



Greenhouse Gas Neutrality Assessment of Coal Mine Methane and Waste-to-Energy Pyrolysis Projects

JUNE 2016



COLORADO
Energy Office

Prepared by:



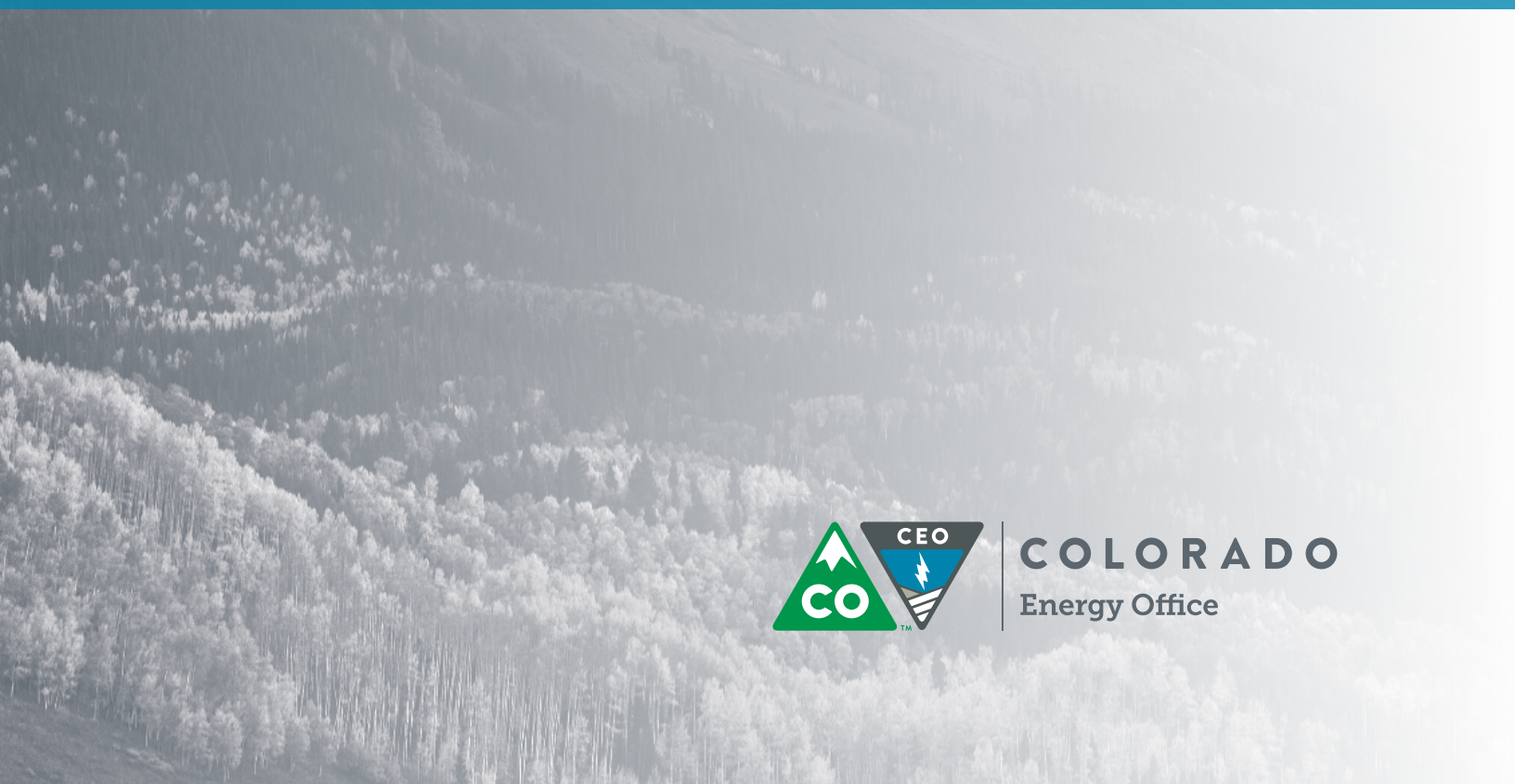
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Abbreviations and Acronyms List

AEC	Alternative Energy Credit	MACT	Maximum Achievable Control Technology
AEP	American Electric Power	MMBtu	Millions of British Thermal Units (BTUs)
AERS	Alternative Energy Resource Standard	MBtu	Thousands of British Thermal Units (BTUs)
AMM	Abandoned Mine Methane	MRF	Materials Recycling Facility
APCD	Air Pollution Control Division	MSW	Municipal Solid Waste
APEN	Air Pollutant Emission Notice	MW	Megawatt
BTU	British Thermal Unit	MWh	Megawatt Hour
CBM	Coal Bed Methane	NESHAP	National Emission Standards for Hazardous Air Pollutants
CDPHE	Colorado Department of Public Health & Environment	NOx	Nitrogen Oxides
CH ₄	Methane	NSPS	New Source Performance Standards
CHP	Combined Heat and Power	PAC	Powered Activated Carbon
CMM	Coal Mine Methane	PET	Polyethylene Terephthalate
CMOP	Coalbed Methane Outreach Program	PM	Particulate Matter
CO	Carbon Monoxide	PP	Polypropylene
CO ₂	Carbon Dioxide	PS	Polystyrene
CPS	Clean Energy Portfolio Standard	PUC	Public Utilities Commission
EPA	United States Environmental Protection Agency	PVC	Polyvinyl Chloride
F	Fahrenheit	REC	Renewable Energy Certificate
Ft ³	Cubic Feet	RES	Renewable Energy Standard
GHG	Greenhouse Gas	RPS	Renewable Portfolio Standard
GMI	Global Methane Initiative	SE	Specific Emissions
HAP	Hazardous Air Pollutant	Synfuel	Synthetic Fuel
HDPE	High Density Polyethylene	Syngas	Synthetic Gas or Synthesis Gas
IC	Internal Combustion	TPD	Tons Per Day
ICE	Internal Combustion Engine	TPY	Tons Per Year
kW	Kilowatt	VAM	Ventilation Air Methane
kWh	Kilowatt Hour	VOC	Volatile Organic Compound
LDPE	Low Density Polyethylene	WHRB	Waste Heat Recovery Boiler
LHV	Lower Heating Value		



Executive Summary

Colorado's Renewable Energy Standard (RES) has been in effect since 2004, but in 2013, coal mine methane (CMM) and synthetic gas produced by pyrolysis of municipal solid waste (MSW) were added as eligible energy resources as long as the renewable energy projects are greenhouse gas (GHG) neutral. The purpose of this study was to develop a framework for project developers and the Colorado Public Utilities Commission (PUC) to assess the GHG-neutrality of specific CMM and pyrolysis projects that generate electricity in Colorado. The report and accompanying calculation tools will serve as guidance in the RES certification process. The calculations use GHG accounting principles and equations from internationally-recognized CMM and MSW project protocols.

With the inclusion of CMM as an eligible energy resource under Colorado's RES, there is increased incentive to install CMM electricity generation projects in the state. Electricity generation is the most widely-used CMM utilization technology internationally, while natural gas pipeline sales traditionally have been the end-utilization choice for CMM projects located in the U.S. There are around 88 active CMM power generation projects worldwide, mostly in China and Germany. Currently, only one CMM power generation project is operating in the U.S., located in western Colorado.

As part of the study, four electric generation technologies were assessed for CMM-internal combustion engines, gas turbines, microturbines, and fuel cells—all of which could be installed at active or abandoned mines in Colorado. However, there are many factors that influence whether a technology type is practical for a given mine or location. Mine location, proximity to electric substations, and the quality and quantity of CMM produced are important considerations during the development of a new power project. Each technology has important advantages and disadvantages related to factors such as variability of CMM concentration, power plant size, electrical efficiency, maintenance requirements, and project emissions from the power system. In general, internal combustion engines have proven to be the most economically attractive technology option for electricity generation and are the most widely used, having fewer disadvantages than the other technologies.

Eligible CMM includes methane from both active and abandoned underground coal mines. Whether a project is GHG neutral depends on the emission source and quantity of methane recovered from an active mine gas drainage system, ventilation system, or abandoned mines.

Projects involving the destruction of methane from mine ventilation systems and post-mining gob wells always will be GHG neutral. The destruction of methane from an active mine gas pre-drainage system may be considered GHG neutral if the majority of the pre-mining wells are bisected by mining activities within five years. Projects involving the destruction of methane at abandoned mines compare the quantity of methane collected and destroyed against the estimated quantity of methane emissions, calculated by applying a hyperbolic emissions rate decline curve. The lesser of these two quantities is the baseline emissions. Depending on the mine, the quantity of methane collected and destroyed by the project can be five to 10 times higher than the quantity of methane estimated using the hyperbolic emissions rate decline curve and still remain GHG neutral.

A coal mine methane-to-electricity project may include a combination of methane sources from CMM, ventilation air methane (VAM), and abandoned mine methane (AMM). Likely combinations include projects with CMM drainage gas and AMM, CMM drainage gas and VAM, or AMM from multiple abandoned mines. In general, the use of combined methane sources requires combining the different GHG neutrality calculations, and could increase the likelihood that the project will be GHG neutral.

Similarly, with the inclusion of municipal solid waste (MSW) pyrolysis as an eligible energy resource under Colorado's RES, there is increased incentive to install MSW pyrolysis electricity generation projects in the state. Electricity generation via MSW pyrolysis is not the most widely-used technology, as most existing MSW-based facilities that produce electricity are mass-burn combustion plants or gasification plants. The RES defines pyrolysis as "the thermochemical decomposition of material at elevated temperatures without the participation of oxygen." This definition excludes the other most popular thermochemical conversion technology, gasification, which uses oxygen to initiate the reactions. Internationally, there are approximately



19 MSW pyrolysis projects, in various developmental/operational stages. In the U.S., there are only three commercial-scale demonstration facilities, and none appear to be currently operating. The MSW feedstock accepted by these facilities is almost exclusively non-recovered plastics waste, rather than bulk MSW.

As part of the study, data from six U.S.-based pyrolysis technology vendors was used to characterize likely facilities that could be deployed in Colorado—three of which are commercial-scale and three of which are pilot-scale plants. Generally, these existing MSW pyrolysis facilities accept waste plastics to produce liquid synthetic fuel products that may be further refined to a transportation fuel or used as a chemical input. None of the existing facilities currently are producing electricity from the synthetic fuel. Colorado’s RES specifies the eligible energy resource to be “...synthetic gas produced by pyrolysis of municipal solid waste...” For the six technologies studied, synthetic gas was a secondary by-product to the liquid synthetic fuels (synfuel).

For this study, it is assumed that the synfuel (and not synthetic gas) would be combusted in internal combustion engine-generator sets for electricity generation, as

this is the most widely used technology and has fewer disadvantages than the other technologies (e.g., steam boilers and gas combustion turbines) in the MSW sector. The GHG neutrality for MSW pyrolysis primarily will be governed by baseline emissions, which include methane emissions from MSW landfill(s) and GHG emissions avoided from grid-based electricity production. MSW pyrolysis facilities are unlikely to be GHG neutral, given that the primary feedstock for MSW pyrolysis consists only of fossil-based wastes (namely plastics which do not decompose in landfills and produce methane emissions). As a result, the synfuel produced and combusted for electricity generation is from fossil-based wastes (plastics, tires, etc.) and creates fossil-based emissions.

There is a remote chance that MSW pyrolysis projects could be GHG neutral if technologies are developed that utilize significant fractions of organic waste to produce a bio-based fuel and are located near landfills that have no landfill gas collection and control systems. There are few candidate landfills in Colorado that have no collection system and receive significant amounts of MSW each year. The two largest include the Colorado Springs Landfill and Midway Landfill (near Colorado Springs).

1 | Assessment of Coal Mine Methane Electric Power Generating Technologies

1.1 Background

Methane within a coal seam and surrounding strata is held in place by surface and hydrostatic pressures. As the earth's crust shifts and changes, coal seams naturally can be lifted to the surface, exposing coal layers to the atmosphere and creating outcrops allowing methane to flow more freely and naturally escape to the atmosphere. Essentially, the same process releases methane to the atmosphere during mining activities.

Section 40-2-124(1)(a)(II), C.R.S., defines coal mine methane as "methane captured from active and inactive coal mines where the methane is escaping to the atmosphere." In the case of methane escaping from active mines, "only methane vented in the normal course of mine operations that is naturally escaping to the atmosphere is coal mine methane for purposes of eligibility under this section¹." Coal mine methane has an identical definition under PUC Rules.

At underground mines, coal is removed by long-wall or room and pillar mining methods. Concurrently, the mine minimizes methane concentrations in the mine workings by employing ventilation and degasification systems. The coal mine methane being vented from active underground mine drainage systems is known as CMM while the ventilation air methane is referred to as VAM. Abandoned underground mines produce another source of methane known as abandoned mine methane (AMM). As an abandoned mine's tunnels and passageways continuously collapse, the released methane escapes from coal seams and migrates to the surface through poorly sealed shafts, old boreholes, and subsidence fractures in the overburden.

While the potential economic and environmental benefits of CMM generated electricity are recognizable, an uncertain energy market and declining coal production have impeded potential project development since 2013. CMM feedstocks can promote the development of smaller scale electrical generation technologies at coal mines and can serve as distributed energy sources in remote rural areas. However, legal, regulatory, and technical challenges

¹For purposes of this report methane "naturally escaping" from active mines is deemed to include all methane in and immediately above or below a coal seam within a designated area that is to be mined pursuant to an active mine plan and all subsequent amendments thereto.

make CMM project business risks and commercial feasibility difficult to assess, particularly at active mines where CMM emissions can be highly variable.

A detailed inventory of more than 30 active and inactive coal mines in Colorado with reported CMM emission volumes and electricity generating potential is included in the Colorado Energy Office's *Coal Mine Methane in Colorado Market Research Report*. The areas include six counties: Mesa, Delta, Gunnison, Pitkin, Huerfano, and Las Animas. The Somerset area mines in Delta and Gunnison counties have the highest electrical generation potential from total methane emissions (consisting of VAM, CMM drainage, and AMM)—about 76 MW, of which 25 MW may be economically and technically feasible to develop. The second area with highest potential is west of Redstone, about 16 miles south of Carbondale, where four abandoned mines are collectively capable of generating in excess of 5 MW.

The following sections of this report provide an assessment of the electric power generating technologies that have been proven using CMM from active and abandoned coal mines. Internationally, electricity generation is the most popular CMM utilization technology generating hundreds of megawatts, while natural gas pipeline sales have traditionally been the end-utilization choice in the United States. Currently, the only U.S. CMM power project—a 3 MW CMM electric power project—is operating in Colorado at the Elk Creek mine in Somerset.

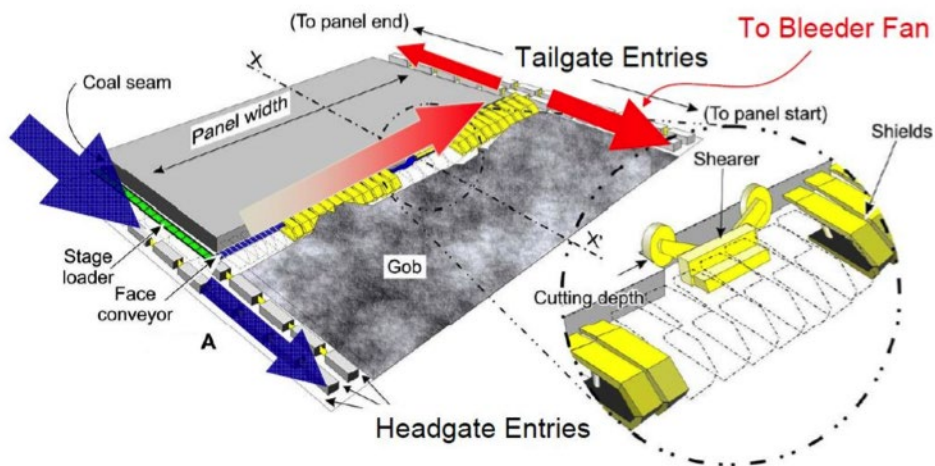
1.2 CMM Ventilation and Degasification Systems

1.2.1 Active Underground Mines

1.2.1.1 Ventilation Air Methane (VAM)

Methane in active underground mines is removed to protect the miners and maintain safe working conditions. All active underground mines utilize mine ventilation systems in which large quantities of fresh air are pumped into the mine to dilute the methane. Ventilation air flows leaving the mine typically contain concentrations of <1 percent methane. This methane source is known as ventilation air methane (VAM). Despite the low concentration, VAM is released into the atmosphere and is the largest source of CMM emissions in the United States. Figure 1-1 is a

FIGURE 1-1: SCHEMATIC OF LONGWALL PANEL AND SHEARING MACHINE. THE SHIELD MOVES FORWARD AFTER EACH CUT.
(SOURCE: MSHA)



schematic representation of how the ventilation air is drawn onto the working face of a modern longwall mine. The shearing machine runs along a track cutting into the panel of coal. The coal falls onto a conveyor that takes it to the surface. This releases methane into the working area which is diluted by the ventilation air. The contaminated air (red arrows) is exhausted at the surface.

