in the size range of 3 to 10 MM Btu/hr heat output BACT for PM10 is likely to be a well controlled multistage combustion unit or gasifier with an emission rate of less than 0.2 lb/ MM Btu controlled by an appropriately sized LSR Core Separator. The final emission rate is likely to be less than 0.1 lb/MM Btu. In order to allow for the variability of wood fuels the BACT emission rate should probably be set at 0.1 lb. MM Btu. Some combustion units could meet an emission level of 0.1 lb/MM Btu with a multicyclone. However, BACT is established by reference to technology and cost therefore the same combustion unit could achieve levels well below 0.1 lb/MM Btu controlled with a Core Separator. As the cost difference between an Core Separator and a high efficiency multicyclone is small there are few disadvantages in choosing the Core Separator as BACT. The only technology consideration is that the Core Separator is much newer than muliticyclones and experience on wood-fired boilers is more limited.

PM2.5 CONTROLS

Particulate matter less than 2.5 micrometers diameter (PM2.5) is more injurious to health and in consequence the EPA has proposed a new more stringent NAAQS for PM2.5. It is currently unclear when the new standard will be implemented. When the new standard is implemented for fine particulate there will be implications for the control of most combustion sources of air pollutants. Approximately 75% of the total particulate emissions from wood-fired boilers are below 2.5 micrometers and 67% are below 1 micrometer[1].

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[1] EPA AP-42 section 1.6 table 1.6-7

The recommendation made in this report concerning BACT for PM10 would also apply to a BACT determination for PM2.5. The only caveat is that because the Core Separator is better than a multicyclone at collecting particles below 2.5 micrometers the argument for the Core Separator is strengthened in the case of PM 2.5. Unless the generally accepted standards for economic feasibility are changed under new PM 2.5 rules ESPs would still be rejected on the grounds of cost.

NITROGEN OXIDE CONTROL TECHNOLOGY

INTRODUCTION

Nitrogen oxide (NOx) emissions from wood burning have two origins. First, is the fuel NOx which is produced by the oxidation of the nitrogen in the fuel. The second is the thermal or flame NOx, which is produced in the combustion flame from the oxidation of nitrogen in the air supplied to the boiler.

Fuel NOx is dependent on the nitrogen content of the fuel, which is highly variable, but largely unaffected by combustion conditions. The thermal NOx is strongly affected by combustion conditions but in rather complex ways. In wood-fired boiler combustion fuel NOx is the dominant source of total NOx. NOx is one of the precursor pollutants for ozone and New England has many areas which are classified as non-attainment for the ozone standard therefore the New England states have State Implementation Plans targeted at NOx reductions.

The AP-42 reports a very wide range of NOx emission rates for wood-fired boilers from 0.073 to 0.4 lbs/MM Btu for stoker boilers. The AP-42 typical rate is 0.165 lb/MM Btu, which is close to the emission rate for several boilers in this size range (See Table 1). Higher and lower emission rates are also reported for other types of wood-fired boilers by the AP-42 and by boiler manufacturers. Two typical boilers in this size range given in Table 1 have NOx emission rates ranging from 0.146 to 0.211 lb/MM Btu. However, these emission rates should not be considered as representative of a specific manufacturer's boiler as they could change if the fuel composition changes.

NITROGEN OXIDE CONTROLS

Selective Catalytic Reduction

Selective catalytic reduction (SCR) is a process whereby ammonia vapor is injected into the flue gas which then passes through a catalyst bed to convert nitric oxide to free nitrogen and water. The ammonia can be anhydrous (99.5%) or aqueous (25% to 30% in solution) in form. The latter is significantly safer to handle, store and transport than the anhydrous form.

SCR systems are now widely used on large utility scale coal and natural gas fired boilers in this country and on large oil-fired boilers in Europe and Japan. There are also a number of applications on diesel engines and a small number of installations on oil-fired boilers in the 50 to 100 MM Btu size range. SCR systems can reduce NOx emission by 85% to 95%. There are no installations on wood-fired boilers in

North America and no vendor in North America is offering this system for wood-fired boilers. Siemens AG is offering it's SINOx SCR system for larger wood-fired boilers in Europe.

SCR systems are feasible if ammonia slip can be properly controlled. Apart from cost, the main problem is the temperature requirements of the catalyst. The optimal operating temperature for the catalyst is 675 degrees F. The typical temperature of the flue gas in a small wood-fired boiler is between 300 and 500 degrees F. Therefore supplementary heating of the flue gas will be needed at all times that the boiler is operating with the firing rate increasing as the load decreases. In order to make SCR work effectively in a small wood-fired boiler with seasonal heat loads a propane-fired duct heater will be needed after the boiler breaching and before the SCR. It has not been possible to obtain costs on this system because none have been installed.

In addition to the need for supplementary heating with associated fuel cost and pollution problems, the SCR uses ammonia which can result in ammonia slip or increased ammonia emissions unless very carefully controlled. Such controls would be extremely difficult on a small wood-fired boiler. Therefore SCR cannot be considered a practical NOx control system on wood-fired boilers of this size.

Selective Non-Catalytic Reduction

Selective non-catalytic reduction (SNCR) is a process where ammonia or urea is injected in to the high temperature zone (1,600 – 2,000 degrees F) of the flue gas. The ammonia or urea reacts with the exhaust NOx to form nitrogen, water and in the case of urea, carbon dioxide. If the temperature is too high or the ammonia/urea concentration too low then additional NOx is formed. If the temperature is too low then the reaction is incomplete and ammonia slip occurs. In addition, in urea reactions, up to 30% of the N_2 can be converted into N_2O, a greenhouse gas. Using urea as a reagent, SNCR systems are generally 50% to 60% efficient at removing NOx from the flue gas. In order to avoid ammonia slip or poor NOx removal, SNCR needs to be closely controlled which is difficult in the variable flame combustion conditions associated with wood firing. As in the case of SCR there are also problems in handling ammonia in institutional and commercial settings without full-time boiler staff.

There is one SNCR system installed on a 150 MM Btu wood-fired boiler. There are none installed on small wood-fired boilers and no vendors offering system in that size range. Generally SNCR systems are considered inferior to SCR systems. For all these reasons therefore SNCR cannot be considered a practical NOx control system on wood-fired boilers of this size.

Oxidation Catalysts

Oxidation catalysts are used in automobiles, diesel engines and wood stoves to reduce emissions by oxidation in a catalyst bed. So called three way oxidation catalysts reduce NOx, CO and hydrocarbons. In boilers they are not an optimal method for NOx control but as multiple pollutant control systems they have demonstrated their value in some applications notably in automobiles. Oxidation catalysts are not used in wood-fired boilers in this size range for a number of reasons but notably because operating temperature for the catalyst is 1,200 to 1,600 degrees F whereas the temperature in the exhaust stream of a small wood fire boiler is typically below 600 degrees F. Therefore oxidation catalysts are not practical for control of NOx, CO, or hydrocarbons in small wood-fired boilers.

Summary

There are no cost effective or practical NOx control systems for wood-fired boilers in this size range other than good combustion conditions. However, because most of the NOx is fuel-derived there is only so much that can be done. Furthermore, some of the measures that might be taken to reduce thermal NOx during the combustion process could lead to increasing CO, PM10, and volatile organic compounds.

The typical NOx emission rates for wood-fired boilers in this size range shown in Table 1 are very close to the NOx emission rates of distillate oil-fired commercial boilers of similar size (See table 6). There has been no attempt in New England or elsewhere to impose NOx control requirements on small distillate oil-fired boilers.

CARBON MONOXIDE CONTROL TECHNOLOGY

Carbon monoxide (CO) is produced by all combustion processes. The CO emission rate for wood-fired boilers is highly variable. The AP-42 emission rates vary by over an order of magnitude depending on boiler and fuel specific factors. Boiler data available for well-controlled units, as shown in Table 1, ranges from 0.9 to 2.1 lb/MM Btu. One of the lower reported CO emission rates for similar units is an average emission rate of 0.5 lb/MM Btu for a Chiptec unit with a regulatory limit of 0.9 lbs/MM Btu.

CO control using oxidation catalysts is discussed above in the NOx section. No post combustion control technology is practical for CO reduction in wood-fired boilers.

SULFUR DIOXIDE CONTROL TECHNOLOGY

Sulfur dioxide (SO_2) emissions from wood combustion are very low due to the low levels of sulfur in natural wood. The AP-42 gives an emission rate of 0.0082 lb/MM Btu. There are no practical add on controls for SO_2 at these levels and therefore there is no BACT determination for SO_2.

ORGANIC COMPOUNDS CONTROL TECHNOLOGY

Organic compounds, usually referred to as volatile organic compounds (VOCs) or total organic compounds (TOCs), include a very wide range of organic compounds many of which are toxic or carcinogenic. There are more than 30 organic compounds widely recognized in wood boiler exhaust gas they include the aldehydes, benzene and several polycyclic organic compounds[1]. The emission rate for TOCs is strongly affected by combustion conditions. Wood-fired boilers of modern design using staged combustion or gasification to insure complete combustion have lower TOC emissions. However, the variable characteristics of wood and the difficulty of controlling the firing rate make it difficult to control the TOC emissions. Control technologies for TOCs include thermal oxidizers, which are after burners using natural gas or propane, wet scrubbers and catalytic afterburners. No control systems specifically for TOC control are currently being used on wood-fired boilers of any size. Some organic compounds condense in the cooler regions of the stack gas and are deposited on particles. Therefore reducing the PM10 emission rate by the use of the control systems described will also to some extent reduce the emissions of some but not all TOCs.

No BACT is proposed for TOC control. Most of the TOCs are listed as toxic substances by the states of Massachusetts, New Hampshire and Vermont. Vermont has a BACT-like requirement, the Hazardous Most Stringent Emission Rate (HMSER) rule[2] which requires the use of BACT for control of air toxics above a threshold action level. Because there is no available control technology suitable for TOC control on small wood-fired boilers, a technical and cost analysis will likely conclude that HMSER is good combustion technology as demonstrated by CO and PM10 control.

TRACE ELEMENT CONTROL TECHNOLOGY

Wood combustion releases 36 trace elements listed by the EPA AP-42[3]. These are metals that are released from wood in the combustion process. The emission rates are variable depending on the species and the environmental conditions under which the wood was grown. Most of the metals are listed as toxic air pollutants by the states of Massachusetts, New Hampshire and Vermont. As was the case with the TOCs, Vermont has a BACT like requirement for toxic metals, the Hazardous Most Stringent Emission Rate (HMSER) rule, which requires the use of BACT for control of air toxics including metals above a threshold action level. Most of the metals with the exception of mercury and selenium are attached to particles and therefore are controlled by particulate control systems. The use of a Core Separator is preferred over a multicyclone because it has better control efficiency in the small particle size classes where more of the toxic metals are concentrated. In order to control the trace metals effectively either ESPs or fabric filters will be needed . These technologies are not BACT for the reasons previously given. When considered specifically as a control technology for trace metals, which have very low emission rates, the cost of using ESPs increases to several million dollars per ton of toxic metals reduced[4]. This analysis does not however take into consideration the relative risk associated with some of the toxic metals. Using established practices at this time BACT for PM10 is also BACT for trace metals.

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[1] EPA AP-42: Compilation of Air Pollutant Emission Factors, Section 1.6, Table 1.6-4.

[2] Vermont Air Pollution Control Regulations Section 5-261.

[3] EPA AP-42: Compilation of Air Pollutant Emission Factors, Section 1.6, Table 1.6-5.

[4] Vermont ANR Air Pollution Control Division Air Permit for Britton Limber Company Ely Vermont 1993.

COMPARISON OF BOILER EMISSIONS FIRED BY WOOD, DISTILLATE OIL, NATURAL GAS AND PROPANE

In evaluating BACT for small wood-fired boilers it is useful to compare the emission rates for wood with those of distillate oil, natural gas and propane in comparably sized boilers. Table 6 summarizes some of these emissions. Overall criteria pollutant emissions from wood-fired boilers are higher than oil and gas for all pollutants except sulfur dioxide. The PM10 emission rate, even when controlled to 0.1 lb/MMBtu is still higher than other fuels used in boilers of this size. The sulfur dioxide emission rate for wood is less than for distillate oil with a sulfur content of 0.5 %[1] which is frequently specified as a permit limit for number 2 oil-fired commercial boilers. Number 2 distillate oil (transportation grade) with a sulfur content of 0.05% or 0.025% is available. The use of 0.025% sulfur oil would result in an emission rate of 0.025 lb/MM Btu, which would probably constitute BACT for SO_2 in distillate oil boilers if such a requirement were implemented. The SO_2 emission rate for wood at 0.0082 lb/MM Btu is below even the most stringent possible BACT for distillate oil-fired boilers in that size range.

The nitrogen oxide emission rate for wood is higher but very close to distillate oil. It is higher than natural gas but below propane. Some wood-fired boilers, depending on the nitrogen content of the wood burned, could be lower than distillate oil. Carbon monoxide and TOC emission rates are higher for wood also.

In terms of greenhouse gas emissions, wood has the highest gross carbon dioxide emission rate. However, wood is a renewable fuel, so that as long as the trees being used are being replaced either by planting or natural re-growth then there is no net release of carbon dioxide. As the New England forests are currently growing in volume it is reasonable to conclude that on average there is zero net release of carbon dioxide from wood burning.

In overall comparison with distillate oil, wood is better in terms of sulfur dioxide and net greenhouse gas emissions. Wood is in the same general range for nitrogen oxide emissions. It is clearly worse for PM10, carbon monoxide and total organic compounds. Each of these pollutants has it's own issues. The use of wood, as it reduces sulfur dioxide helps to reduce the acid deposition problem. This is important in a region seriously impacted by acid deposition. The higher CO emissions are of relatively minor concern, except in a few urban areas where there are high carbon monoxide levels, usually due to automobile exhaust. The relatively higher emissions of PM10 and TOCs are primarily a concern for public health especially because both PM10 and TOCs include toxic air pollutants.

[1] In New Hampshire 0.4% sulfur content is frequently specified.

Table 6: Comparison of Boiler Emissions Fired by Wood, Distillate Oil, Natural Gas and Propane [1]

	Wood	Distillate Oil	Natural Gas	Propane
	lb/MM Btu	lb/MM Btu	lb/MM Btu	lb/MM Btu
PM 10	0.1	0.014	0.007	0.004
NOx	0.165	0.143	0.09	0.154
CO	0.73	0.035	0.08	0.021
SO2	0.0082	0.5	0.0005	0.016
TOC	0.0242	0.0039	0.01	0.005
CO2	gross 220 (net 0)	159	118	137

There is no BACT requirement on small boilers using distillate oil, natural gas or propane. Based on the analysis undertaken for this report it is clear that add on controls on small wood-fired boilers can reduce PM10 at a reasonable cost and that a LSR Core Separator is probably BACT for this size of boiler. There appears to be no valid reason to require wood-fired boilers to employ add-on controls for NOx reduction when they are not required for distillate oil-fired or propane-fired boilers with NOx emission rates in the same range.

[1] All emission rates are without additional controls except the wood PM10 is controlled with a Core Separator as discussed. The sulfur content of number 2 distillate oil is assumed to be at 0.5% by weight which is common. Other grades of oil are rarely used in boilers below 14 MM Btu heat input. Number 2 oil with a sulfur content as low as 0.025% is available but is rarely used. Propane is commercial grade with a heat content of 91,500 Btu/gal and a sulfur content of 15 gr/100 cf. The CO2 emission rate is gross except that the net emission rate is also given for wood.

ATT 3.0

Emissions from Wood-Fired Combustion Equipment

Prepared for:

Mr. Tony Wakelin, P.Eng.
Unit Head Industrial Air Emissions,
Environmental Management Branch
Ministry of Environment
PO Box 9342, Stn Prov Govt
Victoria, BC V8W 9M1

Prepared By:

Paul A. Beauchemin, P.Eng.
Martin Tampier, P.Eng.
Envirochem Services Inc.
310 East Esplanade
North Vancouver, B.C.
Tel: (604) 986-0233

June 30, 2008

ATT 4.d

173-400-036 << 173-400-040 >> 173-400-045

Agency filings affecting this section

WAC 173-400-040

General standards for maximum emissions.

(1) All sources and emissions units are required to meet the emission standards of this chapter. Where an emission standard listed in another chapter is applicable to a specific emissions unit, such standard takes precedence over a general emission standard listed in this chapter. When two or more emissions units are connected to a common stack and the operator elects not to provide the means or facilities to sample emissions from the individual emissions units, and the relative contributions of the individual emissions units to the common discharge are not readily distinguishable, then the emissions of the common stack must meet the most restrictive standard of any of the connected emissions units.

All emissions units are required to use reasonably available control technology (RACT) which may be determined for some sources or source categories to be more stringent than the applicable emission limitations of any chapter of Title 173 WAC. Where current controls are determined to be less than RACT, the permitting authority shall, as provided in RCW 70.94.154, define RACT for each source or source category and issue a rule or regulatory order requiring the installation of RACT.

(2) **Visible emissions.** No person shall cause or allow the emission for more than three minutes, in any one hour, of an air contaminant from any emissions unit which at the emission point, or within a reasonable distance of the emission point, exceeds twenty percent opacity except:

(a) When the emissions occur due to soot blowing/grate cleaning and the operator can demonstrate that the emissions will not exceed twenty percent opacity for more than fifteen minutes in any eight consecutive hours. The intent of this provision is to allow the soot blowing and grate cleaning necessary to the operation of boiler facilities. This practice, except for testing and trouble shooting, is to be scheduled for the same approximate times each day and the permitting authority must be advised of the schedule.

(b) When the owner or operator of a source supplies valid data to show that the presence of uncombined water is the only reason for the opacity to exceed twenty percent.

(c) When two or more emission units are connected to a common stack, the permitting authority may allow or require the use of an alternate time period if it is more representative of normal operations.

(d) When an alternate opacity limit has been established per RCW 70.94.331 (2)(c).

(e) Exemptions from twenty percent opacity standard.

(i) Visible emissions reader certification testing. Visible emissions from the "smoke generator" used for testing and certification of visible emissions readers per the requirements of 40 C.F.R. Part 60, Appendix A, Reference Method 9 and ecology methods 9A and 9B shall be exempt from compliance with the twenty percent opacity limitation while being used for certifying visible emission readers.

(ii) Military training exercises. Visible emissions resulting from military obscurant training exercises are exempt from compliance with the twenty percent opacity limitation provided the following criteria are met:

(A) No visible emissions shall cross the boundary of the military training site/reservation.

(B) The operation shall have in place methods, which have been reviewed and approved by the permitting authority, to detect changes in weather that would cause the obscurant to cross the site boundary either during the course of the exercise or prior to the start of the exercise. The approved methods shall include provisions that result in cancellation of the training exercise, cease the use of obscurants during the exercise until weather conditions would allow such training to occur without causing obscurant to leave the site boundary of the military site/reservation.

(iii) Firefighter training. Visible emissions from fixed and mobile firefighter training facilities while being used to train firefighters and while complying with the requirements of chapter 173-425 WAC.

(3) **Fallout.** No person shall cause or allow the emission of particulate matter from any source to be deposited beyond the property under direct control of the owner or operator of the source in sufficient quantity to interfere unreasonably with the use and enjoyment of the property upon which the material is deposited.

(4) **Fugitive emissions.** The owner or operator of any emissions unit engaging in materials handling, construction, demolition or other operation which is a source of fugitive emission:

(a) If located in an attainment area and not impacting any nonattainment area, shall take reasonable precautions to prevent the release of air contaminants from the operation.

(b) If the emissions unit has been identified as a significant contributor to the nonattainment status of a designated nonattainment area, the owner or operator shall be required to use reasonable and available control methods, which shall include any necessary changes in technology, process, or other control strategies to control emissions of the air contaminants for which nonattainment has been designated.

(5) **Odors.** Any person who shall cause or allow the generation of any odor from any source or activity which may unreasonably interfere with any other property owner's use and enjoyment of his property must use recognized good practice and procedures to reduce these odors to a reasonable minimum.

(6) **Emissions detrimental to persons or property.** No person shall cause or allow the emission of any air contaminant from any source if it is detrimental to the health, safety, or welfare of any person, or causes damage to property or business.

(7) **Sulfur dioxide.** No person shall cause or allow the emission of a gas containing sulfur dioxide from any emissions unit in excess of one thousand ppm of sulfur dioxide on a dry basis, corrected to seven percent oxygen for combustion sources, and based on the average of any period of sixty consecutive minutes, except:

When the owner or operator of an emissions unit supplies emission data and can demonstrate to the permitting authority that there is no feasible method of reducing the concentration to less than one thousand ppm (on a dry basis, corrected to seven percent oxygen for combustion sources) and that the state and federal ambient air quality standards for sulfur dioxide will not be exceeded. In such cases, the permitting authority may require specific ambient air monitoring stations be established, operated, and maintained by the owner or operator at mutually approved locations. All sampling results will be made available upon request and a monthly summary will be submitted to the permitting authority.

(8) **Concealment and masking.** No person shall cause or allow the installation or use of any means which conceals or masks an emission of an air contaminant which would otherwise violate any provisions of this chapter.

(9) **Fugitive dust.**

(a) The owner or operator of a source or activity that generates fugitive dust must take reasonable precautions to prevent that fugitive dust from becoming airborne and must maintain and operate the source to minimize emissions.

(b) The owner or operator of any existing source or activity that generates fugitive dust that has been identified as a significant contributor to a PM-10 or PM-2.5 nonattainment area is required to use reasonably available control technology to control emissions. Significance will be determined by the criteria found in WAC 173-400-113(4).

[Statutory Authority: Chapter 70.94 RCW. WSR 11-06-060 (Order 09-01), § 173-400-040, filed 3/1/11, effective 4/1/11. Statutory Authority: RCW 70.94.152. WSR 05-03-033 (Order 03-07), § 173-400-040, filed 1/10/05, effective 2/10/05. Statutory Authority: Chapter 70.94 RCW, RCW 70.94.141, [70.94.]152, [70.94.]331, [70.94.]510 and 43.21A.080. WSR 01-17-062 (Order 99-06), § 173-400-040, filed 8/15/01, effective 9/15/01. Statutory Authority: [RCW 70.94.331, 70.94.510 and chapter 70.94 RCW.] WSR 00-23-130 (Order 98-27), § 173-400-040, filed 11/22/00, effective 12/23/00. Statutory Authority: Chapter 70.94 RCW. WSR 93-18-007 (Order 93-03), § 173-400-040, filed 8/20/93, effective 9/20/93; WSR 91-05-064 (Order 90-06), § 173-400-040, filed 2/19/91, effective 3/22/91. Statutory Authority: Chapters 43.21A and 70.94 RCW. WSR 83-09-036 (Order DE 83-13), § 173-400-040, filed 4/15/83. Statutory Authority: RCW 70.94.331. WSR 80-11-059 (Order DE 80-14), § 173-400-040, filed 8/20/80. Statutory Authority: RCW 43.21A.080 and 70.94.331. WSR 79-06-012 (Order DE 78-21), § 173-400-040, filed 5/8/79; Order DE 76-38, § 173-400-040, filed 12/21/76. Formerly WAC 18-04-040.]

Chapter 173-400 WAC contains the main air quality rules.

