Benefits of Combined Heat and Power Systems for Reducing Pollutant Emissions in MANE-VU States

MANE-VU Technical Support Committee

3/9/2016

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Executive Summary

CHP, or cogeneration, is a general term that refers to converting systems that separately produce heat and electricity to integrated systems that produce both. A traditional system with separate power and heat production can achieve an efficiency of 45%, whereas CHP can achieve efficiencies of 80%. A more advanced type of system called trigeneration uses a single integrated process for heating, electricity, and cooling. In addition to the efficiency benefits associated with CHP, transmission losses are decreased since electricity is now produced closer to the end user. This report examines the benefits of installing cogeneration or trigeneration systems for different applications in the MANE-VU states.

This report incorporates an analysis conducted by ICF international that examined the technical and economic potential for CHP installations on a national basis. The ERTAC EGU tool was then used to estimate criteria pollutant benefits from reduced generation in the power sector.

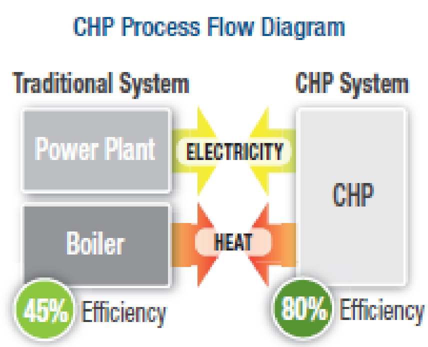
With the CHP technologies discussed in the paper, increases in CHP penetration would lead to significant decreases in SO_2 pollution in MANE-VU due to displacement of current base load generation. Conversely, there was an increase in onsite NO_X emissions from CHP systems in some of the scenarios examined. Smaller CHP systems would need to meet the NO_X standards outlined in the OTC Stationary Generator Model Rule to have a benefit. Larger systems would have a NO_X emission benefit if lowest achievable emission rates (LAER) were applied.

Overview

In November 2012, the Mid-Atlantic North East Visibility Union (MANE-VU) members charged the Technical Support Committee (TSC) with evaluating the potential for combined heat and power strategies to reduce ozone and fine particulate matter levels in MANE-VU states. The TSC was also charged with recommending an appropriate strategy or strategies. In February 2013, the TSC launched the Combined Heat & Power (CHP) Workgroup to fulfill MANE-VU's charge. The workgroup decided to initially focus on the reduction potential for installations and retrofits of commercial and industrial systems with CHP.

Purpose of this report: This report estimates the magnitude of oxides of Nitrogen (NO_X) and Sulfur Dioxide (SO_2) emission reductions possible in MANE-VU from installation and retrofit of commercial and industrial systems with CHP.

Background



CHP, or cogeneration, is a general term that refers to converting systems that separately produce heat and electricity to integrated systems that produce both. A traditional system with separate power and heat production can achieve an efficiency of 45%, whereas CHP can achieve efficiencies of 80% (note: efficiency is defined here as the conversion of fuel to useful energy). A more advanced type of system called trigeneration uses a single integrated process for heating, electricity, and cooling. In addition to the efficiency benefits associated with CHP, transmission losses are decreased since electricity is now produced closer to the end user.

Since CHP systems use the same fuel to produce heat and electricity rather than the traditional separated power plant/boiler system, they also produce fewer emissions. For example, with CHP, an institution would produce a similar level of emissions as it would with just a boiler used for heating, but power no longer needs to be generated elsewhere to meet the institution's electricity needs. So the overall system does not emit the same level of criteria, toxic, and greenhouse pollutants as traditional separate heat-producing and electricity-generating processes.

There are other benefits to the installation of CHP systems. CHP systems can be set up as distributed generation resources, to be called on during times of peak energy needs. In addition, CHP systems can continue to function and provide local power during electrical grid failures. This allows facilities with CHP systems to remain electrified at times when the grid fails due to acts of nature, voltage problems, or blackouts.

There are also challenges to implementation of CHP systems. In a report on CHP produced by Oak Ridge National Laboratory it was stated that "challenges include unfamiliarity with CHP, technology limitations, utility business practices, regulatory ambiguity, environmental permitting approaches that do not acknowledge and reward the energy efficiency and emissions benefits, uneven tax treatment, and interconnection requirements, processes, and enforcement.[1]" Additionally, since CHP systems are smaller than a conventional electrical generating unit (EGU), emissions from these systems could in some case outweigh the benefits of the reduced offsite electricity production from the grid. There are also many economic factors that could prevent CHP from being feasible. The interactions between fuel prices, electricity prices, potential capacity, physical constraints, and available capital, among other factors, could prevent some CHP capacity from being realized. Regulations also play a role in reducing the amount of economically feasible CHP.