VAM abatement technologies now can destroy low concentrations of methane through oxidation. The resulting thermal energy (waste heat) can be used to produce heat and power. A successful VAM-to-power project has been operating at the BHP Billiton's West Cliff Mine in Australia generating about 6 MW of electricity since 2007. There is one active VAM abatement project currently operating in the U.S.; however, the facility does not recover waste heat (Sindicatum, 2016).

1.2.1.2 Drainage Systems

At particularly gassy mines (emitting greater than 100 Mcf of methane per day), ventilation systems alone are not enough to maintain safe methane concentrations. Underground and surface drainage systems are employed to reduce methane quantities within the mine working areas by extracting gas from the surrounding strata before, during, and after mining operations.

An efficient methane drainage system can both significantly reduce mine ventilation system costs and be a source of additional mine revenue. By collecting and removing large volumes of methane with higher BTU content (35 percent-85 percent) the gas can be used for energy generation. Several drainage techniques typically are employed at gassy active underground mines.

Pre-mining vertical drainage wells

Pre-mining drainage wells are drilled vertically into the target coal seam from the surface to remove methane from the coal and surrounding gas-bearing strata. This activity usually takes place two to 10 years prior to mining activities. Depending on the distance of the well from the mining operations, recovering gas from pre-mining drainage systems increases the likelihood that the methane is not contaminated with ventilation air and is of a higher quality (>70 percent). Production of methane may require stimulating the wellbore, similar to methods utilized in oil and gas extraction. Aggressive pre-mining gas drainage systems in operation more than 10 years in advance of mining can recover over 50 percent of the coal's methane that normally would be vented to the atmosphere via the ventilation system (CMOP, 2009).

Horizontal Boreholes

Horizontal boreholes can be drilled from the mine workings into the target coal seam prior to the advancing longwall miner. Typically, wells are short-lived—less than two years—and up to 1,000 feet in length. Like other pre-mine degasification wells, horizontal boreholes can produce higher quality gas depending on coal permeability.

Longhole Horizontal Boreholes

Similar to horizontal boreholes, longhole boreholes are drilled horizontally from within the mine into the target coal seam. Directional drillings techniques are used to create boreholes greater than 4,000 feet in length. Longhole boreholes produce high-quality methane that can be utilized for most end-use technologies including electric power generation. Drilling longhole horizontal boreholes can be most effective for gassy coals with medium to high permeability.

Post Mining Gob Wells

The largest producing underground coal mines in Colorado are “longwall” mines. Longwall mining is highly efficient (80 percent coal recovery), recovering significantly more coal than room and pillar mining methods (50 percent coal recovery). As the longwall equipment advances along the face of the coal, the roof supporting shields move forward as well, allowing the roof to collapse behind the equipment, creating a gob area. This collapsed and fractured zone can extend hundreds of feet into the strata above the mined seam and is the source of additional methane.

To manage gob gas, degasification wells are drilled from the surface to about 10 to 50 feet above the mined coal seam. As mining operations advance beneath the wells’ locations, the wells are activated. Blowers attached to the wells at the surface create a suction pressure that allows the methane released from the gob area to flow to the surface rather than into the mine workings and/or ventilation system. Gob well gas quantity and quality is initially very high but decreases over time. Gob wells

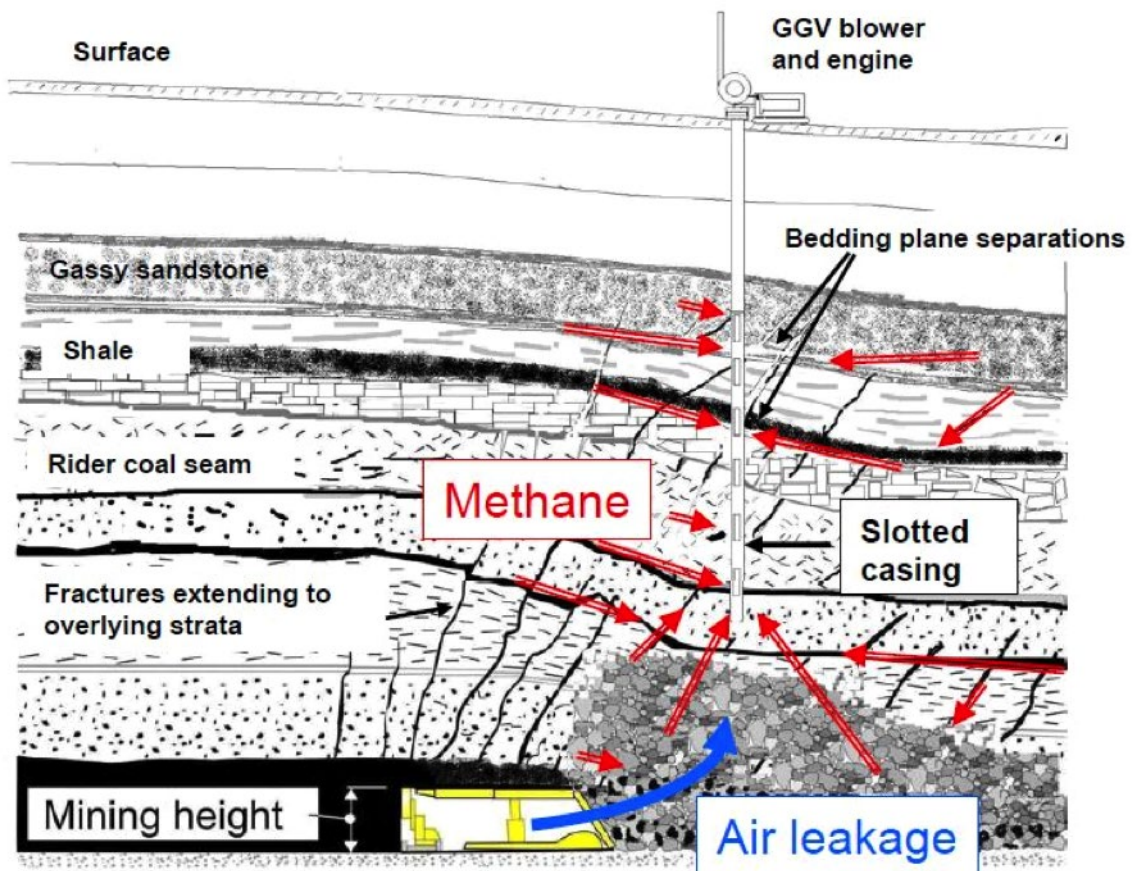
are an effective method to recover useable medium-quality gas (30 percent to 80 percent) normally vented during mining operations. Figure 1-2 illustrates, as a cross-section, the mined coal, shearing machine and associated shields, the gob and gob well.

1.3 Abandoned Coal Mines

Once the coal is produced, the mine closes and is abandoned. Even though operations have terminated, CMM continues to be released from the mine’s remaining coal bearing strata. As many of the safety issues associated with active mining operations are no longer concerns, abandoned coal mines can offer an excellent opportunity for methane recovery.

Following abandonment, a mine releases methane at a declining rate for an extended period of time. However, mine workings that are flooded from surface or ground water infiltration will produce methane for only a few years until the mine void is full of water, making it impossible to produce gas from the flooded area.

FIGURE 1-2: GAS METHANE RELEASED BY THE COLLAPSE OF THE GOB IS CONTAMINATED WITH VENTILATION AIR. (SOURCE: MSHA)



Commonly, methane extraction wells are drilled vertically from the surface into the mine workings. Blowers are attached to the well network to create a negative pressure that pulls the CMM from the mine. The quality of methane is site specific and can vary greatly. If the mine is well-sealed, the methane concentrations can range from 50 percent to 90 percent.

1.4 CMM Technologies to Generate Electricity

There are approximately 88 active CMM power generation projects worldwide—either at active or abandoned underground coal mines. More than two-thirds of these projects are in China and Germany. There are an estimated 13 additional projects in development including four in China and three in the United Kingdom (GMI, 2013). Globally, the primary use for medium-concentration (30 percent–80 percent methane) CMM is power generation. Today’s small-scale power generation equipment can use CMM as a feedstock throughout the medium-methane concentration range.

There is a limited market for large (>10 MW) power plants utilizing CMM because most coal mines do not produce enough methane for larger plants or the mines are in regions that have low electricity rates, making the projects uneconomic. Colorado does not have many opportunities for large power plants; however, there are opportunities for smaller projects using a range of technologies.

CMM is an attractive eligible energy source because it can serve as a base load power source. Base load power sources are plants that consistently can generate electricity, 24 hours a day, unlike renewable sources such as wind and solar that generate electricity intermittently.

Assessing the most appropriate technology requires an analysis of CMM qualities such as methane concentration and volume variability as well as the power market conditions and mining operation requirements. It also is important to appropriately size a power project. Key factors to consider with respect to fuel supply include an analysis of historical CMM emission rates and mining activities, as well as future mine plans and remaining



CMM resource estimates. Many commercial projects are constructed below the peak capacity of CMM volumes and flare the excess methane as part of the project. Examples of available CMM fueled technologies are listed below.

Power generation technologies not discussed here include VAM power generation, which is not economically feasible without added financial incentives like public grants, loan guarantees, and long-term carbon credit revenue. Typically, these projects involve simultaneous heat and power generation through cogeneration.

TABLE 1-1: PARAMETERS FOR CHOOSING A CMM POWER GENERATION TECHNOLOGY

Technology	Size (kW)	Equipment Cost (\$/kW)	Maintenance Cost (\$/kW)	Overhaul Frequency (hours)	Electrical Efficiency (%)	Minimum CH ₄ Concentration (%)
IC Engine/Lean burn engine	110-2,700	465-1,600	0.01-0.025	28,000-90,000	30-38	25
Conventional Turbine	1,200-15,000	1,100-2,000	0.008-0.010	30,000-50,000	26-34	40
Microturbine	30-250	800-1,650	0.012-0.025	30,000-50,000	26-30	35
Fuel Cell (Molten Carbonate Fuel Cell)	300-1,200	4,390-4,660	0.004-0.019	10,000-40,000	40-45	40

1.4.1 Internal combustion engines

Internal combustion (IC) engines are the technology of choice for CMM applications worldwide because of their low price, flexible operating parameters and ease of maintenance.

IC engines mix fuel with air and ignite the fuel inside the engine's combustion chamber. The engines contain a fixed cylinder and a moving piston. The hot gases produced by combustion expand to push the piston to rotate the crankshaft. Efficiency rates of IC engines are 35 percent to 44 percent and engines are available in a wide range of unit sizes—100 kW to 4,000 kW.

IC engines can be adapted to generate electricity using low concentration CMM, as low as 25 percent; however, there are safety concerns with transporting gas in concentrations below 30 percent. Only lean-burn engines currently are available for CMM power generation. Some engine manufacturers report that for typical lean-burn gas engines, at 50 percent load, the engine efficiency is eight to 10 percent less than full-load efficiency. Alternatively, conventional gas turbines show a decrease of 15–25 percent at half load (Su et al., 2005). An operation would benefit from a gas engine since CMM volumes are likely to vary with changes in the coal seam and mining rates and processes. Still, it may be beneficial to have multiple smaller units rather than one large unit to maintain highest efficiency.

Internal combustion engines are capable of using VAM instead of fresh ambient air in the combustion air intake. At Appin Colliery in New South Wales, Australia, 54 one-megawatt Caterpillar G3516 spark-fired engines were installed to combust drainage gas, but they also use VAM as combustion air in the engines.

FIGURE 1-4: GE JENBACHER IC ENGINES USING CMM
(SOURCE: GENERAL ELECTRIC)



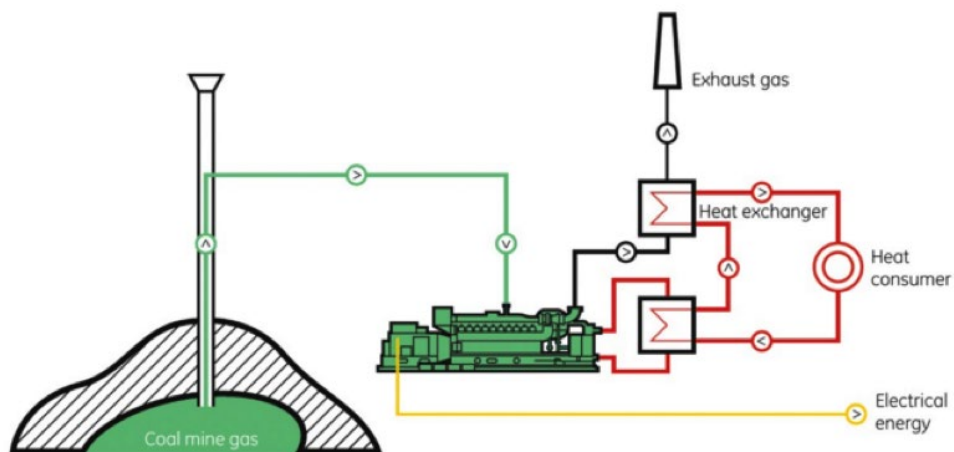
Advantages

- Reliable, well-proven technology available from several reputable manufacturers.
- Greatest combined electrical and thermal efficiency of all combined heat and power (CHP) technologies.
- Capable of being maintained and understood by mine staff.
- Requires fuel to be pressurized to only 3–5 psig.
- Models with advanced fuel injection technology can handle variable CMM concentrations well.

Disadvantages

- Requires continual cooling.

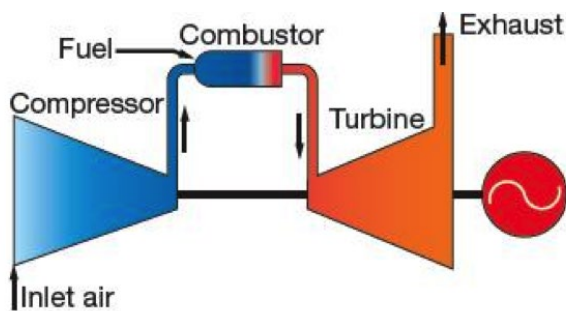
FIGURE 1-3: OPERATION OF AN INTERNAL COMBUSTION ENGINE
(SOURCE: GENERAL ELECTRIC)



1.4.2 Gas turbines

A gas turbine is a type of IC engine that heats a mixture of air and fuel at very high temperatures causing turbine blades to spin, which then drives a generator to produce electricity. The main difference between an IC engine and a gas turbine is that the turbine uses a rotary motion rather than the reciprocating motion. The compressor—a series of blades on a shaft—pulls air in through the air inlet. An intercooler cools the intake air, increasing its density and thereby increasing compressor efficiency. Compressed air exits through an exhaust heat recuperator which preheats the air. CMM is injected and then combusted. The hot gas expands through the turbine and produces the mechanical energy necessary to generate electricity and operate the compressor. Efficiency rates are 26 percent to 34 percent (Consol, 2010a), and turbines are available in unit sizes of 1,200 to 15,000 kW for CMM usage.