Grain loading standards for combustion and incineration units are found in WAC 173-400-050(1):0.23 gram per dry cubic meter at standard conditions (0.1 grain/dscf), except, for an emissions unit combusting wood derived fuels for the production of steam. No person shall allow the emission of particulate matter in excess of 0.46 gram per dry cubic meter at standard conditions (0.2 grain/dscf), as measured by EPA method 5 in Appendix A to 40 C.F.R. Part 60, (in effect on July 1, 2012) or approved procedures contained in "*Source Test Manual - Procedures For Compliance Testing*," state of Washington, department of ecology, as of September 20, 2004, on file at ecology.

In addition, opacity requirements of 20 percent are found in WAC 173-400-040(2).

Let me know if you need further information.

Elena Guilfoil
Air Quality Program
Dept. of Ecology
PO Box 47600
Olympia, WA. 98504-7600
elena.guilfoil@ecy.wa.gov
360-407-6855

Thanks Elena:

I will evaluate these laws and use them for a comparison to Oregon laws.
By the way my daughter and 6 of my grandchildren live in Olympia.

Paul

ATT 5,0

COMMONWEALTH OF MASSACHUSETTS
EXECUTIVE OFFICE OF ENERGY & ENVIRONMENTAL AFFAIRS
DEPARTMENT OF ENVIRONMENTAL PROTECTION
ONE WINTER STREET, BOSTON, MA 02108 617-292-5500

DEVAL L. PATRICK
Governor

TIMOTHY P. MURRAY
Lieutenant Governor

IAN A. BOWLES
Secretary

ARLEEN O'DONNELL
Commissioner

MEMORANDUM

To:	Biomass Energy Stakeholders
From:	James C. Colman, Assistant Commissioner, Bureau of Waste Prevention, MassDEP
Date:	April 18, 2007
Subject:	BACT guidance for Biomass Projects

As part of the MassDEP and Massachusetts Division of Energy Resources (DOER) coordination on revised procedures for reviewing biomass facility proposals, MassDEP is publishing the attached BACT (best available control technology) guidance document. This guidance is applicable to biomass facilities in Massachusetts that require a plan approval from MassDEP, and may differ from the proposed "low emission" limits[1] that pertain to qualification under the Massachusetts Renewable Portfolio Standard (RPS) for biomass plants in other states throughout the region. Biomass plants constructed in other states and requesting RPS qualification must meet the air permitting requirements in the permitting state, as well as the MA RPS' low emission limits, but not MassDEP BACT requirements.

This guidance was published in draft on June 23, 2006, and was open for comment until July 21, 2006. The Department received one formal comment, which related to the use of C&D wood waste as a biomass fuel. Specifically, the commenter was concerned about the use of C&D wood waste contaminated with heavy metals and the potential air emissions from such fuel. The commenter was also concerned about the ability of C&D wood fuel suppliers to adequately sort C&D wood waste to prevent the use of contaminated wood waste as a fuel.

MassDEP shares the concern about the potential emissions from contaminated C&D wood, and believes that the attached Guidance addresses this issue. In particular, an applicant proposing to use such fuel will be required to demonstrate that the emission controls on the proposed facility will prevent exceedances of health based standards. The sorting of C&D wood, if required, would be addressed in the Beneficial Use Determination (BUD) that MassDEP would issue for the use of C&D wood as a fuel.

Any questions about this guidance may be directed to Marc Wolman at (617) 292-5515 or Marc.Wolman@state.ma.us

[1] The proposed MA RPS low emission limits include requirements for nitrogen oxides and particulate matter. See http://www.mass.gov/doer/rps/rps-225cmr14-summary.pdf

Best Available Control Technology (BACT) Guidance
Biomass-Fired Electric Generating Units
April 2007

INTRODUCTION

As a result of the Commonwealth's renewable energy programs, there is increasing interest in Massachusetts in building electric generating units that utilize biomass as a fuel. This guidance is meant to provide greater certainty to prospective developers of biomass facilities when preparing plan approval applications for MassDEP under 310 CMR 7.02. It provides guidance on Best Available Control Technology (BACT) for biomass fuel and technology combinations based on MassDEP experience.

The initial guidance (issued in April, 2007) addresses solid biomass fuel–fired steam electric generating units; future versions will address other fuel/technology combinations. In general, MassDEP intends to provide two sets of emissions limits for each fuel/technology combination covered. The first table will include limits from recently issued permits for the specific fuel/technology (for example, in the initial guidance below, see Table 1). Any application for a new generating unit of the specific type will need to comply with at least those limits. The second table will include limits MassDEP considers to be technically achievable (for example, in the initial guidance below, see Table 2). The more stringent limits will be based on applying advanced technology for a specific fuel/technology combination and achieving the same level of emission reductions achieved for other fuel sources. MassDEP considers these limits as the starting points from which to make determinations on emission limits for a new generating unit of the specific type based on fuel use, energy, environmental, and economic impacts and other costs.

While this April, 2007 Guidance for new solid fuel-fired steam electric generation units is based on current permits and expectations for technology transfer, MassDEP anticipates that this Guidance will evolve over time and the emission limits for solid fuel-fired steam electric generation units may be amended in the future to reflect advances in technology. This guidance will expire on December 31, 2009. Prior to that date, MassDEP will review its experience with this guidance and initiate a public discussion to determine next steps, such as affirming and/or revising this guidance, or proposing regulations that will codify biomass performance standards.

In order to expedite permitting, and provide greater certainty, transparency and consistency across regions, MassDEP has formed a multi-disciplinary Energy Team[1] to expedite the review of air, solid waste, water, and other issues that may arise from energy projects, as well as to work with the Division of Energy Resources (DOER) on Renewable Portfolio Standard issues. MassDEP strongly encourages project proponents to contact the Regional Director in the appropriate regional office or the Chief of Staff in the Commissioner's Office early in the project planning process in order to discuss the application of this guidance, as well as other applicable regulations, if necessary. This will help reduce delays later in the permitting phase of the project.

[1] The Energy Team is co-chaired by the Assistant Commissioner of the Bureau of Waste Prevention (BWP) and the Associate Commissioner for Operations, and is made up of representatives of the region in which the facility is proposed and Boston staff as appropriate. The Chief of Staff in the Commissioner's Office is the Boston contact for the Energy Team.

BACKGROUND

Before starting construction of a fuel utilization facility (e.g. boiler, combustion turbine, reciprocating engine, etc.) whose energy input capacity will be above the thresholds contained in the regulations (310 CMR 7.02), the owner or operator must obtain written approval of the Plan Application from MassDEP.

The requirement to obtain a Plan Approval before the start of construction is set forth at 310 CMR 7.02(4) and (5). The thresholds for obtaining a Limited Plan Application are set forth at 310 CMR 7.02(4)(a), and for a Comprehensive Plan Application at 310 CMR 7.02(5)(a). Applicants proposing to install internal combustion engines burning a bio-fuel have the option of complying with the standards contained in Engines and Combustion Turbines (310 CMR 7.26(40)-(44)).

A Plan Approval for a fuel utilization facility requires the utilization of BACT, where BACT is defined as:

> BEST AVAILABLE CONTROL TECHNOLOGY means an emission limitation based on the maximum degree of reduction of any regulated air contaminant emitted from or which results from any regulated facility which MassDEP, on a case-by-case basis taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such facility through application of production processes and available methods, systems and techniques for control of each such contaminant. The best available control technology determination shall not allow emissions in excess of any emission standard established under the New Source Performance Standards, National Emission Standards for Hazardous Air Pollutants or under any other applicable section of 310 CMR 7.00, and may include a design feature, equipment specification, work practice, operating standard, or combination thereof. [310 CMR 7.00 Definitions]

In addition, more stringent emission limits than are determined through the BACT analysis are required if MassDEP determines they are necessary to avoid causing a condition of air pollution, which is "the presence in the ambient air space of one or more air contaminants or combinations thereof in such concentrations and of such duration as to:

(a) cause a nuisance;
(b) be injurious, or be on the basis of current information, potentially injurious to human or animal life, to vegetation, or to property; or
(c) unreasonably interfere with the comfortable enjoyment of life and property or the conduct of business."[310 CMR 7.00 Definitions]

This guidance is intended to provide the framework for the application of BACT to biomass energy projects.

GUIDANCE

This guidance contains emissions limits from recently permitted facilities that MassDEP believes represent state of the art limits for some specific fuel/technology combinations. An application that proposes to meet the more stringent of these limits (the "starting point" seen in Table 2) will not be required to perform a top-down BACT analysis as part of the application[2].

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[2] While MassDEP believes these limits represent a good starting point for a BACT evaluation, a final determination cannot be made on emissions limits for a specific facility until any required public comment period is completed. Reviews requiring public comment include: Non-attainment New Source Review (310 CMR 7.00 Appendix A) for non-attainment pollutants, and the Massachusetts Environmental Policy Act (MEPA – 301 CMR 11.00). Similarly, for projects subject to Prevention of Significant Deterioration (PSD – 40 CFR 52.21), which is administered in Massachusetts by the US Environmental Protection Agency, EPA cannot make their determination until after the close of the required public comment period.

If the applicant believes the limitations contained in this Guidance (Table 2) are either technologically or economically infeasible, or if the proposal is for a fuel/technology not covered by this guidance, the applicant may request further guidance from MassDEP. The Energy Team will attempt to respond to any such request within 30 days. If an applicant moves ahead with a proposal, the application will be reviewed using MassDEP's standard fee and permitting timelines, unless the applicant opts to use MassDEP's "fast-track" permitting process[3].

BIOMASS-FIRED STEAM ELECTRIC GENERATING UNITS

Two sets of limits are included in the following tables. Table 1 contains limits from recent permits issued for solid fuel biomass-fired boilers. In general, MassDEP expects that any application for a new solid fuel biomass-fired boiler will need to comply with these limits.

Table 2 contains limits MassDEP believes are technically achievable. These more stringent limits are based on applying Selective Catalytic Reduction (SCR – control of NOx), and an Oxidation Catalyst (control of carbon monoxide and unburned hydrocarbons) to biomass-fired boilers[4] to achieve the same level of reduction that has been achieved on other fuel sources. In evaluating technical feasibility (part of the BACT analysis) of achieving the Table 2 limits, MassDEP considers the ability of the applicant to obtain manufacturer guarantees.

MassDEP is concerned with reducing NOx, PM and CO because:

- NOx is a precursor to the formation of ozone, a pollutant for which the Commonwealth is classified non-attainment for the National Ambient Air Quality Standard. NOx is also a precursor to acid deposition and regional haze.
- PM can accumulate in the lungs and produce respiratory and cardio-vascular symptoms. PM emissions contain unburned carbon, toxic metals (depending on the fuel source), and unburned hydrocarbons.
- Unburned hydrocarbons are a precursor to ozone formation, and many of the unburned hydrocarbons are also air toxics.
- Symptoms of high CO exposure include shortness of breath, chest pain, headaches, confusion, and loss of coordination. Achieving low CO levels also minimizes unburned hydrocarbon emissions.

In general, if an applicant proposes the limits in Table 2, MassDEP believes these are approvable as BACT – please see footnote 2. Depending on the fuel(s) being combusted, MassDEP will consider alternative emission limits to Table 2 once the applicant has prepared a complete application, including a BACT determination.

Typical biomass electric generating facilities are smaller than fossil fuel-fired generating facilities. In addition, biomass fuels are generally more variable than fossil fuels, the typical operating temperatures of biomass facilities are lower than in fossil-fuel-fired facilities, and the amount of catalyst needed to meet

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[3] Pursuant to Section 40 of Chapter 149 of the Acts of 2004, MassDEP and a permit applicant may agree upon appropriate fees, related funding and schedules for projects that meet certain criteria.

[4] Although they are not meeting the same stringent limits as in Table 2, there are two wood-fired boilers in New England equipped with SCR. One of these is also equipped with an oxidation catalyst.

the emission limits in Table 2 may be large. Therefore, MassDEP understands that Table 2 emissions limits may not be readily achievable at this time and may not require facilities to achieve these limits in every case. However, given the likely improvements in biomass technology, MassDEP considers believes these limits represent a reasonable starting point for a BACT analysis.

In any case, where MassDEP requires the applicant to design the facility to approach or meet the Table 2 emission limits, MassDEP may adjust the final permit limits after optimization if such optimization demonstrates that the limits cannot be met in practice.

Table 1
New Solid Fuel-Fired Steam Electric Generation Units
Currently Permitted Emission Limitations[1]

Nameplate capacity	Equal to or greater than 25 MW	Equal to or greater than 10 MW and less than 25 MW	Equal to or greater than 1 MW and less than 10 MW
SO2	0.025 lbs/MMBtu	0.025 lbs/MMBtu	0.025 lbs/MMBtu
NOx	0.075 lbs/MMBtu	0.075 lbs/MMBtu	0.093 lbs/MMBtu
Ammonia	13 PPM @ 3%O2	13 PPM @ 3%O2	25 PPM @ 3%O2
CO	0.1 lbs/MMBtu	0.17 lbs/MMBtu	0.25 lbs/MMBtu
PM[2]	0.012 lbs/MMBtu	0.012 lbs/MMBtu	0.012 lbs/MMBtu
VOC	0.01 lbs/MMBtu	0.01 lbs/MMBtu	0.01 lbs/MMBtu
Toxics[3]	Based on modeling	Based on modeling	Based on modeling
Opacity	10%	10%	10%
HCl (biomass containing chlorinated compounds)	20 ppm @ 3% O2	20 ppm @ 3% O2	20 ppm @ 3% O2
Monitoring	CEMS – NOx, opacity, NH3, SO2 Annual PM test For C&D, also metals[4] testing	CEMS – NOx, opacity, NH3, SO2 Annual PM test. For C&D, also metals[4] testing	PMS Annual PM. For C&D, also metals[4] testing
Reporting	Quarterly, annually	Quarterly, annually	Quarterly, annually

[1] The boilers used to develop these limits are: Schiller Station in Portsmouth, NH, Whitefield Power in Whitefield, NH, Boralex in Stratton, ME, Ware Cogen in Ware, MA, and McNeil Station in Burlington, VT.

[2] The PM limits are designed to ensure compliance with toxics limits, including metals, and will likely require use of a baghouse. Compliance testing for PM emissions are to be tested according to 40 CFR 60 Appendix A Method 5. In addition, testing for condensable PM will be required.

[3] Ambient air quality modeling will be required to demonstrate that the MassDEP's Acceptable Ambient Levels and Threshold Effects Levels will be required for some projects. For example:

1. Where construction and demolition wood is burned. MassDEP may require it for some other fuels of particular environmental concern.
2. For boilers that are major sources of criteria or Hazardous Air Pollutants.

[4] Metals testing is required for facilities burning wood from construction and demolition wood, and possibly other biomass sources. This testing would be required to demonstrate that any limits in a plan approval to prevent exceedances of AALs/TELs are being met.

Table 2

New Solid Fuel-Fired Steam Electric Generation Units
Suggested BACT Starting Point[1]
[The limits more stringent than Table 1 are shaded.]

Nameplate capacity	Equal to or greater than 25 MW	Equal to or greater than 10 MW and less than 25 MW	Equal to or greater than 1 MW and less than 10 MW
SO2	0.02 lbs/MMBtu	0.02 lbs/MMBtu	0.02 lbs/MMBtu
NOx	0.015 lbs/MMBtu	0.015 lbs/MMBtu	0.093 lbs/MMBtu
Ammonia	2 PPM @ 3%O2	2 PPM @ 3 %O2	10 PPM @ 3%O2
CO	0.01 lbs/MMBtu	0.01 lbs/MMBtu	0.25 lbs/MMBtu
PM[2]	0.012 lbs/mmBtu	0.012 lbs/mmBtu	0.012 lbs/MMBtu
VOC	0.01 lbs/MMBtu	0.01 lbs/MMBtu	0.01lbs/MMBtu
Opacity	5%	5%	5%
HCl (biomass containing chlorinated compounds)	20 ppm @ 3% O2	20 ppm @ 3% O2	20 ppm @ 3% O2
Toxics[3] - arsenic, antimony, beryllium, cadmium, chromium III, chromium VI, copper, lead, mercury, nickel, and selenium (wood containing C&D wood)	85% removal of mercury and 99% removal of the other metals, or reduce emissions below the detection limit. Also, ambient modeling to demonstrate MA AALs/TELs are not exceeded.	85% removal of mercury and 99% removal of the other metals, or reduce emissions below the detection limit. Also, ambient modeling to demonstrate MA AALs/TELs are not exceeded.	85% removal of mercury and 99% removal of the other metals, or reduce emissions below the detection limit. Also, ambient modeling to demonstrate MA AALs/TELs are not exceeded.
Monitoring	CEMS – NOx, opacity, NH3, SO2 Annual PM. For, C&D, also metals[4] testing	CEMS – NOx, opacity, NH3, SO2 Annual PM. For C&D, also metals[4] testing	Parametric monitoring will be defined. Annual PM. For C&D, also metals[4] testing
Reporting	Quarterly, annually	Quarterly, annually	Quarterly, annually

[1] These limits are based on applying Selective Catalytic Reduction (SCR) and Oxidation Catalyst to wood fired boilers, to achieve the same level of reduction that has been achieved on other fuel sources. SCR and oxidation catalyst have been used on wood-fired boilers. MassDEP thinks there are opportunities to achieve lower emissions than have been achieved.

[2] The PM limits are designed to ensure compliance with toxics limits, including metals, and will likely require use of a baghouse. Compliance testing for PM emissions are to be tested according to 40 CFR 60 Appendix A Method 5. In addition, testing for condensable PM will be required.

[3] Ambient air quality modeling will be required to demonstrate that the MassDEP's Acceptable Ambient Levels and Threshold Effects Levels will be required for some projects. For example:

1. Where construction and demolition wood is burned. MassDEP may require it for some other fuels of particular environmental concern.
2. For boilers that are major sources of criteria or Hazardous Air Pollutants.

[4] Metals testing is required for facilities burning wood from construction and demolition wood, and possibly other biomass sources. This testing would be required to demonstrate that any limits in a plan approval to prevent exceedances of AALs/TELs are being met.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON D.C. 20460

OFFICE OF THE ADMINISTRATOR
SCIENCE ADVISORY BOARD

September 29, 2006

EPA-CASAC-LTR-06-003

Honorable Stephen L. Johnson
Administrator
U.S. Environmental Protection Agency
1200 Pennsylvania Avenue, NW
Washington, DC 20460

Subject: Clean Air Scientific Advisory Committee Recommendations Concerning the Final National Ambient Air Quality Standards for Particulate Matter

Dear Administrator Johnson:

We, the seven members of the Clean Air Scientific Advisory Committee (CASAC or Committee), are writing to express our serious scientific concerns regarding the public health and welfare implications of EPA's final primary (health effects) and secondary (welfare effects) National Ambient Air Quality Standards (NAAQS) for airborne particulate matter (PM). As you know, the CASAC is mandated by the Clean Air Act to provide scientific advice on the setting of these standards that are intended to protect both public health and public welfare, and in the case of the protection of public health, to do so with "an adequate margin of safety." The Committee has conscientiously fulfilled its duty in providing our best scientific advice and recommendations to the Agency. Regrettably, however, EPA's final rule on the NAAQS for PM does not reflect several important aspects of the CASAC's advice.

In its letter dated June 6, 2005, the CASAC recommended that the 24-hour standard for $PM_{2.5}$ be decreased from 65 micrograms per cubic meter ($\mu g/m^3$) to 30–35 $\mu g/m^3$. We are pleased with the Agency's decision in the final PM NAAQS rule to decrease the daily primary $PM_{2.5}$ standard to a level consistent with the CASAC's recommendation (35 $\mu g/m^3$), as this decrease will provide additional health protection in some cities. In addition, we recommended a decrease in the annual primary $PM_{2.5}$ standard from 15 $\mu g/m^3$ to 13–14 $\mu g/m^3$. However, the CASAC is concerned that EPA did not accept our finding that the annual $PM_{2.5}$ standard was not protective of human health and did not follow our recommendation for a change in that standard.

The CASAC recommended changes in the annual fine-particle standard because *there is clear and convincing scientific evidence that significant adverse human-health effects occur in response to short-term and chronic particulate matter exposures at and below 15 $\mu g/m^3$, the level of the current annual $PM_{2.5}$ standard.* The CASAC affirmed this recommended reduction in the annual fine-particle standard in our letter dated March 21, 2006 concerning the proposed rule for the PM NAAQS, in which 20 of the 22 members of the CASAC's Particulate Matter

Review Panel — including all seven members of the chartered (statutory) Committee — were in complete agreement. While there is uncertainty associated with the risk assessment for the $PM_{2.5}$ standard, this very uncertainty suggests a need for a prudent approach to providing an adequate margin of safety. *It is the CASAC's consensus scientific opinion that the decision to retain without change the annual $PM_{2.5}$ standard does not provide an "adequate margin of safety ... requisite to protect the public health" (as required by the Clean Air Act), leaving parts of the population of this country at significant risk of adverse health effects from exposure to fine PM.*

Significantly, we wish to point out that the CASAC's recommendations were consistent with the mainstream scientific advice that EPA received from virtually every major medical association and public health organization that provided their input to the Agency, including the American Medical Association, the American Thoracic Society, the American Lung Association, the American Academy of Pediatrics, the American College of Cardiology, the American Heart Association, the American Cancer Society, the American Public Health Association, and the National Association of Local Boards of Health. *Indeed, to our knowledge there is* no *science, medical or public health group that disagrees with this very important aspect of the CASAC's recommendations.* EPA's recent "expert elicitation" study (*Expanded Expert Judgment Assessment of the Concentration-Response Relationship Between $PM_{2.5}$ Exposure and Mortality*, September 21, 2006) only lends additional support to our conclusions concerning the adverse human health effects of $PM_{2.5}$.

Furthermore, the CASAC was completely surprised at the decision in the final PM NAAQS to revert to the use of PM_{10} as the indicator for coarse particles. In our September 15, 2005 letter, the CASAC recommended a new indicator of $PM_{10-2.5}$, which EPA put forward in its proposed rule for the PM NAAQS. The option of retaining the existing daily PM_{10} standard of 150 $\mu g/m^3$ was not discussed during the advisory process, and in fact the CASAC views this as highly-problematic since PM_{10} includes both fine and coarse particulate matter. The Committee acknowledges the need for the Agency to increase its understanding of the health risks of coarse particles and is concerned that ongoing dependence on PM_{10} sampling as an imprecise measure of coarse particulate matter will provide inadequate information on coarse PM concentrations, compositions and exposures in both urban and rural areas. However, the CASAC agrees that having a standard for PM_{10} is better than no standard at all for coarse particles, and was pleased with the Agency's decision against offering exemptions to specific industries (*i.e.*, agricultural, mining) in its regulation of coarse particles.

With respect to the secondary PM standard, the decision was made "to revise the current PM secondary standards by making them identical in all respects to the revised suite of primary PM standards." In our June 6, 2005 letter, the CASAC affirmed the recommendation of Agency staff regarding a separate secondary fine particle standard to protect visibility. This sub-daily secondary $PM_{2.5}$ standard is a better indicator of visibility impairment than the 24-hour primary standard. The CASAC wishes to emphasize that continuing to rely on primary standards to protect against all PM-related adverse environmental and welfare effects assures neglect, and will allow substantial continued degradation, of visual air quality over large areas of the country.

