Combined Heat and Power (CHP)

Summary: This initiative encourages distributed CHP systems to reduce fossil fuel use and GHG emissions. Reductions are achieved through the improved efficiency of CHP systems, relative to separate heat and power technologies, and by avoiding the T&D losses associated with moving power from central generation stations to distant locations where electricity is used.

Goals:

- Utilization of 64 million MMBtu of natural gas in CHP applications in 2020
- Utilization of 7 million MMBtu of biomass in CHP applications in 2020

Other Involved Agencies: N/A

Possible New Measure(s):

CHP is a term used to describe scenarios in which waste heat from energy production is recovered for productive use the concept of which, is embodied in Pennsylvania's Alternative Energy Portfolio Standard (AEPS) definition for distributed generation systems, which reads, "which shall mean the small-scale power generation of electricity and useful thermal energy." The theory of CHP is to maximize the energy use from fuel consumed and to avoid additional GHG's by the use of reclaimed thermal energy. The reclaimed thermal energy can be used by other nearby entities (e.g., within an industrial park or district steam loop) for productive purposes. Generating stations in urban areas may have existing opportunities or may require the co-location of new industry. For Pennsylvania, the largest source of new, cost-effective CHP potential is in industrial facilities that have continuous thermal loads for domestic hot water and process heating (ACEEE et al., 2009). CHP units are typically sized to the minimum thermal load for the facility.

Potential Work Plan Costs and GHG Reductions:

Table 1 Work Plan Costs and GHG Results ($2010)

Annual Results (2020)			Cumulative Results (2013-2020)		
GHG Reductions ($MMtCO_2e$)	Cost (Million $)	Cost-Effectiveness ($\$/tCO_2e$)	GHG Reductions ($MMtCO_2e$)	Costs (NPV, Million $)	Cost-Effectiveness ($\$/tCO_2e$)
3.8	$-178	$-47	17.1	$-544	$-32

The composition of the costs presented in Table 9.1 differs according to the type of CHP. Commercial CHP has the highest costs, in part because of the relatively low capacity factor (47% in 2010, rising to 64% in 2020) implied in the ACEEE et al. (2009) report. These low capacity factors are somewhat unusual because CHP units, especially commercial applications, are typically sized to the meet the constant thermal demand of the facility. These units are then run at maximum capacity to generate the required thermal output.

The cost and emission estimates assume two types of technologies are representative of the CHP portfolio in the future. Table 2 reflects the assumptions for each technology.

- The CHP supply estimates in the ACEEE et al. (2009) report targets the year 2025. For interim years such as 2020, supplies are linearly interpolated. The avoided CO_2 emission rates are assumed to be the same as in the Act 129 work plan.

- As noted in the goals the two fuels analyzed for this work plan are natural gas and biomass. The sectors for deployment include commercial (includes institutions) and industrial.
- T&D losses are 6.6%.
- Retail electricity prices are the avoided electric prices. The associated and avoided CO_2 emissions rate is 0.~~91~~ 69 tCO_2/MWh, from a mix of 50% coal, 50% natural gas.
- Estimating the costs of CHP into the distant future is tentative, because cost estimates are highly sensitive to natural gas prices, the cost of avoided power, and the assumption about the CO_2 intensity of displaced electricity.

CHP potentials come from ACEEE et al. (2009) Table E-14. Market Penetration Results for $500/kW Incentive Case. This is the aggressive policy case where clean public energy funds subsidize the capital costs to install CHP at a rate of $500 per kilowatt (kW). This quantification incorporates the total social costs, including private and public costs, into the cost per MMtCO_2e measure.