FIGURE 1-5: OPERATION OF A GAS TURBINE
(SOURCE: COMBINED CYCLE JOURNAL)



CMM can be used as a fuel source for gas turbines. Best results occur when the methane concentration is greater than 40 percent with minimal concentration variability. Turbines generally are smaller and lighter than IC engines and have been shown to have lower operation and maintenance costs (Kolanowski, 2004).

Gas turbines that utilize medium quality CMM—35 percent to 75 percent methane—are available. However, for safety reasons it is not recommended to use gas turbines for CMM with less than 40 percent methane content.

A potential drawback to using gas turbines is that variations in the CMM quality may create operating difficulties. The variability range is about 10 percent (CMOP, 2009). As a result, additional equipment may be necessary to blend the CMM with conventional natural gas to ensure that variations are within a usable range. Active mine gob gas flow rates and methane concentrations are unpredictable which makes the use of gob gas as a fuel source problematic.

Advantages

- Reliable, well-proven technology available from several reputable manufacturers.
- High thermal efficiency.
- Contain fewer moving parts and generally require less frequent maintenance than internal combustion engines.
- Relatively clean exhaust emissions.
- Suitable for unattended operation.

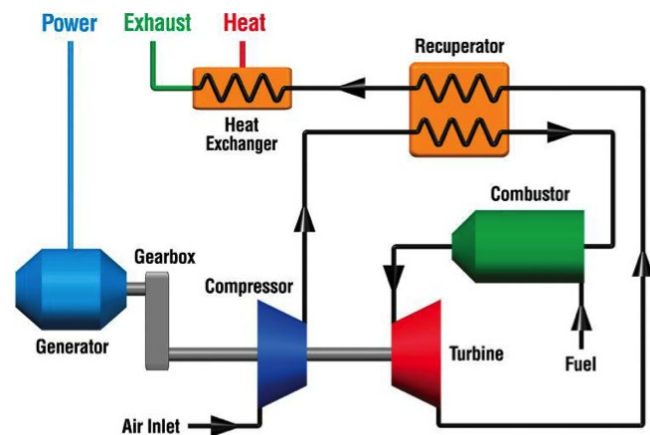
Disadvantages

- Less energy efficient than IC engines.
- Warm weather (above 59°F) and high elevation reduce power generation and fuel efficiency.
- Require high pressure fuel (100 to 400 psig), which in turn requires costly fuel compression.
- Variations in CMM quality may create operating difficulties.
- Require specialized maintenance.

1.4.3 Microturbines

A microturbine is a small, air-cooled gas turbine that drives a high-speed generator and compressor on a single shaft. Efficiency rates are 26 percent to 30 percent and are available with size ranges from 30 to 250 kW.

FIGURE 1-6: OPERATION OF A MICROTURBINE
(SOURCE: INGERSOLL RAND)



Microturbines are capable of burning CMM with low methane quantities and can handle fluctuations in methane concentration. They can operate with methane concentrations ranging from 35 percent to 100 percent (CMOP, 2004) with a destruction efficiency of up to 99 percent (Rafter, 2007). A main benefit of a microturbine is that it is able to operate on a smaller source of CMM with the lower end of the generation capacity around 30 kW.

An operation may choose to integrate multiple units and can scale an installation according to power needs and CMM availability. Microturbines can be located close to the gas source, and the generated electricity can be used on-site or transmitted to nearby facilities. Another advantage is that the small size makes microturbines easier to install at remote sites.

Because of the compact size, microturbines can be located at remote locations or inside existing mine buildings. This may enable the developer to design a project that tailors the power generation to the fuel supply, thereby reducing the required investment and maintenance associated with other types of generators.

Advantages

- Available in smaller size ranges (30 to 250 kW) for smaller CMM flows or smaller capacity plants.
- Produce low levels of NOx and carbon monoxide (CO) exhaust emissions.
- Relatively quiet and suitable for outdoor installation without adding additional noise mitigation.

Disadvantages

- Low electrical and thermal efficiencies compared to other technologies
- Requires significant fuel gas cleanup
- Requires high pressure fuel (75 to 100 psig), which in turn requires fuel compression

- Reduced power generation and fuel efficiency in warm weather (above 59°F) and high elevation
- Has failed to demonstrate a long-service life due to issues with fuel treatment
- Currently available from limited number of manufacturers

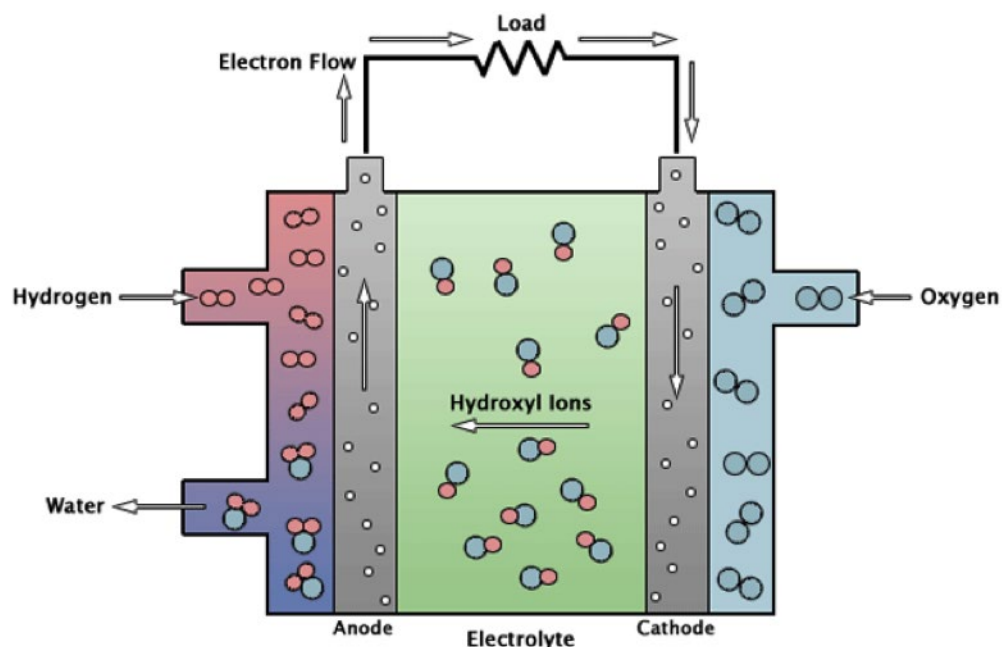
1.4.4 Fuel Cells

Fuel cells generate electricity through a chemical reaction, rather than from fuel combustion. A fuel cell is basically a large, continuously operating battery that produces electricity as long as there is a fuel supply. Each fuel cell contains an anode, a cathode, and an electrolyte layer in between. They convert chemical energy from hydrogen-rich fuels into electrical power and heat. Efficiency rates range from 40 percent to 45 percent, and fuel cells are available with size ranges from 300 to 1,200 kW.

CMM can be used as a fuel source for fuel cells. As the CMM enters the fuel cell stack, it reacts with oxygen from ambient air to produce electric current and heat, and water as a byproduct. Fuel cells are almost silent and there are no emissions from methane combustion. There are also no particulate pollutants emitted.

Another advantage to fuel cells is that there are no moving parts. Consequently, they require less maintenance. Fuel cells are scalable and systems can be designed based on conditions at a coal mine. Multiple cells can be combined to create larger systems.

FIGURE 1-7: OPERATION OF A FUEL CELL



Fuel cells have been shown to operate on CMM with an approximate 40 percent methane content. Additionally, variations in CMM flow did not cause problems with the operation of the fuel cell. Fuel cell energy estimates that a CMM composition of at least 60 percent methane is needed for a fuel cell plant to be economically attractive. Equipment cost is estimated at \$4,390 to \$4,660 per kW with maintenance costs of \$0.004 to \$0.019 per kW (Brown and Caldwell, 2010).

Advantages

- Produce exceptionally low levels of NO_x and CO exhaust emissions
- Frequently exempt from air permitting
- Very high electrical power efficiency
- Extremely quiet
- Suitable for unattended operation

Disadvantages

- Require extremely clean fuel
- Require highly specialized contract maintenance and servicing
- Have short lives of typically five years or less for cell stacks
- Produce less recoverable heat than IC engines and gas turbines
- Have a long start-up time
- Susceptible to periodic shut-downs during warm weather, unless equipped with a load bank.
- Very costly, although highly efficient with almost no emissions
- Existing systems are too large for use at small degas vents and smaller systems are even more costly than large systems.
- Currently available from limited number of manufacturers

1.5 Factors Influencing Project Economics

The basic factors that influence any natural gas power generation project's economic viability are capital expenses, operating costs, and revenue.

Capital expenses include the money needed to engineer, design, and construct the project, including the CMM fuel supply, power generation, and transmission systems, which includes among other things the equipment to clean, process, and compress the CMM; monitoring and metering equipment; and equipment necessary to meet electrical grid safety requirements.

Operating costs include the manpower and supplies needed to develop, operate, and maintain the CMM fuel supply, power generation, and transmission systems, which includes, among other things, administrative costs (permits, contracts, etc.), taxes, and royalties.

Revenue includes all funds generated from delivery and sale of electricity and other incentives such as alternative energy credits (AECs), renewable energy certificates (RECs), or carbon offsets.

The capital and operating costs are generally well-known for a given project size and location; however, the quantity and deliverability of the CMM and the power sales price are less certain. As a result, the variability in CMM quantity and quality can affect the choice of end-utilization technology as well as the economics of a project.

1.5.1 Methane Resource

The methane resource quality (the percent methane in the mine gas) and quantity and deliverability are different for an active mine capture and use project compared to an abandoned mine power project.

1.5.1.1 Methane content

An active mine project that obtains CMM from surface drilled gob wells may have significant variations in the methane content since some quantity of atmospheric gases from the mine workings will enter the gob area due to the pressure sink associated with the gob wells. An individual well's methane content is typically high initially and then declines over time, so the gas needs to be gathered from subsequent wells which are activated as the longwall panel progresses. This results in increased operating and capital costs to move the gathering system from well to well and eventually from panel to panel.

An abandoned mine can be visualized as a gas well with two methane reservoirs: the abandoned roadways and gob areas (the void volume), which holds gas in the free state, and the gas adsorbed in the remaining coal in contact with the void volume. The remaining coal includes unmined coal in the target seam as well as coal above and below the mined seam that has been fractured by the roof collapse and floor due to mining.

Once a mine is abandoned, the oxygen remaining in the void combines with the coal to form carbon dioxide, and the nitrogen either is displaced by methane desorbing from the remaining coal or is adsorbed onto the coal. In a well-sealed mine without direct access to the atmosphere through a pipe or shaft, mine gas can contain up to 90 percent methane and remains relatively stable. However, because of the buoyancy force of methane relative to air, it will find a way out of the mine over time either as diffuse emissions through fractures in the overburden or through poorly sealed well bores and

shafts. Since the methane in the coal is at a higher pressure than the void, the gas will occupy the void until it reaches some “escape” pressure. As methane in the void escapes it is replaced by methane that desorbs from the coal. This continues at a declining rate until the methane in the coal is depleted. Generally, AMM will range from 60 percent to 90 percent depending on how well-sealed the mine is.

1.5.1.2 Recoverable quantity of methane

Active mine

For an active mine with a surface gob well drainage system, historical mine gas drainage rates and composition are good indicators of future flow rates and composition. Coal thickness and gassiness can vary within a mining plan, but the variations can be accounted for with the proper adjustments to the historical model. The primary consideration for active mine gas recovery will be mine life, which is dependent on the mine plan, and other controlling factors such as the price of coal and unforeseen geologic hazards and accidents that make continued mining uneconomic.

Abandoned mine

For an abandoned mine, the size of the mine, together with the gassiness of the mine when in operation and the time since abandonment, are the most important indicators regarding the recoverable volume of methane.

Mine size

Obviously the larger the abandoned mine, the larger the two gas reservoirs will be. In some cases a large mine (greater than 1,000 acres) can be drained of methane with one or two wells because the void area is in pressure communication throughout the mine. This can be the case

even if seals are placed at strategic locations when the mine was active in order to isolate mined-out areas from areas of active workings. As seal integrity declines over time, given the low viscosity of gas, a single well may be able to drain an entire mine void. However, water flooding of parts of the mine creates hydrostatic pressure that effectively seals significant areas of the mine. This is called “compartmentalization,” which may require more wells in order to effectively drain the mine. In order to determine whether there is sufficient producible gas within a mine void, a well or opening is flow-tested to determine if its pressure and rate response through time matches a modeled response based on no compartmentalization.

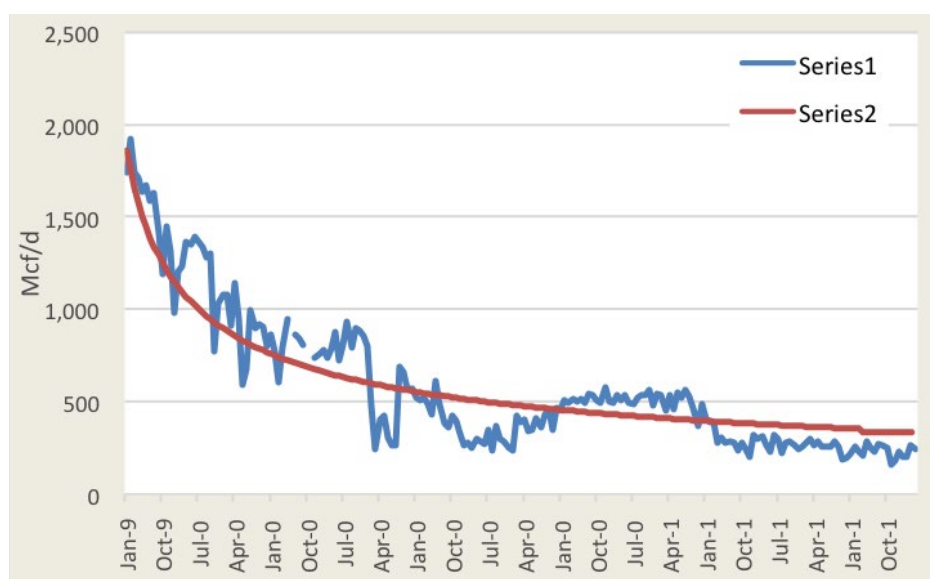
Mine gassiness

An undisturbed coal seam has an initial gas content expressed as cubic feet methane per ton of coal in-place. The volume of methane emitted during active mining operations is primarily a function of the tonnage of coal mined (specific emissions or SE), and is a good indicator as to whether a mine will continue to produce significant amounts of methane, at least soon after abandonment. However, during active mining, disturbance of the bounding coals can be higher than the in-place gas content sometimes by two or three times. High mine emissions is also an indicator that the pathway of the gas from the bounding coals is good and will facilitate the recharging of the gas removed from the void.

Mine age

Because abandoned mines emit methane from void areas and are recharged by a limited supply of adsorbed methane, the recharge rate will decline through time. This is illustrated by the production history of the abandoned Golden Eagle Coal Mine shown in Figure 1-8.

FIGURE 1-8: THE GOLDEN EAGLE MINE METHANE PRODUCTION HISTORY



The Golden Eagle mine in southeastern Colorado near Trinidad used surface-drilled gob vent boreholes to help lower methane volumes entering the mine during coal production. Upon abandonment, a local natural gas operator continued to produce some of those wells and blended the gas with local natural gas (CBM) for pipeline sales. The gas decline follows a decline curve described by a hyperbolic equation commonly used in the oil and gas industry. This behavior has been observed in several long-term abandoned mine methane production projects, and is used to estimate baseline natural methane emissions from abandoned mines. Obviously, it is better to start a methane capture-and-use project at an abandoned mine sooner than later after significant volumes of methane have been vented into the atmosphere. Also, because the gas rate is expected to decline, sizing a power generation project needs to take this into account.