Criteria Pollutant Reduction Potential from Commercial and Industrial Installation & Retrofits of Heating Systems with CHP

Potential for CHP Installation in MANE-VU States

The first step in determining potential emission reductions from CHP installations is to determine how much potential there is for such installations, especially since many states in MANE-VU have existing installed CHP. A report by ICF International examined the technical potential for installation of CHP systems, beyond current installations, on a national basis. This report was relied on for determining the technical potential in the MANE-VU region. Table 1 shows the technical potential for CHP systems in the U.S.

An examination of the benefits of CHP systems in the MANE-VU region was performed by estimating the emissions associated with all technically feasible CHP in MANE-VU as listed in Table 2.

[1] Oak Ridge National Laboratory. "COMBINED HEAT AND POWER Effective Energy Solutions for a Sustainable Future." http://www1.eere.energy.gov/manufacturing/distributedenergy/pdfs/chp_report_12-08.pdf. Accessed March 23, 2013.

Table 1: Technical potential (MW) for CHP systems in the U.S. by capacity and application[2]

Sector		Load Factor	Application	Technical Potential (MW) .05-1 MW	1-5 MW	5-20 MW	>20 MW	Total	Class
Cogeneration	Industrial	High	Food & Beverage	2,744	3,250	1,330	697	8,021	63,823
			Textiles	586	751	726	176	2,239	
			Lumber and Wood	1,413	854	332	164	2,763	
			Paper	1,230	1,869	3,601	7,597	14,297	
			Printing/Publishing	2,306	5,875	8,165	8,223	24,569	
			Chemicals	424	897	697	1,941	3,959	
			Petroleum Refining	1,023	314	120	28	1,485	
			Rubber/Misc Plastics	88	122	53	0	263	
			Stone/Clay/Glass	406	532	953	1,214	3,105	
			Fabricated Metals	254	21	6	0	281	
			Transportation Equip.	681	469	725	304	2,179	
			Furniture	44	2	0	0	46	
			Chemicals	173	23	5	0	201	
			Machinery/Cptr Equip	74	62	17	0	153	
			Instruments	76	23	24	0	123	
			Misc Manufacturing	85	20	34	0	139	
	Comm/Inst	High	Waste Water Treatment	111	66	0	0	177	3,242
			Prisons	318	1,343	850	554	3,065	
		Low	Laundries	116	13	0	0	129	612
			Health Clubs	125	26	8	0	159	
			Golf/Country Clubs	235	28	15	0	278	
			Carwashes	43	3	0	0	46	
Trigeneration	Comm/Inst	High	Refrig Warehouses	67	33	9	7	116	21,188
			Data Centers	272	380	339	46	1,037	
			Nursing Homes	765	159	13	0	937	
			Hospitals	892	3,179	769	345	5,185	
			Colleges/Universities	641	1,648	1,669	1,471	5,429	
			Multi-Family Buildings	3,774	1,325	0	0	5,099	
			Hotels	1,330	1,386	460	209	3,385	
		Low	Airports	125	261	290	0	676	43,014
			Post Offices	29	11	0	0	40	
			Food Sales	1,079	65	41	0	1,185	
			Restaurants	1,179	62	15	0	1,256	
			Commercial Buildings	20,378	12,842	0	0	33,220	
			Movie Theaters	3	1	0	0	4	
			Schools	789	87	0	0	876	
			Museums	41	13	0	0	54	
			Government Facilities	1,276	1,334	955	170	3,735	
			Big Box Retail	1,662	251	25	30	1,968	

[2] ICF International. "Effect of a 30 Percent Investment Tax Credit on the Economic Market Potential for Combined Heat and Power." October 2010. Accessed October 29, 2014.

Table 2: Existing and technical potential (MW) for CHP systems in MANE-VU states by capacity

State	Existing (MW)[3]	Technical Potential (MW) [2]				
		.05-1 MW	1-5 MW	5-20 MW	>20 MW	Total
CT	741	492	396	78	0	966
DC[4]	14	0	0	0	0	0
DE	231	104	59	21	0	184
ME	936	176	142	0	6	324
MD	705	682	457	0	75	1,214
MA	1,576	976	755	0	140	1,871
NH	47	184	130	9	0	323
NJ	3,049	1,133	875	421	28	2,457
NY	5,775	2,851	2,671	820	259	6,601
PA	3,269	1,631	1,442	233	155	3,461
RI	126	159	117	22	0	298
VT	24	85	61	19	0	165
Total	16,493	8,473	7,105	1,623	663	17,864

Table 1 examines various CHP applications and whether they: 1) would produce electricity, heating, and cooling (trigeneration) or just electricity and heating (cogeneration), 2) would be used for industrial purposes or commercial/institutional purposes, and 3) run only during business hours (low load factor) or closer to 24 hours a day (high load factor). Data from the ICF analyses was also used to estimate annual operating hours from for systems in each class.