In summary, the Agency has rejected the CASAC's expert scientific advice with regard to lowering the level of the annual primary fine particle ($PM_{2.5}$) standard and establishing a new coarse particle ($PM_{10-2.5}$) standard — both of which are consistent with the recommendations of the nationally-recognized science, medical and public health groups such as those cited above — and, in addition, EPA has not followed our advice in setting a separate secondary $PM_{2.5}$ standard. We note that, since the CASAC's inception in the late 1970s, the Agency has always accepted the Committee's scientific advice with regard to final NAAQS decisions. In view of this, we question whether you have appropriately given full consideration to CASAC's expert scientific advice — obtained through open, public processes — in your final decisions on the PM NAAQS.

The CASAC shares a common goal with EPA to protect the public health and welfare. We earnestly hope that the Agency's future consideration of the CASAC's scientific advice with respect to standard-setting for the criteria air pollutants will prove more fruitful in achieving that very important goal.

Sincerely,

/Signed/

Rogene Henderson, Ph.D.
Chair, Clean Air Scientific Advisory Committee
Scientist Emeritus
Lovelace Respiratory Research Institute
Albuquerque, NM

/Signed/

Mr. Richard L. Poirot
Environmental Analyst
Vermont Agency of Natural Resources
Waterbury, VT

/Signed/

Ellis Cowling, Ph.D.
University Distinguished Professor At-Large
North Carolina State University
Raleigh, NC

/Signed/

Frank Speizer, M.D.
Edward Kass Professor of Medicine
Channing Laboratory
Harvard Medical School
Boston, MA

/Signed/

James D. Crapo, M.D.
Professor, Department of Medicine
National Jewish Medical and Research Center
Denver, CO

/Signed/

Barbara Zielinska, Ph.D.
Research Professor
Desert Research Institute
Reno, NV

/Signed/

Frederick J. Miller, Ph.D.
Cary, NC
Consultant

Sierra Club v. U.S. EPA

The D.C. Circuit Court decision on January 22, 2013 in *Sierra Club v. EPA* will have significant ramifications on future PSD permitting. The Sierra Club challenged the EPA rule establishing Significant Impact Levels (SILs) and Significant Monitoring Concentrations (SMCs) for PM2.5, which are screening tools designed to exempt the applicant from cumulative modeling and preconstruction monitoring requirements under the Clean Air Act. These tools can be essential to obtaining a PSD permit within a reasonable time to achieve business objectives. The court found that EPA overstepped its authority in establishing SILs and SMCs. The court reads the Clean Air Act to require continuous preconstruction ambient monitoring sufficient to perform a "complete and adequate analysis" of the pre-project ambient conditions to enable a determination as to whether the PSD project will result in a violation of the NAAQS. The court determined that EPA could not exempt all projects with impacts below the SILs without first analyzing whether there was enough ambient headroom in the area to accommodate the project without violating the NAAQS.

While this decision is specific to PM2.5, the analysis could be applied to challenge the way that SILs and SMCs are used for other pollutants in areas that do not have local ambient air quality monitoring for the PSD pollutants implicated by a major modification or a new source. The decision is expected to encourage the siting of ambient monitors in areas of anticipated growth. To the extent that Cliffs is considering ambient monitors to challenge or calibrate over predictive model results, this decision offers additional support for using a continuous ambient monitor that measures all regulated pollutants that could be implicated by future PSD expansion projects. Sites with adequate monitoring will be one year ahead of competing sites without local monitors for getting major modifications or new sources through the PSD permitting process.

Wednesday, January 23, 2013

Sierra Club v. U.S. EPA

Jan 22: In the U.S. Court of Appeals, D.C. Circuit, Case No. 10-1413. On Petition for Review of Final Actions of the United States Environmental Protection Agency.

The Appeals Court explains that in October 2010, U.S. EPA issued a final rule establishing regulations for particulate matter less than 2.5 micrometers (PM2.5) under § 166 of the Clean Air Act (the Act), 42 U.S.C. § 7476. *See* Prevention of Significant Deterioration (PSD) for Particulate Matter Less Than 2.5 Micrometers (PM2.5) -- Increments, Significant Impact Levels (SILs) and Significant Monitoring Concentration (SMC), 75 Fed. Reg. 64,864 (Oct. 20, 2010). In this rule, the EPA established Significant Impact Levels (SILs) and a Significant Monitoring Concentration (SMC) for PM2.5, screening tools the EPA uses to determine whether a new source may be exempted from certain requirements under § 165 of the Act, 42 U.S.C. § 7475. 75 Fed. Reg. at 64,890– 91, 64,895. Petitioner Sierra Club seeks review of this regulation.

After the Sierra Club filed its petition, the EPA acknowledged that portions of the rule establishing SILs did not reflect its intent in promulgating the SILs, and now requests that we vacate and remand some (but not all) parts of its PM2.5 SIL regulations. The Appeals Court indicated that, "Notwithstanding the EPA's concession, the Sierra Club maintains that the EPA lacks authority to establish SILs and requests that we rule accordingly. The Intervenor, Utility Air Regulatory Group (UARG), on the other hand, urges us to uphold the SIL provisions EPA established, or alternatively, to remand the SIL provisions without ordering that they be vacated."

The Appeals Court said, "Although the EPA conceded that it needs to revise some of the SIL provisions, it continues to assert that the portions of its rule establishing the SMC were valid. For the reasons stated below, we accept the EPA's concession on the SILs, and vacate and remand some portions of the EPA's rule establishing SILs. We further conclude that the EPA exceeded its authority in establishing the SMC, and grant the Sierra Club's petition as to those portions of the EPA's rule."

The Appeals Court explains further that, "After the Sierra Club filed its petition, the EPA acknowledged that portions of the rule establishing SILs did not reflect its intent in promulgating the SILs, and now requests that we vacate and remand some (but not all) parts of its PM2.5 SIL regulations. Notwithstanding the EPA's concession, the Sierra Club maintains that the EPA lacks authority to establish SILs and requests that we rule accordingly. . .

"Despite the EPA's concession, the Sierra Club asserts that vacatur and remand, while warranted, does not fully resolve its challenge, and asks that we determine whether the EPA has authority to promulgate SILs. We disagree with the Sierra Club that it is necessary to decide the EPA's authority to promulgate SILs at this point. To do so would require that we answer a question not prudentially ripe for determination. On remand the EPA may promulgate regulations that do not include SILs or do include SILs that do not allow the construction or modification of a source to evade the requirements of the Act as do the SILs in the current rule. In such an event, we would not need to address the universal disallowance of all *de minimis* authority. If the EPA promulgates new SIL provisions for PM2.5 and those provisions are challenged, we can then consider the lawfulness of those SIL provisions."

Further, the Appeals Court rules, "We are not now ruling on the methodology the EPA used to determine the SILs. Instead, we are vacating and remanding §§ 51.166(k)(2) and 52.21(k)(2) based on the EPA's lack of authority to exempt sources from the requirements of the Act. Therefore, vacatur and remand of § 51.165(b)(2) is not necessary at this point. Accordingly, we vacate and remand the portions of the EPA's rule regarding SILs, with the exception of those portions codified in 40 C.F.R. § 51.165(b)(2). . .

"We disagree with the EPA that the Sierra Club's petition is time-barred, and we agree with the Sierra Club that the EPA did not have *de minimis* authority to promulgate the SMC because we hold Congress was "extraordinarily rigid" in mandating preconstruction air quality monitoring. . ."

Finally, the Appeals Court concludes, ". . .we vacate and remand to the agency for further consideration the portions of the EPA's rule addressing SILs, except for the parts of its rule codifying PM2.5 SILs in 40 C.F.R. § 51.165(b)(2). We grant the Sierra Club's petition as to the parts of the EPA's rule establishing a PM2.5 SMC, and vacate them because these parts of the rule exceed the EPA's statutory authority. *See* 42 U.S.C. § 7607(d)(9)(3)."

October 30, 2013

An Overview of Biomass Thermal Energy Policy Opportunities in the Northern Forest Region

Prepared for:
Northern Forest Center

Prepared by:

BERC

Renewable • Reliable • Resourceful

Biomass Energy Resource Center

APPENDIX B – Maine 126LR1271(01)

ACKNOWLEDGEMENTS

This document was prepared for the Northern Forest Center with funding provided by the US Endowment for Forestry and Communities. This work was conducted by the **Biomass Energy Resource Center** (BERC) at Vermont Energy Investment Corporation (VEIC). The BERC at VEIC study team consisted of Adam Sherman serving as the study's project manager and principal author, and Christine Donovan serving as co-author and providing strategic input and management oversight.

Support and feedback was provided by the members of the Northeast Biomass Thermal Working Group (NEBTWG). The views expressed in this report are those of the authors, consistent with the commissioning of this work as an independent study. For more information and to contact the study author:

Adam Sherman
Biomass Energy Resource Center at VEIC
128 Lakeside Avenue, Suite 401
Burlington, Vermont 05401
(802) 540-7863
asherman@biomasscenter.org
www.biomasscenter.org

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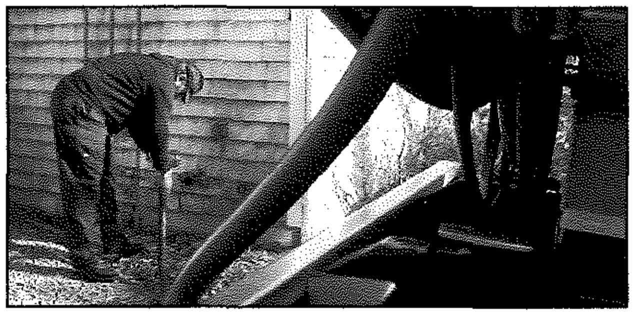
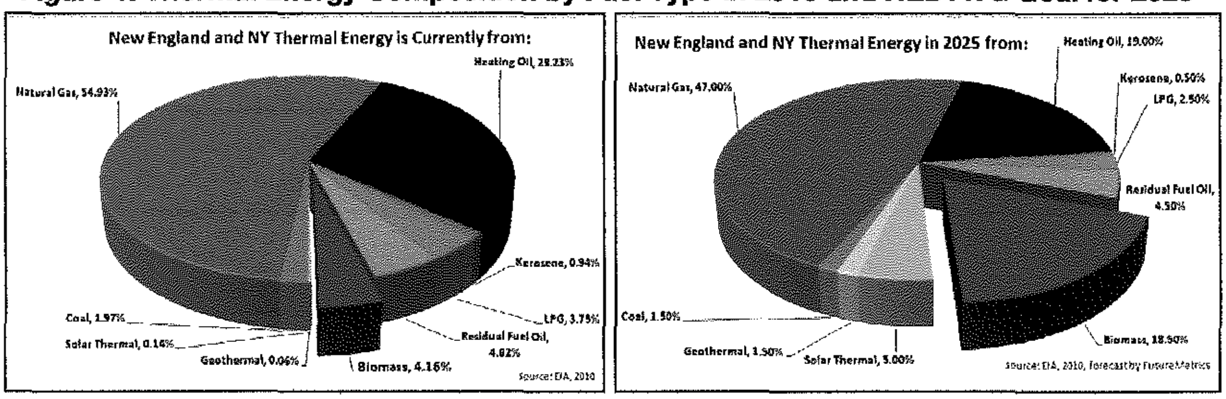
1.0 Introduction



The use of energy for space and water heating, referred to as thermal energy, accounts for roughly one third of the total energy consumed in the US and is supplied almost entirely by fossil fuels such as natural gas, propane and heating oil.[1] Over 4.4 billion gallons of heating oil are used annually in the Northeastern US alone, primarily for space heating. This accounts for approximately 86% of the national demand for heating oil.[2]

As the Northeast region looks to decrease reliance on imported fossil fuels used for heating, local biomass resources sourced from well-managed forests and farms have the potential to significantly reduce our dependence on heating oil, propane and natural gas and at the same time, provide a wide range of economic and environmental benefits.

Figure 1: Thermal Energy Composition by Fuel Type in 2010 and NEBTWG Goal for 2025



Many northeastern US states have recently established aggressive targets for renewable energy as a way to expedite the transition away from fossil fuels, with most of the targets focused on the use of renewable energy for electricity generation rather than for thermal energy or transportation. In an effort to stimulate more aggressive state targets for the use of biomass for thermal energy, a coalition of biomass thermal energy advocates, the Northeast Biomass Thermal Working Group (NEBTWG)[3], released a vision statement in 2010 calling for policies to grow the use of biomass energy from 4% of thermal energy demand to 18.5% of demand in the Northeast by 2025.[4] Referred to as "The Bold Vision," the report explains the basis for the 18.5% target and identifies the job creation and local economic benefits that could be achieved by 2025. However, to achieve such a target, immediate and dramatic

[1] http://www.eia.gov/totalenergy/data/annual/diagram1.cfm
[2] http://www.eia.gov
[3] NEBTWG is an informal network of biomass thermal advocates from New England, New York, Pennsylvania and Maryland. Started in 2008, NEBTWG's purpose is to identify and accelerate growth and adoption of biomass heating in the Northeast.
[4] http://nebioheat.com/pdf/heatne_vision_summary.pdf

change is needed for policies, regulations, and programs affecting the development and use of biomass thermal energy.

1.1 Study Objectives

Public policies and regulations at the state level can have a sudden and significant impact on the development of biomass thermal opportunities. State policy and regulation can help support the appropriate development and use of biomass thermal, or can directly (or inadvertently) result in significant market barriers that prevent or hold back market development.

This study was commissioned with the objective of developing model legislation that could be used to help inform future state-level policy initiatives that seek to advance the use of biomass thermal energy in the Northern Forest region. The primary focus of the study is on the four Northern Forest states of New York, Vermont, New Hampshire, and Maine. Information is also provided on other states (such as Massachusetts) when a state has been pursuing progressive policies affecting biomass thermal energy opportunities. The focus of the study is on policies and regulations affecting the development and use of systems fueled with solid biomass heating fuels such as chunkwood, pellets, and chips. Liquid biofuels (such as biodiesel) are not addressed.

The four key questions this study addresses include:

1. What policies and regulations are currently in effect in the Northern Forest region that affect development and use of biomass thermal energy and where are there gaps?
2. How have existing policies and/or regulations helped to advance or to hinder biomass thermal energy in the region?
3. What new policies are needed to advance biomass thermal energy? Has legislation been developed that can serve as model legislation for other states?
4. What are key next steps for advancing biomass thermal energy policy in the Northern Forest region?

This document identifies and assesses three major areas of policy affecting biomass thermal energy including legislative, regulatory, and financial policy. The report identifies key legislative, regulatory, and finance policies currently in place in the Northern Forest region that affect biomass thermal energy. Examples of biomass thermal legislation developed by others previously are provided and these are examined for their potential to serve as model legislation for others to implement in their own state in the future.

1.2 Study Partners

Northern Forest Center

This study was commissioned by the Northern Forest Center (NFC), a mission-driven non-profit organization that advocates for the Northern Forest region and helps its communities benefit from forest-based economic and conservation initiatives. Since it was founded, NFC has rallied people around a vision for the region's future that is built on three essential ingredients: thriving communities, healthy forests and innovative and resilient local economies that can support both. NFC plays a unique role as the only organization coordinating regional strategy across multiple interest areas—conservation, economic development and community development—in the four-state region. This enables NFC to amplify the work and voice of their partners, adding value to their work and advancing their shared goals. Funding for this study was provided by the US Endowment for Forestry and Communities, as part of its four-year grant to the Northern Forest Center for the Northern Forest Investment Zone (NFIZ) initiative.

Biomass Energy Resource Center (BERC) at VEIC

The Biomass Energy Resource Center (BERC) is a program of the Vermont Energy Investment Corporation (VEIC), a national not-for-profit organization based in Burlington, Vermont working to reduce the economic and environmental impacts of energy use. BERC at VEIC works to advance community-scale biomass energy throughout North America through technical consulting, program design and implementation, and advocacy services. Since its inception in 2001, BERC has played a crucial role in increasing the quantity and quality of community-scale biomass energy projects in North America. BERC is a founding member of the Biomass Thermal Energy Council (BTEC), the national trade association for the biomass thermal industry, and of NEBTWG. BERC has played an active role in biomass thermal energy policy at the federal, regional and state levels and has participated in several previous studies conducted as part of the Northern Forest Investment Zone initiative.

2.0 State Renewable Energy Targets

Many states have established state-level targets for achieving specific levels of renewable energy by various dates in the future. Some states develop such targets through energy planning processes that result in aspirational renewable energy goals, but do not establish clear authority or mechanisms for achieving such goals. Other states enact such targets through legislation and/or regulation, and establish clear authority and mechanisms for achieving the goals. In some cases, state renewable energy targets specifically address biomass energy and/or biomass thermal opportunities while in other cases, the goal is stated more broadly. Presented below is the status of state renewable energy targets in each of the Northern Forest region states.

2.1 New York

In September of 2009, a law was passed establishing the New York State Energy Planning Board and requiring the board to develop a state energy plan. The *2009 New York State Energy Plan* called for at least 30% of renewable electricity by 2015 (sometimes referred to as '30 x 15').[5] In addition, the 2009 plan called for an 80% reduction in Greenhouse Gas (GHG) emissions by 2050. There is little in the 2009 plan that directly discusses thermal energy and resource-specific targets are not set for biomass energy (or other renewable resources such as solar, wind, or hydro).

New York is now working on the next version of the plan, referred to as the "2013 State Energy Plan." The planning process is being led by the State Energy Planning Board and will culminate in recommendations that, when implemented, will "help provide reliable, economical, and clean energy to New Yorkers."[6] It is unclear who will be responsible for achieving the goals and tasks to be identified in that plan.

In 2012, The New York State Energy Research and Development Authority (NYSERDA) launched an effort to develop a state-wide roadmap for developing the biomass thermal market in New York State. The purpose of the roadmap is to "assess critical technical, environmental, public health, economic, and policy issues related to biomass heating to provide a better understanding of the possible impacts and opportunities in New York State, and to provide the information in a format that will assist in the development of a responsible and economically viable biomass heating industry in New York State."[7] NYSERDA hired the Northeast States for Coordinated Air Use Management (NESCAUM) to lead the roadmap development. The roadmap is scheduled to be completed in early 2014.[8]

2.2 Vermont

Vermont recently published a state energy plan that addresses all forms of energy use - both electrical and thermal energy used in buildings as well as energy used for transportation. *Vermont's Energy Future – 2011 Comprehensive Energy Plan* calls for 90% of energy from

[5] http://www.nysenergyplan.com/
[6] Ibid.
[7] http://www.nyserda.ny.gov/Funding-Opportunities/Current-Funding-Opportunities/PON-2329-Development-of-a-Biomass-Heating-Roadmap-for-New-York.aspx
[8] http://www.nescaum.org/documents/developing-a-biomass-heating-roadmap-for-new-york-state

renewables by 2050.[9] The report specifically states that the plan will need to be implemented by Vermonters broadly and that the governor's climate cabinet is tasked with monitoring progress toward the goals.[10] Biomass thermal is described in the plan as one way of helping to achieving the target but it is not specified how much biomass thermal is recommended for the state.

In 2012, the Vermont legislature passed Act 170 of 2012 that tasked the Vermont Department of Public Service with conducting a study to identify key policy options that could be pursued to achieve the state's renewable energy and carbon targets.[11] The study, conducted by the Regulatory Assistance Project (RAP), explored how various policy options (carbon tax, total energy standard, etc.) could encourage a broad range of energy efficiency and renewables—including biomass heating.

An additional study, the "Vermont Total Energy Study" is now underway and due to the legislature by December 15, 2013. The in-depth study, being conducted by Dunsky Consulting based in Montreal, will analyze and recommend specific energy policies options for achieving the renewable energy and GHG emission targets set in the *2011 Comprehensive Energy Plan*.

2.3 New Hampshire

In 2001, Governor Shaheen signed a bill charging the Office of Energy and Community Services (ECS) to develop a 10-year energy plan for the state. [12] The plan was completed in 2002 and has not since been updated or replaced with a more recent version. The 2002 plan established a baseline of New Hampshire energy needs and called for the creation of a Renewable Portfolio Standard (RPS) as well as for pursuing strategies to reduce dependence on foreign oil in the state. The plan did not directly address delivered fuels for heating.[13] Since 2002, an RPS was passed through legislation which sets the target of achieving 24.8% of electricity from renewable energy by 2025.[14] As part of its regulatory authority overseeing the electric industry in New Hampshire, NH Public Utility Commission (NH PUC) staff oversees implementation of the RPS. The RPS was modified in 2012 to allow renewable sources of thermal energy to qualify for Renewable Energy Certificates (RECs) developed as part of the implementation structure for the RPS.

2.4 Maine

Maine has one of the highest renewable energy standards in the nation, requiring through legislation originally enacted in 1997 that 40% of total retail electricity sales come from renewable resources by 2017.[15] There are no specific targets for renewable thermal energy included in the legislation. The Maine Energy Action plan subsequently developed calls for a reduction of oil use for electricity, heating, and transportation of by 50% by 2050.[16] The Governor's Energy Office is responsible for providing the leadership to achieve these targets. While transportation is a large percentage of oil (i.e. gasoline) consumption in Maine, heating is also a major component. Although weatherization, wider natural gas distribution, and other

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[9] http://publicservice.vermont.gov/sites/psd/files/Pubs_Plans_Reports/State_Plans/Comp_Energy_Plan/2011/CEP%20Overview%20Page_Final%5B1%5D.pdf
[10] Ibid.
[11] http://publicservice.vermont.gov/sites/psd/files/Pubs_Plans_Reports/TES/Total_Energy_Study_RFI_and_Framing_Report.pdf
[12] http://www.nh.gov/oep/resource-library/energy/documents/energy-plan-summary.pdf
[13] Ibid.
[14] http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=NH09R&ee=1
[15] http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=ME01R
[16] http://maine.gov/energy/about/index.html

renewable energy will likely be a significant part of the strategy to meet this goal, biomass thermal could also have an important contributing role.

2.5 Massachusetts

Originally enacted with legislation passed in 1997, Massachusetts currently has both a RPS and an Alternative Portfolio Standard (APS) that apply to electric utilities serving the state. Implementation of the RPS and APS is overseen by the Department of Energy Resources (DOER).[17] The RPS sets a target of 15% 2020 for Class I new resources and increases 1% per year thereafter.[18] The APS provides businesses and institutions opportunity for incentives toward non-renewable energy measures (CHP, flywheel storage, and certain steam technologies) that would not otherwise qualify for REC under the traditional RPS. In 2010, the Massachusetts Agency of Energy and Environmental Affairs issued a report entitled, *Massachusetts Clean Energy and Climate Plan for 2020* in response to legislation calling for such a plan passed in 2008.[19] This plan called for considerable reductions in GHG emissions from the energy sector over 1990 levels by the year 2020 using a wide range of renewable energy sources, including biomass. The plan also called for an integrated portfolio of policies to achieve these targets.

2.6 Policy Opportunity for Biomass Thermal Energy

As noted above, all of the Northern Forest states (and Massachusetts) have clear goals for renewable energy in the electrical generation sectors and are moving forward with RPS policies (with the exception of Vermont) as a method to achieve the stated goals. Except for Vermont, none of the other Northern Forest states have comprehensive energy plans that directly address thermal energy and that set specific targets for thermal energy.