1.6 Technology Case studies

1.6.1 Internal Combustion Engine Case Study

Elk Creek Coal Mine Methane Destruction & Utilization Project—Somerset, Colorado

The only active underground CMM project west of the Mississippi River currently generating electricity from CMM is the 3 MW Elk Creek Coal Mine Methane Destruction & Utilization Project. Installed and operated by Vessels Coal Gas, Inc., other partners on the project are Oxbow Mining LLC (the owner of the mine), Gunnison Energy LLC, and Aspen Skiing Company. Holy Cross Energy purchases power generated by the project.

CMM is drained from sealed areas of the mine through an underground drainage system. The project commenced operation in 2012 and consists of three 1,500 horsepower Guascor generator sets, each capable of generating 1 MW of electricity, an electric substation, a gas conditioning skid, as well as monitoring and metering equipment and control systems. The project generates enough electricity to power all of Aspen Skiing Company's operations including four ski mountains, 17 restaurants, and three hotels, which is equivalent to the electricity demand of 2,000 average American homes (Gunnison Energy, 2014).

The project also includes a thermal oxidizer to combust gas above what is required to generate 3 MW of electricity. More gas is combusted in the thermal oxidizer than in the three generator sets. The Elk Creek Mine is estimated to have the capacity to provide enough methane to generate 12 MW of electricity. Mining operations stopped in 2013, and may impact the long-term CMM resource for the project and the scale of the project.

CMM produced from the mine has a methane concentration ranging from 35 percent to 85 percent. The plant filters any rock particles and removes water from

the gas. Then it slightly compresses the CMM prior to combustion by the IC engines to improve the gas quality going to the engines. Gas in excess of that used by the power plant is combusted in the thermal oxidizer instead of being vented to the atmosphere in order to reduce GHG emissions.

The project's capital cost was \$6 million. Holy Cross Energy committed to purchasing the electricity generated by the project, which was essential to making the project economically feasible. Holy Cross Energy is a non-profit electric cooperative utility that provides electricity to more than 55,000 consumers in western Colorado, primarily in Eagle, Pitkin, and Garfield counties. Members of Holy Cross Energy are willing to pay higher rates for clean energy sources, which provides the utility opportunities to increase rates to cover the costs of purchasing electricity from renewable sources. The 3 MW of electricity from the Elk Creek Project represents about 2 percent of Holy Cross Energy's generation needs.

1.6.2 Gas Turbine Case Studies

VP #8 and Buchanan Mines—Virginia, United States

CONSOL Energy and Allegheny Energy have developed an 88 MW power generation station at the VP #8 and Buchanan mines in Virginia. The project began in June 2002 and is fueled by mostly coalbed methane (CBM), along with small volumes of CMM from the mines. The project also has direct pipeline sales of gas and uses some of the gas for coal drying operations. The electricity generated is sold to the wholesale market (CMOP, 2009). It is a peaking plant and operates infrequently. The project is unique because it utilized two large, 44 MW each, General Electric LM6000 turbines instead of multiple small turbines, like most other projects (CMOP, 2010).

FIGURE 1-9: 44 MW GAS TURBINES AT VP#8 AND BUCHANAN PROJECT (SOURCE: CONSOL ENERGY)



Harworth Colliery—United Kingdom

The Harworth Colliery used CMM to fuel two combined cycle gas turbines. The plant provided electricity for the mine. The technology consisted of two Ruston 4 MW gas turbines with a waste heat recovery boiler (WHRB) and a Peter Brotherhood 10 MW steam turbine. The WHRB was fired with CMM to raise the total plant output to 18 MW (Butler, 2015).

Additional natural gas from the local distribution system was needed to keep the plant operating as the CMM from the mine typically contained around 30 percent methane. The additional natural gas kept methane concentrations above 40 percent for safety purposes. Project maintenance was expensive, and availability was lower than comparable gas engines. These turbines were used from 1992 until 2007 and then replaced with IC engines.

1.6.3 Microturbine Case Studies

Bailey Mine Gob Degas Project—Southwestern Pennsylvania

The Bailey Mine Gob degas project was a 70 kW electric generation project installed at the active Bailey Mine in Greene County, Pennsylvania. This demonstration project began in September 2006 and operated for one year, using unprocessed drainage gas from a gob gas vent borehole at the mine with methane concentrations ranging from 43 percent to 55 percent (Ingersoll Rand, 2006).

The project utilized an Ingersoll Rand MT70 microturbine that converted low and variable CMM into electricity. The MT70 is designed to operate with a minimum methane concentration of 35 percent and has a high methane destruction efficiency of 99 percent.

FIGURE 1-10: BAILEY MINE MICROTURBINE
(SOURCE: INGERSOLL RAND)



One challenge the project faced was during winter months when temperatures dropped, and the moisture in the highly saturated gas from the Bailey Mine froze, freezing the fuel line to the microturbine as well. CMM has more water in it than some alternative gases like landfill gas. The gas collection system included a knockout phase but was unable to remove enough moisture. The project added a regenerative blower to the microturbine to act as a small radiator to control the gas temperatures in the fuel line. The project reported no other major issues and operated fairly smoothly after the blower was installed (Rafter, 2007).

The electricity was used by the Bailey Mine operations. Total project cost as reported by Consol was \$400,000 (Consol Energy, 2010b). According to Consol, the unit logged 4,870 operating hours between October 2006 and October 2007 and generated 330,027 kWh of electricity. Operations were frequently suspended because mine gas methane concentrations dropped below 35 percent. Consol believes the technology used in this demonstration project is not economically attractive without additional financial incentives, such as a carbon credit value of more than \$6 per ton of CO₂ equivalent or a larger microturbine (Consol Energy, 2010c).

Akabira Mine—Japan

Sumitomo Coal Mining's Akabira Mine, located in Akabira, Japan, has a 150kW electric generation project that consists of five Capstone C30 microturbines. The mine was abandoned in 1994 and continues to discharge CMM. The microturbines were commissioned in 2001 and consume 30 percent of the mine's total methane discharge. The electricity is used on-site to power facility loads and is sold to a nearby factory (CMOP, 2004).

FIGURE 1-11: MICROTURBINES OPERATING AT ABANDONED AKABIRA MINE IN JAPAN
(SOURCE: U.S. EPA)



The CMM is treated at a pumping and compression plant before going to the microturbines. The project consists of a “closed loop” system, which sends the hot exhaust gases back into the mine to help liberate more CMM for electricity generation. The CO₂ in the exhaust is thus sequestered in the coal seams as the coal pores preferentially take up the CO₂ to replace CH₄ (Capstone Turbine Corporation, 2004).

1.6.4 Fuel Cell Case Study

Rose Valley Mine Site–Hopedale, Ohio

The first fuel cell power plant to operate on CMM was a 200 kW demonstration project installed and operated by Fuel Cell Energy at the American Electric Power (AEP) Ohio Coal LLC Rose Valley Site in Hopedale, Ohio. Northwest Fuel Development operates the site. AEP purchased the electricity generated at the plant under a power purchase agreement between Northwest Fuel Development and AEP.

FIGURE 1-12: 200KW FUEL CELL AT ROSE VALLEY MINE
(SOURCE: U.S. EPA)



The project was installed at the Rose Valley Mine site, which supplied CMM to the fuel cell and IC engines. Before being supplied to the fuel cell, the CMM was compressed and dried, which required additional electric power. During the period of operation, no performance disadvantages were noted compared to natural gas. Before being moved to the project site, the power plant ran on natural gas in Los Angeles, California. The plant’s performance on CMM on a Btu basis was similar to its performance on natural gas. The CMM had a lower Btu value (393 Btu/ft³) than natural gas (907 Btu/ft³), and thus the CMM flow rate had to be higher by a factor of 2.3 to reach the same power level. Some modifications were made to the plant in order for it to utilize the higher flow rate necessary for CMM, including replacing a pressure relief valve to relieve higher pressures and installing a new high range fuel flow meter (Steinfeld & Hunt, 2004).

The fuel cell power plant operated between August 1, 2003 and December 13, 2003 and delivered electric power to the grid. The plant consumed 55,000 to 80,000 cubic feet per day of CMM with a methane concentration of 42 percent to 47 percent.

1.7 Overview of the Permitting Process

Any business or operation emitting air pollutants in Colorado may be required to apply to the state for a Construction Permit to Emit and to report its emissions. The type of permit is dependent on the volume and type of projected emissions. The permit defines what pollutants can be emitted and the allowable levels, and authorizes the emissions compliance with certain plant requirements and operating terms and conditions. Key air pollutants include particulate matter, combustion gases, volatile organic compounds (VOCs), Hazardous Air Pollutants (HAPs), and greenhouse gases. The Colorado Department of Public Health & Environment’s (CDPHE) Air Pollution Control Division (APCD) manages and issues air permits in Colorado.

The regulatory process mandates permit processing times of 90 days without public notice and 135 days with public notice (Hea, 2013). With the APCD’s backlog, processing times are likely to be longer. Some operations will require a 30-day public comment period, but only for sources that generate projected controlled emissions exceeding 50 tons per year, violate requirements on odor emissions, fall under National Emissions Standard for Hazardous Air Pollutants (NESHAP) or Federal Maximum Achievable Control Technology (MACT), and sources seeking to obtain federally enforceable limits to avoid major source status through a construction permit (CDPHE, 2015). New CMM projects should plan for at least six to 12 months to complete the permitting process. This is, in part, because these projects often are unique and not as familiar to APCD personnel as the standard electrical generation or flaring projects.

1.7.1 Air Pollutant Emission Notice

The first step is to submit an Air Pollutant Emission Notice (APEN) to the APCD. An APEN is required for all new emission sources exceeding defined thresholds as shown in Table 1-2. The APEN describes the proposed emission point, includes the name and address of the operator and owner of the facility, provides a description of the proposed activity, identifies fuel types and consumption rates, and estimates the types and quantities of expected emissions. APCD provides an APEN application specific to reciprocating internal combustion engines, which in addition to general information, requests information about the engine, stack, fuel consumption, emissions, and emission control. Other technologies use the general APEN.

TABLE 1-2: APEN THRESHOLDS

Pollutant Category	Uncontrolled Actual Emissions (per year)	
	Attainment Area	Non-Attainment Area
Criteria Pollutant	2 tons	1 ton
Non-Criteria Pollutant	250 lbs	250 lbs
Lead	100 lbs	100 lbs

(Source: CDPHE)

The next step is to identify and evaluate pollutants. Emissions estimates are required. These can be based upon results of testing or upon acceptable estimation methods including mass balance calculations, manufacturer’s specs, data from other facilities or studies, published emission factors, or other engineering calculations. Air quality dispersion modeling may be required for some projects.

APENS are required for criteria pollutants for each emission point in an attainment area or attainment/maintenance area with uncontrolled actual emissions of two tons per year or more on any individual criteria pollutant. For non-criteria pollutants, the APEN must include each emission point with uncontrolled emissions equal to or greater than 250 pounds per year of any individual non-criteria reportable pollutant (CDPHE, 2014).

More than one emission point from multiple pieces of equipment or processes at a single facility can be grouped on a single APEN as long as the accuracy of emissions information is maintained and certain guidelines are met. Guidelines include ensuring that the grouped sources have the same source classification codes and emission factors for criteria pollutants, and none of the sources previously have been issued a separate emissions permit.

Once emission sources and quantities of each pollutant have been identified and estimated, it can be determined whether an APEN needs to be submitted. If the project has uncontrolled actual emissions for an emission point or group of emission points that exceed defined emission thresholds, as shown in Table 1-2, an APEN must be submitted. There is a filing fee required for each APEN submitted and all sources required to file APENs must pay annual fees. Additionally, there are annual fees on emissions (per ton of criteria pollutants and HAPs), if applicable. Each APEN is valid for five years.

Another step in the application process is to determine if MACT, NESHAP, or New Source Performance Standards (NSPS) requirements apply to the project. In Colorado, NSPS applies to internal combustion engines but only those combusting diesel and thus this step is not applicable to CMM technologies.

1.7.2 Construction Permit

A construction permit may be required prior to the construction of a new source if emissions from all emissions points at the facility that require an APEN exceed the levels shown in the table below. Fuel cell projects are unlikely to require a construction permit as emission levels are so low; however, if there are other emission sources at the site, the facility as a whole may trigger the requirement to obtain a permit. Submission of the APEN and Application for Construction Permit (which is one form) will start the permitting process. There are additional fees that apply for permit processing.

The APCD developed general permits which offer a streamlined approach to permitting but only are available for specified sources, and thus CMM projects must apply for an individual permit through the traditional construction permit process. The minimum requirements for the application typically include the completed APEN and Application for a Construction Permit—which includes documentation to support the emissions calculations, equipment information including specification sheets, and the application filing fee.

Once the permit is issued, construction may begin, and within 15 days of commencement of operation, a Notice of Start Up form must be submitted. The final step in the permitting process is to submit a Self-Certification Package which allows the project to certify compliance with the terms and conditions of the permit as well as modify the permit if necessary. The permit is applicable for the life of the emission source until there are changes to the project or other changes requiring modification of the permit, whichever occurs first.

TABLE 1-3: CONSTRUCTION PERMIT THRESHOLDS

Pollutant Category	Uncontrolled Actual Emission (tons per year)	
	Attainment Area	Non-Attainment Area
Volatile Organic Compounds	5	2
PM-10, PM-2.5	5	1
Total Suspended Particulates	10	5
Sulfur Dioxide	10	5
Nitrogen Oxides	10	5
Lead	200 lbs	200 lbs
Other Criteria Pollutants	2	2

(Source: CDPHE)

1.8 State Incentives for CMM Recovery and Use

A number of states have renewable/alternative energy portfolio standards (RPS) or clean energy goals (CEG) that direct electricity providers to generate or obtain minimum percentages of their power from “eligible energy resources” by certain dates. Out of 15 major coal producing states, six states—Pennsylvania, West Virginia, Ohio, Utah, Indiana, and Colorado—currently include CMM in their renewable or alternative energy standards, one of which is strictly voluntary (Indiana).

Generally, the term renewable energy refers to sources such as solar-electric, solar thermal energy, wind power, hydropower, geothermal energy, fuel cells, and certain biomass energy and biologically derived fuels. Utah legislation defines CMM from abandoned mines and coal degasification operations produced with a state-approved mine permit as a “renewable energy resource.” Pennsylvania, West Virginia, and Ohio each designate CMM as an “alternative energy resource” rather than a “renewable” energy resource. Indiana does not specifically address CMM but defines coal bed methane as a clean energy technology; and Colorado considers CMM to be an eligible energy resource under the RPS as long as the Colorado Public Utilities Commission (PUC) determines that the project’s electricity generated is “greenhouse gas neutral,” which is defined in the RPS. Where CMM is included as part of a state’s renewable or alternative energy portfolio standards, there are state alternative energy incentives for development.

In 2013 and 2014, Vessels Coal Gas generated 7,579 RECs from the Cambria 33 Abandoned Coal Mine Methane Project in Pennsylvania (Vessels Coal Gas, 2015). Another AMM project in Ohio generated RECs from the sale of AMM as supplemental fuel for a gas turbine electric power project.

Pennsylvania

Pennsylvania was the first state to define CMM in its Alternative Energy Portfolio Standard (AEPS) which took effect on February 28, 2005. Among other things, the AEPS requires each electric distribution company and electric generation supplier to retail customers in Pennsylvania to supply 18 percent of its electricity using alternative energy resources by 2020. The AEPS offers a variety of incentives for the recovery and use of CMM, including alternative energy credits (AECs), alternative energy tax credits, and state grant programs. AEPS does not designate any energy resource as renewable energy but rather designates all sources as alternative energy resources.

West Virginia

West Virginia’s portfolio standard requires investor-owned utilities with more than 30,000 residential customers to supply 25 percent of retail electric sales from eligible alternative and renewable energy resources by 2025. It is similar to those in other eastern states, except that it does not require a minimum contribution from renewable energy sources. In other states, the term “alternative energy resources” is more broadly defined than the term “alternative energy.” Included in alternative energy resources are sources such as CBM and recycled energy, including “waste gas, waste fuel, or other forms of energy that would otherwise be flared, incinerated, disposed of, or vented,” such as CMM.