Table 2 includes state level totals of both existing and technical potential by system capacity as found in the ICF report. The technical potential is the basis for the capacity estimates throughout this paper. Since ICF did not analyze Washington, DC, although it has 14 MW of existing CHP capacity, it was excluded from the remainder of the paper.

Since no information was available for technical potential for each class at the state level, it was assumed that each state had the same distribution of classes as was found nationally Equation 1 was used to estimate the technical potential for each class/state/capacity possibility. The resulting distribution that was used throughout the rest of this paper can be found in Table 3.

Equation 1: State/Class/Size Technical Potential

$$PercentageTechPotential_{Class/\,Size} = (TechPotential_{Class/Size}/TechPotential_{National/Size})$$

[3] https://doe.icfwebservices.com/chpdb/. Accessed September 4, 2015.
[4] Since ICF did not analyze Washington, DC, although it has 14 MW of existing CHP capacity, it was excluded from the remainder of the paper.

Table 3: Percentage of technical potential for each class by capacity in the U.S.

Class	Op. Hours[2]	System Capacity			
		.05-1 MW	1-5 MW	5-20 MW	>20 MW
Cogen/Industrial/High Load	7,000	24.77%	38.09%	75.47%	87.78%
Cogen/Commercial/High Load	7,000	0.92%	3.56%	3.82%	2.39%
Cogen/Commercial/Low Load	4,000	1.11%	0.18%	0.10%	0.00%
Trigen/Commercial/High Load	7,000	16.52%	20.48%	14.65%	8.97%
Trigen/Commercial/Low Load	5,000	56.69%	37.69%	5.96%	0.86%

Additionally, only the CHP systems that are economically feasible were examined. ICF produced three scenarios looking at differing levels of the Investment Tax Credit (ITC) to determine what could be economically feasible (Table 4). Since this information was not available at the state level, it was assumed that each state had the same distribution of classes as was found nationally. The percentage of each size that was found to be economically feasible was applied to each state's technical feasibility for these scenarios.

Table 4: Economic feasibility of CHP at three levels of the ITC in the U.S.[2]

Class	National Capacity (MW)				
	.05-1 MW	1-5 MW	5-20 MW	>20 MW	Total
0% ITC	125 0.27%	371 0.94%	567 2.55%	1,547 6.68%	2,610
Expanded ITC (10% up to 25 MW)	181 0.39%	500 1.26%	674 3.03%	1,802 7.78%	3,157
30% ITC (30% up to 25 MW)	258 0.55%	681 1.72%	973 4.37%	2,284 9.86%	4,196
Technical Potential	46,857	39,600	22,246	23,176	131,879

Potential Emission Reductions

There are two ways in which installation of CHP can change emissions levels, onsite and offsite. The onsite emission changes would be due to retrofits and repowering necessary to convert a system to CHP (for example, a newly installed boiler or turbine that produces different emissions from the previous equipment). Offsite emissions changes would occur because CHP acts as a replacement for electricity produced elsewhere.

Calculations for Estimating Onsite Emission Changes

The breakouts in Table 3 were used to calculate emission reductions by capacity and the class of facility. For each state, emission reductions were calculated for NO_X and SO_2.

Using the same capacity breakout, an assessment conducted by NYSERDA contained emission reductions from replacing a subset of the boilers in their region with natural gas fired CHP systems[5]. Average annual emission rates for existing and replacement systems were calculated

[5] NYSERDA. "Combined Heat and Power Market Potential for New York State." October 2002.

on a per MW basis for NO_X and SO_2 using the base case scenario found in the NYSERDA report (except NO_X emission rates for replacement systems, see below). Since emission rates are not available for systems sized .05-.5 MW in the NYSERDA report, it was assumed that they had the same emission rates as systems sized .5-1 MW.