This indicates new opportunity exists for encouraging policy makers and regulators to proactively include thermal energy as part of the energy policies and strategies in place in a state, so that a more comprehensive approach is being used that addresses all uses of energy, not just electricity.[20]

As state renewable policies are being developed and specific targets are set for various forms of renewable energy (including thermal energy from biomass), it is vital that any specific targets be set with careful examination and consideration of the biomass resource potential. Numerous state government commissioned biomass resource quantification studies have been conducted over the past 10 to 20 years covering the Northern Forest states. Thus far, no states have gone as far as setting targets directly for the quantity of sustainable supply or to allocate the amount of biomass resource to different potential markets (i.e. electricity production, thermal energy, and transportation). [21,22,23,24]

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[17] http://dsireusa.org/incentives/incentive.cfm?Incentive_Code=MA05R
[18] Ibid.
[19] http://www.mass.gov/eea/docs/eea/energy/2020-clean-energy-plan-summary.pdf
[20] This same opportunity exists for transportation-focused energy policy as well, which is not addressed in this study due to the focus on biomass thermal energy policy opportunities.
[21] http://www.biomasscenter.org/images/stories/VTWFSSUpdate2010_.pdf
[22] http://www.nyserda.ny.gov/Publications/Research-and-Development-Technical-Reports/Biomass-Reports/Renewable-Fuels-Roadmap.aspx
[23] http://www.maine.gov/doc/mfs/pubs/pdf/biomass_memo_071708.pdf
[24] http://www.mass.gov/eea/docs/doer/renewables/biomass/manomet-biomass-report-chapter3.pdf

3.0 Regulatory Policy Overview

Regulation can be a positive tool that allows industry to expand under a clear and predictable framework. It can also help demonstrate to the general public and the market place that a sector is mature and has the appropriate level of regulatory oversight. That said, regulation can also inadvertently hinder an industry and development of the market for that industry. Presented below is an overview of the key regulatory policies in place in each of the Northern Forest region states that affect development of the biomass thermal industry and market. This information is provided to help inform future regulatory policy activities in the region.

3.1 Forestry

Biomass used for fuel can come from various sources. This study is focused on the most common biomass fuel used for thermal energy—wood. Clean woody biomass used for making fuels such as chips and pellets can be automatically fed into heating appliances and are increasingly being sourced from commercial harvesting.

Presented in Table 1 is a summary of various forestry policies in each state related to forest ownership, management, and harvesting that affect the fuel supply chain for the biomass energy markets (including both biomass thermal and biomass electricity).

Table 1: State Policies Affecting the Fuel Supply Chain for Biomass Energy Markets

	Property Tax Incentives	Best Management Practices (BMP)	Heavy Cut Law	Forester Licensing	Logger Licensing	Biomass Harvesting Guidelines
New York	Program 480a	Recommended BMP	None	None	Voluntary training program	None
Vermont	Use Value Appraisal (UVA) Program	Voluntary AMP (Accepted Management Practices)	Permit required for heavy cut of 40 acres or more	None	Voluntary training program	Regulatory standards for power plants. General guidelines under development
New Hampshire	Current Use Program	Recommended BMP	Various minor rules	State license required	Voluntary training program	Guidelines in updated 2010 BMPs
Maine	Tree Growth Tax Law	Voluntary BMP	Forest Practices Act & Chapter 23 standards to eliminate liquidation harvesting	Required licensing	Voluntary training program	State recommended guidelines for biomass retention
Massachusetts	Forest Tax Law Program	BMP Manual	Forest Cutting Practices Act	Required licensing	License required	Requirements through APS eligibility

Nearly all states in the Northeast have tax policies that encourage private forestland owners to actively manage their forestland and periodically harvest timber. Public policies such as the "current use" property tax relief programs provide tremendous benefit to the entire forest products industry and help sustain the working forested landscape in this region where a very large majority of forestland is privately owned. It is vital that these policies stay in place to continue to help ensure supply of wood fuel from well-managed forests in the face of patterns like forest parcelization and fragmentation.

Other policies such as best management practices and forest and logger licensing provide safeguards that help ensure that forests are responsibly managed and periodic harvesting is conducted in a manner that reduces potential adverse impacts. These policies also help send a signal to the general public and the market that forests are well managed and that increased demand for biomass heating will not over burden the forest or drive management toward unsustainable practices. Of course, the effectiveness of these policies to achieve the goals depends entirely on the details of how they are structured and implemented.

A recent Northeast (State) Foresters Association (NEFA) report reviews how select states have further adopted biomass harvesting guidelines, and examines the issues of how much biomass should be retained after harvesting to ensure long-term site productivity, biodiversity, and carbon storage.[25] These guidelines are designed to build upon the more general Best Management Practices (BMPs) which have historically aimed to protect water quality and wildlife habitat. Currently, Maine and New Hampshire have specific biomass retention guidelines incorporated into their broader BMP and several states are looking at adopting similar guidelines on a voluntary basis in the future.[26]

It is important for forestry guidelines to be adaptive, to be based in science, and to not put arbitrary constraints on silvicultural practices. It is equally important that clear systems be developed to indicate to the general public and a growing prospective biomass heating market that the forests will continue to be well managed and responsibly harvested.

3.2 Air Quality

Federal and state air emissions regulations for biomass combustion devices vary widely in terms of what is covered and how the systems are permitted and regulated. The standards are typically regulated by the type of system, fuel type, and system size. Historically, states in the Northeast have had widely differing air quality rules, ambient level thresholds for key pollutants, point-source emission limits, and permitting processes for biomass thermal energy systems. Of greatest concern to air quality regulators for wood combustion equipment are typically emission levels of particulate matter (PM).

Although, a large percentage of the biomass heating market is in the residential sector and smaller residential stoves and appliances have historically been where the highest emission rates occur, this sector is, for the most part, below the state level regulatory threshold when it comes to air quality. Despite the largely unregulated nature of the residential sector, the US

[25] http://www.nefainfo.org/NEFA%20Biomass%20BMP%20comparison%20Report%20FINAL%209.2012.pdf
[26] Ibid.

Environmental Protection Agency (EPA) has developed standards and combustion equipment certifications to help increase combustion efficiency and lower emissions.

One portion of the residential biomass thermal market that is experiencing state and even municipal regulations regarding air quality is the Outdoor Wood Boiler (OWB) market. Regulations for OWBs vary from state to state. Currently, all five states reviewed allow OWBs provided they meet EPA certification standards and follow specific guidelines in terms of stack heights and setbacks to neighbors, etc. However, several municipalities in Massachusetts currently ban the use of OWBs. Several states have programs to fund the change out/replacement of inefficient, polluting OWBs with more modern efficient options.

For the larger commercial and institutional boiler market there are widely varying permitting and emission thresholds from state to state. A summary is provided below in Table 2.

Table 2: Northeastern State Emissions Limits for Biomass Boilers[27]

State	Air Quality Permitting Threshold	Specific Limits for PM
New York	>1 MMBtu/hour output	0.6 pounds/MMBtu
Vermont	4.5 MMBtu/hour output	0.2 pounds /MMBtu and demonstrated use of BACT
New Hampshire	>2 MMBtu/hour output	0.3 pounds/MMBtu
Maine	10 MMBtu/hour output	Best Available Control Technology (BACT) determined on a case-by-case basis
Massachusetts	1 MMBtu/hour output	0.1 to 0.2 pounds/MMBtu

While there have been highly variable rules and emission limits from state to state, the new Federal EPA Maximum Achievable Control Technology (MACT) rules are moving toward greater consistency and may help move states toward greater consistency for larger boilers that fall under the MACT standards. Presented in Table 3 is a summary of the new EPA boiler rules based on the size of the boiler:

Table 3: Recently Adopted EPA MACT Rules for Biomass Boilers

Status	BTU Capacity	Boiler Technology	PM (lbs/MMBtu)	CO (ppm @7% O2)
Existing	>10MMBtu/hr	All technologies	N/A – Biannual tune-up required	
	< 10MMBtu/hr	All technologies	N/A – Biannual tune-up required	
New	>30MMBtu/hr	All technologies	0.03	N/A
	10-30MMBtu/hr	All technologies	0.07	N/A
	< 10MMBtu/hr	All technologies	N/A –Biannual tune-up required	

Each state has widely differing levels of ambient air quality and needs to be able to manage allowable point-source emissions based on good science specific to their ambient air quality situation. This results in some inconsistency in regulations across the Northern Forest region

[27] http://www.mass.gov/eea/docs/doer/renewables/biomass/doer-biomass-emissions-and-safety-regulations.pdf

and is experienced as a barrier to market entry by the biomass thermal industry. Industry representations suggest that even if emission limits vary, might the permitting thresholds at least be made more consistent? Eventually, as the biomass heating market grows, the industry matures, the fuels become more standardized, and the combustion equipment advances, it is hoped there will be less variability of the resulting emissions and air quality regulations and permitting will become more consistent and normalized regionally.

3.3 Boiler and Fire Safety

Different states have different boiler safety rules and fire codes. Historically, most states require boilers to be certified to the codes established by the American Society of Mechanical Engineers (ASME). ASME is a non-profit organization that sets industry standards that define the acceptable construction, inspection and testing of boilers and pressure vessels.[28] ASME standards for boiler safety are generic for all heating fuels—there are no specific standards for biomass systems.

Table 4: State Boiler Safety Requirements[29]

State	State Boiler Requirements[30]
New York	Requires ASME certified boilers primarily for public and commercial buildings. Local residential building codes regarding boiler certifications may vary.
Vermont	Vermont requires all boilers to meet ASME standards however in 2011 the rules were revised to allow boilers with either Canadian Standards Association or European Committee for Standardization certification only for boilers under 250,000 Btu/hour (input).[31]
New Hampshire	New Hampshire allows EN303-5 accredited boilers up to 300kWh (roughly 1.0 MMBtu/hr output) but requires everything else to be ASME stamped.[32]
Maine	Maine requires ASME boiler certification for public and commercial buildings. Local residential building codes regarding boiler certifications may vary.
Massachusetts	Massachusetts has the most restrictive requirements – they require ASME boiler certification for public, commercial, ***and residential*** buildings.

In the past four to five years, a few states have relaxed their state requirements for all boilers to carry ASME certifications and have recognized equivalent European or Canadian standards as an effort to see more high-efficiency, low emissions appliances from Europe installed. See Appendix C for a full copy of Vermont S.293 that changed the rules to allow European boiler safety certifications.

Several years ago, many European boiler manufacturers who were interested in selling in the US market had not achieved ASME certification and the state requirements were a considerable deterrent to attracting these manufacturers of modern, efficient biomass fueled heating systems to the US market. However, in the past few years an increasing number of

[28] http://files.asme.org/Catalog/Codes/PrintBook/34011.pdf
[29] http://www.mass.gov/eea/docs/doer/renewables/biomass/doer-biomass-emissions-and-safety-regulations.pdf
[30] Ibid.
[31] http://firesafety.vermont.gov/sites/firesafety/files/pdf/06FireCodeADOPTEDJune2009CORRECTED2011.pdf
[32] http://www.gencourt.state.nh.us/rules/state_agencies/lab1200.html

European pellet boiler manufacturers have gone through the process to achieve ASME certification for their systems and this no longer seems to be a critical issue preventing the import of the efficient and clean technologies manufactured in Europe.

There is a need for greater regional consistency for boiler safety standards which is not considered a critical barrier for the industry but rather an inconvenience. Perhaps the larger barrier associated with these standards is the issue of how the standards are enforced. Boiler safety standards are enforced by different agencies and departments from state to state. Most states rely predominantly on private-sector insurance inspectors to enforce state boiler safety codes for private buildings. Inconsistency in how and when the codes are enforced is reported repeatedly by industry representatives. Also reported is how private insurance companies and their inspectors view modern, bulk-fed, central biomass heating systems. Many insurance companies do not recognize centralized biomass heating systems as sole sources of heat in the same way as oil, propane or gas natural gas fired boilers or furnaces are, and this presents issues for homeowners seeking to secure mortgages with a centralized biomass heating system as its primary heat source.

3.4 Heat Sales

With the strong potential for more biomass district heating and companies offering large commercial or institutional customers delivered heat (instead of buying the boiler and fuel themselves), there is a certain level of ambiguity whether these new business models will fall under some level of state and/or federal regulation as energy "utilities." Centralized biomass district heating plants using modern, efficient, thermal energy delivery (piped hot water) function in the same way as electric utilities—instead of poles and wires delivering electricity, there are buried water pipes delivering heat to customers.

Heat sales and regulations for metering are important for several reasons. Selling heat is a core component of district heating. Second, selling heat is a new business model being offered by an increasing number of biomass thermal energy businesses. Rather than sell boilers and the fuel, they install their own boilers, provide the fuel and service, and sell the customer metered heat. Heat metering is an important part of heat sales and is a key ingredient in a thermal RPS policy and the delivery of thermal RECs.

In Vermont, biomass district heating is subject a wide array of state and local permitting—local zoning, state air quality permitting, state development permitting (Act 250), and Certificate of Public Good permitting (Act 248) if the project is a combined heat and power project (CHP) featuring grid interconnection. However, in Vermont there are currently no heat utility specific regulations similar to those applied to suppliers of electricity.[33] Currently, the biomass district heating project under way in Montpelier, Vermont has no regulatory oversight by the State of Vermont's Public Service Department (the department who regulates energy, telephone, and other utilities in the state).

In New Hampshire, Senate Bill 74 passed in the 2013 legislative session and that legislation exempts hot water district heating systems and their operators from being considered a "public utility" and as a result exempts the district heating system for New Hampshire PUC regulations.[34]

[33] http://www.biomasscenter.org/images/stories/District_Energy_Permitting.pdf
[34] http://www.gencourt.state.nh.us/legislation/2013/SB0074.html

At this time there is little need for regulatory oversight and control of heat metering and district heating as there is limited market activity. However, as this sector grows in the future, a certain level of regulatory oversight or perhaps industry standards may help provide consistency to project developers and develop public (and market) trust in the concept of buying thermal energy by the delivered Btu–not the fuel by the gallon or cubic foot. Ultimately, there is a need to demonstrate to the market place that district heating and metered contractual heat sales are a viable and trusted way to purchase energy. Some level of thoughtful and appropriate regulatory oversight or industry standards may help to achieve that.

4.0 Financial Policy Overview

A policy signal is sent on the extent to which a new or emerging market is being encouraged—in part based on the availability of funding and/or financial incentives for the services or goods being brought to market. A variety of funding sources and financial incentives (such as grants, system rebates, low-interest loans, and loan guarantees) can be an effective method for helping to develop the market for biomass thermal energy. Thus far, grants have played an important role in helping establish many of the early installed projects. Over time, other financial incentives such as system rebates and creative financing options have come into play. Presented below is a summary of key funding sources and financial incentives that have been, or could be, used to advance the development and use of biomass thermal energy. This information is provided to inform future policymaking in the Northern Forest region (and beyond).

4.1 Federal Grants

Federal grants for biomass thermal energy have been available periodically over the years and have helped establish both individual biomass thermal projects as well as comprehensive programs that resulted in multiple biomass thermal projects within a given geographic area.

The USDA Forest Service is a long-time supporter of wood energy and has offered millions of dollars in grants to the development of a wood energy market to help achieve the forest management objectives of forest ecological restoration and stewardship thinnings to reduce risk of catastrophic wildfires. Many of the Fuels for Schools woodchip heating systems in western states such as Montana and Idaho were funded largely with grants from the USDA Forest Service. The Wood Education and Resource Center (WERC), a program of the USDA Forest Service, has offered a number of biomass energy grants over the years specifically aimed at the Northeast region of the US.[35] In addition, the USDA Forest Service administers a few other grant programs aimed at wood energy including the Woody Biomass Utilization Grants.

Other federal agencies that offer grant programs that can be used toward funding biomass thermal energy projects and programs include the US Department of Energy Biomass Program and USDA Rural Development, for example.[36, 37]

While many of the federal grant programs have resulted in multiple successful biomass energy projects, the funding is highly competitive and the availability of funds is variable, depending on federal priorities.

4.2 State Grants

State grants also have had a vital role in advancing biomass thermal energy in the Northeastern US. The Vermont School Energy Program provided grants to public schools installing woodchip and pellet systems over the last decade. Over the past two years, both New Hampshire and Maine have developed aggressive state grant programs that assisted a number of biomass heating projects – primarily for heating institutional buildings. Presented in Table 5 are highlights of key state funding programs that can be (or recently were) used for biomass thermal projects and/or programs:

[35] http://www.na.fs.fed.us/werc/grants.shtm
[36] http://www1.eere.energy.gov/bioenergy/
[37] http://www.rurdev.usda.gov/Energy.html

Table 5: Potential State Funding Sources for Biomass Thermal Projects

State	Agency	Funding Source
New York	New York State Energy Research and Development Authority (NYSERDA)	NYSERDA periodically issues competitive solicitations for R&D grants that could be used for biomass thermal technologies or projects.[38]
Vermont	Vermont Public Service Department (VT PSD) - Clean Energy Development Fund	$500k to be granted in 2014 as part of Community Clean Heat Challenge.
New Hampshire	New Hampshire Public Utilities Commission (NH PUC)	NH PUC offers grant funding (via noncompliance payments from RPS) for renewable-energy projects installed at commercial, industrial, public, non-profit, municipal or school facilities, or multi-family residences.[39]
Maine	Maine Forest Service (MFS)	$10 Million in one-time ARRA funds were available beginning in 2009. Funds have since been allocated and currently no future funding of grant program is in place.[40]
Massachusetts	Massachusetts Department Of Energy Resources (DOER)	"Green Communities" state renewable energy grant program allocates funds from Regional Greenhouse Gas Initiative (RGGI).[41]

Similar to federal grants, state grants can be an extremely helpful tool to selectively target new and innovative projects. Generally, federal and state funding is most effective when used on a sustained basis, over multiple years to fund programs and projects that address market barriers, and encourage the sustained, orderly development of markets over time, with reduced public intervention as the market matures. Looking to the future there is an opportunity to use one-time funding for grants to fund innovative and first of their kind projects (such as new CHP technology, district heating, and state of the art emission control technology). In addition, there is an opportunity to use modest state-level funding toward programmatic support services to catalyze the installation of multiple biomass heating projects.

[38] http://www.nyserda.ny.gov/Funding-Opportunities/Current-Funding-Opportunities.aspx
[39] http://www.puc.nh.gov/Sustainable%20Energy/RFPs.htm
[40] http://www.maine.gov/doc/mfs/arra/pages/documents/RFP200910535WoodtoEnergyProgramFinalfordistribution_MKandPJB.pdf
[41] http://www.mass.gov/eea/energy-utilities-clean-tech/green-communities/

4.3 Biomass Heating System Rebates

Rebate programs provide financial assistance to overcome initial capital costs that can be a barrier to customer investment absent the rebate. Optimization of such programs involve setting the rebate high enough to stimulate private investment, but low enough to enable sufficient rebates to generate enough participation to help develop the market. Presented in Table 6 are highlights of various state biomass boiler rebate programs:

Table 6: State Biomass Thermal Rebate Programs

State	Administrator	Requirements	Notes
New York	None at this time		
Vermont	Efficiency Vermont (EVT)[42]	• Fuel storage of at least one ton (or at least 7 days of uninterrupted system operations without refilling fuel storage) • Automated fuel feeding from fuel storage • On/off system controls • Ability to modulate firing as heating load increases/decreases. • Systems must meet all EPA and VT standards for PM emissions • Systems must be installed indoors by a professional	• Offers $1,000 toward a pellet boiler or furnace system (no stoves) • Legislative mandate is to provide 30% cost share – funding is currently insufficient to meet this funding level. • Current funding comes from forward capacity credit payments and RGGI payments to the State of Vermont.
New Hampshire	NH PUC[43]	• Primary residents (no second homes) • Thermal efficiency rating of 80% or greater • 0.32 lbs/MMBtu heat output or less for PM • Bulk fueled with a minimum of three tons storage capacity	• Offers 30% or $6,000 toward the cost and installation of a pellet boiler of furnace system (whichever is less) • Originally ARRA funded program now funded via Alternative Compliance Payments from NH electric utilities
Maine	Efficiency Maine[44]	• Details are still being sorted out	• Brand new program
Massachusetts	Clean Energy Center (CEC)[45]	• Year round home or small business	• Non-compliance payments for APS • One time pot of funds - $475,000 issued in March 2013 – over subscribed as of

[42] http://www.efficiencyvermont.com/for_my_business/ways-to-save-and-rebates/hvac/rebates/all_rebates.aspx
[43] http://www.puc.nh.gov/Sustainable%20Energy/RenewableEnergyRebates-WP.html
[44] http://www.onlinesentinel.com/news/Details-still-to-be-ironed-out-with-new-home-heating-rebate-program-from-Efficiency-Maine.html?pagenum=full
[45] http://www.masscec.com/programs/commonwealth-small-pellet-boiler-program

			June 6th 2013 • Offers between $7,000 and $15,000 toward high-efficiency pellet boilers

Programs to deliver modest financial rebates toward the purchase and installation of modern, efficient, clean burning, and centralized biomass heating appliances can play a key role in kick-starting the market. However, it is essential that rebate programs secure long-term stable funding sources and are managed to provide the optimal level of rebate to effectively stimulate fuel switching without overpaying and creating long-term market expectations and dependency.

Numerous states with pellet boiler rebate programs, such as Vermont and New Hampshire, are challenged with how to adequately and sustainably fund the programs as are other states looking to develop such programs, such as Maine. Three potential long-term funding mechanisms that could be used to provide adequate financial resources to state-wide rebate programs are discussed in detail in Section 5.0 of this report.

4.4 Tax Credits

Another policy option that is currently used in the region and could be expanded and extended is the use of tax credits. The following section discusses the current use and potential to further use sales, income, investment, and property tax exemptions/credits to incent the installation and use of biomass heating systems.

4.4.1 Sales Tax Exemptions

While waiving the state sales tax may not have a huge impact to incentivize the biomass thermal sector (most state sales tax is 4-7%), it is a powerful symbolic gesture that can send a positive signal to the market place that state policymakers support biomass thermal.

Table 7: State Sales Tax Policies for Biomass Boilers and Fuel

State	Sales Tax on Equipment	Sales Tax on Fuel
New York	Biomass boilers are subject to sales taxes.	Exempts wood for residential and multi-family housing heating fuel from state sales tax and allows towns to also exempt the fuel from local sales tax. Other sectors (schools, businesses have to pay sales tax on pellets, chips and firewood)
Vermont	Sales tax exemption for biomass boilers	Sales tax exemption for biomass fuel
New Hampshire	No sales tax for any goods or services	No sales tax for any fuel [46]
Maine	Charges 5% sales tax on boilers	Residential wood fuel is exempt. Commercial sector is taxed.
Massachusetts	Charges sales tax on boilers (MA offers sales tax	Residential heating fuels (including wood) are sales tax exempt. Commercial and industrial

[46] There is no sales tax on the fuel in New Hampshire but there is a state stumpage tax paid on wood fuel at the point of harvest.

	exemptions on solar hot water, PV, wind, heat pumps – just not biomass systems)	fuel is taxed but with some exceptions.

Of the five states examined, Vermont offers a sales tax exemption for both biomass heating appliances and for biomass fuel. The New Hampshire exemption is not because of a preferable treatment of biomass heating, but rather a component of their overall sales tax policy for all goods.