Ohio

Ohio’s Alternative Energy Resource Standard (AERS) was created in May 2008 and is administered by the Public Utilities Commission of Ohio. The AERS applies to electric utilities and electric service companies serving retail electric customers in Ohio. Under the standard, utilities must provide 25 percent of their retail electricity supply from alternative energy sources by 2025. The original definition of “advanced energy resource” in the AERS included any process or technology that increases the generation output of an electric generating facility without additional carbon dioxide emissions. However, CMM was not included as an advanced energy resource in the original law. Effective October 16, 2009, the definition was amended to add methane gas emitted from abandoned coal mines as a renewable energy resource and methane gas emitted from operating or abandoned coal mines as an advanced energy resource.

Utah

Utah established a renewable portfolio goal in March 2008, which is similar to renewable portfolio standards in other states. The Emission Reduction Act stipulates that so long as it is cost-effective to do so, investor-owned utilities, municipal utilities, and cooperative utilities must use eligible renewables to account for 20 percent of their 2025 adjusted retail electric sales. Utilities may meet their targets by producing electricity with an eligible form of renewable energy or by purchasing RECs. In 2010, the definition of “renewable energy source” was amended and the definition of waste gas or waste heat captured or recovered that is used as an energy source for an electric generation facility was amended to include “methane gas from an abandoned coal mine or a coal degassing operation associated with a state-approved mine permit.”

Indiana

Indiana’s voluntary clean energy portfolio standard (CPS) took effect January 1, 2012 for public utilities or electricity suppliers (excluding municipally owned utilities and electric cooperatives) that furnish retail electricity to Indiana customers. The goal is for each participating electricity supplier to obtain 10 percent of the total electricity supplied to its Indiana retail customers from clean energy sources by 2025 (based on 2010 levels). Participating utilities must obtain at least 50 percent of qualifying clean energy from within Indiana. A utility may purchase clean energy credits generated from 21 clean energy resources or alternative technologies. Coal bed methane is listed as an eligible technology.

Colorado

Colorado’s renewable energy standard took effect in November 2004. Each qualifying retail utility is required to generate or obtain electricity from eligible energy resources for its retail electricity sales, based on defined schedules increasing until 2020 when the following requirements apply for 2020 and each subsequent year: for investor-owned utilities—30 percent, for electric cooperatives serving 100,000 meters or more—20 percent, and for electric cooperatives serving less than 100,000 meters and municipal utilities serving more than 40,000 meters—10 percent. In July 2013, Colorado amended the standard to include CMM produced from active and inactive mines as an eligible energy resource if it is determined to be greenhouse gas neutral.

TABLE 1-4: STATE CMM INCENTIVES

State	Definition of CMM	Incentives and Programs
Pennsylvania	CMM an alternative energy resource	Alternative Energy Portfolio Standard <ul style="list-style-type: none"> • Alternative energy certificates and tax credits (15% of net cost, \$1 million per taxpayer) State Grant Programs <ul style="list-style-type: none"> • \$21 million available
West Virginia	CMM an alternative energy resource	Alternative Energy Standard <ul style="list-style-type: none"> • Alternative energy credits (AECs)
Ohio	CMM an advanced energy resource; AMM a renewable energy resource	Alternative Energy Resource Standard <ul style="list-style-type: none"> • Renewable energy certificates (RECs) Advanced Energy Program <ul style="list-style-type: none"> • Forgivable and non-forgivable loans
Utah	CMM a renewable energy resource	Alternative Energy Portfolio Standard <ul style="list-style-type: none"> • Renewable energy certificates (RECs)
Indiana	CBM is defined as an alternative energy source and clean energy resource	Voluntary Clean Energy Portfolio Standard <ul style="list-style-type: none"> • Incentives to help pay for compliance projects
Colorado	CMM is an eligible energy resource as long as the PUC determines it: (i) meets the statutory definition of CMM, and (ii) is GHG neutral	Renewable Energy Standard <ul style="list-style-type: none"> • Renewable energy credits (RECs)



2 | Framework for Coal Mine Methane GHG Neutrality

2.1 Background

This framework provides technical guidance to the Colorado Energy Office (CEO) and others concerning the methodologies used for determining whether electrical generation projects using CMM are “greenhouse gas (GHG) neutral” under Colorado’s “Renewable Energy Standard” (RES).² The statute designates the Colorado Public Utility Commission (Commission) as the responsible agency for determining whether such projects qualify as “eligible energy resource” in the RES. (See: CRS §40-2-124(1)(a))

As background, in June 2013, Senate Bill 13-252³, amended the RES to include CMM as an eligible energy resource. The amendment defined “coal mine methane” as:

... methane captured from active and inactive coal mines where the methane is escaping to the atmosphere. In the case of methane escaping from active mines, only methane vented in the normal course of mining operations that is naturally escaping to the atmosphere is coal mine methane for purposes of eligibility under this section. (See: CRS §40-2-124(1)(a)(II))

With respect to CMM, the amendment defined “greenhouse gas neutral” as that:

... volume of greenhouse gases emitted into the atmosphere from the conversion of fuel to electricity [which] is no greater than the volume of greenhouse gases that would have been emitted into the atmosphere over the next five years, beginning with the planned date of operation of the facility, if the fuel had not been converted to electricity, where greenhouse gases are measured in terms of carbon dioxide equivalent.” (See: CRS §40-2-124(1)(a)(IV))

Since 2013, no electrical generation projects using CMM resources have been submitted to the Commission for approval under the RES. However, effective September 30, 2015, the Commission adopted Rule 3668(d) directing that the greenhouse gas neutrality for such projects shall be determined on a case-by-case basis; leaving the process and procedure for determining energy eligibility as an open question. (See: 4 Code of Colorado Regulations (CCR) 723-3 (2015))

²The “Renewable Energy Standard” is set forth in CRS §40-2-124 (2015).

³SB13-252 was entitled “Concerning Measure to Increase Colorado’s Renewable Energy Standard so as to encourage the Deployment of Methane Capture Technologies.”



The GHG neutrality calculation method differs for each source of methane—CMM, VAM, and AMM—and are therefore named differently for clarity. With respect to the RES, as amended, all three sources are considered coal mine methane.

2.2 Accounting for GHG Emissions

The proposed framework utilizes standard GHG accounting methods from internationally recognized CMM project protocols (including ACM0008, CARB’s Compliance Offset Protocol Mine Methane Capture Projects, and Verified Carbon Standard Methodology VMR0002), and can be summarized by the following equation:

$$ER = BE - PE$$

Where:

ER= Emissions reductions/GHG neutrality

BE= Baseline emissions

PE= Project emissions

Baseline emissions represent the GHG emissions that would have been emitted in the absence of the CMM capture and electrical generation project (Project) activity. GHG emissions associated with the baseline are methane emissions from the active mining operations and/or fugitive methane emissions from inactive mines.

Project emissions represent the total GHG emissions that result from the Project activities. Included in Project emissions are GHG emissions from energy consumed to operate the Project (combustion of fossil fuels and electricity consumption), carbon dioxide emissions from the combustion of methane, and un-combusted methane.

TABLE 2-1: DEFINITION OF BASELINE EMISSIONS, PROJECT EMISSIONS, AND HOW THEY ARE CONSIDERED IN THE PROPOSED FRAMEWORK

Baseline/ Project	Sources Included	GHG	Justification/Explanation
Baseline Emissions	Emissions from the venting of mine methane extracted through methane drainage systems	CH ₄	Major source of baseline emissions for CMM projects
	Emissions of mine methane liberated after the conclusion of mining operations	CH ₄	Major source of baseline emissions for AMM projects
	Emissions from the venting of VAM through mine ventilation system	CH ₄	Major source of GHG emissions in the baseline attributable to ventilation air
	Emissions from electricity generation	CO ₂	Emission reductions resulting from the displacement of fossil fuel or electricity
Project Emissions	Emissions resulting from energy consumed to operate additional equipment used to capture, treat, or destroy drained mine gas for all project types	CO ₂	Includes grid electricity consumption as well as any fossil fuels consumed in order to operate the project
	Emissions from un-combusted methane	CH ₄	CH ₄ vented to the atmosphere that is not fully combusted in a destruction device; applicable to CMM, AMM and VAM projects.
	Emissions from CMM, AMM and VAM combustion	CO ₄	Approximately 2.774 metric tonnes of CO ₂ are emitted from the combustion of every one metric tonne of CH ₄

2.3 CMM and VAM Baseline Emissions

Baseline emissions for CMM *post-mining* wells and VAM emissions are determined using the same method. Essentially, all methane emitted to the atmosphere from either source is considered to be part of the baseline scenario. CMM *pre-mining* wells are calculated differently because methane is being degassed from the coal seam up to five years ahead of the mining activities. The emission reduction benefit is not realized until the mine operation intersects the area of influence surrounding the CMM pre-mining well location or the well bore as required by the applicable CMM protocol, as the case may be—where it is assumed that the methane previously removed from the coal seam would have been emitted via the ventilation system. CMM pre-mining wells are located within the outer boundaries of a current mine plan.

GHG emissions related to the baseline emissions include:

- BE_{MR}: Methane emissions resulting from the venting of the methane extracted through the ventilation and drainage systems

Baseline emissions are therefore: BE = BE_{MR}

2.4 AMM Baseline Emissions

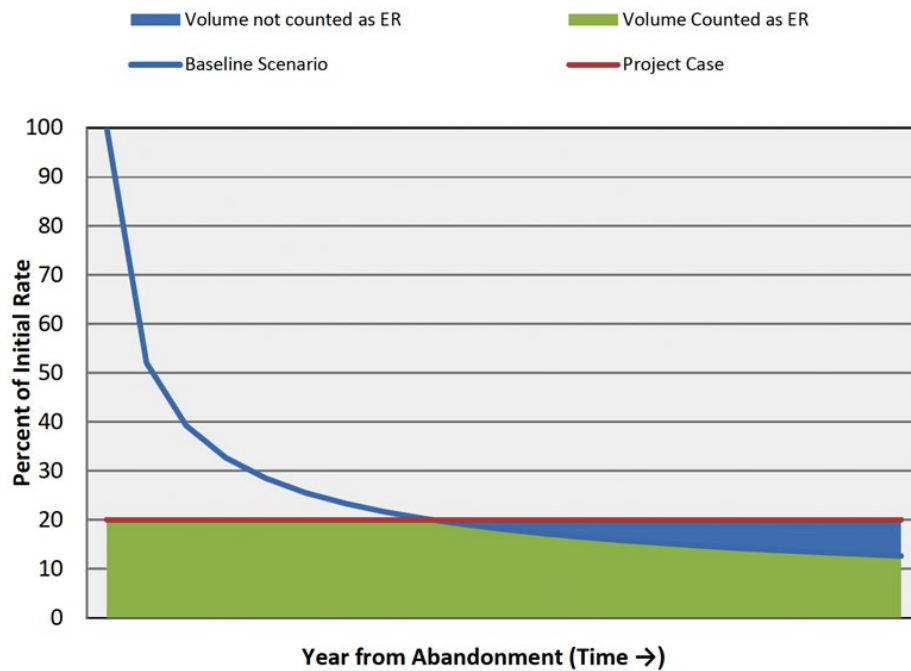
The recoverable methane gas from an inactive (abandoned) mine is based on a hyperbolic decline rate model used by the U.S. Environmental Protection

Agency (EPA) and GHG programs such as Verified Carbon Standard (VCS), Intergovernmental Panel on Climate Change (IPCC), and California Air Resources Board (CARB). The decline rate model takes into account the time elapsed since mine closure, average methane emissions rate over the life of the mine, and whether the mine is fully sealed or venting methane. Methane emissions from abandoned mines decline significantly following closure and level-off over time.

The U.S. EPA uses this model to estimate the methane emissions from abandoned mines for their GHG emissions inventory for the United States. The purpose of the decline curve is to account for factors that influence the rate of methane release from an abandoned mine over time including gas content, flow capacity in the coal seam and time since abandonment.

CARB approved a mine methane capture project protocol in April 2014, which uses a version of this hyperbolic decline model to set the baseline methane emissions for AMM compliance offset projects. According to the protocol, methane destruction up to the baseline volume can qualify for GHG offset credits. A project can produce more methane than the baseline amount and still be GHG neutral, although the additional methane volumes do not qualify for CARB's emission offset credits. This is illustrated by Figure 2-1.

FIGURE 2-1: BASELINE EMISSIONS AS A PERCENT OF INITIAL RATE AND EXAMPLE PROJECT METHANE MITIGATION



GHG emissions related to the baseline emissions are either—the volume of methane destroyed by the Project activity, or the methane emissions rate derived from the decline curve. The reason the lesser of these values are chosen is because the methane extracted using mechanical equipment can increase the methane production at levels greater than what might otherwise be released following mine abandonment. This requirement accounts for a baseline scenario that estimates a lower limit of what methane would have been emitted in the absence of the Project on an annual basis.

Baseline emissions are the lower of:

- BE_{MR} : Methane emissions resulting from the release of the methane from the inactive mine
- BE_{DC} : Methane emissions derived from the decline curve calculation

Baseline emissions are therefore: $BE = \min (BE_{MR} : BE_{DC})$

2.5 Project Emissions

Project emissions for CMM, VAM, and AMM are determined using the same methods. GHG emissions related to the Project activities include:

- PE_{MD} : Carbon dioxide resulting from the destruction of methane in the Project device (e.g. power generation equipment)

- PE_{EC} : GHG emissions related to energy consumed by the operation of the Project (electricity, heat, or fossil fuel)
- PE_{UM} : Methane un-combusted by the Project device where the methane destroyed is above the baseline emissions

Project emissions are therefore: $PE = PE_{MD} + PE_{EC} + PE_{UM}$

2.6 GHG Neutrality

Based on the equation $ER = BE - PE$, any CMM/VAM/AMM Project is considered GHG neutral as long as the baseline emissions are greater than the project emissions. For most CMM power projects, there will be a limited amount of energy used to support the Project (electricity from the grid or by fossil fuels used for heat or power generation); however, these project emissions are relatively small compared to the baseline emissions from the destruction of methane.

The carbon dioxide produced through the destruction of methane in a Project device is also relatively small since methane has a global warming potential (GWP) much greater than that of carbon dioxide. Using GWPs allows comparisons between different GHGs and may change over time as new information becomes available. The IPCC’s GWP values for methane currently range from 21 to 28 based on a 100-year time scale. Methane is a short-lived climate pollutant and has a much higher GWP based on a 20-year outlook (84–87). This study uses a GWP of 25 for methane from IPCC’s fourth assessment report (IPCC AR4) and should be considered a conservative value.

Using the IPCC AR4, one metric ton of methane equals 25 metric tons of carbon dioxide and one metric ton of combusted methane produces 2.744 metric tons of carbon dioxide. Therefore, the net benefit of combusting methane to produce carbon dioxide is a factor of nine in terms of global warming potential. However, there are site or Project specific conditions where total project emissions at a CMM Project with pre-mining wells or an AMM Project could exceed the baseline emissions.

CMM pre-mining wells are typically deployed two to 10 years ahead of mining activities. Under the Colorado RES, the CMM is an eligible energy resource, so long as that methane would have been vented under normal circumstances as part of ordinary mining operations in a five-year timeframe. As a result, only pre-mining wells that are either within an area of influence around actual mining operations or where the well bores are mined through (as required under the applicable CMM protocol) within five years of initial methane production, can the captured methane be included in the baseline emissions. Project emissions from pre-mining wells are accounted for whether the wells are intersected or not, and therefore, some risk exists that project emissions can be greater than the overall baseline emissions, and the project may not be GHG neutral. The most likely scenario is that CMM power projects can be GHG neutral if all or even a portion of the pre-mining wells get intersected

by mining activities within a five-year time frame. CMM power projects that use a combination of pre-mining and post-mining degasification wells would be more likely to be GHG neutral, but could be not GHG neutral—for example, if 80 percent of the methane was produced from non-bisected pre-mining wells.