Instead of relying on the NYSERDA report, several estimates of NO_X emission rates were used when calculating emissions from replacement systems. Systems smaller than 5 MW were assumed to employ Reciprocating Internal Combustion Engines (RICE). Systems larger than 5 MW were assumed to employ Combustion Turbines (CT). Microturbines and fuel cells were also considered for the smaller systems, but these technologies are still evolving and using RICE would result in a more conservative estimate. For systems sized less than 5 MW, Delaware's stationary generator rule was used for Delaware, the OTC 2010 stationary generator model rule was used for New Jersey, and the RICE NSPS was used for all other states.

For systems in the 5-15 MW range, it was assumed that the emission rates from the OTC Model Rule for Additional NO_X Control Measures applied, regardless of state. Also regardless of state, all systems greater than 20 MW used the New Source Performance Standard for CTs. Additionally, average emission rates for the 5-20 MW category were calculated by averaging regulatory values for systems sized 5-15 MW (given 2/3 weight) and 15-20 MW (given 1/3 weight).

However, the emission rates for systems 5 MW and greater would almost certainly trigger New Source Review (NSR) or Prevention of Significant Deterioration (PSD), which would in turn lead to requirements to install the Lowest Achievable Emission Rate (LAER) or Best Available Control Technology (BACT) respectively. In order two find an appropriate BACT emission rate, the workgroup searched the RACT/BACT/LAER Clearinghouse (RBLC) for CHP combustion turbines installed since 2005 that ran on natural gas and were less than 25 MW.

Three units were found in the RBLC that had an emission rate in the appropriate format and that met the criteria – Woodbridge Energy Center (.034 lb/MWh) and Hess Newark Energy Center (0.170 lb/MWh) in New Jersey and Wesleyan University (0.109 lb/MWh) in Connecticut. These units had an average emission rate of 0.105 lb/MWh, considered to be BACT, and a lowest emission rate of 0.034 lb/MWh, considered to be LAER. Given that there are several ozone nonattainment areas in MANE-VU, that many other areas have a history of ozone nonattainment, and that some states in MANE-VU require LAER in attainment areas, the LAER emission rate was applied to the CHP systems in this analysis.

Although units smaller than 5 MW could trigger NSR, the second scenario (which assumes all states have adopted the OTC Stationary Generator Model Rule) should be sufficient to address BACT. Therefore no further analysis was conducted with respect to BACT.

A second set of calculations was made showing what would happen if all MANE-VU states adopted the 2010 stationary generator rule for the replacement systems. This meant that all states, except Delaware, had NO_X emission rates equivalent to those used for New Jersey in the first scenario. Emission factors used in the onsite calculations are summarized in Table 5.

Table 5: Annual average emission rates (lb/MWh) for CHP replacement and existing heating only boilers

Capacity	NO_X				SO_2		*CHP Heat Rate (Btu/kWh)*[2]
	CHP - DE[6]	CHP – OTC M.R.[7]	CHP – Fed.[8]	Existing	CHP	Existing	
.05-.5 MW	0.60	0.88	2.96	-	-	-	10,800
.5-1 MW	0.60	0.88	2.96	0.6355	0.0062	0.0031	10,800
1-5 MW	0.60	0.88	2.96	0.8246	0.0070	0.0028	9,492
5-20 MW[9][10]	1.87/0.034	1.87/0. 034	1.87/0. 034	0.7750	0.0069	0.0027	11,765
> 20 MW[10]	1.20/0. 034	1.20/0. 034	1.20/0. 034	0.5546	0.0055	0.0022	9,220

The systems were assumed to run according the annual operating hours listed in Table 3. It should be noted that the replacement systems themselves produce more emissions than the original systems.

Calculations for Estimating Offsite Emission Changes

As discussed earlier, the other way in which CHP systems can reduce pollution is by reducing the amount of electricity that power plants need to produce.

Several assumptions were made in order to estimate the emission reductions from the power sector due to implementation of CHP:

- For each state, CHP systems would replace base load coal generation in the ERTAC region in which the state was predominately located. In regions where coal generation does not occur, the system would replace Combined Cycle Natural Gas units. The coal assumption in particular could lead to an overstatement of the benefits.
- Transmission loss would be the average in the Eastern Interconnection of 5.82%.
- Although CHP systems would undertake routine maintenance during shoulder months, this activity will have a negligible effect on emission estimates.
- New CHP systems will be operational by the modeled future year of 2018, which was chosen due to its importance for Ozone and Regional Haze planning.

To calculate the number of hours that the low load factor cogeneration CHP systems would run during the year, the number of heating degree days and cooling degree days were averaged from 2004-2013 for each of month of the year. The ratio of heating degree days to total degree days was used to approximate the number of hours in the month the heating system would run (heating hours).