4.4.2 Income Tax Credits

No states in the US currently offer an income tax credit for the purchase of biomass thermal heating equipment. However, there are several states that offer income tax credits for other renewable energy equipment. For example, New York has an income tax credit (25% - maximum $5k) for solar PV and solar thermal systems.[47] In addition, New York offers an income tax credit for the purchase of bio-diesel fuel for residential space and water heating. [48] These are two examples of state income tax credits used on both alternative heating ***equipment*** and alternative heating ***fuel*** that could potentially be extended to apply to biomass heating.

While there are currently no state income tax credits available for biomass thermal, it is important to note a federal bill introduced by Senator Angus King of Maine on May 22, 2013. The **Biomass Thermal Utilization Act of 2013 (BTU Act)** is a bill that proposes to amend the Internal Revenue Code of 1986 to include biomass heating appliances for tax credits available for energy-efficient building property and energy property. The bill would provide a 30% tax credit for high efficiency residential biomass heating equipment and a two-tiered Investment Tax Credit of 15% or 30%, depending on the operating efficiencies for commercial and industrial biomass systems. [49]

The bill defines "qualified biomass fuel property expenditure" as an expenditure for property which uses the burning of biomass fuel (a plant-derived fuel available on a renewable or recurring basis) to heat a dwelling used as a residence, or to heat water for use in such dwelling, and which has a thermal efficiency rating of at least 75%. The bill allows an energy tax credit until 2017 for investment in open-loop biomass heating property, including boilers or furnaces which operate at thermal output efficiencies of not less than 65% and provide thermal energy.

This bill has not yet passed out of committee and has not yet been voted on by either the US Senate or the US House of Representatives. It is not certain the bill will continue to move as the Chairs of the House and Senate tax writing committees seek to reform the tax code. In general, the focus on tax reform has ceased discussion about new tax proposals at this time. If this Congress moves forward with tax reform, it seems unlikely new taxes will be added to the tax code. If tax reform fails, the tax committees might return to the regular order of considering bills and this bill could potentially be reconsidered at that time.

[47] http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=NY03F&re=0&ee=0
[48] http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=NY84F&re=0&ee=0
[49] http://www.govtrack.us/congress/bills/113/s1007

4.4.3 Investment Tax Credits

In addition to income tax credits, it is possible for state and federal governments to provide investment tax credits to businesses that make investments in biomass heating systems. Of the five states reviewed for this study, Vermont currently offers an investment tax for installations of renewable energy equipment on business properties, including biomass equipment. The credit is equal to 24% of the "Vermont-property portion" of the federal business energy tax credit.[50] This investment tax credit is not applicable to individuals.

One interesting example that could be considered by other states is the Oregon tax credit for Renewable Energy Equipment Manufacturers. Targeted for industry recruitment, biomass boiler manufacturers who set up in Oregon are eligible for a business tax credit of 50% of eligible costs (10% per year for 5 years).[51]

4.4.4 Property Tax Exemptions

New York, Vermont, and New Hampshire state laws allow the option for municipal governments to waive property taxes for various renewable energy projects including biomass. Maine does not have such a law in place. Massachusetts law does not list biomass as an eligible form of renewable energy for their property tax exemption.

4.5 Finance Mechanisms

Another approach to stimulating market activity is to develop programs that provide access to financing. In addition to traditional commercial financing, there are numerous creative financing programs supported by public policy. Each state has multiple financing options such as, for example, revolving loan funds targeted for community projects that include the use of renewable energy. In addition, federal agencies such as the USDA Rural Development Agency offer low/no interest loans, loan guarantees, and other financial instruments.

4.5.1 Property Assessed Clean Energy (PACE)

An emerging and potentially important way for financing energy efficiency upgrades or renewable energy installations for buildings is through a Property Assessed Clean Energy (PACE) offering. In areas with enacted PACE legislation, local governments can offer to loan money to residents and businesses to install energy retrofits and renewable energy systems through the issuance of a municipal bond. The energy-related capital costs are repaid by the property owner over the term of the loan (typically 20 years) through an assessment on their property tax bill by the municipality. This type of creative financing approach helps home and small-business owners overcome the significant upfront costs of installing energy efficiency measures and renewable energy systems, such as biomass heating systems.

To date PACE enabling legislation has passed in 30 states. Thus far all of the Northern Forest states have enacted PACE programs and the status of the PACE offerings in the states is provided in Table 8:

[50] http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=VT37F&re=0&ee=0

[51] http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=OR107F&re=0&ee=0

Table 8: PACE Offerings in the Northern Forest States

State	PACE Program Manager	Details
New York	Energize New York[52]	Commercial and low-income housing sectors in select communities
Vermont	Efficiency Vermont	State enabling legislation passed residential program offered in 13 municipalities that have passed local PACE enabling resolutions thus far.[53]
New Hampshire	None	State enabling legislation passed but no program enacted yet.
Maine	Efficiency Maine	Residential
Massachusetts		Municipalities are authorized to create revolving loan funds.

Once state level legislation has passed, the local adoption PACE financing works through a progression of basic steps:

1. The local government creates a PACE assessment or charge.
2. The property owner agrees to the terms offered by the local government.
3. Local government provides the financing for the project and adds the assessment of the project to the property owner's tax roll.
4. The property owner pays the assessment to the local government for up to 20 years.

To date, PACE programs have been slow to get started, with Vermont currently being the farthest along in the Northern Forest region. Key provisions in the Vermont enabling legislation include:[54]

- The legislation enables municipalities to create and secure debt for a PACE program if they choose, and to secure funding to pay for energy efficiency and renewable energy projects.
- Participating municipalities can join together to obtain funding more cost effectively.
- Participating property owners pay for the benefit over up to 20 years through a special assessment charged as an additional line item on their property tax bills.
- The maximum amount that can be financed is 15% of the assessed value of the property, capped at $30,000. The total amount financed by PACE plus any outstanding mortgages on the property cannot exceed 90% of the assessed value.
- Participants must contribute to a loan loss reserve fund.
- Non-participating property owners have no obligation to pay for any of the costs of a PACE district.

There are some significant benefits to a PACE program. It is a creative way to remove the financial hurdle of the high capital costs of renewable energy projects. Biomass heating systems are eligible. PACE allows for positive cash flows because the debt service is spread over 20 years rather than the 5 to 10 years commonly offered through bank financing. In addition, property owners who do not choose to participate incur no cost.

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[52] http://energizeny.org/

[53] To date, 13 Vermont towns have voted to create PACE districts including Albany, Burlington, Cornwall, Craftsbury, East Montpelier, Halifax, Marlboro, Montpelier, Newport, Putney, Thetford, Waitsfield and Westminster.

[54] http://pacevermont.wikispaces.com/Welcome+to+PACE+Vermont

4.5.2 Clean Renewable Energy Bonds (CREBs)

The federal Energy Act of 2005 established this financial mechanism to finance renewable energy projects – primarily by the public sector. Administered by the IRS, Clean Renewable Energy Bonds (CREBs) are tax credit bonds, where the borrower who issues the bond pays back only the principal of the bond, and the bondholder receives federal tax credits in lieu of the traditional bond interest. The tax credit may be taken quarterly to offset the tax liability of the bondholder.[55] The program is relatively complex and few, if any, have used this to finance biomass thermal projects.

[55] http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=US51F&ee=1

5.0 Legislative Policy Overview

In addition to the renewable energy, regulatory, and financial policies discussed above, there are state-level Renewable Portfolio Standards (RPS), System Benefits Charges (SBC), and Lead by Example (LBE) policies and/or programs that can have significant impacts on market development in a state. Presented below is the status of RPS, SBC, and LBE policies in place in the four Northern Forest states (as well as other states, when relevant to the discussion). This information is provided to help inform future biomass thermal legislative policy activities in the Northern Forest region.

5.1 Thermal Inclusion in State Renewable Portfolio Standard

A Renewable Portfolio Standard is a policy that requires increased production of energy from renewable energy sources. An RPS policy generally places an obligation on ***electric utilities*** within a given jurisdiction to produce a specified portion of their ***electricity*** from renewable energy sources – such as wind, solar, biomass, hydro, etc. RPS policies typically allow generators of approved renewable energy to earn certificates for every unit (typically a megawatt hour [MWh]) of electricity they produce. These certificates (referred to as Renewable Energy Credits [RECs]) can be sold to the utilities to demonstrate they meet the required RPS targets. RECs are the foundation of an RPS policy and provide a market mechanism for achieving policy goals stated in an RPS. When a power producer generates 1 MWh of renewable energy, it generates 1 REC. The power producer can sell the REC to a utility to help the utility meet their state-mandated target for renewable energy in the state's energy portfolio. This market-based system provides incentive for the construction of new renewable energy systems and increases demand for their output.

Over the course of roughly two decades, state-level Renewable Portfolio Standards for the promotion of renewable ***electric*** energy have been widely adopted – today 29 states and the District of Columbia have some sort of Renewable Portfolio Standard (RPS) in effect.[56] While most states with an RPS focus on electrical energy generation, the same concept can be applied to both energy efficiency and thermal energy. Currently 12 states include CHP eligibility in their electrical RPS.[57] Several states also currently allow energy efficiency as a means to generate RECs.

In addition to the targets for achieving certain levels of electrical energy from renewable sources, there is growing interest among the biomass and solar thermal industries as well as among some regulators and policymakers to include thermal energy in RPS strategies. They pose this would achieve a more comprehensive approach to energy policy that addresses both electricity and thermal energy simultaneously. Conceptually, there are two ways to include thermal energy in an RPS:

- Develop a separate thermal RPS that requires fossil heating fuel suppliers to purchase RECs from renewable thermal energy generators; or
- Allow thermal energy from eligible renewable energy sources to qualify for RECs purchased by electric utilities that currently are only allowed to purchase RECs from renewable electric generation.

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[56] http://www.dsireusa.org/documents/summarymaps/RPS_map.pdf
[57] http://www.dsireusa.org/

It is technically possible for thermal energy to be metered and measured (just as electricity is) and in many countries other than the US it is common to do so. Although in the US thermal energy is most often measured in British Thermal Units (BTU), it is already common in other countries to meter, measure, and sell thermal energy on the basis of kilowatt-hour equivalents. Thinking about and measuring thermal energy in terms of kilowatt or megawatt hours enables the application of an RPS to readily include thermal energy as well as electricity. Typically, each REC has a minimum value of 1 kWh for the purpose of RPS compliance. For a thermal credit, 3,412 Btu of useful thermal energy is equivalent to at least 1 KWh for purposes of compliance with an RPS.

Presented in Table 9 is a summary of states that have adopted some form of thermal energy in RPS policies (usually focused on solar thermal and not biomass thermal), and that now enable the selling of thermal RECs:[58]

Table 9: States with an RPS that Includes Thermal Energy

State	Type of Thermal Energy Recognized in RPS
Arizona	Solar water heat & solar space heat
Delaware	Solar water heat & solar space heat
Hawaii	Solar water heat, solar space heat, & solar process heat
Indiana	Solar water heat & solar space heat
Nevada	Solar water heat & solar space heat
New Hampshire	A range of renewable energy sources, including biomass thermal
New York	Solar water heat
Pennsylvania	Solar water heat, solar space heat, & solar process heat
Utah	Solar water heat, solar space heat, & solar process heat
Washington D.C.	Solar water heat, solar space heat, & solar process heat
Wisconsin	Solar water heat & solar space heat

The inclusion of thermal energy from renewables in an RPS results in the need to meter and measure the energy. Btu meters are commercially available on a widespread basis in Europe, for example, and consist of a relatively simple combination of supply and return temperature sensors, a flow gauge, and a calculator. Currently, there are no official heat metering standards at the national level in the US. Both the ASTM and the US EPA are working on adopting a national standard for accurate measure and reporting of thermal energy. The cost to measure and verify thermal energy is a factor when considering a thermal RPS and economies of scale are likely to inspire utilities to source thermal RECs from larger energy projects.

Recent analysis conducted by Future Metrics and presented at the 2013 Heating the Northeast Conference indicates that, given the higher system efficiencies of biomass thermal energy projects compared to biomass power plants, thermal RECs are expected to have a lower cost of compliance than RECs produced from biomass power plants due to the cost of the fuel and the efficiency of its use.[59] Based on this rationale, RECs produced by biomass thermal energy projects may present a lower cost of compliance than biomass power plants for utilities operating in states with a biomass thermal RPS in place.

[58] http://www.dsireusa.org/
[59] http://heatne.com/pdfs/2013/Breakout%20Session%201/strauss.pdf

It is very important to note that thermal eligibility in RPS policies do not necessarily offer price certainty for thermal RECs and one of the greatest barriers to biomass thermal energy is the high first costs which typically would not be addressed by annual thermal REC payments. In order to make thermal RECs effectively overcome the first cost barrier of purchasing and installing biomass heating systems, creative RPS mechanisms need to be used–such as issuing multi-year (5-10) "strips" of thermal RECs to create bankable revenue that can be used toward successfully financing projects.[60] By allocating multi-year strips of RECs to qualifying renewable energy projects, the market value of the REC strip does not fluctuate overtime and can therefore be used to secure project financing.

5.1.1 Example – New Hampshire's Recent Inclusion of Thermal Energy in their RPS

In 2012 the New Hampshire legislature passed Senate Bill (SB) 218 to include thermal energy in the State's existing RPS policy. According to the law, the "Class I Thermal Renewable Energy Certificate Program" is an amendment of the Renewable Portfolio Standard law and creates a Class I sub-class for useful thermal renewable energy from solar, biomass, and geothermal sources. Effective January, 2013, **0.2%** of Class I REC requirements are to be met with thermal resources. The requirement increases by **0.2%** annually to **2.6%** by 2025. The New Hampshire Public Utilities Commission (NH PUC) is required to "establish procedures by which electricity and useful thermal energy production not tracked by ISO-New England from customer-sited sources, including behind the meter production, may be included within the certificate program, provided such sources are located within NH."[61]

This new law requires the NH PUC to establish procedures for metering, verifying and reporting thermal energy output from qualifying systems on a quarterly basis. The PUC will then certify this energy output for Renewable Energy Certificates which can then be bought and sold in regional REC markets, just as electricity is. Systems will require BTU meters in order to accurately meter heat energy output.

The law sets the Alternative Compliance Payment (ACP) for renewable thermal energy at $28/MWH, the lowest level of any existing class. It is likely that RECs will sell for less than the $28/MWh ACP. The small percentage increase in the RPS mandate, combined with a low ACP is expected to result in a bill impact of $0.098 (9.8 cents) per month for an average residential electric bill of 600 kWh.[62]

The law also establishes emissions standards for biomass heating systems, as proposed and supported by the New Hampshire Department of Environmental Services (NH DES) including the following:

- For biomass energy systems between 3 and 30 MMBtu/hr (input capacity), systems must demonstrate one time stack testing emissions rate below 0.1 lbs/MMBtu for particulate matter.
- For biomass energy systems greater than 30 MMBtu/hr (input capacity), systems must demonstrate emissions rates less than 0.02 lbs/MMBtu.

[60] http://www.mass.gov/eea/docs/doer/pub-info/heating-and-cooling-in-aps.pdf
[61] http://www.puc.state.nh.us/Sustainable%20Energy/Class%20I%20Thermal%20Renewable%20Energy.html
[62] Ibid.

5.1.2 Example - Massachusetts Legislation to Add Thermal renewable Energy to APS

In the beginning of 2013, members of the biomass, geothermal heat pump, solar thermal, renewable natural gas, bio fuel, and oil supply industries came together to create a campaign to enact legislation that would include a Thermal Energy component in the Massachusetts Alternative Energy Portfolio Standard (APS).[63] On January 18, 2013, Massachusetts Senate Bill (SB) 1593 was filed by Sen. Finegold of Andover. SB 1593 would add heating and cooling from renewable fuels to the technologies eligible for Alternative Energy Credits in the state. Technologies that produce useful thermal energy using fuels such as sunlight, biomass, bio-gas, bio-liquids, and temperature differences in the ground and air would be eligible. Such technologies currently can receive credits when used to produce electricity, but not when used to produce thermal energy. Public testimony on SB1593 was taken in July of 2013 and the bill is now in joint committee. SB 1593 is presented in Appendix A.

Similar legislation was recently introduced in Maine (see Appendix B) and Connecticut to recognize thermal renewable energy sources as part of the compliance strategies in their electrical RPS.

5.2 System Benefits Charge (SBC) on Heating Fuels

For many years numerous states have imposed a modest surcharge on regulated forms of energy –specifically electricity and in some cases natural gas. Revenues generated from the surcharge are used to finance energy efficiency programs delivered by electric and gas utilities, or by a third-party program administrator such as Efficiency Vermont and Efficiency Maine. These energy surcharges are referred to as a “system benefits charge” (SBC) when applied to electricity and referred to an energy efficiency charge (EEC) or location distribution adjustment charge (LDAC) when applied to natural gas. They have generated billions of dollars throughout the US that are invested in energy conservation and efficiency programs that benefit rate payers served by the utilities, and can serve as a model for a similar surcharge that could potentially be used to advance biomass thermal energy.

As referred to by biomass thermal advocates, a “thermal SBC” could take the form of a modest assessment administered at the state level on heating fuels, such as oil and propane. The main challenge for applying an SBC approach to biomass thermal is that SBCs are typically assessed on customers of regulated energy utilities and the incentives created by these surcharges generally do not fund programs that *eliminate* the customer’s use of the that regulated energy – but rather *lower* their use (i.e. efficiency). Following the example of an SBC applied to electric bills, a thermal SBC could be used to fund thermal efficiency measures (rather than for fuel switching).

A legislative proposal was recently made in Massachusetts to establish an SBC of $.025 (or 2.5 cents) per gallon for heating oil and propane, the proceeds from which would be used to fund energy efficiency programs directed at heating oil and propane users.[64] A full copy of Massachusetts H.3897 can be found in Appendix D.

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[63] http://www.masscleanheatbill.org/

[64] https://malegislature.gov/Bills/187/House/H03897

A recent op-ed article included a detailed proposal for how a thermal SBC could be implemented and how the funds could be used.[65] The article called for establishing a fund through a thermal SBC that would be used to:

- Finance comprehensive education and outreach to the residential, commercial, and industrial sectors;
- Support the adaptation of the traditional fossil heating appliance and fuel industry to renewables; and
- Provide financial incentives, such as rebates, toward the purchase and installation of biomass heating systems.

It is further suggested that the SBC fee be applied to both fossil fuels used for heating and to renewable fuels, such as wood pellets, where there is a mature fuel distribution system in place. The SBC could be adjusted periodically to help level out the highs and lows of fossil heating fuel prices, and might be faded out over time as the renewable energy-based thermal market matures. The use of an SBC applied to both fossil and renewable fuels, such as wood pellets, used for thermal energy is an interesting policy option for further stimulating the biomass thermal market in the Northern Forest region. Examples of key questions to consider further in future policy activities should include:

- How to tie the SBC to achievable and measurable goals as an RPS policy does?
- Whether the SBC should apply to all heating fuels including renewables, such as wood pellets and chips?
- What is the optimum value for an SBC and how much of a thermal SBC fee would be tolerated by policymakers, regulators, the thermal industry, and consumers?
- How to ensure fair and equitable access to funds by all sectors: residential, commercial, and industrial?
- How to establish program and policy without technology or fuel bias?
- Who will evaluate, measure, and verify progress toward meeting goals?

One interesting example of an existing heating fuel surcharge is the Vermont Weatherization Trust Fund which applies a 0.5% tax on gross sales receipts on the suppliers of heating fuels including natural gas, heating oil, propane, and kerosene to help fund low-income weatherization programs in the state.[66] Such a program could serve as a template and could potentially be expanded to provide funding to renewable heating technologies such as biomass and solar to compliment the current efficiency programs.

5.3 Public Lead by Example (LBE) Programs

State and municipal governments own and operate hundreds of facilities and this presents a unique opportunity for governments to lead by example. Installing energy efficiency measures and renewable energy systems can help state and municipal governments lower energy costs, reduce carbon emissions, and perhaps most importantly visibly demonstrate to the private sector that renewables, such as biomass thermal, work and are becoming more mainstream. State governments have often become leaders in the use of renewables by taking action through legislation or executive order to achieve a target goal for energy use in their own buildings and vehicles. Municipal governments are increasingly taking actions as well.

[65] http://www.renewableenergyworld.com/rea/news/article/2012/07/time-to-consider-a-thermal-system-benefits-charge
[66] http://www1.eere.energy.gov/wip/solutioncenter/pdfs/fundingforenergyefficiencyprogramsforunregulatedfuels.pdf

State and local governments operate many facilities, including office buildings, public schools, colleges, and universities, and the energy costs to run these facilities can account for as much as 10% of a typical government's annual operating budget.[67] An excellent example of a LBE policy adopted by state government is the Vermont Buildings and General Services Department (VT BGS) whose energy plan calls for the use of biomass heating systems in state owned facilities.[68] Vermont BGS manages dozens of buildings (court houses, state office buildings, police facilities, and hospitals) heated with woodchips, pellets, and cordwood. Two other examples of state government LBE programs are the 2011 NH Hampshire Executive Order calling for reduced energy consumption and increased energy efficiency and the Massachusetts Energy Reduction Plan for State Buildings.[69, 70]

5.4 Building Code Requirements

In addition to LBE, state and local governments have the option to enact building code requirements that set energy efficiency thresholds and thresholds for the use of renewable energy. While there are numerous examples of voluntary building certification systems such as LEED that provide points toward the use renewables, there are few states that have pursued mandatory policy.

All states that accepted federal American Resource Recovery Act (ARRA) funds were required to pledge to the U.S. Department of Energy that they would achieve 90% compliance with International Energy Conservation Code (IECC) in residential buildings and the ANSI code for commercial buildings by 2017. That is an ambitious target and there is no enforcement mechanism in place for monitoring progress. Many states have adopted such codes while indicating meeting the codes is voluntary. One state that has enacted mandated building code requirements for energy efficiency is California where mandatory building efficiency standards were adopted in 2008.[71] In Europe, building code requirements for the use of energy efficiency and renewables are widespread. Upper Austria, for example, has a requirement since 2008 that all new or renovated private buildings larger than 10,000 square feet in size must use renewable energy for space and hot water heating.[72]

[67] http://www.aceee.org/sector/state-policy/lead-example-initiatives
[68] http://bgs.vermont.gov/sites/bgs/files/pdfs/BGS-VTStateEnergyPlan.pdf
[69] http://www.nh.gov/dot/media/documents/energy-sept08.pdf
[70] http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=MA13R&ee=0
[71] http://www.energycodes.gov/adoption/states/california
[72] http://www.esv.or.at/fileadmin/redakteure/ESV/Info_und_Service/Publikationen/Biomass_heating_2010.pdf

6.0 Discussion of Market Drivers, Barriers, and Policy Solutions

Despite the variety of renewable energy, regulatory, and financial policies in place already in the Northern Forest region, some of which specifically address biomass thermal energy, a variety of barriers exist to further development of the biomass thermal market. Presented below is an overview of key market drivers affecting development of biomass thermal in the region, discussion of key barriers to further market development, and suggestions for policy solutions that could address the barriers. [73]

6.1 Market Drivers

The use of biomass thermal energy provides a variety of societal benefits including: the increased economic activity resulting from the use of local fuels; the positive environmental impacts of using renewable, low-carbon fuel; providing a market for biomass resulting from sound forest management practices; and keeping energy dollars in the local economy. In addition to these benefits, perhaps the greatest driver behind this sector's growth to date are the economic savings achieved for the end user from the lower cost of heating with biomass fuel compared to other heating fuel choices. Biomass heating fuels such as cordwood, woodchips, and wood pellets are typically 25 to 60% of the cost of fossil heating fuels, such as oil and propane, when assessed on the basis of cost per unit of energy (or heat) delivered to the customer. As shown in Table 10, heat provided by woodchips costs the end user $8.36 per million Btu (MMBtu) while the same amount of heat provided by propane costs the end user $35.17.