The AMM baseline emissions are a theoretical construct that reflects diffuse methane emissions through the overburden and from poorly sealed boreholes and shafts. Although the hyperbolic model does a fair job of approximating these emissions, the actual emissions from the mine at any given time can vary. For this reason, an AMM Project may produce more or less than the theoretical baseline. The derived baseline emissions also reflect the emission rates venting to the atmosphere under atmospheric conditions. Most AMM Projects will install compression to boost or maintain the mine’s methane production rate being delivered to the electric power equipment, and therefore, could produce significantly more methane than the derived baseline amount. The project emissions could theoretically exceed the baseline emissions. As an example, a project using a lean-burn internal combustion engine (with a destruction efficiency of 93.6 percent) would have to produce over five times the baseline emission rate to negate all emission reductions and not be GHG neutral.

TABLE 2-2: BASELINE EMISSIONS EQUATIONS FOR CMM, AMM AND VAM

Variable	Description	Units	Comments (as needed)
Emissions from Release of Methane—Active Underground Mines (Equation 5.16 ARB MMC Protocol)			
$BE_{MR} = (PW_{Vol,Gas} \times C_{PW,CH_4} + GW_{Vol,Gas} \times C_{GW,CH_4}) \times 0.0423 \times 0.000454 \times GWP_{CH_4}$			
$PW_{Vol,Gas}$	Volume of gas from pre-mining drainage wells sent to a destruction device	Thousand cubic feet	
C_{PW,CH_4}	Concentration of CH ₄ in the pre-mining drainage well gas	Fraction	
$GW_{Vol,Gas}$	Volume of gas from gob wells sent to a destruction device	Thousand cubic feet	
C_{GW,CH_4}	Concentration of CH ₄ in the gob well gas	Fraction	
GWP_{CH_4}	Global warming potential of CH ₄	25	IPCC 4 th Assessment Report
0.0423	Conversion	Pounds CH ₄ /standard cubic foot CH ₄	Standard density of methane
0.000454	Conversion	Metric tonnes CH ₄ /pounds CH ₄	
Emissions from Release of Methane—Abandoned Underground Mines (Equation 5.43 ARB MMC Protocol)			
$BE_{MR} = \min\left(AMM_{DC}, \sum_i MM_i\right) \times GWP_{CH_4}$			
AMM_{DC}	Emissions of methane as calculated by the decline curve	Metric tonnes CH ₄	
MM_i	Measured methane sent to a destruction device	Metric tonnes CH ₄	

Variable	Description	Units	Comments (as needed)
Emissions from Release of Methane Derived from the Hyperbolic Emission Rate Decline Curve (Equation 5.44 ARB MMC Protocol)			
$AMM_{DC} = ER_{AMM} \times S \times (1 + b \times D_i \times t)^{\left(\frac{-1}{b}\right)} \times RP_{days} \times 0.0423 \times 0.00454$			
ER _{AMM}	Average ventilation air methane emission rate over the life of the mine (Mscf/d)		
S	Default effective degree of sealing	Fraction	S = 1 for venting mines and 0.5 for sealed mines.
b	Dimensionless hyperbolic exponent	Unitless	b = 1.886581 for venting mines and 2.016746 for sealed mines
D _i	Initial decline rate	1/day	D _i = 0.003519 for venting mines and 0.000835 for sealed mines
t	Time elapsed from the date of mine closure to midpoint of the reporting period (days)	days	
Days		1,825	Five year forecast
0.0423	Conversion	Pounds CH ₄ /standard cubic foot CH ₄	Standard density of methane
0.000454	Conversion	Metric tonnes CH ₄ /pounds CH ₄	
Emissions from Release of Methane–Abandoned Underground Mines (Equation 5.16 ARB MMC Protocol)			
$BE_{MR} = (PW_{Vol,Gas} \times C_{PW,CH_4} + GW_{Vol,Gas} \times C_{GW,CH_4}) \times 0.0423 \times 0.000454 \times GWP_{CH_4}$			
PW _{Vol,Gas}	Volume of gas from pre-mining drainage wells sent to a destruction device	Thousand cubic feet	
C _{PW,CH₄}	Concentration of methane in the pre-mining drainage well gas	Fraction	
GW _{Vol,Gas}	Volume of gas from gob wells sent to a destruction device	Thousand cubic feet	
C _{GW,CH₄}	Concentration of methane in the gob well gas	Fraction	
GWP _{CH₄}	Global warming potential of methane	25	IPCC 4 th Assessment Report
0.0423	Conversion	Pounds CH ₄ /standard cubic foot CH ₄	Standard density of methane
0.000454	Conversion	Metric tonnes CH ₄ /pounds CH ₄	
Baseline Emissions from Release of Methane–Ventilation Air Methane (Equation 5.5 ARB MMC Protocol)			
$BE_{MR} = \sum_i [VA_i \times C_{CH_4} + MG_{Supp,i} \times C_{CH_4,MG}] \times 0.0423 \times 0.000454 \times GWP_{CH_4}$			
VA _i	Volume of ventilation air sent to a destruction device	Standard cubic feet	
C _{CH₄}	Methane concentration of ventilation air sent to a destruction device	Fraction	
GWP _{CH₄}	Global warming potential of methane	25	IPCC 4 th Assessment Report
0.0423	Conversion	Pounds CH ₄ /standard cubic foot CH ₄	Standard density of methane
0.000454	Conversion	Metric tonnes CH ₄ /pounds CH ₄	
Combined Emission Factor for Displaced Electricity			
$CEF = EF_{grid,BM} \times W_{BM} + EF_{grid,OM} \times W_{OM}$			
EF _{grid,BM}	Build margin CO ₂ emission factor	Metric tonnes CO ₂ e/MWh	eGRID 2012 data for the state of Colorado. 1,668.72 pounds of CO ₂ per MWh converted to metric tonnes CO ₂ per MWh.
EF _{grid,OM}	Operating margin emission factor	Metric tonnes CO ₂ e/MWh	
W _{BM}	Weight of build margin	50%	UNFCCC Methodological Tool to calculate emissions factors for an electric system
W _{OM}	Weight of operating margin	50%	UNFCCC Methodological Tool to calculate emissions factors for an electric system

TABLE 2-3: PROJECT EMISSIONS EQUATIONS FOR CMM, AMM AND VAM

Variable	Description	Units	Comments (as needed)
Total Project Emissions (Equation 5.45)			
$PE = PE_{EC} + PE_{MD} + PE_{UM}$			
PE _{EC}	Emissions from on-site energy consumption	Metric tonnes CO ₂ e	
PE _{MD}	Emissions from the destruction of CH ₄	Metric tonnes CO ₂ e	
PE _{UM}	Emissions from un-combusted CH ₄	Metric tonnes CO ₂ e	
Project Emissions from Energy Consumed (5.46)			
$PE_{EC} = (CONS_{Elec} \times CEF_{Elec}) + \frac{(CONS_{FF} \times CEF_{FF})}{1000}$			
CONS _{Elec}	Grid electricity consumed by project activity	MWh	
CEF _{Elec}	Grid carbon emission factor	Metric tonnes CO ₂ e/ MWh	
CONS _{FF}	Fossil fuels consumed by project activity	Gallons	Diesel, gasoline and propane included in the calculator as choices
CEF _{FF}	Fossil fuel emission factor	Kilogram CO ₂ /gallon	Emission factor for diesel, gasoline and propane included in the calculator
1000	Conversion factor	Kilograms/metric tonne	
Project Emissions from Methane Destroyed (Equation 5.47)			
$PE_{MD} = \sum_i MD_i \times CEF_{CH_4}$			
MD _i	CH ₄ destroyed in device	Metric tonnes CH ₄	
CEF _{CH₄}	CO ₂ emission factor for combusted CH ₄	Metric tonnes CO ₂ / Metric tonne CH ₄	
Project Emissions from Un-combusted Methane for CMM and AMM (Equation 5.49)			
$PE_{UM} = \sum_i [MM_i \times (1 - DE_i)] \times GWP_{CH_4}$			
MM _i	CH ₄ sent to destruction device	Metric tonnes CH ₄	
DE _i	Efficiency of destruction device	Fraction	
GWP _{CH₄}	Global warming potential of CH ₄	25	IPCC 4 th Assessment Report
Project Emissions from Un-combusted Methane for VAM (Equation 5.10)			
$PE_{UM} = \sum_y (VA_{flow,y} \times 60 + CA_{flow,y} \times 60) \times C_{CH_4,exhaust} \times 0.0423 \times 0.000454 \times GWP_{CH_4}$			
VA _{flow,y}	Hourly average flow rate of ventilation air sent to a device for destruction during the reporting period	Standard cubic feet per minute	
CA _{flow,y}	Hourly average flow rate of cooling air sent to a destruction device	Standard cubic feet per minute	
y	Hours	Hours	
C _{CH₄,exhaust}	CH ₄ concentration of exhaust gas	Standard cubic feet of methane per standard cubic foot of flow	
GWP _{CH₄}	Global warming potential of methane	25	IPCC 4 th Assessment Report
0.0423	Conversion	Pounds CH ₄ / Standard Cubic Foot CH ₄	Standard density of methane
0.000454	Conversion	Metric Tonnes CH ₄ / Pounds CH ₄	

2.7 Applicability of GHG Neutrality Calculator

The GHG neutrality calculator includes calculation tabs for three project alternatives—CMM, VAM, and AMM power projects. Depending on the project type, there are nine-to-12 inputs to each calculator. Typical inputs for all calculations include gas flow, methane concentration, equipment type, fossil fuel use, and electricity use. The CMM calculator separates methane sourced from pre-mining and post-mining wells. Additional inputs are required for pre-mining wells. The VAM calculator includes an input for CMM (for blending) also. The AMM calculator includes inputs for historical emissions and closure information.

For each case, the calculators determine the total estimated baseline and project emissions and any resulting emissions reduction over a five-year time frame. A result of positive emission reductions confirms the GHG neutrality of the project activities. A negative result demonstrates that the project activity may not be GHG neutral.

Other than CMM and synthetic gas produced by pyrolysis, the RES does not require any of the other eligible energy resources to be GHG neutral. For methane-to-energy type projects, the majority of emission reductions originate from the destruction of the methane itself and are fairly easy to demonstrate. Emissions avoided from supplying eligible renewable energy to the electric grid could account for 10-15 percent reduction in GHG emissions from active and inactive coal mines. The GHG calculators contain an option to include or exclude emissions avoided from the electric grid—most projects do not require the additional emission reductions to demonstrate GHG neutrality. In order to be consistent with the pyrolysis GHG neutrality calculator, RCE recommends the option be included. It is important to note that if electric grid-based emissions avoided from renewable energy sources are excluded, wind and solar projects would not be able to demonstrate GHG neutrality.



3 | Assessment of the Municipal Solid Waste (MSW) Pyrolysis Technology Landscape

3.1 Background

This report provides the technology landscape for pyrolysis of municipal solid waste (MSW) derived feedstock for purposes of electricity production in North America. The differentiation between pyrolysis of MSW derived feedstock and others such as pyrolysis of biomass and tires is important as these technologies are tailored to enhance end products according to the characteristics of the feedstock.

Senate Bill 13-252 by the General Assembly of the State of Colorado, "Concerning Measure to Increase Colorado's Renewable Energy Standard so as to Encourage the Deployment of Methane Capture Technologies," defines pyrolysis as "the thermochemical decomposition of material at elevated temperatures without the participation of oxygen." This definition excludes the other most popular thermochemical conversion technology, gasification, which uses oxygen to initiate the reactions.

Pyrolysis often is grouped with gasification under the category of thermochemical emerging technologies (those in a commercial or advanced pre-commercial development stage). While the application of pyrolysis technologies to MSW feedstocks is just emerging in the U.S., other parts of the world including Australia, Canada, Europe, and Japan have utilized these technologies for the management of various components of the MSW stream:

- In Sapporo, Japan, there is a facility with a capacity of 40 million tons per day. Toshiba is the technology supplier and Sapporo Plastics Recycling, Co. is the system owner/operator.
- Also in Japan, Mitsui Engineering and Shipbuilding—formerly Mitsui Babcock—has taken over the Siemens Schwelbrenn process and has brought into operation a number of installations based on this technology.
- The AUD \$4 million Berkeley Vale project in New South Wales, Australia, has a 50 million-ton-per-day capacity for non-recyclable household plastics. Constructed by Integrated Green Energy and Foyson Resources, this technology uses a catalytic restructuring process.
- Cynar operates multiple facilities in Ireland, UK, and Spain with capacities of 10-20 million tons per day.



A key aspect of the success involving international applications of pyrolysis is advanced segregation of waste streams. Locations with already established programs for waste segregation and collection, dedicated waste streams, and waste supply contracts have been successful in demonstrating that potential plants can operate economically.

This overview of the pyrolysis technology landscape in North America provides:

- A description of MSW pyrolysis, identifying the types of feedstock that have or can be used and the air, water, and waste emissions;
- Information on energy and mass balance;
- Information on the economics of MSW pyrolysis technologies to help decision-makers understand the key cost factors and economic feasibility;
- A listing of proposed and operational facilities in the U.S., and pertinent examples of the technologies; and
- A summary of regulatory and other considerations decision-makers should be aware of when evaluating MSW pyrolysis technologies.

This study is a characterization of MSW pyrolysis in the U.S. that builds upon ongoing and past research for MSW waste conversion technologies conducted for the American Chemistry Council (RTI, 2013 and ACC, 2012) and the U.S. EPA (U.S. EPA, 2012). In these prior studies, pyrolysis and gasification technology vendors have been identified and asked to provide process, environmental, and cost information. Additionally, publicly available data sources have been retrieved to update and complement the data received from each vendor.

3.2 Technology Description

Thermal conversion technologies contain a continuum of processes ranging from thermal decomposition in a primarily nonreactive environment in the absence of air (commonly referred to as pyrolysis/cracking processes) to decomposition in a chemically reactive environment with air input (or gasification processes). This report focuses on technologies designed to manage MSW derived feedstock that best fit Colorado’s pyrolysis definition: “thermochemical decomposition of material at elevated temperatures without the participation of oxygen.”

It should be noted that vendor technologies often are difficult to fit as either pyrolysis or gasification and sometimes include characteristics common to both. For example, in a two-stage (pyrolysis-gasification) fixed bed gasification process, some of the oxygen injected into the system is used in reactions that produce heat, so that pyrolysis (endothermic) reactions can initiate. After initiation, the exothermic reactions control and cause the gasification process to be self-sustaining. Table 3-1 presents a summary of the characteristics used to differentiate between pyrolysis and gasification of MSW derived feedstock and Figure 3-1 presents a generic MSW pyrolysis diagram.