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[6] DE 7 § 1144 3.2.2
[7] OTC Model Rule for Stationary Generator Control Measures.
[8] 40CFR60-JJJJ
[9] OTC Model Rule for Additional Nitrogen Oxides (NOx) Control Measures
[10] 40CFR60-KKKK

In order to estimate the start and end of the heating season, the shoulder months were examined to determine which had the clearest end date-and then the average annual heating hours were used to calculate the other date based on the assumption that the heating would run straight through. An overview of the heating/cooling degree days and heating hours are in Table 5, as well as the approximate dates used as the end and beginning of the heating season for each state.

Table 6: Average annual heating and cooling degree days, last and first date of heating season, and calculated hours for heating by state from 2004-2013[11]

State	Annual Average Degree Days		Heating Season		Heating Hours
	Heating	Cooling	Last Day	First Day	
CT	5,780	625	6/7	9/14	6,386
DE	4,414	1,210	5/17	9/27	5,545
MA	6,043	534	6/14	9/12	6,622
MD	4,497	1200	5/17	9/27	5,568
ME	7,622	236	7/22	8/19	7,563
NH	7,327	310	6/20	8/21	7,268
NJ	5,045	913	5/23	9/19	5,900
NY	5,909	647	6/7	9/14	6,405
PA	5,623	734	5/24	9/7	6,208
RI	5,682	585	6/15	9/18	6,488
VT	7,778	249	6/22	8/13	7,498

The ERTAC EGU tool was then used to estimate the emission reductions from reduced need for generation in the power sector. Version 2.3 of the ERTAC inputs was used as the basis for the runs and the runs were conducted using a modified copy of version 1.01 of the software. The modifications were made to limit the number of hours that units could be run based on the utilization factor.

To use ERTAC EGU to project CHP's impacts on the grid, a "virtual CHP plant" was created for: 1) each state (three in the case of New York), 2) each class of facilities, 3) the four tiers of capacities, and 4) in the case of the CHP low load class, each season. This resulted in a total of 364 "virtual CHP plants." The scenario in which all of the technically feasible CHP systems are built will be henceforth called "Technical Potential Scenario". In addition, the benefits of only installing larger systems (those greater than or equal to 5 MW) and of only installing smaller systems (those less than 5 MW) were examined. These cases are henceforth called "Large Systems Scenario" and "Small Systems Scenario," respectively. Finally, the three economic options, "0% ITC Scenario," "10% ITC Scenario," and "30% ITC Scenario" were assessed.

ERTAC EGU distributes generation using geographic regions that are based on the regions used by the Energy Information Agency in their Annual Energy Outlook report. In most cases the

[11] NCDC Climate Indicators. http://www7.ncdc.noaa.gov/CDO/CDODivisionalSelect.jsp. Accessed April 11, 2014.

entirety of the MANE-VU state is within the applicable ERTAC region so 100% of the virtual CHP systems are allocated to that region. Even though part of western Pennsylvania, and to a lesser extent part of western Maryland, is in the RFCW region, all of the CHP systems were allocated to the RFCE region since the RFCW region extends well beyond the MANE-VU region. New York has three regions. To allocate the CHP systems across those regions, the percentage of the population from 2010 US Census data in each region was used as a surrogate[12]. A map of all of the ERTAC regions is in Figure 1 and the list of regions analyzed is in Table 7.

Figure 1: Map of ERTAC Regions

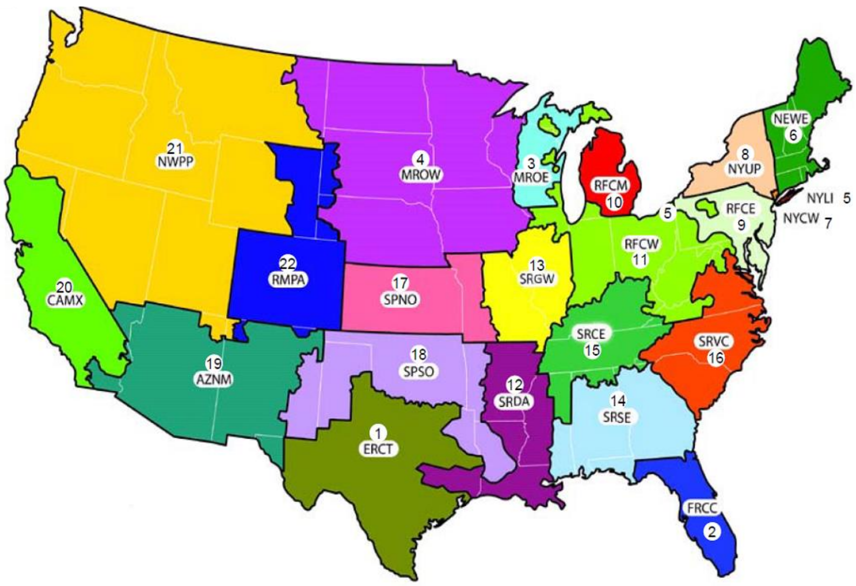

Table 7: List of ERTAC EGU regions analyzed and which states are allocated to the regions