Table 10: Comparison of Heating Fuel Costs[74]

Fuel Type	Cost per Unit	Btu per Unit (dry)	Moisture Content	Average Seasonal Efficiency	Cost per MMBtu After Combustion
Natural Gas (ccf)	$1.15	102,800	0%	85%	$13.16
Oil (gallon)	$3.75	138,000	0%	80%	$33.97
Propane (gallon)	$2.75	92,000	0%	85%	$35.17
Woodchips (green ton)	$56.00	16,500,000	42%	70%	$8.36
Wood Pellets (ton)	$230.00	16,500,000	6%	80%	$18.54

6.2 Barriers to Biomass Thermal Energy

Despite the societal and end user benefits of biomass thermal energy, numerous barriers continue to impede market expansion for biomass heating. These barriers are discussed below.

[73] http://www.mass.gov/eea/docs/doer/renewables/renewable-thermal-study.pdf

[74] Calculated values based on average regional heating fuel prices for 2012/2013 heating season.

6.2.1 Capital Costs

Perhaps the single largest barrier is the high upfront capital cost for biomass heating equipment compared to natural gas, propane, or oil-fired furnaces or boilers. The purchase and installation costs for automated, self-feeding wood pellet and woodchip systems range from two to five times the cost of fossil fuel heating systems. A typical installed cost for a modern, efficient, bulk fueled residential pellet boiler is roughly $19,000 whereas a comparable oil system may cost approximately $8,500.[75]

6.2.2 Access to Capital

Despite the compelling potential heating fuel savings, borrowing funds to for the purchase and installation of biomass heating systems is a major challenge for both the residential and commercial markets. Many banks and traditional lenders perceive renewable energy financing as risky and often require higher interest rates, more owner equity, and shorter finance terms.

6.2.3 Public Awareness and Misconceptions

Modern, efficient, clean burning, automatically-fed biomass heating systems are not widely understood in the general public or in the heating, ventilating, and air conditioning (HVAC) industry in the US. Lasting impressions continue of outdated technologies which are remembered as dirty, unreliable systems that produce smoke. Key areas where there continue to be misconceptions about the potential impacts of expanded biomass thermal energy are:

- System performance and reliability;
- Emissions;
- Forest sustainability; and
- How biomass thermal solutions compare against other heating options.

6.2.4 Lack of Regulatory and Policy Framework to Incentivize Biomass Thermal

The thermal energy industry operates in an open and competitive market and is therefore not regulated in the same way the electric and gas utility industries are (both of which operate in a geographically-bound monopoly). As a result, the regulatory framework and mechanisms that are used to create and implement energy efficiency and renewable energy goals and requirements for electric and gas utilities do not apply to propane and heating oil suppliers. The thermal energy sector, as a result, lacks a regulatory structure and related regulatory mechanisms to incentivize thermal efficiency and renewable energy use compared to the electric sector.[76] Policies and programs designed to reduce consumption of fossil fuels through thermal efficiency measures and the use of renewable energy such as biomass face the challenges of securing funding sources and political difficulties in applying charges on fuels not regulated by the state Public Utility Commissions that oversee the electric sector.

6.2.5 Other Barriers

Looking beyond the propane and heating oil option, two additional barriers exist that may prove even more significant in the future. The push to expand the piping networks of natural gas in New England and the move to provide heating with electric-driven air source heat pumps will likely increase dramatically in the years ahead. Already several states in the region are moving toward policies that expand the use of natural gas and electricity to replace heating oil and meet their GHG emission targets.[77]

[75] Based on recent direct communications with numerous pellet and oil boiler vendors.
[76] http://www1.eere.energy.gov/wip/solutioncenter/pdfs/fundingforenergyefficiencyprogramsforunregulatedfuels.pdf
[77] http://publicservice.vermont.gov/sites/psd/files/Pubs_Plans_Reports/TES/Total_Energy_Study_RFI_and_Framing_Report.pdf

6.3 Policy Option Optimization

To optimize the effectiveness of policies aimed to advance biomass thermal energy, ideally policies should be developed in a way that seeks to directly address the key barriers discussed above. Presented in Table 11 are examples of policy options (or solutions) for addressing the key barriers.

Table 11: Policy Options for Overcoming Market Barriers for Biomass Thermal Sector

Barrier	Potential Policy Solution
High capital costs	• Federal 30% tax credit • State income tax credits • State funded rebate programs • Thermal inclusion in RPS in a way that creates "credit worthy" thermal RECs used toward capital costs
Public awareness	• Adopt policies such as "lead by example" programs by state and local government • Provide program support services to show case "best in class" projects using modern, efficient biomass thermal technologies • Support education, outreach, and training for architectural, building construction, insurance, real estate, and engineering professions
Lack of regulatory framework for thermal sector	• Develop comprehensive "total energy" approach including electrical, thermal, and transportation energy • Expand RPS to include thermal energy • Apply SBC to heating fuels
Expanded natural gas service into new jurisdictions	• Apply a SBC to natural gas to further fund thermal efficiency and renewables such as biomass
Expanded use of electric powered air source heat pumps	• Create policies to encourage the combined use of biomass boilers and heat pumps as back-up systems

6.3.1 Policy Design Criteria

No single biomass thermal policy is a "silver bullet" solution to solving the multitude of current and future barriers to biomass thermal energy. Instead, it will be a combination of policies that work together that will be needed, with some policies having greater impacts than others.

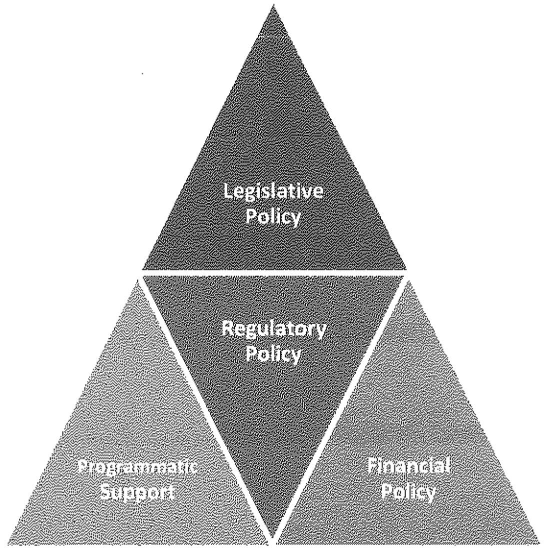
Ultimately, each state will need to evaluate numerous policy options and determine which policies will best achieve the desired effect. Presented in Table 12 are potential design strategies to use when considering potential policies to advance biomass thermal energy in a state.

Table 12: Design Strategy for Developing Biomass Thermal Policies

Design Strategy	Design Considerations
Pursue a multi-sector approach	Need to seek policies that support residential, commercial, institutional, and industrial sectors as well as community-scale district heating and that avoid benefitting one sector over another.
Create market "pull"	Need to help overcome the capital cost barrier (i.e. – if more boilers are installed, there is more demand for fuel.). Seek to avoid situations that try to push the market through over subsidizing the fuel.
Demonstrate the new "normal"	Need to help show that biomass heating is not "fringe" but rather an increasingly "mainstream" way to reliably and cost – effectively heat homes, businesses, and institutional buildings.
Expand markets within the regional resource capacity	Need to ensure markets do not grow beyond the regional capacity for sustainable biomass fuel supply.
Enhance market stability and predictability	Need to provide industry a stable, predictable regulatory environment as well as financial incentives that can be sustained over time as the market moves to increased private equity investments.
Create incentives from the thermal sector	When possible, strive to develop thermal incentives that are funded from within the thermal sector. Drawing funds for thermal incentives from the electric sector is not ideal under the current regulatory structure in most states.

A combination of policies is needed – regulatory, legislative, and financial as well as a programmatic structure and support for achieving the policies. Each state is unique and will design its own package of policies, and the ideal approach should use a portfolio of policies that include elements from each of the categories depicted in Figure 2 below:

Figure 2: Policy Pyramid



This approach to packaged biomass thermal policy and program development is similar to the approach used by the Upper Austrian energy agency (Oberösterreich Energiesparverband), an international leader in biomass thermal market transformation. The OÖESV advocates the "carrot, stick, and tambourine" approach in which the stick refers to legal approaches (fuel quality, emissions, and efficiency standards as well as building energy code mandates), the carrot refers to financial incentives (grant programs, etc.), and the tambourine refers to education, outreach, and training services.[78]

6.3.2 Example Impact of Incentives on Typical Residential and Commercial Project Economics

To help optimize biomass thermal policies and better understand how much of what kind of incentive could help further the biomass thermal market, a basic financial analysis was performed as part of this study. It was based on a hypothetical residential home that was converting from heating with oil to heating with wood pellets for a central boiler system. The analysis was done with the objective of determining what the optimum levels of incentive are. Below are key assumptions used in the analysis:

Table 13: Key Assumptions for Residential Scenario Analysis

Annual heating oil use	1,000 gallons
Heating oil price	$4.00 per gallon
Pellet boiler capital costs	$19,000
Pellet fuel cost	$235 per ton
Percent borrowed	80%
Financing term	7 years
Interest rate	6.5%

[78] http://www.esv.or.at/fileadmin/redakteure/ESV/Info_und_Service/Publikationen/Biomass_heating_2010.pdf

In this example, the first year savings would be $2,026 and the investment would have a less than 10 year simple payback. The first year cash flow is negative because the annual debt service ($2,708) is greater than the potential fuel savings. This is a situation where some level of subsidy could help encourage a homeowner to make the investment in a biomass thermal energy alternative. In this scenario, a ***27.5%*** subsidy to lower the upfront costs would be necessary to create positive cash flow beginning in year 1. However, it is important to note that there a different ways to achieve the same goal of breakeven cash flow. Another option would be to increase the term of borrowing. In this case, simply extending the term from 7 to 11 years would yield a cash flow positive outcome begin in year 1 in the example cited above.

Below are key assumptions used in a similar analysis for a typical commercial building conversion from heating oil to pellets:

Table 14: Key Assumptions for Commercial Scenario Analysis

Annual heating oil use	5,000 gallons
Heating oil price	$3.50 per gallon
Pellet boiler capital costs	$54,000
Pellet fuel cost	$235 per ton
Percent borrowed	80%
Financing term	7 years
Interest rate	6.5%

In this example, the first year savings would be $7,365 and the investment would have a less than 8 year simple payback. The debt service would be slightly higher than the annual fuel savings and as a result the year one cash flow is slightly negative ($332). This is a situation in which only a small subsidy would be needed to encourage a commercial building owner to make the investment in a biomass thermal energy alternative. In this scenario a ***4.5%*** subsidy to lower the upfront costs would be necessary to achieve a positive cash flow beginning in year 1. Similar to the residential scenario above, another option to achieve breakeven cash flow in year 1 would be to increase the term of borrowing. Extending the term from 7 to 8 years would yield a cash flow positive outcome beginning in year 1 as well.

The hypothetical scenarios above illustrate three important points that should be taken into account as when policies strategies are considered— 1. the amount of subsidy needed to catalyze biomass thermal market expansion is dynamic and changes depending on various market conditions (i.e. a simple increase in heating oil price can dramatically improve the economics of a typical project) 2. subsidy is one approach but there are other ways to bridge the economic gaps and 3. the economic gap that needs to be bridged with subsidy is often smaller for larger buildings with larger heat loads.

7.0 Summary, Conclusions & Recommendations

Research and policy analysis conducted for this study confirms substantial opportunities exist in the four-state Northern Forest region for advancing the use of biomass thermal energy through new and expanded policy initiatives. Doing so could result in both societal benefits, such as increased economic activity and improved environmental impacts from energy use, as well as end user benefits in the form of decreased heating fuel costs. Presented below are the key conclusions resulting from the study, organized in response to the four key questions the study was designed to address.

Question 1: ***What are the policies and regulations currently in effect in the Northern Forest region that affect development and use of biomass thermal energy and where are there gaps?***

There are currently a wide range of regulatory, financial, and legislative policies in use in the region that impact the biomass thermal energy sector. Table 15 illustrates where these various policies are in place and where there are presently gaps.

Table 15: Summary of broad categories of policies that could support biomass thermal

	NY	VT	NH	ME	MA
Flexible Boiler Regulations		√	√		
Sales Tax Exemption on Biomass Appliances		√	√	Partial	Partial
Sales Tax Exemption on Biomass Fuel		√	√	Residential only	Residential only
State Income Tax Credit			N/A		
Pellet Boiler Incentives		√	√		√
PACE Financing		√			
Thermal RPS			√		Almost
State Grants for Biomass Thermal Projects	√	√	√	√	√
Government "Lead by Example" for Biomass Thermal		√			√
System Benefits Charge		For weatherization only			
Mandatory Renewable Energy Targets Applied to Building Codes					

The green highlighting in the table above indicates where there are policy gaps that present opportunities for consideration and pursuit of well-rounded and complete package of policies aimed to advance biomass thermal energy in the region.

Question 2*: How have existing policies and/or regulations helped to advance or to hinder biomass thermal energy in the region?***

Generally speaking, the most effective policies are those that directly help overcome the two biggest barriers to biomass thermal energy – high first costs and public perceptions. While it is difficult to isolate any single policy with the greatest impact, it is reasonable to conclude that the recent biomass market growth can be attributed to improving market conditions (rising oil and propane prices, increased numbers of quality system vendors and fuel suppliers, etc.) and the combinations of various policies at work in each state. Of the states reviewed in this report, Vermont has the broadest combination of policies toward biomass thermal energy and also has arguably the most developed biomass thermal market. While it is likely there is a direct correlation between the package of policies and the successful market build out, Vermont's success is, at least partially, a function of the long history of wood energy policies and programs.

As for policies that hinder biomass thermal energy, no single policy stands out as a primary hindrance. Instead, it is the *absence* of the full package of policies that could advance biomass thermal energy that is the greatest hindrance.

Question 3: ***What new policies are needed to advance biomass thermal energy? Has legislation been developed that can serve as model legislation for other states?***

Each state is different and their policies and regulatory structure are generally not interchangeable – there is no one size fits all solution. As a result, individual policies and combinations of policies need to be (and should be) tailored to each state. Furthermore, the residential, commercial, and institutional biomass heating markets and their expansion in each state are each impacted differently by policies.

Generally, there is a need for greater regulatory policy consistency (air emissions, boiler safety, etc.) across the region. There is also a need for "low-hanging fruit" policies that can effectively help incent the biomass thermal market without getting into onerous legislative processes that can be expected to be more controversial and complex to implement. Simple policies like state sales tax exemptions and income tax credits could provide "low hanging fruit" policy opportunities in the region.

Table 16 – List of possible policy options ranked by relative simplicity to adopt

Relatively Straight Forward	Sales tax exemption on efficient clean biomass heating appliances and fuels
	State income/investment tax rebate on high efficiency clean biomass heating appliances
↓	Adopting flexible boiler regulations
	Adopting government agency LBE policies
	Modest boiler rebates via cobbled funding sources
Increasingly Complex	Aggressive subsidies funded through comprehensive energy policies like Thermal RPS and SBS.
	Mandatory renewable energy use in building codes

However, the greatest need for policies are those that can generate long-term sustained funding sources that can provide the right amount of cost-share and programmatic support to transform the market over time. Unfortunately, these policies are the most complex and difficult to implement through legislative process.

Nonetheless, several interesting examples of biomass thermal energy policies from around the region are provided in Appendices A-D that can serve to help other states as they consider the best policy options.

Question 4: ***What are key next steps for advancing biomass thermal energy policy in the Northern Forest region?***

In order to develop a systematic approach to pursue both the more complex and the "low-hanging fruit" policy options in each of the states in the Northern Forest region, BERC recommends the following action items:

- Pursue sales tax exemption for high-efficiency biomass heating appliances and local biomass heating fuels in all NF states (except New Hampshire).
- Pursue state income tax rebate programs for the purchase and installation of biomass heating equipment in each of the NF states (except New Hampshire) and use this state action to demonstrate support for federal tax rebates for biomass thermal.
- Pursue official and visible adoption of pro-biomass thermal LBE policies by state and local governments in NF region.
- For states with an RPS in place, broadening eligibility for RECs from thermal sources is one policy option that should be pursued. For thermal inclusion in RPS policies to have the desired effect, state PUCs should adopt strategies such as issuing multi-year "strips" of thermal RECs if this payment is to be helpful toward securing project financing.
- For states without an RPS (such as Vermont) or for states that don't wish to further complicate an existing RPS, assessing the equivalent of an SBC on heating fuels that supports both energy efficiency and the use of biomass thermal energy can be pursued
- As state renewable policies are developed and specific targets are set, ensure that any specific targets be set with careful consideration of the sustainable biomass resource potential.
- If rebate programs are pursued, ensure long-term, stable funding sources and provide the optimal level of rebate to effectively stimulate fuel switching without over paying and creating long-term market expectations of and dependency on subsidization.
- Look to European countries such as Austria and Germany provide helpful examples of how balanced approaches, combining incentives, regulations, and programmatic support can drive development of a clean, low-emission biomass heating industry.
- Biomass thermal sector should team up with solar thermal sector for a stronger collective voice to advocate for renewables in the thermal energy sector.

APPENDIX A – Massachusetts SB 1593

SENATE DOCKET, NO. 1135 FILED ON: 1/18/2013

SENATE . . . . No. 1593

The Commonwealth of Massachusetts

PRESENTED BY:

Barry R. Finegold

To the Honorable Senate and House of Representatives of the Commonwealth of Massachusetts in General Court assembled:

The undersigned legislators and/or citizens respectfully petition for the passage of the accompanying:

An Act relative to credit for thermal energy generated with renewable fuels.

PETITION OF:

NAME:	DISTRICT/ADDRESS:
Barry R. Finegold	*Second Essex and Middlesex*
James B. Eldridge	*Middlesex and Worcester*
Marcos A. Devers	*16th Essex*

SENATE DOCKET, NO. 1135 FILED ON: 1/18/2013

SENATE . . . . No. 1593

By Mr. Finegold, a petition (accompanied by bill, Senate, No. 1593) of Barry R. Finegold, James B. Eldridge and Marcos A. Devers for legislation relative to credit for thermal energy generated with renewable fuels. Telecommunications, Utilities and Energy.

The Commonwealth of Massachusetts

An Act relative to credit for thermal energy generated with renewable fuels.

Be it enacted by the Senate and House of Representatives in General Court assembled, and by the authority of the same, as follows:

SECTION 1. Section 3 of chapter 25A of the General Laws, as appearing in the 2010 Official Edition, is hereby amended by inserting after the definition "State Agency" the following new definition:-

"Useful thermal energy", energy in the form of direct heat, steam, hot water, or other thermal form that is used in production and beneficial measures for heating, cooling, humidity control, process use, or other valid thermal end use energy requirements and for which fuel or electricity would otherwise be consumed.

SECTION 2. Section 11F½ of said chapter 25A, as so appearing, is hereby amended by striking, in line 12, the following word:- "electricity" and inserting in place thereof the following word:- "energy";

and by striking, in line 21, the following:- "or (6)" and inserting in place thereof the following:-

(6) any facility that generates useful thermal energy using sunlight, biomass, bio-gas, liquid bio-fuel or naturally occurring temperature differences in ground, air or water, whereby one megawatt-hour of alternative energy credit shall be earned for every 3,412,000 British thermal units of useful thermal energy produced and verified through an on-site utility grade meter or other means satisfactory to the department; or (7)

An Act To Include Useful Thermal Energy as a Renewable Energy Source

COPY

PRESENTED BY:______________________________________

(Senator TROY D. JACKSON)
COUNTY: Aroostook

126LR1271(01)

PROPOSED SHORT TITLE:
INCLUDE USEFUL THERMAL ENERGY
AS A RENEWABLE ENERGY SOURCE
(Subject to change)

Be it enacted by the People of the State of Maine as follows:

Sec. 1. 35-A MRSA §3210, sub-§2, ¶B-3, as enacted by PL 2009, c. 542, §3, is amended to read:

B-3. "Renewable capacity resource" means ~~a source of electrical generation~~:

(1) ~~Whose~~ A source of electrical generation whose total power production capacity does not exceed 100 megawatts and relies on one or more of the following:

(a) Fuel cells;

(b) Tidal power;

(c) Solar arrays and installations;

(d) Geothermal installations;

(e) Hydroelectric generators that meet all state and federal fish passage requirements applicable to the generator; or

(f) Biomass generators that are fueled by wood or wood waste, landfill gas or anaerobic digestion of agricultural products, by-products or wastes; ~~or~~

(2) ~~That~~ A source of electrical generation that relies on wind power installations~~.~~; or

(3) Useful thermal energy.

Sec. 2. 35-A MRSA §3210, sub-§2, ¶D is enacted to read:

D. "Useful thermal energy" means renewable energy derived from geothermal, solar thermal or biomass thermal sources that can be metered, that is delivered to an end user in the form of direct heat, steam, hot water or other thermal form and that is used for heating, cooling, humidity control, process use or other thermal end use, the energy requirements for which nonrenewable fuel or electricity would be otherwise consumed.

Sec. 3. Commission rules; renewable energy credits based on useful thermal energy. The Public Utilities Commission shall adopt rules providing a methodology for measurement of useful thermal energy and valuation of that energy for purposes of calculating renewable energy credits under the Maine Revised Statutes, Title 35-A, section 3210. Rules adopted under this section are routine technical rules as defined in Title 5, chapter 375, subchapter 2-A.

SUMMARY

This bill provides that renewable energy credits may be based on renewable energy derived from geothermal, solar thermal or biomass thermal sources that can be metered, that is delivered to an end user in the form of direct heat, steam, hot water or other thermal form and that is used for heating, cooling, humidity control, process use or other thermal end use, the energy requirements for which nonrenewable fuel or electricity

would be otherwise consumed. The bill requires the Public Utilities Commission by rule to provide a methodology for measurement of useful thermal energy and valuation of that energy for purposes of calculating renewable energy credits.

APPENDIX C – Vermont S.293

S.293

Introduced by Committee on Economic Development, Housing and General Affairs

Date:

Subject: Internal security and public safety; prevention and investigation of fires; boilers and pressure vessels

Statement of purpose: This bill proposes to set standards for the use of boilers and pressure vessels in the state, including authorizing the use of boilers or pressure vessels manufactured in accordance with Canadian or European standards.

An act relating to state standards for boilers and pressure vessels

It is hereby enacted by the General Assembly of the State of Vermont:

Sec. 1. 20 V.S.A. § 2882 is amended to read:

§ 2882. RULES; INSTALLATION STANDARDS

(a) The commissioner may adopt rules pertaining to boilers and pressure vessels, and standards to be observed, necessary for the safety and protection of the public, employees and property. ~~All standards adopted by the commissioner shall conform to the codes of the American Society of Mechanical Engineers and the National Board of Boiler and Pressure Vessel~~

~~Inspectors.~~ The commissioner may provide for operating certificates to be issued before a boiler or pressure vessel may be used.