TABLE 3-1: CHARACTERISTICS TO DIFFERENTIATE BETWEEN THERMOCHEMICAL CONVERSION TECHNOLOGIES FOR MSW DERIVED FEEDSTOCK¹

Thermochemical Conversion Technology	Pyrolysis	Gasification
Reaction Inputs	Feedstock Heat source	Feedstock Heat source Oxygen
MSW derived feedstock	Plastics ³ (<20% moisture)	Organic material ⁴ (<10% moisture)
Throughput	10-60 tons per day	75-400 tons per day
Reaction products	Oil (mainly) Syngas Char	Syngas (mainly) Ash and/or slag
Main end products	Liquid fuels (e.g., syncrude oil, heating oil, gasoline, diesel, and naphtha) Electricity	Electricity Methanol Ethanol
Conversion efficiency ²	62-85%	69-82%
End product energy value	15,000-19,050 BTU/lb	11,500 ⁵ -18,800 BTU/lb

¹Data sources: U.S.EPA (2012), ACC (2013), ACC (2015)

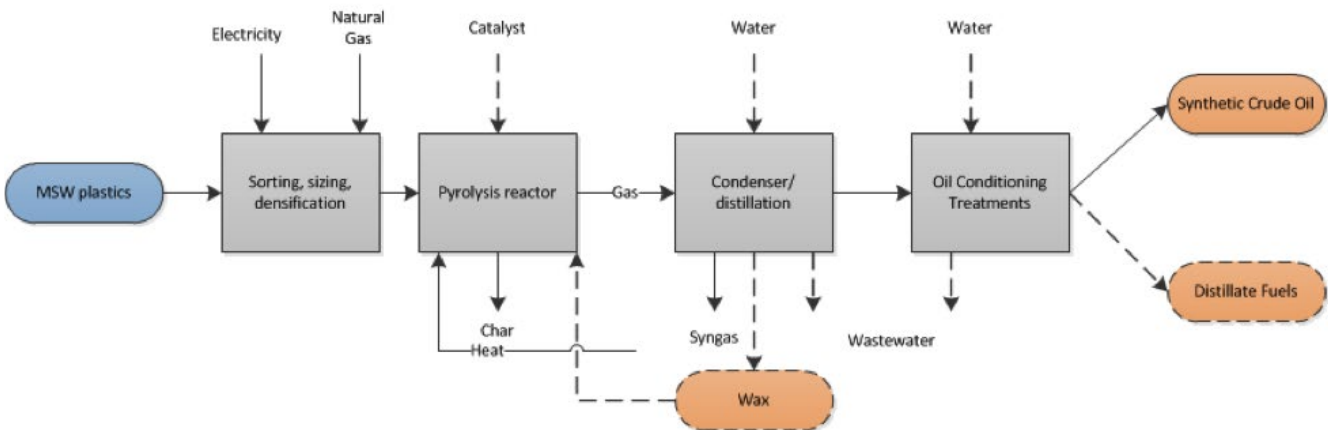
²Conversion efficiency is defined as the percentage of feedstock energy value (e.g., btu/lb) that is transformed to and contained in the end product (e.g., liquid fuels and electricity). These values are based on U.S.EPA (2012)

³Plastics are the only fractions of the MSW stream that are reported for use in pyrolysis. Tires and clean biomass may be considered MSW but often have distinct and separate collection and management schemes from MSW.

⁴Only certain MSW fractions can be input to a gasifier. Glass, metals, aggregate, and other inerts are not desirable and may cause damage to the reactor.

⁵These values are based on U.S.EPA (2012) LHV of ethanol.

FIGURE 3-1: GENERIC MSW PYROLYSIS DIAGRAM.
NOTE: OPTIONAL STEPS ARE INDICATED BY DASHED LINES.



Pyrolysis is defined as an endothermic process involving the use of heat to thermally decompose carbon-based material in the absence of oxygen (i.e., no burning). According to Table 3-1, the main product from pyrolysis is a liquid fuel sometimes called “synfuel.” Other products include syngas and char, and their proportion in comparison with the main product differs depending on reactor design, reaction conditions, and feedstock. Synthetic or bio-based fuels either can be combusted to produce electrical energy, used as a transportation fuel, or sold as a chemical commodity product based on regional markets.

The MSW pyrolysis technologies identified in the U.S. are designed to maximize products in a liquid phase rather than in a gaseous phase.

In order for MSW pyrolysis facilities to be successful and operate economically, they must overcome a number of potential barriers. Examples include:

- **Segregation of waste**—established programs are needed for collection and/or segregation of desired waste feedstocks accepted by pyrolysis technology.
- **Waste supply contracts**—contracts for steady supply of dedicated waste feedstock are needed for potential pyrolysis facilities.
- **Electricity off-take contracts**—contracts are needed for the purchase of electricity produced by pyrolysis technology.

- **Proximity to utility connections**—pyrolysis facilities will need access to utilities, including electricity and water.
- **Permitting and compliance**—pyrolysis facilities will need to meet state and local air and other environmental requirements which can create addition capital and operating costs for the facility.
- **Public perception**—in the U.S., there is often a negative perception of thermal waste treatment technology, as compared to other options such as recycle, as well as a lack of understanding about the differences between MSW pyrolysis and mass-burn combustion technologies. These, and “not-in-my-backyard” concerns related to any waste management facility, can make it difficult to site a pyrolysis facility.

The following sections provide additional information about pyrolysis, and Appendix A presents a brief description of gasification followed by a table listing active technologies in the North America region and their basic characteristics.

3.3 Types of Pyrolysis

Technology vendors include variations and names for pyrolysis processes in their technology descriptions, which can be confusing to waste managers. These variations can be defined according to the use of catalysts, the temperature and feedstock residence time, and type of reactor used. Tables 3-2 to 3-3 present the main categories.

TABLE 3-2: PYROLYSIS CLASSIFICATIONS ACCORDING TO CATALYST USE
(SOURCE U.S. EPA, 2012)

Categories	Definitions
Thermal pyrolysis/ cracking	The feedstock is heated at high temperatures (350-900°C) in the absence of a catalyst. Typically, thermal cracking uses mixed plastics from industrial or municipal sources.
Catalytic pyrolysis/ cracking	The feedstock is processed using a catalyst. The presence of a catalyst reduces the required reaction temperature and time (compared to thermal pyrolysis). The catalysts used in this process can include acidic materials (e.g., silica-alumina), zeolites, or alkaline compounds (e.g., zinc oxide). Research has shown that this method can be used to process a variety of plastic feedstocks, including low density polyethylene (LDPE), high density polyethylene (HDPE), polypropylene (PP), and polystyrene (PS).
Hydrocracking	Sometimes referred to as “hydrogenation,” the feedstock is reacted with hydrogen and a catalyst. The process occurs under moderate temperatures and pressures (e.g., 150-400°C and 30-100 bar hydrogen). Most research on this method has involved the use of MSW plastics, plastics mixed with coal, plastics mixed with refinery oils, and scrap tires.

TABLE 3-3: PYROLYSIS CLASSIFICATIONS ACCORDING TO TEMPERATURE AND FEEDSTOCK RESIDENCE TIME
(SOURCE: WILLIAMS, CIRCA 2009)

Technology	Residence time	Heating rate	Temp (°C)	Major products
Slow pyrolysis	Hours-days	Very low	300-500	Charcoal
Conventional pyrolysis	5-30 min	Medium	400-600	Char, liquids, syngas
	5-30 min	Medium	700-900	Char, syngas
Fast pyrolysis	0.1-2 sec	High	400-650	Liquids
	< 1 sec	High	650-900	Liquids, syngas
	< 1 sec	Very high	1000-3000	Syngas

TABLE 3-4. PYROLYSIS CLASSIFICATIONS ACCORDING TO THE TYPE OF REACTOR
(SOURCE: WILLIAMS, CIRCA 2009)

Reactor Type	Heating Method	Mode of Contact	Heating Rate
Fluidized Bed	Heated recycle gas Fire tubes	Bubbling: relatively low gas velocity, inert solid stays in reactor Circulating: much higher gas velocities, inert solid is elutriated, separated and re-circulated	High-Moderate
Entrained Flow	Recycled hot sand	High particle velocities and turbulence to effect high reaction rates Good gas-solid contact	High
Fixed Bed	Heated recycle gas	Downdraft: solids move down, gas moves down, (i.e. co-current Solids) Updraft: solids move down, gas moves up, (i.e. counter-current Solids) Cross draft: solids move down, gas moves at right angles (i.e., left or right)	Low
Rotary Kiln	Wall heating	Usually there is an inert solid, has highest gas velocity of lean phase systems Good gas-solid contact High particle velocities and turbulence to effect high reaction rates	Low

3.4 Development Status and Technology Vendors Considered

There are a number of ongoing efforts in North America to develop and commercialize MSW pyrolysis. New technologies are being developed at every stage in a pyrolysis operation. It is useful to consider each development stage as illustrated in Figure 3-2 when discussing these technologies. This study identifies three commercial demonstration facilities operating in the U.S.

Most facilities are at a pilot stage. Even facilities that are commercial-scale often are operating in more of a demonstration mode and do not have waste contracts, energy, or product contracts in place. According to EREF (2013), there are 16 pyrolysis facilities at a commercial

stage worldwide that are concentrated in a handful of countries.

The technology landscape information presented in this report largely focuses on technology vendors with MSW processing facilities in the U.S. that are at the pilot-to-commercial stage, and that include both the waste pre-processing and the conversion technology components (per Figure 3-1). There are also a few pyrolysis equipment vendors that operate in the U.S. that were not considered in this report because they only focus on a particular component of the process, generally the conversion reactor.

Table 3-5 presents a list of technology vendors with MSW pyrolysis facilities in the U.S.

FIGURE 3-2: STAGES OF MSW CONVERSION TECHNOLOGY DEVELOPMENT.
NOTE: MOST OF THE FACILITIES CONSIDERED IN THIS REPORT ARE IN THE STAGES INDICATED BY THE THICKER BORDER SHAPE

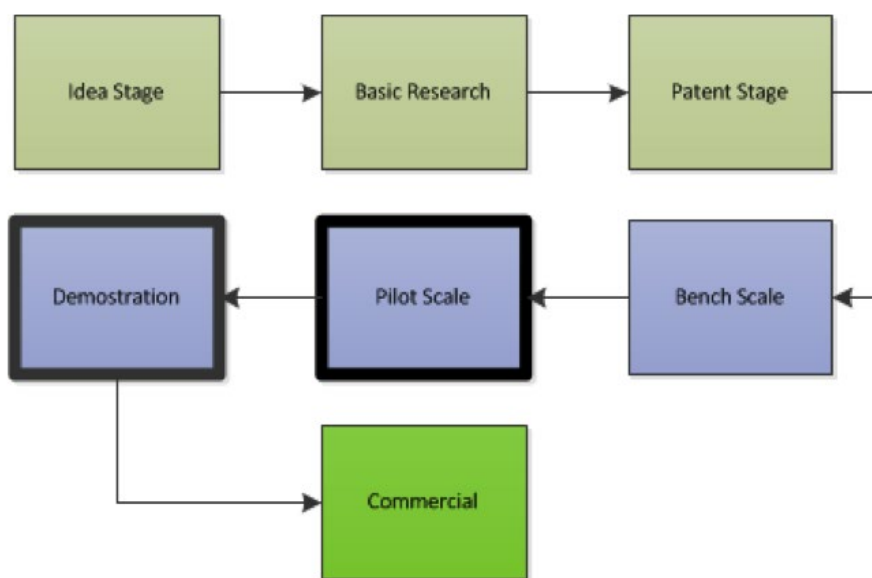


TABLE 3-5: MSW PYROLYSIS TECHNOLOGY VENDORS WITH FACILITIES IN THE U.S.

Vendor Name	Facilities (ACC, 2015)	Status	Feedstock	Head-quarters	Main Product (ACC, 2015)
Agilyx¹	1. Tigard, OR, USA Pilot (10 TPD)-Gen6; Continuous Operations, At Capacity 2. Plymouth, MN, USA* Commercial-Gen5; Operating Status Unknown 3. Lithia Springs, GA, USA Commercial-Gen5; Did Not Disclose 4. North Portland, OR, USA* Commercial-Gen5; Operating Status Unknown	Commercial demo	Plastics	Tigard, OR	Synthetic crude oil
Golden Renewables²	1. Yonkers, NY, USA Demonstration (24 TPD); Discontinuous Operations	Demonstration	Plastics	Pasco, WA	Diesel blend stock Gasoline blend stock
Nexus Fuels³	1. Atlanta, GA, USA Pilot (1.5-2 TPD) Discontinuous Operations	Pilot	Plastics	Atlanta, GA	Light Sweet Synthetic Crude and distillate fuel oils depending on configuration
JBI⁴	1. Niagara Falls, NY, USA Demonstration (25 TPD); Not Operational	Commercial demo	Plastics	Niagara Falls, NY	Naphtha Diesel Blend stock Fuel Oil #6
RES Polyflow⁵	1. Perry, OH, USA Demonstration (60 TPD); Not Operational	Commercial demo	Plastics	Akron, OH	Naphtha blend stock, distillate blend stock and heavy oil
Vadxx⁶	1. Danville, PA, USA Pilot (1 TPD); Discontinuous Operations 2. Akron, OH Commercial (60 TPD); In Construction	Pilot Scale	Plastics, synthetic fibers, used industrial solvents, waste oils	Akron, OH	Light end/Naphtha, Middle distillate diesel fuel No 2

¹http://www.sustainablebusinessoregon.com/articles/2010/06/plas2fuel_opens_showcase_facility_changes_name_to_agilyx.html

²<http://www.goldenrenewable.com/>

³<http://www.nexusfuels.com/>

⁴<http://www.plastic2oil.com/site/home>

⁵<http://www.respolyflow.com/>

⁶<http://www.wksu.org/news/story/26888>

Most MSW pyrolysis vendors in Table 3-5 are operating in a demonstration mode, in batch rather than continuous production. Therefore, there is a high level of uncertainty in the data to characterize the performance, cost, and environmental aspects of these technologies when used to predict true commercial operation.

3.5 Process Characterization and Environmental Impact Potential

Table 3-6 presents a summary of pyrolysis process data and considers data provided by vendors that have facilities in the U.S.

FIGURE 3-3: MSW PYROLYSIS MAIN PROCESSES, INPUTS AND OUTPUTS
NOTE: THICKER-BORDER SHAPES INDICATE THE MAIN CONVERSION PATHWAYS AND PRODUCTS.

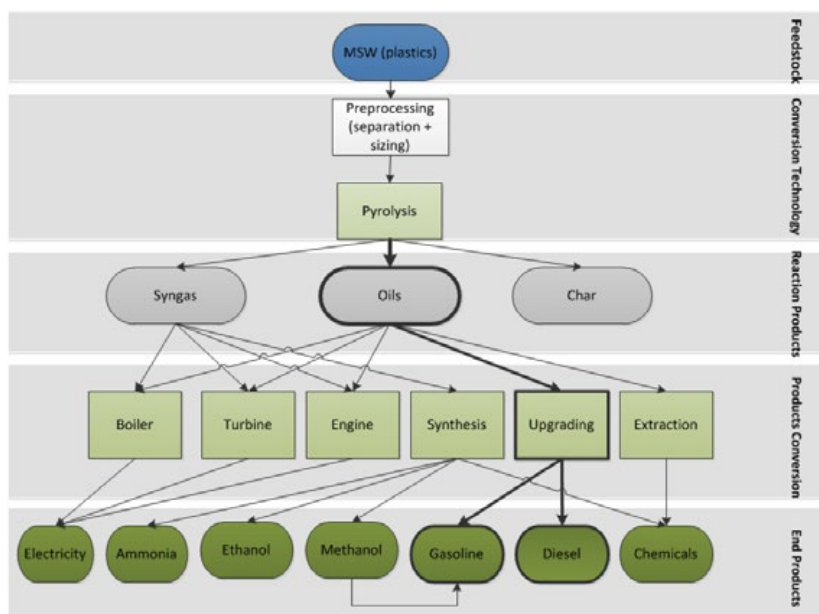


TABLE 3-6: PYROLYSIS PROCESS CHARACTERIZATION DATA FROM NORTH AMERICAN TECHNOLOGY VENDORS

Parameters	Units	Value	
Process Inputs			
Power consumption/parasitic load	kWh/dry ton	0.3-826	
Supplemental fuel use	Natural Gas MMBtu/dry ton	0.7-7.9	
Water	gal/dry ton	29-216	
Catalyst	lb/dry ton	proprietary	
Nitrogen	lb/dry ton	66	
Hydrogen	lb/dry ton	Amount Not Reported	
Process Outputs			
Energy product	Diesel	lb/dry ton	500-1460
	Synthetic crude oil	MMBtu/dry ton	33
	Gasoline blending stock	lb/ dry ton	700
	Syngas	MMBtu/dry ton	0.0005-5
	Heating oil	lb/dry ton	166-200
	Naphtha	lb/dry ton	333-450
Residuals	Char	lb/dry ton	62-240
	Solid residues	lb/dry ton	5-20
Water losses	gal/dry ton	10-23	
Greenhouse Gas (GHG) Emissions			
Fossil Carbon Dioxide (CO ₂ Fossil)	lb/dry ton	250-1261	
Methane (CH ₄)	lb/dry ton	0.003-0.01	
Nitrous Oxide (N ₂ O)	lb/dry ton	0.1-20	

Several subtypes of pyrolysis with varying proprietary elements were identified among the vendor technologies from which data were considered in this report. Appendix B describes three technologies (selected as examples) from vendors that are currently operating in the U.S. Differences in conversion process elements were stated to enhance conversion efficiency and/or to tailor end products to site-specific markets.