ERTAC EGU Region	State Allocation
NEWE	100% of CT, ME, MA, ME, NH, RI, VT
NYCW	42% of NY
NYLI	15% of NY
NYUP	43% of NY
RFCE	100% of DE, MD, NJ, PA

The ERTAC EGU input files must contain several data elements to process the "virtual CHP plants":

1. Capacity: calculated using Equation 2 using the distributions from Table 3.
2. Annual heat rate: based on the capacity tier, obtained from the ICF report and listed in Table 5.

[12] http://www.census.gov/popest/data/counties/totals/2014/CO-EST2014-01.html. Accessed August 6, 2015.

3. Utilization fraction (percentage of hours operating): The operating hours, based on the class obtained from the ICF report, are listed in Table 3. For the low load cogeneration class, the utilization fraction was the same as that used for low load trigeneration facilities for the non-summer months and was adjusted accordingly for the summer months using the length of the heating season defined in Table 5.
4. Maximum heat input: calculated using Equation 3.
5. NO_X and SO_2 emission rates: set to 0 since the onsite emissions were calculated separately.

Equation 2: "Virtual CHP plant" capacity

$$Capacity_{Virtual\ Plant} = PercentageTechPotential_{Class/Size}/TechPotential_{State/Size}/(1-TransLoss)$$

Equation 3: "Virtual CHP plant" maximum heat input

$$Maximum\ Heat\ Input = Annual\ Heat\ Rate * Capacity_{Class/State/Size}/1000$$

Additionally, to properly shutdown the "virtual CHP plants" during hours which they are not running, the ERTAC EGU code was altered so that systems do not run after the maximum number of hours was met. The maximum number of hours is based on the utilization fraction.

Results

When looking at the scenarios that examined technical potential only, the replacement of boilers in MANE-VU with CHP systems would yield substantial increases in onsite NO_X if the model rule is not adopted by all of the states. These emission increases outweigh the benefits of reduced power needed from the grid. Implementing the model rule would lead to regional NO_X benefits. Using BACT emission limits for the large systems, which are independent of the model rule, has a positive impact on NO_X emissions. In all situations the implementation of CHP systems has a clear SO_2 benefit. Table 8 summarizes the changes in onsite and offsite NO_X and SO_2 for all of the scenarios analyzed.

For the systems that ICF found to be economical at the various ITC levels, the emission changes increase at higher ITC levels. This is an expected trend. Having the model rule implemented throughout MANE-VU resulted in NO_X benefits at all levels of the ITC, whereas all of the scenarios without full implementation of the model rule resulted in NO_X increases. In all cases there was a benefit in reduced SO_2.

More details on the changes in emissions are in Table 9.

Table 8: Changes in NO_X and SO_2 annual emissions (tons) in the MANE-VU region as a result of CHP replacement

Scenario		Pollutant	Total	Scenario		Pollutant	Total
"Technical Potential"	Onsite	NO_X - no Model Rule	85,993	"30% ITC"	Onsite	NO_X - no Model Rule	686
		NO_X - w/ Model Rule	1,819			NO_X - w/ Model Rule	-246
		SO_2	201			SO_2	4
	Offsite	NO_X	-28,894		Offsite	NO_X	-295
		SO_2	-64,628			SO_2	-1,303
	Total	NO_X - no Model Rule	57,098		Total	NO_X - no Model Rule	390
		NO_X - w/ Model Rule	-27,075			NO_X - w/ Model Rule	-542
		SO_2	-64,427			SO_2	-1,299
	CHP Capacity (MW)		17,680		CHP Capacity (MW)		303
"Large Units"	Onsite	NO_X	-5,342	"10% ITC"	Onsite	NO_X - no Model Rule	495
						NO_X - w/ Model Rule	-181
		SO_2	31			SO_2	3
	Offsite	NO_X	-1,912		Offsite	NO_X	-211
		SO_2	-9,653			SO_2	-947
	Total	NO_X	-7,254		Total	NO_X - no Model Rule	284
						NO_X - w/ Model Rule	-392
		SO_2	-9,623			SO_2	-944
	CHP Capacity (MW)		2,265		CHP Capacity (MW)		221
"Small Units"	Onsite	NO_X - no Model Rule	91,334	"0% ITC"	Onsite	NO_X - no Model Rule	334
		NO_X - w/ Model Rule	7,160			NO_X - w/ Model Rule	-159
		SO_2	170			SO_2	2
	Offsite	NO_X	-12,804		Offsite	NO_X	-161
		SO_2	-58,066			SO_2	-737
	Total	NO_X - no Model Rule	78,230		Total	NO_X - no Model Rule	174
		NO_X - w/ Model Rule	-5,644			NO_X - w/ Model Rule	-319
		SO_2	-57,895			SO_2	-735
	CHP Capacity (MW)		15,415		CHP Capacity (MW)		173