<u>(b) A boiler or pressure vessel regulated by the rules adopted under this section shall be designed, manufactured, and assembled in accordance with the relevant standards published by the:</u>

<u>(1) American Society of Mechanical Engineers;</u>

<u>(2) Canadian Standards Association;</u>

<u>(3) European Committee for Standardization, for boilers with a maximum water jacket size of 60 gallons, a maximum input of 250,000 Btu, and a maximum relief valve setting of 30 pounds per square inch gauge; or</u>

<u>(4) European Committee for Standardization, for boilers or pressure vessels with an input of greater than 250,000 Btu or a water jacket size of greater than 60 gallons as approved by the commissioner.</u>

<u>(c) A boiler or pressure vessel regulated by the rules adopted under this section shall be installed in accordance with the National Board Inspection Code, as amended, including control, safety, and pressure relief devices in accordance with the relevant standards published by the American Society of Mechanical Engineers.</u>

<u>(d) A boiler or pressure vessel regulated by the rules adopted under this section shall provide the manufacturer's design information, instructions, data plates, and warning labels in English.</u>

<u>(e) In reviewing an application for a variance, the commissioner may rely upon decisions or information from other states or governmental entities that have reviewed and approved a boiler or pressure vessel that does not meet one of the standards set forth under subsection (b) of this section.</u>

Sec. 2. EFFECTIVE DATE

<u>This act shall take effect upon passage.</u>

APPENDIX D – Massachusetts H.3897

HOUSE . . . . No. 3897

The Commonwealth of Massachusetts

In the Year Two Thousand Twelve

An Act further promoting energy efficiency and green jobs.

Be it enacted by the Senate and House of Representatives in General Court assembled, and by the authority of the same, as follows:

SECTION 1. Chapter 10 of the General Laws is hereby amended by inserting after section 35OO the following section:

Section 35PP: There shall be established and set up on the books of the commonwealth a separate fund to be known as the Oil Heat Energy Efficiency Fund. The fund shall consist of amounts credited to the fund in accordance with sections 11J of chapter 25A and expended exclusively for the purposes of said section 11J of said chapter 25A. The fund shall be administered by the commissioner of energy resources, pursuant to section 11J(b) of chapter 25A, in coordination with the secretary of administration and finance. The fund shall be an expendable trust fund and shall not be subject to appropriation or allotment. The commissioner shall report monthly by source all amounts credited to the fund and all expenditures by subsidiary made from the fund on the Massachusetts management and accounting reporting system. Amounts remaining in the fund at the end of a fiscal year shall not revert to the General Fund and shall be available for expenditure by the fund in the next fiscal year and thereafter.

SECTION 2. Chapter 25A of the General Laws is hereby amended by adding after section 11I the following new sections:

Section 11J. (a) For the purposes of section 11J, the following terms shall have the following meanings:

"Fuel oil industry" or "oil heat industry," persons in the production, transportation, or sale of oil heat fuel; and persons engaged in the manufacture or distribution of oil heat fuel utilization equipment; provided that "fuel oil industry" or "oil heat industry" shall not include ultimate consumers of oil heat fuel.

"No. 1 distillate," fuel oil classified as No. 1 distillate by the American Society for Testing and Materials (ASTM).

"No. 2 dyed distillate," fuel oil classified as No. 2 distillate by the American Society for Testing and Materials (ASTM) that is indelibly dyed in accordance with regulations prescribed by the Secretary of the Treasury under section 4082(a) (2) of the Internal Revenue Code of 1986.

"Cost Effective," with respect to an energy efficiency program, means that the program meets a cost-benefit test, which requires that the net present value of economic benefits over the life of the program or measure, including avoided supply and delivery costs and deferred or avoided investments, environmental benefits and avoided environmental costs, avoided operation and maintenance costs and other appropriate energy and non-energy benefits as determined by the department, is greater than the net present value of the costs over the life of the program.

"Energy Efficiency Advisory Council (EEAC)," refers to the energy efficiency advisory council established pursuant to section 22 of chapter 25 of the general laws.

"Oil heat fuel," No.1 distillate and No.2 dyed distillate that is used as a fuel for residential or commercial space or hot water heating.

"Retail marketer," a person engaged primarily in the sale of oil heat fuel to ultimate consumers.

"Wholesale distributor," a person or business entity that produces No. 1 distillate or No. 2 dyed distillate; imports No. 1 distillate or No. 2 dyed distillate; blends No. 1 distillate or No. 2 dyed distillate with biodiesel or biofuels; or transports No. 1 distillate or No. 2 dyed distillate across state boundaries or among local marketing areas; and sells the products to retail home or commercial heating oil companies for resale.

(b)(1) Beginning , June 1, 2013, the department shall require a systems benefit assessment of two and one-half cents ($.025) per gallon be placed on all gallons of oil heat fuel sold for residential or commercial use in Massachusetts in order to establish oil heat energy efficiency programs. The assessment shall be collected at the point of sale of oil heat fuel by a wholesale distributor to a person other than a wholesale distributor, including a sale made pursuant to an exchange. A wholesale distributor shall be responsible for payment of the assessment to the Commonwealth on a quarterly basis; and shall provide to the Commonwealth certification of the volume of fuel sold. No. 1 distillate and No. 2 dyed distillate fuel sold for uses other than as oil heat fuel are excluded from the assessment. Distillate fuel used by vessels, railroad, utilities, farmers and the military are exempt from the assessment.

(2) Such funds shall be deposited by the secretary of administration and finance into the Oil Heat Energy Efficiency Fund pursuant to section 35PP of chapter 10. The Fund shall be expended by the commissioner of energy resources, pursuant to this section, and subject to the

approval of the energy efficiency advisory council (EEAC) for the sole purpose of designing, marketing and providing cost-effective energy efficiency programs through financial incentives and services for residential and small business demand-side management programs that improve energy efficiency and reduce consumption for residential and commercial customers who utilize oil heat fuel for space heat or domestic hot water heating, including but not limited to: replacing or upgrading older, inefficient oil heating or domestic hot watersystems; duct sealing and insulation, pipe insulation, building envelope sealing and insulation; storm windows; blower door air sealing services; research and design; and marketing of oil heat efficiency products or services. Program design for envelope measures and measures that will save electricity or natural gas, in addition to oil heat,shall be conducted by the EEAC and the program administrator(s), and result in integrated programs that serve all customers, regardless of heating fuel type. Program design elements that result in savings of multiple fuels shall be funded from the oil heat efficiency trust in an equitable manner and in proportion to the oil heat savings generated.No more than one percent (1%) of such funds may be used for training. No more than one percent (1%) of such funds may be allocated to the department for administration of the fund and coordination of the programs. Program design for heating system programs shall be conducted by EEAC and the program administrator(s), provided, however, that under the programs, an oil heating system shall be replaced with a new oil heating system. The commissioner shall act as the fiscal agent responsible with ensuring these services are delivered as approved by the EEAC and in a cost effective manner that is coordinated with other energy efficiency programs.

At least 20 percent of the funds collected shall be spent on comprehensive low-income residential oil heat energy efficiency and education programs. The commissioner shall designate that these programs be implemented through the low income weatherization and fuel assistance program network administered by the department of housing and community development.

(c) (1) The EEAC shall advise the department on all aspects of oil energy efficiency funds and programs in the commonwealth. Actions of the EEAC pertaining to disbursement of the oil heat efficiency funds and programs shall require a majority vote.

The EEAC shall establish a target budget designed to ramp-up over time to capture cost-effective energy efficiency for heating oil, and a corresponding annual assessment designed to recover enough money to fund the programs.

(2) To implement this section, the commissioner, with the approval of the EEAC and, is hereby directed and authorized to enter into contracts with appropriate organization(s) to serve as energy efficiency program administrator(s), selected through a competitive procurement process, to deliver and operate, in a cost-effective manner, oil heat energy efficiency programs to be provided by retail heating oil dealers and other business entities, organizations and agencies with qualified technical personnel including oil heat technicians in good standing with the Commonwealth in possession of a certificate of competency as defined by Code of

Massachusetts Regulation (CMR) 527 CMR 4.00. Programs shall be approved by the EEAC and shall be delivered in a cost effective manner that is coordinated with other energy efficiency programs.

(3) Every 3 years, in a manner consistent with natural gas and electric efficiency plans set forth in section 21 of chapter 25, on or before April 30, the program administrators shall jointly prepare an oil heat efficiency investment plan for approval by the department and the EEAC. Each plan shall provide for the acquisition of energy efficiency resources that are cost effective or less expensive than supply and shall be prepared in coordination with the energy efficiency advisory council established by section 22 of chapter 25. A program included in the plan shall be screened through cost-effectiveness testing which compares the value of program benefits to the program costs to ensure that the program is designed to obtain energy savings and system benefits with value greater than the costs of the program. Program cost effectiveness shall be reviewed periodically by the department and by the EEAC. If a program fails the cost-effectiveness test as part of the review process, it shall either be modified to meet the test or shall be terminated. The EEAC may allow for transitional, one year plans in order to achieve consistency with section 21 of chapter 25.

An investment plan shall include: (i) an assessment of the estimated lifetime cost, reliability and magnitude of all available energy efficiency resources that are cost effective or less expensive than supply; (ii) the estimated energy cost savings that the acquisition of such resources will provide to oil heat consumers, including, but not limited to, reductions in energy costs and increases in price stability and affordability for low-income customers; (iii) a description of programs, which may include, but which shall not be limited to: (A) efficiency programs; (B) programs for research, development and commercialization of products or processes which are more energy-efficient than those generally available; (C) programs for development of markets for such products and processes, including recommendations for new appliance and product efficiency standards; (D) programs providing support for energy use assessment, real time monitoring systems, engineering studies and services related to new construction or major building renovation, including integration of such assessments, systems, studies and services with building energy codes programs and processes, or those regarding the development of high performance or sustainable buildings that exceed code; (E) programs for planning and evaluation; and (F) programs for public education regarding energy; provided, however, that not more than 1 per cent of the fund shall be expended for items (B) and (C) collectively, without authorization from the advisory council; (iv) a proposed mechanism which provides performance incentives to the program administrator(s) based on their success in meeting or exceeding the goals in the plan; (v) the budget that is needed to support the programs; (vi) data showing the percentage of all monies collected that will be used for direct consumer benefit, such as incentives and technical assistance to carry out the plan.

(4) The program administrator(s) shall submit the investment plan to the EEAC. Not later than 90 days after the submission of a plan, the department and EEAC shall approve, modify and approve, or reject and require the resubmission of the plan accordingly.

(5) Programs shall be designed to treat all energy use in a building in a comprehensive and coordinated fashion across the state with maximum use of common program designs, integrated programs, and a common pool of energy efficiency vendors and contractors who can treat all energy use in a building comprehensively.

The financial incentives used in said programs may be a combination of low or zero interest loans or direct rebates and other financial incentives. The EEAC shall solicit input from the oil heat industry, consumer groups, and low income advocacy groups regarding the implementation of this section and delivery of all program services.

(6) The department shall issue regulations implementing this section within 1 year of enactment of this section and the commissioner shall enter into contracts within 6 months after such regulations have been made final.

(7) From time to time, the EEAC shall undertake, or cause to be undertaken, an assessment of cost effective oil heat energy efficiency resource potential in the commonwealth.

(8) Evaluation, monitoring, and verification of the efficiency programs shall be conducted by an independent third-party selected by the EEAC. Said independent third party shall report its findings to the EEAC, the joint committee on telecommunications, utilities, and energy, and the public through the department of energy resourses. Allocations for independent third-party monitoring and other consulting services shall not exceed 1 per cent of the fund on an annual basis

(9) The EEAC, in collaboration with the program administrator(s), shall prepare an annual report for submission to the joint committee on telecommunications, utilities, and energy and the public through the department of energy resources that includes, but is not limited to: a description of the amount and use of proceeds of the Oil Heat Energy Efficiency Fund collected under this section; a description of the cost effective energy efficiency programs funded through such proceeds; the demonstration of consumer savings, cost-effectiveness, and the lifetime and annual energy savings achieved by the energy efficiency programs funded; and the lifetime and annual greenhouse gas emissions benefits achieved by energy efficiency programs funded.

SECTION 3. Chapter 25 of the General Laws is amended by in Section 21 by inserting after subsection (e) the following new subsections:-

(f) In implementing its energy efficiency plan, each electric and natural gas distribution company Program Administrator, the Oil Heat Energy Efficiency Program Administrator, and any other entity that receives public subsidy and provides energy efficiency services shall, in consultation with the Energy Efficiency Advisory Council, as defined by section 22 of chapter 25 of the General Laws, and subject to the approval of the Department of Public Utilities:

(1) Report aggregate residential and commercial ratepayer data for those who receive energy efficiency program benefits to the Department Of Energy Resources. The report shall specify for each zip code the number of participants served; energy efficiency measures provided; program and participant dollars spent per measure; energy savings per measure; and the number of participants that reside in rental units.

(2) Not later than January 1, 2013 and every January 1 and July 1 of each year thereafter, each electric, natural gas distribution company, and oil heat energy efficiency Program Administrator, and any other entity that receives public subsidy and provides energy efficiency services shall submit the data identified in Section (f)(1) to the Department Of Energy Resources.

(g) The Department Of Energy Resources shall establish and maintain a database to store and manage all energy efficiency program data collected under section (f) of chapter 25.

(h) The Department Of Energy Resources shall establish annual benchmarks for reaching the statewide goals and providing equitable access to historically harder-to-reach segments, including, but not limited to, residential rental properties, low and moderate-income homeowners and renters (those earning up to 120% state median income), communities whose primary language is not English, and small commercial businesses, which may not be participating at rates commensurate with the funds that they are paying into the programs as ratepayers.

(i) Not later than January 1, 2014 and every January 1 of each year thereafter, the Department Of Energy Resources shall provide a report to the Joint Committee on Telecommunications, Utilities and Energy, and the public through the department, demonstrating whether energy efficiency programs are reaching ratepayers and buildings equitably.

(j) The Department Of Energy Resources shall promulgate regulations to implement the requirements of this legislation within one year of enactment.

SECTION 4. Chapter 23J of the General Laws, as so appearing, is hereby amended in Section 5 by inserting at the end the following new paragraph:-

The center shall annually, no later than April 1, submit to the governor, the joint committee on telecommunications, utilities and energy, energy efficiency advisory council a report detailing the energy efficiency and green industry workforce development needs in the State. The report shall include:

(A) data on jobs created and demographic information about who is hired;

(B) recommended target hiring goals;

(C) average salaries and benefits information;

(C) recommended legislation to implement the proposed plan on a long-term basis.

SECTION 5. Section 7 of chapter 465 of the acts of 1980 is hereby amended by inserting after subsection (g) the following subsections:-

(h) A utility shall be exempt from the requirements of subsection (b) if said utility includes the Massachusetts residential conservation service as part of an efficiency investment plan prepared and submitted to the department in accordance with Section 21 of Chapter 25 of the General Laws.

(i) The department shall be exempt from the requirements of subsection (f) for any utility that includes the Massachusetts residential conservation service as part of an efficiency investment plan prepared and submitted to the department in accordance with Section 21 of Chapter 25 of the General Laws.

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PLUME OPACITY AND PARTICULATE MASS CONCENTRATION

MICHAEL J. PILAT and DAVID S. ENSOR

Department of Civil Engineering, University of Washington, Seattle, Washington

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Abstract—A general theoretical relationship between plume opacity and the properties of particulate air pollutants has been developed. These results are in agreement with previously reported theoretical equations for specific emissions and with the known measurements of plume opacity and particle properties. A parameter K, defined as the specific particulate volume/light extinction coefficient ratio ($cm^3\ m^{-3} m$), was used to relate the plume opacity to the particle properties. Graphs of K *vs.* the particle geometric mass mean radius at geometric standard deviations of 1, 1.5, 2, 3, 4 and 5 are presented for particles of refractive index 1.33 (water) and $1.95-0.66i$ (carbon). An example is included illustrating the use of the theoretical results to calculate the maximum allowable particle concentration which will meet a given Ringelmann number.

NOMENCLATURE

a_t, b_t	Mie amplitude coefficients
B_E	Extinction coefficient
cm	Centimeter
$f(r)$	Particle number fraction frequency distribution
I	Intensity of transmitted light
I_0	Intensity of incident light
I/I_0	Light transmittance
i	Imaginary unit $(-1)^{1/2}$
g	Gram
K	Specific particulate volume/extinction coefficient ratio
L	Illumination path length
m	Refractive index of particle relative to air
m	Meter
N	Total particle number concentration
$n(r)$	Particle number frequency distribution, which, multiplied by the radius increment, dr, is the number of particles between r and $r+$dr
Q_E	Extinction efficiency factor
r	Particle radius
Δr	Particle radius increment
r_{gn}	Geometric number mean radius
r_{gw}	Geometric mass mean radius
S_E	Extinction cross-section per particle
t	Order of function
W	Total particle mass concentration
$Z_t^{(1)}(y)$	Spherical Bessel function of the first kind
$Z_t^{(3)}(y)$	Spherical Bessel function of the third kind

Greek symbols

α	Particle size parameter, $2\pi r/\lambda$
$\eta_t^{(1)}(y)$	Derivative of spherical Bessel function of the first kind
$\eta_t^{(3)}(y)$	Derivative of spherical Bessel function of the third kind
λ	Wavelength of light
π	3.14159
ρ	Particle density
σ_g	Particle size geometric standard deviation.

1. INTRODUCTION

AIR POLLUTION control laws may limit the emission of particulate matter into the atmosphere by four types of regulations:

1. visible emission (Ringelmann number)
2. particulate concentration in the stack (gr ft^{-3})
3. process weight code (lb particulate matter/lb process material).
4. particulate concentration at the property line boundary ($\mu g\ m^{-3}$).

Because of the ease of making a visual observation of a plume with a Ringelmann number, it is the particulate emission evaluation technique most frequently used. However, the design of particulate air pollutant control equipment is based on a removal efficiency for a certain inlet particulate weight concentration, size distribution, and density. Thus for equipment design purposes it would be useful to know the relationship between the plume visual properties (Ringelmann number) and the particulate properties (weight concentration and size distribution).

Relationships between plume opacity and particulate mass concentration have been reported for specific emissions. HAWKSLEY *et al.* (1961) estimated the relationship of the particulate mass concentration to the plume opacity for two sizes of light absorbing particles of 2 g cm^{-3} density. The relationship for particles much smaller than the light wavelength is

$$\ln (I/I_0) = -4.0\, WL, \tag{1}$$

where I/I_0 is the fraction of incident light which is transmitted (light transmittance), L is the illumination path length in meters (usually stack diameter), and W is the total particle mass concentration in g m^{-3}. The equation for particles much larger than the wavelength of light (average specific surface area diameter of 12 μm) is

$$\ln (I/I_0) = -0.125\, WL, \tag{2}$$

HAWKSLEY *et al.* (1961) reported good agreement between the relationship for small particles (1) and the data of HURLEY and BAILEY (1958). Measurements of plume opacity and particulate mass concentration have been reported by CONNER and HODKINSON (1967). Some attempts to correlate the measured light extinction and particle concentration in stacks have been reported by STOECKER (1950) and HURLEY and BAILEY (1958). These studies indicated that in a single source the light extinction of the particles is directly related to the particle mass concentration. Scatter in the experimental data was attributed to changes in the particle size distribution. The inability to control or measure the particle size distribution was cited by ENGDAHL (1951) and by MITCHELL and ENGDAHL (1963) as a problem in developing a relationship.

The Bay Area Pollution Control Board Regulation 2 (1962) has a requirement limiting the concentration of particulate matter emissions to that given by

$$W[\text{g m}^{-3}] = \frac{1.01}{L(\text{m})} \tag{3}$$

ROBINSON (1962) reported that this equation was developed for a plume opacity of Ringelmann number 2 (40 per cent extinction) and a hypothetical oil aerosol (mass mean radius of 0.23 μm and a geometric standard deviation of 3.4).

This paper presents a general theoretical analysis of the relationship between particulate air pollutant properties and plume opacity. These results should assist in: (1) developing regulations for the control of particulate air pollutants, (2) designing particulate control equipment which can meet opacity standards, and (3) explaining the results of attempts to correlate particulate mass concentrations and light extinction measurements.

2. THEORY

(a). *Development of equation relating plume opacity to particle properties*

A general relationship can be developed between plume opacity (I/I_0), the plume path length, and the particle properties (particle size distribution, density, mass concentration, and refractive index). The transmission of light through a volume containing an aerosol is described by the Lambert–Beer law

$$I/I_0 = \exp(-B_E L), \tag{4}$$

where L is the illumination path length and B_E is the extinction coefficient. Assuming that the light extinction in the volume is entirely due to aerosol particles of constant concentration throughout the illumination path length, B_E can be defined in terms of the extinction cross-section per particle S_E and $n(r)$, the particle number frequency distribution (number of particles/volume of air between r and $r+dr$).

$$B_E = \int_0^\infty S_E(r, \lambda, m)\, n(r)\, \mathrm{d}r. \tag{5}$$

The extinction cross-section per particle S_E is related to the extinction efficiency factor Q_E (total light flux scattered and absorbed by a particle divided by the light flux incident on the particle) and the projected cross-sectional area of a spherical particle by

$$S_E = \pi r^2 Q_E. \tag{6}$$

Therefore the extinction coefficient of a polydisperse aerosol is given by

$$B_E = \int_0^\infty Q_E(r, \lambda, m)\, \pi\, r^2\, n(r)\, \mathrm{d}r. \tag{7}$$

The extinction efficiency factor Q_E can be computed using the Mie equations (VAN DER HULST, 1957).

$$Q_E = \frac{2}{\alpha^2} \sum_{t=1}^{\infty} (2t+1)\, Re(a_t + b_t) \tag{8}$$

The term Re means a real part of the complex number in parenthesis and α is the size parameter $2\pi r/\lambda$.

The complex Mie amplitude coefficients a_t and b_t are defined as:

$$a_t = \frac{\eta_t^{(1)}(m\alpha)\, Z_t^{(1)}(\alpha) - m\, Z_t^{(1)}(m\alpha)\, \eta_t^{(1)}(\alpha)}{\eta_t^{(1)}(m\alpha)\, Z_t^{(3)}(\alpha) - m\, Z_t^{(1)}(m\alpha)\, \eta_t^{(3)}(\alpha)}, \tag{9}$$

$$b_t = \frac{m\, \eta_t^{(1)}(m\alpha)\, Z_t^{(1)}(\alpha) - Z_t^{(1)}(m\alpha)\, \eta_t^{(1)}(\alpha)}{m\, \eta_t^{(1)})m\alpha(\, Z_t^{(3)}(\alpha) - Z_t^{(1)}(m\alpha)\, \eta_t^{(3)}(\alpha)}. \tag{10}$$

Where: $Z_l^{(1)}(y)$ = Spherical Bessel function of the first kind.
$Z_l^{(3)}(y)$ = Spherical Bessel function of the third kind.
$\eta_l^{(1)}(y)$ = Derivative of Spherical Bessel function of the first kind.
$\eta_l^{(3)}(y)$ = Derivative of Spherical Bessel function of the third kind.