Table 2. CHP Technology Assumptions

	Commercial	Industrial	
Demand and Energy Charge kW month	4.45	$10.83	PPL GS-3 charges for comm. LP-6 charges for industrial (>69 kv)
Distribution Charge kW month (commercial)	4.69		PPL GS-3 charges for comm. LP-6 charges for industrial (>69 kv)
Distribution Charge Customer/Month (industrial)		$891.00	PPL GS-3 charges for comm. LP-6 charges for industrial (>69 kv)
T&D Losses (%)	6.6	6.6	PA Assumption
Heat Recovered from CHP Power to heat ratio (%)	70	90	Source: Catalogue of CHP Technologies. EPA CHP Partnership. Introduction p. 7
CHP Unit Size MW	0.25	10.00	
CHP Technology	Microturbine	Gas Turbine	
Heat Rate MBTU/MWh	11,750	10,800	ACEEE, et al (2009) p. 212
Capacity Factor (%)	64%	75%	Calc for comm/ind based on ACEEE.
Installed Capital Costs $/kW	2,240	1,400	2010-2015 Costs as average for the period. Plus after treatment costs of $200/kw
O&M Costs $/kWh	0.01	0.01	2010-2015 Costs as average for the period
Economic Life/years	20.00	20.00	Assumption
Displaced boiler efficiency (%)	80%	80%	Assumption
Fixed O&M $/MBTU	0.07	0.07	Assumption
Variable O&M $/MBTU	0.07	0.07	Assumption
Net Generation Cost $/MWh	107.71	31.21	Calc
Avoided Price of Power $/MWh	97.84	76.62	Assumption
MW Capacity	386	661	Ind/Comm from ACEEE, et al (2009)
MWh Generation	2,171,000	4,345,000	Ind/Comm from ACEEE, et al (2009)

Implementation Steps:

The key to implementing CHP systems is to provide adequate incentives for the development of infrastructure to capture and utilize the waste heat. Such incentives could come in many forms, such as recruiting suitable end users to a centralized location to utilize the waste heat, ~~a feed-in tariff for CHP electricity,~~ tax credits, grants, zoning, and offset credits for avoided emissions. Additionally, Section 9.4.8 of the Governor’s Marcellus Shale Advisory Commission report, issued on July 22, 2011, recommends that, “The Commonwealth should promote the use of cogeneration technology (Combined Heat & Power (CHP) through the use of Permit-by-Rule, standardized utility power grid interconnection rules and direct financial incentives.” As previously mentioned, CHP systems, including those fueled by natural gas, are already an eligible Tier II resource under Pennsylvania’s AEPS. The AEPS also established a set of statewide interconnection standards.

A large group of locally financed small projects spread widely across the commonwealth could capture the value of replacing high-cost fuel imports and gain carbon benefits while limiting transportation costs of the feedstock. This model has been shown to allow displacement of significant quantities of current or projected fossil carbon release from a broad range of users—including industry, public institutions, commercial offices, and multi-family buildings—through reduced electrically driven cooling and distributed generation of electricity through CHP facilities.

The following are policies that can potentially increase the installed capacity of CHP in Pennsylvania:

- Create or expand markets for CHP units by using incentives designed to promote implementation for residential, commercial, and industrial users.
- Promote CHP technologies through provisions for tax benefits, attractive financing, utility rebates, and other incentives.
- Remove barriers to CHP development, such as utility rate structures that allow discounted electric rates to compete with CHP. Also, design interconnection standards to facilitate economical and efficient CHP connection to the grid.
- Consider the economic and environmental benefits of CHP as a resource in each electric utility's Integrated Resource Plan. Potential measures include training and certification of installers and contractors, net metering and other pricing arrangements, clear and consistent interconnection standards.

Fugitive Methane:

The largest uncertainty with this assessment involves the life cycle greenhouse gas impacts of unconventional natural gas. The EPA's latest national GHG inventory, 2009, of the amount of methane (CH^4) released from leaks and venting in the U.S. natural gas network, from production through distribution to the ultimate consumer, is 570 billion cubic feet (Bcf). This corresponds to an emissions rate equal to 2.4% of gross U.S. natural production. (1.9 – 3.1% at a 95% confidence level)[2]. Methane losses from natural gas extraction and delivery accounted for 32% of U.S. methane emissions and 3% of the total U.S. GHGs in 2009. According to the 2011 EIA Production Year Report, natural gas production in Pennsylvania (conventional and non-conventional) was 854,059,500 thousand cubic feet (Mcf) or 854 Bcf. Applying the EPA-derived CH_4 emissions rate of 2.4% to Pennsylvania's natural gas production in 2011 reflects a total loss of approximately 20.5 BCF. Beginning about 2015 these losses and the associated methane leakage rate are expected to be significantly reduced via the implementation of federal New Source Performance Standard (NSPS) OOOO and DEP's general permit GP5.

Potential Overlap:

Subcommittee Recommendations