Conclusions

With the CHP technologies discussed in this paper, increases in CHP penetration would lead to significant decreases in SO_2 emissions in MANE-VU due to displacement of current base load generation. The same is not true for NO_X emissions, given the increase in onsite NO_X emissions from CHP systems in the vast majority of the scenarios examined. When looking at smaller systems, the replacements need to meet the NO_X standards outlined in the OTC Stationary Generator Model Rule to have a benefit.

Although not specifically addressed in this paper, increased CHP penetration would likely produce the additional benefit of reduced SO_2 emissions. This is an additional consideration that decision-makers should examine when pursuing policies to encourage CHP installations. Finally, there are potential newer technologies on the horizon such as fuel cells. These technologies could reduce the onsite emissions footprint further which would result in more emissions reductions, in particular from NO_X.

Recommendations for Future Work

One limitation of using the ERTAC EGU tool is that economics is not considered on a unit by unit basis, which creates a challenge in ensuring that the CHP systems replace generation from economically marginal units. Additionally, ERTAC EGU segregates generation by fuel further adding to the challenges of only reducing generation from marginal units. Although the technique of creating the “virtual CHP plant” attempted to solve this problem, it would be advisable to attempt using other more appropriate tools in any future analysis. Work is underway to explore incorporating ERTAC EGU projections into the EPA’s AVERT (AVoided Emissions and geneRation Tool) model, which is designed to show the impact of renewables and other unconventional generation on the grid. Once that work is complete, the AVERT tool could be very useful for examining the impact of CHP systems in MANE-VU replacing marginal units and peaking units.

Table 9: Changes in NO_X and SO_2 annual emissions (tons) in MANE-VU as a result of CHP replacement