The particle size frequency distribution $n(r)$ is related to the total particle number concentration N and the particle number fraction frequency distribution $f(r)$ (which, multiplied by the particle radius increment, dr, gives the fraction of particles between r and $r+dr$)

$$n(r) = Nf(r). \tag{11}$$

The total particle number concentration N is defined as

$$N = \int_0^\infty n(r)\,dr, \tag{12}$$

and the particle number fraction frequency distribution $f(r)$ as

$$\int_0^\infty f(r)\,dr = 1.0. \tag{13}$$

Substituting (7) for B_E into the Lambert–Beer law (4) gives

$$\ln(I/I_0) = -L\int_0^\infty \pi r^2 Q(r,\lambda,m)\,n(r)\,dr. \tag{14}$$

Substituting (11) for the particle size number frequency distribution $n(r)$ in (14) produces.

$$\ln(I/I_0) = -NL\int_0^\infty \pi r^2 Q(r,\lambda,m) f(r)\,dr. \tag{15}$$

The particle mass concentration W is related to $n(r)$ and the particle density ρ by

$$W = \int_0^\infty \tfrac{4}{3}\pi r^3 \rho\, n(r)\,dr. \tag{16}$$

and can also be given in terms of the total particle number concentration N by substituting (11) for $n(r)$ into (16)

$$W = \tfrac{4}{3}\pi N\rho \int_0^\infty r^3 f(r)\,dr. \tag{17}$$

An equation relating the plume opacity I/I_0 to the aerosol mass concentration W is obtained by dividing (17) by (15)

$$\frac{W}{\ln(I/I_0)} = -\frac{\tfrac{4}{3}\rho\int_0^\infty r^3 f(r)\,dr}{L\int_0^\infty r^2 Q(r,\lambda,m) f(r)\,dr}. \tag{18}$$

A parameter K defined as the specific particulate volume (cm^3 particles/m^3 air) divided by the extinction coefficient (m^{-1}) is given by

$$K = \frac{\frac{4}{3}\int_0^\infty r^3 f(r)\,dr}{\int_0^\infty r^2 Q(r,\lambda,m) f(r)\,dr}. \tag{19}$$

The relationship of K to the plume and particle parameters can be shown by an equation of the form of the Lambert–Beer law (4) and the other reported specific emission relationships (2) and (3)

$$\ln(I/I_0) = -\frac{WL}{K\rho}, \tag{20}$$

or of a form relating K to the extinction coefficient

$$B_E = \frac{W}{K\rho}. \tag{21}$$

For the calculation of the maximum allowable particle concentration for a given plume opacity, particle density, extinction path length, and parameter K, (20) can be rearranged into the following working equation

$$W = -\frac{\rho K \ln(I/I_0)}{L}. \tag{22}$$

(b). *Calculation of typical magnitudes of* K

The parameter K is a function of the particle size distribution, the particle refractive index, and the wavelength of light. The particle size distribution is very important in the determination of K. The size distribution of particulate air pollutants is usually reported in a log normal form. As the size distributions are commonly reported as cumulative particle mass vs. the particle radius or diameter, a transformation of these parameters to cumulative number distribution parameters is necessary. The size distribution parameters of the geometric mass mean radius r_{gw} and the geometric standard deviation of σ_g are determined by plotting on log probability paper a cumulative curve of particulate mass vs. the log of the particle radius. The geometric mass mean radius occurs at the 50 per cent cumulative point and the ratio of the 84.1 per cent radius to the 50 per cent radius gives the geometric standard deviation. A detailed explanation of particle size analyses and statistics has been published by Herdan (1960) and by Cadle (1965). A log normal frequency is unique in that simple mathematical transformations exist between the various types of distributions (particle number, surface area, or mass). The geometric standard deviation remains the same for all types of distributions

The transformation between number and mass geometric mean radii, r_{gn} and r_{gw}, respectively, is

$$\ln r_{gn} = \ln r_{gw} - 3\ln^2\sigma_g. \tag{23}$$

The equation for a log normal distribution of the particle number fraction frequency distribution $f(r)$ is

$$f(r) = \frac{1}{r\sqrt{2\pi}\ln\sigma_g}\exp-\left[\frac{\ln^2 r/r_{gn}}{2\ln^2\sigma_g}\right], \tag{24}$$

substituting (24) for $f(r)$ gives an equation for the parameter K

$$K = \frac{\frac{4}{3}\int_0^\infty r^2 \exp-\left[\frac{\ln^2 r/r_{gn}}{2\ln^2\sigma_g}\right]\mathrm{d}r}{\int_0^\infty r\,Q_E(r,\lambda,m)\exp-\left[\frac{\ln^2 r/r_{gn}}{2\ln^2\sigma_g}\right]\mathrm{d}r}. \tag{25}$$

The parameter K was calculated using a digital computer (IBM 7094). Equations (8), (9), (10) and (23), were used to convert the input data (geometric mass mean radius r_{gw}, geometric standard deviation σ_g, particle refractive index m, and light wavelength λ) into the variables needed in (25). Equation 25 was evaluated numerically with the trapezoidal rule which is reported by DAVIS and RABINOWITZ (1967) to be a suitable numerical technique for periodic functions. The inputs of the light extinction efficiency factor $Q_E(r, \lambda, m)$ and the particle number fraction frequency distribution $f(r)$ were computed for discrete values of r over the radius range from 0.001 to 1000 μm. Because r extended over 7 orders of magnitude the value of Δr was maintained at about 1 per cent of r (Δr varied from 0.00001 to 10 μm) in order not to exceed the computer memory capacity. The spherical Bessel functions were computed for higher orders of t by forward recursion formulas and the initial values at $t = 0$ and $t = 1$. The extinction efficiency factor Q_E was set equal to 2.0 for magnitudes of the particle size parameter α greater than 85 to avoid convergence problems. A value of 2.0 for Q_E was based on the assumption that the illuminated path is long compared with the diameter of the light source and thus the light scattered by the aerosol particles should not reach the detector.

3. DISCUSSION OF RESULTS

(a). *Effect of particle refractive index*

The parameter K was calculated as a function of the geometric mass mean radius r_{gw} and the geometric standard deviation σ_g for homogeneous spherical particles of refractive indices of 1.33 (pure light scatterer) and of 1.95–0.66i (light absorber) at a light wavelength of 0.5 μm. These refractive indices were selected to represent the extremes of the particulate pollutant emissions. The effect of non-homogeneous refractive index is significant only for particles smaller than the wavelength of light as reported for concentric spheres by FENN and OSER (1965) and PILAT (1967).

The computed results for K at a particle refractive index of 1.33 (liquid water) are presented in FIG. 1. Curves for geometric standard deviations of 1.0 (monodisperse) 1.5, 2.0, 3.0, 4.0, and 5.0 are included. The oscillating nature of the monodisperse curve reflects the inverse of the familiar plot of the extinction efficiency factor vs. the size parameter. In FIG. 2 K is plotted vs. the geometric mass mean radius for a particle refractive index of 1.95–0.66i (carbon or soot). It is evident from these two figures that above a geometric mean radius of 0.5 μm the particle refractive index does not significantly influence the plume opacity. The major variation in K is caused by changes in the particle size distribution.

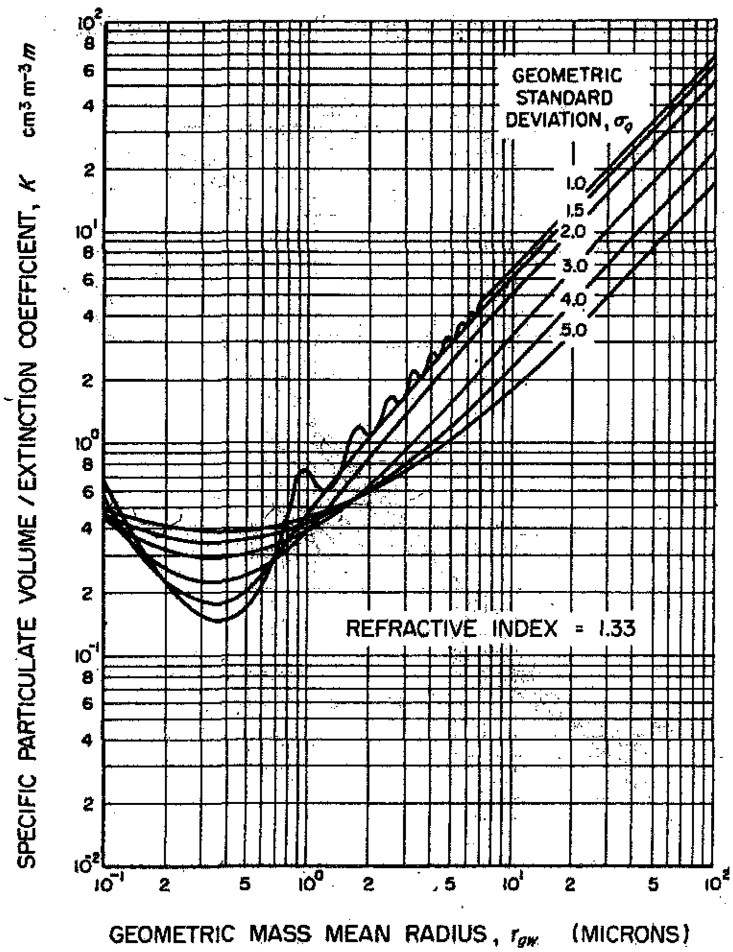

FIG. 1. Relationship of K to particle size distribution parameters for a white aerosol.

TABLE 1. PARTICULATE AIR POLLUTANT SIZE DISTRIBUTION DATA

Source	Geometric mass mean radius (μ)	Geometric standard deviation	Reference
Electric steel furnace	1.1	8.2	*Air Pollution Engineering Manual* (1967)
Cement dust	8.5	3	KREICHELT *et al.* (1967)
Wood smoke	0.035	1.7	FOSTER (1960)
Pulverized coal	9.5	4	SMITH and GRUBER (1966)

(b). *Particulate air pollutant size distributions of emission sources*

As the particulate size distribution has a significant effect on K an examination of typical source size distributions is appropriate. Particulate air pollutant size distribution data for emission sources is presented in TABLE 1. The geometric standard deviation ranges from 1.0 for monodisperse particles to about 8 for very polydisperse emission with the average σ_g around 3. The geometric mass mean radius ranges from about

0.04 to 10 μm. Therefore FIGS. 1 and 2 generally cover the particle size distribution range of interest.

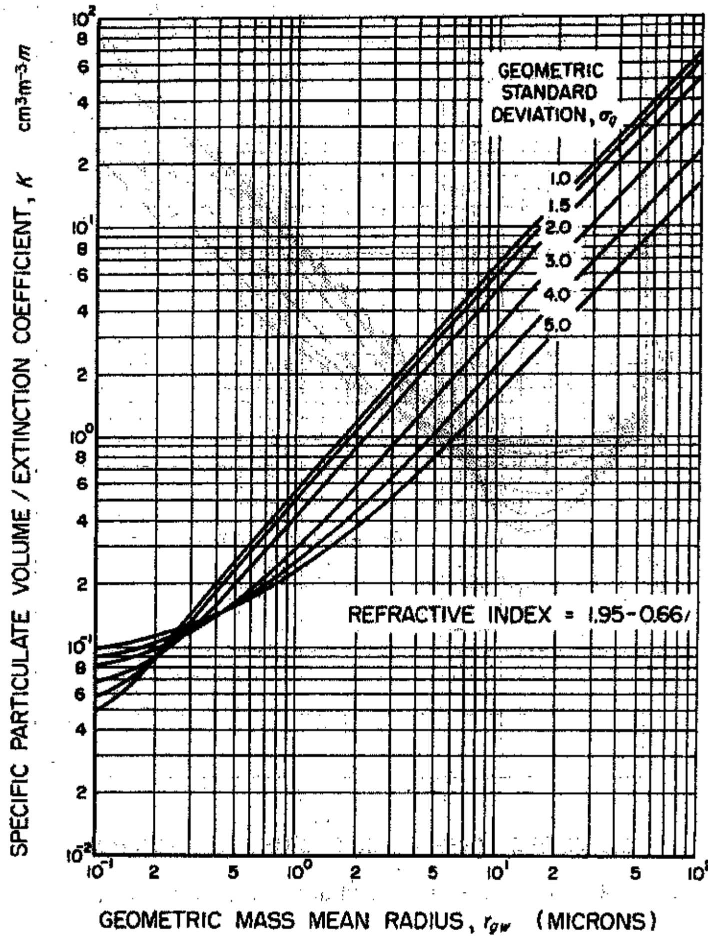

FIG. 2. Relationship of K to particle size distribution parameters for a black aerosol.

C. *Comparison of calculated K with previously reported relationships*

The theoretical results for K presented in FIGS. 1 and 2 are in good agreement with the relationships reported by HAWKSLEY *et al.* (1961). Equation 1 is for light absorbing particles smaller than the wavelength of light and of density 2 g cm^{-3}. Assuming a mass mean radius of 0.2 μm and a standard deviation of 1.0 (monodisperse) a K of 0.09 is obtained from FIG. 2. Substituting these magnitudes for K and ρ into (20) gives

$$\ln(I/I_0) = -5.55\, WL, \tag{26}$$

which is approximately the same as (1).

Equation 2 is for light absorbing particles larger than the wavelength of light having an average specific surface area diameter (i.e. diameter of a sphere with a surface area/volume ratio equal to the average of all the particles) of 12 μm and a particle density of 2 g cm^{-3}. Assuming a standard deviation of 1.0 and a mass mean radius of 6 μm, K from FIG. 2 is 4.0. Substituting these variables into (20) gives

$$\ln(I/I_0) = -0.125\, WL, \tag{27}$$

which is exactly equal to (2).

Equation 3 is for an oil aerosol (probably a pure scatterer), with a mass mean radius of 0.23 μm, and a geometric standard deviation of 3.4 which gives a K of about 0.33 from FIG. 1. Assuming a particle density of 0.9 g cm^{-3} and substituting into (20) gives

$$\ln(I/I_0) = -3.36\,WL, \tag{28}$$

changing into the form of (3) which is for a Ringelmann number 2

$$W = \frac{1.63}{L}. \tag{29}$$

This equation disagrees somewhat with (3). However, (3) was developed using only 5 size distribution increments. Also the refractive index of the oil was probably around 1.5 whereas FIG. 1 is for a refractive index of 1.33.

(d). *Comparison of calculated and experimental magnitudes of* K

To completely verify the theoretical results, independent simultaneous measurements of the particle mass frequency distribution (r_{gw} and σ_g), the light transmittance (I/I_0), and the stack diameter (L) at a particulate air pollutant source are necessary. Unfortunately no reports of these measurements have been found. However, there are reports of light extinction studies to which particle size distribution have been approximated. A summary of the applicable data is presented in TABLE 2. A comparison of

TABLE 2. PLUME OPACITY AND PARTICULATE CONCENTRATION DATA

Source	L (m)	ρ (g m^{-3})	W (g m^{-3})	I/I_0	K (cm^3 m^{-2})	d (μ)	Reference
White smoke Generator	0.2	0.87	0.21	0.90	0.46	0.3	CONNER and HODKINSON (1967)
			0.47	0.70	0.30		
			1.00	0.31	0.20		
Black smoke (oil fired power plant)	0.2	1.95	0.13	0.80	0.060	0.23	CONNER and HODKINSON (1967)
			0.49	0.40	0.055		
			0.95	0.20	0.061		
Black smoke (coal stoker)	0.15	1.95	0.46	0.75	0.12	<1	STOECKER (1950)
			0.92	0.52	0.11		
			1.40	0.34	0.10		
Black smoke (coal stoker)	0.30	1.95	0.46	0.43	0.084	—	HURLEY and BAILEY (1958)
			0.92	0.18	0.083		
			1.4	0.08	0.085		

the measured (TABLE 2) and calculated (FIGS. 1 and 2) magnitudes of K indicates qualitative agreement. The parameter K from the data of STOECKER (1950) and of HURLEY and BAILEY (1958) are in close agreement (K ranges from 0.083 to 0.12 cm^3 m^{-3} m). Both of these sources were coal fired stokers and thus the particulate emissions probably had very similar size distributions. The magnitudes of K calculated from the data of CONNER and HODKINSON (1967) and of STOECKER (1950) decrease with increasing particle mass concentration W. For white smoke it can be seen by examining FIG. 1 that this could only occur if the mass mean radius was less than the minimum in the curve of K vs. mass mean radius (point of maximum optical activity) and the particle size was increasing with increased mass concentration. The value of K calculated from the data of CONNER and HODKINSON (1967) for an oil fired power plant (black smoke) is 0.06 which is in close agreement with the K of about 0.05 obtained from FIG. 2 at a mass mean diameter of 0.23 μm and a standard deviation of 1.0.

E. *Calculation of maximum particle concentration to meet plume opacity regulations*

An example will be presented to illustrate the practical application of the theoretical results presented in FIGS. 1 and 2. Assume the problem is to determine the maximum allowable particle mass concentration for a plume which will meet a Ringelmann number 1 requirement (80 per cent light transmittance). The information required is the particle properties (mass mean radius r_{gw}, particle size standard deviation σ_g, particle density ρ, particle refractive index m) and the plume dimensions (stack diameter L). Assume that the particle properties are: r_{gw} of 2 μm, σ_g of 3, ρ of 2 g cm^{-3}, m of 1.95–0.66i, and L of 3.28 m (10 ft). From FIG. 2 a K of 0.59 cm^3 m^{-3} m is obtained. The maximum particle mass concentration can be calculated by substituting the proper parameters into (22)

$$W = -\frac{(2\,\mathrm{g\,cm^{-3}})(0.59\,\mathrm{cm^3\,m^{-2}})\ln 0.8}{3.28\,\mathrm{m}} \tag{30}$$

$$W = 0.08\,\mathrm{g\,m^{-3}}. \tag{31}$$

Thus the maximum allowable particle concentration is 0.08 g m^{-3} or 0.035 grains ft^{-3} to meet a Ringelmann number 1.

4. CONCLUSIONS

A general theoretical relationship between plume opacity and particle properties has been developed which is in agreement with similar equations for specific particle size distributions and with the known measurements of plume opacity and particle properties. Above a geometric mass mean radius of 0.5 μm, the particle refractive index does not significantly influence the plume opacity relationships. The major variations in the parameter K are caused by changes in the particle size distribution.

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PLUME OPACITY AND PARTICULATE MASS CONCENTRATION*

THE DERIVATION of the opacity of an aerosol cloud from the size distribution and optical properties of aerosol particles given by Pilat and Ensor has the merit of being entirely rigorous under certain conditions, while at the same time minimising the amount of computation left to the experimentalist to convert particle concentrations to a light transmittance, or vice versa. Unfortunately, the accurate application of the data presented in Figs. 1 and 2 is restricted by two underlying assumptions which have not been sufficiently stressed. In the first place, it is assumed that polydisperse aerosols follow strictly a log normal distribution. Such a law may well apply to powders prepared by comminution, or liquid aerosols produced by atomization. However, when such particles are burnt, deviations from the log normal distribution can occur in the plume particles produced. Even so, probably useful approximate results can be obtained from a judicious linearization of the actual size distribution plotted on log-probit paper in the usual way.

A more serious limitation is that the Lambert–Beer (or Bouguer) extinction formula only refers to the light flux received directly from a source of light, such as a lamp or a small portion of the sky behind the plume. The light from a plume reaching an observer includes, in general, important contributions due to sunlight and skylight scattered by plume particles into the eye. On a sunny day, this in-scattering can more than compensate for transmission losses through the plume from power stations, which can then appear brighter than its background (JARMAN and DE TURVILLE, 1969). This phenomenon would not arise if the Lambert–Beer law was applicable under all viewing conditions. For this reason, it is suggested that the results obtained by Pilat and Ensor can only be related directly to Ringelmann numbers for a plume of light-absorbing particles. They are also suitable for the interpretation of in-stack transmissometer measurements of either light absorbing or dielectric aerosols, where all other light sources are absent.

The transmittance of a plume can, however, be measured directly. A telephotometer is sighted to measure the brightness difference between a pair of contrasting targets, directly and through the plume, in the way described by CONNER and HODKINSON (1967). With this method, interference from light scattered by the plume is fully compensated, so the analysis of Pilat and Ensor will then apply.

If Ringelmann charts only are used, some correction for sky and sunlight scattering will be necessary. This limitation unfortunately restricts somewhat the use of this theoretical analysis in the development of regulations for the control of particulate air pollutants.

C.E.G.B.
S. W. Region,
Portishead, Bristol

R. T. JARMAN
C. M. DE TURVILLE

AUTHORS' REPLY

WE AGREE with Jarman and de Turville that an understanding of the simplifying assumptions used in any calculation is necessary for intelligent application of the calculation results. We believe that our calculations are of sufficient accuracy and completeness for use in the air pollution control field. The effects on the plume opacity–particulate mass concentration relationship of such non-ideal factors as deviations from log normal size distributions, particle shape, particle concentration gradients, etc. can only be determined by the collection of additional data. It should be noted that the mathematical derivation of K (equations 4 through 19) in our paper is not limited to log normal particle size distributions.

The changes in the plume appearance caused by changes in the background lighting as described by Jarman and de Turville are not due to failures of the Lambert–Beer law. The Lambert–Beer law is used to describe plume opacity. The plume contrast (plume to background luminance contrast) is expressed as a sum of the plume opacity and the ratio of the light scattered to the observer from the plume to the background luminance (CONNER and HODKINSON, 1967).

$$\text{Plume contrast} = \text{plume opacity} + \frac{\text{light scattered from plume to observer}}{\text{background luminance}}$$

Thus our calculation results may be used to compute the plume opacity (light extinction) contribution to the plume contrast for a given plume diameter, particle size distribution, and particle mass concentration.

* M. J. PILAT and D. S. ENSOR (1970) *Atmospheric Environment* 4 (2), 163–173.

The applicability of our results to plume opacities determined by trained smoke inspectors depends on the relationship between the visually measured plume opacities (Ringelmann numbers or percentage smoke density) to the light transmittance of the plume measured in the stack. In the United States smoke inspectors are carefully trained by air pollution control agencies to qualify as expert smoke readers (qualified to testify in court concerning plume opacity). This training usually consists of learning to read the opacity of both black and white smokes at a wide variety of plume opacities and lighting conditions to within $\pm$ 10 per cent opacity (0·5 Ringelmann number) with an instrumentally measured in-stack plume opacity as the primary standard. WEISBURD (1962) and ROM (1968) presented descriptions of smoke reading schools. To minimize the errors in reading plume opacities smoke inspectors are instructed to:

(1) Read gray and black smoke in densities and to record in Ringelmann numbers.
(2) Read emissions colored other than gray or black in opacities and record in percentages.
(3) The light source (sun) should be behind the observer during daylight hours.
(4) The light source should be behind the plume during hours of darkness.
(5) Readings should be taken at right angles to the wind direction and from any distance necessary to obtain a clear view of the stack.
(6) Readings should be made through the densest part of the plume and where the plume is no wider than the stack diameter.

Thus when reading plumes, smoke inspectors are trained to use their judgement to compensate for variations in the plume contrast due to light scattered to the observer from the plume and to report the plume opacity *not the plume contrast.*

We feel that our mathematical analysis is applicable to both black and non-black plume emissions within the legal limits of plume opacity readings by qualified smoke inspectors.

Department of Civil Engineering MICHAEL J. PILAT
University of Washington, DAVID S. ENSOR
Seattle, Washington 98105,
U.S.A.

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