Scenario		Emission Changes													
		Pollutant	CT	DE	DC	ME	MD	MA	NH	NJ	NY	PA	RI	VT	Total
"Technical Potential"	Onsite	NO_X - no Model Rule	5,792	-106	0	2,137	7,548	11,430	2,099	-162	34,665	19,843	1,807	939	85,993
		NO_X - w/ Model Rule	222	-106	0	140	430	576	132	-162	-57	542	78	23	1,819
		SO_2	11	2	0	4	13	20	4	28	76	39	3	2	201
	Offsite	NO_X	-388	-215	0	0	-6,230	-716	-2,677	-1,180	-4,626	-12,863	0	0	-28,894
		SO_2	-540	-561	0	0	-11,265	-1,508	-3,389	-1,315	-20,786	-25,262	0	0	-64,628
	Total	NO_X - no Model Rule	5,405	-320	0	2,137	1,318	10,713	-578	-1,342	30,040	6,980	1,807	939	57,098
		NO_X - w/ Model Rule	-166	-320	0	140	-5,799	-141	-2,545	-1,342	-4,682	-12,321	78	23	-27,075
		SO_2	-530	-559	0	4	-11,252	-1,488	-3,386	-1,287	-20,710	-25,223	3	2	-64,427
	Capacity (MW)		966	0	0	324	1,214	1,871	323	2,457	6,601	3,461	298	165	17,680
"Large Units"	Onsite	NO_X	-199	-54	0	-11	-136	-254	-23	-1,124	-2,561	-876	-56	-48	-5,342
		SO_2	1	0	0	0	1	2	0	6	15	5	0	0	31
	Offsite	NO_X	9	-14	0	1	-285	-235	240	-94	-565	-970	0	0	-1,912
		SO_2	108	-76	0	0	-1,519	-1,394	491	-237	-4,762	-2,265	0	0	-9,653
	Total	NO_X	-189	-68	0	-10	-421	-489	218	-1,218	-3,126	-1,846	-56	-48	-7,254
		SO_2	109	-75	0	0	-1,518	-1,392	491	-230	-4,748	-2,259	0	0	-9,623
	Capacity (MW)		78	0	0	6	75	140	9	449	1,079	388	22	19	2,265
"Small Units"	Onsite	NO_X - no Model Rule	5,991	-52	0	2,148	7,684	11,684	2,122	962	37,226	20,718	1,863	987	91,334
		NO_X - w/ Model Rule	421	-52	0	151	567	830	155	962	2,504	1,417	134	72	7,160
		SO_2	10	2	0	3	12	19	3	22	61	34	3	2	170
	Offsite	NO_X	-191	-102	0	1	-2,004	-256	-782	-514	-2,212	-6,744	0	0	-12,804
		SO_2	-540	-491	0	0	-9,892	-1,508	-3,390	-1,158	-19,257	-21,831	0	0	-58,066
	Total	NO_X - no Model Rule	5,800	-154	0	2,149	5,680	11,428	1,340	448	35,015	13,974	1,863	987	78,530
		NO_X - w/ Model Rule	230	-154	0	151	-1,437	574	-628	448	293	-5,326	134	72	-5,644
		SO_2	-531	-489	0	3	-9,880	-1,489	-3,386	-1,136	-19,196	-21,797	3	2	-57,895
	Capacity (MW)		888	0	0	318	1,139	1,731	314	2,008	5,522	3,073	276	146	15,415
"30% ITC"	Onsite	NO_X - no Model Rule	55	-3	0	22	64	98	21	-45	275	173	17	8	686
		NO_X - w/ Model Rule	-6	-3	0	0	-9	-19	0	-45	-119	-43	-1	-2	-246
		SO_2	0	0	0	0	0	0	0	1	2	1	0	0	4
	Offsite	NO_X	-7	-1	0	1	-40	-11	-47	-8	-63	-119	0	0	-295
		SO_2	-28	-11	0	0	-209	-71	-149	-35	-547	-254	0	0	-1,303
	Total	NO_X - no Model Rule	48	-4	0	22	25	87	-26	-53	212	54	17	8	390
		NO_X - w/ Model Rule	-13	-4	0	1	-49	-30	-47	-53	-182	-162	-2	-2	-542
		SO_2	-28	-10	0	0	-209	-71	-149	-34	-545	-253	0	0	-1,299
	Capacity (MW)		13	0	0	4	19	32	4	42	123	59	4	2	303
"10% ITC"	Onsite	NO_X - no Model Rule	40	-2	0	16	46	69	15	-31	200	124	12	6	495
		NO_X - w/ Model Rule	-4	-2	0	0	-8	-15	0	-31	-86	-32	-1	-1	-181
		SO_2	0	0	0	0	0	0	0	0	1	1	0	0	3
	Offsite	NO_X	-5	0	0	1	-29	-8	-34	-5	-46	-86	0	0	-211
		SO_2	-21	-8	0	0	-153	-51	-108	-25	-399	-183	0	0	-947
	Total	NO_X - no Model Rule	36	-2	0	16	17	62	-19	-36	154	38	12	6	284
		NO_X - w/ Model Rule	-9	-2	0	0	-37	-23	-34	-36	-132	-118	-1	-1	-392
		SO_2	-21	-8	0	0	-152	-51	-108	-25	-397	-182	0	0	-944
	Capacity (MW)		9	0	0	3	14	24	3	30	90	44	3	2	221
"0% ITC"	Onsite	NO_X - no Model Rule	29	-2	0	11	32	48	11	-27	134	86	9	4	334
		NO_X - w/ Model Rule	-3	-2	0	0	-7	-14	0	-27	-75	-28	-1	-1	-159
		SO_2	0	0	0	0	0	0	0	0	1	0	0	0	2
	Offsite	NO_X	-3	0	0	1	-23	-6	-26	-2	-36	-66	0	0	-161
		SO_2	-16	-6	0	0	-119	-38	-82	-20	-315	-141	0	0	-737
	Total	NO_X - no Model Rule	25	-2	0	12	9	42	-15	-30	98	20	9	4	174
		NO_X - w/ Model Rule	-7	-2	0	0	-30	-20	-26	-30	-111	-95	-1	-1	-319
		SO_2	-16	-6	0	0	-119	-38	-82	-20	-314	-141	0	0	-735
	Capacity (MW)		7	0	0	2	11	19	2	24	71	34	2	1	173