Additional information on the sources of GHG emissions and how they compare to landfill disposal of plastic waste is presented in the “GHG Neutrality Framework for MSW Pyrolysis.” There are other air pollutants that are expected from these pyrolysis facilities, such as particulate material, carbon monoxide, lead and volatile organic compounds, but reported data is limited. An environmental impact assessment should consider these emissions and how they compare with other options, so that an attempt to reduce GHG the project does not increase other emissions.

Some technologies use a water quench to condense syngas vapors into the liquid petroleum product at the tail end of the pyrolysis process or for oil conditioning. Some companies require a water supply connection, while others source water from condensation from the pyrolysis process. The information available from vendors indicates

that the majority of water losses are from evaporation and that most water is reused/recycled in the process to avoid wastewater treatment burdens.

MSW pyrolysis technologies can support landfill diversion and the exact facility capacity and number of facilities will govern the significance of the diverted amount. MSW pyrolysis technologies can only utilize fractions of MSW (most commonly plastics). Source segregation must occur prior to the pyrolysis process. This requires additional cost, energy, and use of processes with additional environmental emissions. For location specific analysis, considerations include existing infrastructure, enhanced segregation of suitable materials, and contractual arrangements for ensuring dedicated feedstocks.

The process of pyrolysis creates residues including char, silica (sand), and bottom ash. Some of these residues may be reused (if approved by an environmental agency) while others must be disposed of in a landfill. The amount of residual waste produced is about 15 percent to 20 percent of the overall feedstock used in the process. Litter, odor, traffic, noise, and dust also must be assessed but vary according to the differences in facility technology, size, and feedstock.

3.6 Financial Considerations

Considering the development stage of most pyrolysis facilities in North America, cost data is not readily available or necessarily reflective of commercial operating conditions. With this consideration in mind, Table 3-7 presents the cost data as ranges based on overseas facilities to provide rough estimates and capture the variability that exists across pyrolysis technologies.

Table 3-7 displays cost information for MSW pyrolysis technologies but is limited by available literature. For comparison, Colorado average landfill tipping fees are \$30.47 of MSW. (Van Haaren et al., 2010)

Operation and maintenance (O&M) cost data is particularly difficult to obtain. Fixed O&M costs include maintenance and expenses associated with acquiring inputs, and managing process residuals constitute the majority of O&M costs. Variable O&M costs such as feedstock purchase and transportation and fuel transport costs can have a significant impact as well.

According to an American Chemistry Council study conducted in 2015, most vendors indicated a willingness to purchase plastics waste at market value. However, many are developing systems with materials recycling facility (MRF) owners or at landfill sites in order to guarantee a long-term, no-, or low-cost supply of feedstock. One vendor indicated that a purchase price exceeding \$62/ton of plastic would impede economic performance. Another vendor indicated that O&M costs are reduced by 50 percent if they can obtain feedstock free of charge.

There are proposed pyrolysis facilities in North America, but the exact number is unknown (up-to-date information on proposed developments was difficult to obtain). The perceived business risk of MSW pyrolysis still remains high. Therefore, project developers must have clear plans to deal with permitting, feedstock supply and energy market fluctuations in order to attract investment.

Obtaining the necessary financing may require innovative funding structures and tapping alternative sources.

Most revenue from pyrolysis comes from the sale of synthetic oil derived products or recyclables rejected as feedstock. Private equity, bond financing, and federal loans are various funding mechanisms to obtain start-up capital. State and federal financial backing remain a key part of the funding mix for many new projects (Renewables Waste Intelligence, 2013).

Equity investment means that investors can take part in the potential upsides promised by early stage waste conversion projects. This upside provides the necessary reward incentive to attractive investors. With climate change mitigation commitments, the renewable energy sector is undergoing an upturn in private equity.

Bonds can be used as a sole source of debt funding for projects or to complement conventional bank debt. The key advantages of bond finance can be longer repayment time frames, less restrictive covenants and lower interest rates. There are also financial structures available that can help to improve the investment rating of bonds, such as technology warranties offered by third-party insurers. Favorable debt-market conditions have allowed some companies to take advantage of this form of capital raising.

Government financial support remains a major contributor to renewable energy development in the U.S. This is in spite of the recent and impending expiration of key loan guarantee and grant programs such as the Department of Energy Loans Programs (<http://www.energy.gov/lpo/loan-programs-office>). This program offers loans for innovative clean energy technologies at low-to-zero interest over a period of 10 years, providing access to capital for firms that typically are unable to obtain conventional private financing due to technology risks (Renewable Waste Intelligence, 2013).

TABLE 3-7: PYROLYSIS COST DATA
(SOURCE: U.S.EPA, 2012 AND ACC, 2015)

Cost Item	Value	Drivers
CAPEX (\$ million)	12-18	Design capacity, system footprint and requirement for full enclosure, Infrastructure requirements, on-site pre-processing, chosen business model, technology, and financing costs
Per ton CAPEX (\$/TPY)	714-1460	Same as above.
O&M cost (\$TPY)	rarely reported	Demand for and cost of inputs (water, electricity, labor, catalyst, hydrogen), feedstock purchase and transportation costs, char production and landfill disposal rates, wastewater production and management costs, fuel transportation costs, maintenance costs, trailing royalty, insurance, and management fees
Breakeven (\$/barrel)	40-50*	Liquid oil/fuel conversion rate, market price for liquid petroleum products, and potential for per ton tipping fees

*The dynamics of the market have changed in recent years with energy prices generally being much lower today in the U.S. Thus, the breakeven point would be different and would need to be assessed on a case-by-case basis.

State subsidies also are available as a funding alternative. An example is The Renewable Energy Production Incentive (REPI), which provides incentive payments for electricity generated and sold by new qualifying renewable energy facilities. A key determinant of the eligibility of projects for subsidies is their classification as renewable. The federal government officially recognizes waste to energy as a renewable resource. However, only 24 states and the District of Columbia follow the same interpretation (Renewable Waste Intelligence, 2013).

Renewable Portfolio Standards place an obligation on electricity supply companies to supply a certain proportion of their electricity from renewable energy sources. A total of 38 states and the District of Columbia have an RPS (Congress.Org, 2015). Where states recognize waste conversion as a renewable resource and there is an RPS, conditions are more favorable for new facility development.

Strategic investments from the large waste management companies are among the most promising sources of cash for MSW pyrolysis at present. Waste Management and Covanta Energy have been particularly active in this sphere, driven by a desire to acquire technologies to boost sustainability and make financially gainful use of their abundant feedstock supply (Renewable Waste Intelligence, 2013).

3.7 Regulatory and Contractual Considerations

The Colorado Air Pollution Control Division provides guidance on what types of facilities will need air permitting. A MSW pyrolysis plant will have air emissions from large boilers to heat the feedstock, generators, and fuel dispensing stations, among other sources. Criteria pollutants are generated from many of the steps involved in the pyrolysis process, and an applicant will need to identify the estimated quantities of each pollutant emitted based on available data or similar technologies. Colorado has 19 Air Quality Control Commission regulations, many of which are applicable to a MSW pyrolysis facility.

Any new facilities also must consider federal, federal and state, and state-only non-hazardous air pollutants including whether a new plant will be located in a non-attainment area. Any new facilities in non-attainment areas will be held to stricter standards for pollutant emissions.

A new pyrolysis plant could be subject to federal standards including NESHAP and NSPS. Specific rules may include those applicable to chemical manufacturing industries, gasoline dispensing/distribution terminals, industrial boilers, and possibly others. It is likely that a new plant will require a Title V permit. Any equipment combusting the synthetic fuels that the plant produces likely would come under a broader permit. However, if the electrical generating equipment is located off-site, the equipment may require a permitting process similar to the one described above for CMM technologies.



It is not always clear whether a MSW pyrolysis technology falls under the category of waste management or renewable energy facility, and this can be a source of confusion when establishing permitting requirements. Another challenge is that there is not long-term performance data from MSW pyrolysis facilities to establish regulatory limits and determine potential impacts on local or regional air sheds.

The permitting process can take time, and the facility owners may have difficulties that lead to substantial delays in construction. Some examples included obtaining solid waste handling permits through the appropriate local agency acquiring air permits in order to address any criteria and toxic air pollutants that may be emitted, and obtaining a Title V Permit. Water quality permits also are necessary to regulate discharges to surface and ground water.

The local or county planning agency may have requirements for the planned facility that encompass building, grading, water system, shoreline, utility, site plan review, septic system, floodplain development, and any zoning variance. Construction operations may not begin until permits are acquired.

Char and other residual products from MSW pyrolysis technologies may be a regulated hazardous waste or solid waste and would need to be assessed and approved by local or state agencies to determine their potential use (e.g., as aggregate) and appropriate disposal (e.g., conventional versus hazardous waste landfill). Char may be characterized by technology vendors as non-leachable. However, it may require testing for compliance with state and local regulations or standards and likely will need to be approved for reuse applications. If a market is developed for char and it is approved for reuse, it may be sold. If not, the char must be landfilled.

After project developers receive permits to operate, they must be able to secure contracts with waste facilities in order to have a secure, continuous feedstock. Feedstocks are often one of the most challenging aspects of successfully operating a MSW pyrolysis facility. The quantity of feedstock needs to be relatively constant because the systems are optimized for a specific flow rate. Also, it is necessary for quality and volume of feedstock to be taken into account.

3.8 Social Acceptance

An implementation barrier can be the negative stigma carried by thermochemical conversion technologies associated with incineration and the lack of understanding about the differences between MSW pyrolysis and combustion technologies. This has led to difficulty in locating sites for pyrolysis plants. Recycling promoters also question the role of pyrolysis type technologies and whether they lead to a disincentive for individuals and communities to recycle or prevent waste generation. Global Alliance for Incinerator Alternatives (<http://www.no-burn.org/>) is a conglomeration of more than 500 grassroots organizations opposed to incinerators, as well as other waste technologies. They argue that the emissions associated with thermochemical conversion facilities (including pyrolysis) fuel climate change, do not address the non-governmental organizations' and advocacy groups' concern for overconsumption, and divert resources and focus from recycling programs.

Most easily accessible information that drives public opinion is derived from these groups, which leads to a negative perception of these facilities. However, communities that have installed thermochemical conversion technology facilities, including incineration with energy recovery, tend to have a more positive opinion of the technologies.

To reduce public resistance to these facilities, it would be helpful for companies to provide outreach to the public to educate them about technological advances and other positive aspects of these technologies. Some measures that may help include siting facilities at brownfields (i.e., abandoned or underused industrial and commercial facilities available for re-use), the use of dome designs to hide smokestack visibility, and integrated "utility campuses" that consist of sewage treatment, electricity generation, and water reclamation facilities.

4 | Framework for Pyrolysis GHG Neutrality

4.1 Background

The framework is proposed to evaluate the greenhouse gas (GHG) neutrality of municipal solid waste (MSW) pyrolysis technologies that produce renewable electricity. According to Senate Bill 13-252 by the General Assembly of the State of Colorado, "Concerning Measure to Increase Colorado's Renewable Energy Standard so as to Encourage the Deployment of Methane Capture Technologies," pyrolysis technologies are defined as follows:

The thermochemical decomposition of material at elevated temperatures without the participation of oxygen.

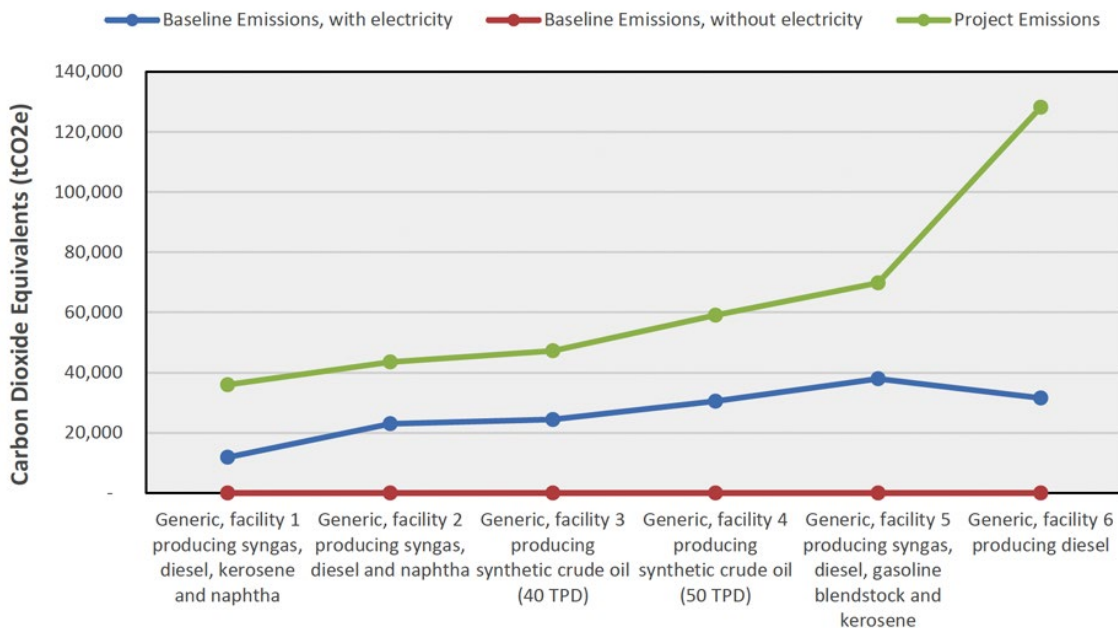
This definition excludes gasification, which uses oxygen to initiate the reactions. The Public Utility Commission (PUC) has not yet held a proceeding to determine whether a MSW pyrolysis project is GHG neutral; thus the process and procedure for the approval process is yet to be determined.

Senate Bill 13-252 defines GHG neutrality as follows:

Greenhouse gas neutral, with respect to electricity generated by a coal mine methane or synthetic gas facility, means that the volume of greenhouse gases emitted into the atmosphere from the conversion of fuel to electricity is no greater than the volume of greenhouse gases that would have been emitted into the atmosphere over the next five years, beginning with the planned date of operation of the facility, if the fuel had not been converted to electricity, where greenhouse gases are measured in terms of carbon dioxide equivalent.

Overall, the GHG neutrality for MSW pyrolysis primarily will be governed by baseline emissions including methane emissions from MSW landfill(s) and emissions generated from grid-based electricity production. As shown in Figure 4-1, MSW pyrolysis facilities will not be GHG neutral-given: (1) the state's accounting protocol, which does not include avoided GHG emissions from displaced grid-based electricity; and (2) the primary feedstock for MSW pyrolysis being only fossil-based wastes (namely plastics which do not decompose in landfills and produce methane).

FIGURE 4-1: ILLUSTRATIVE RESULTS USING SURVEY DATA



*Note: The N₂O emissions reported by the MSW pyrolysis vendors of facility 1 and 6 are driving their project emissions. These and facility 2 were the only vendors that reported N₂O emissions.

4.2 Accounting for GHG Emissions

Consistent with internationally recognized frameworks and accounting protocols (further described below), the proposed framework can be summarized by the following equation:

$$ER = BE - PE$$

Where:

ER = Emissions reduction

BE = Baseline emissions

PE = Project emissions

4.3 Baseline and Project Emissions

The emission reduction calculation takes into account that managing MSW via pyrolysis treatment technology would avoid methane emissions from the placement of waste into a solid waste disposal site (landfill). In addition to avoiding methane emissions from the placement of waste into a landfill, pyrolysis technologies also have the potential to generate electricity. Electricity generated displaces electricity produced from fossil fuel power plants and the associated avoided emissions could be considered emission reductions. Accounting for these offsets is considered optional in the GHG neutrality user form in order to be consistent with the Colorado regulatory framework. Collectively, these two sources are referred to as baseline emissions.

Project emissions are those that are additional to what would have occurred in a business as usual case. These

include emissions from on-site fossil fuel and grid electricity consumption used in the pyrolysis process as well as emissions from syngas production and the consumption of syngas to produce electricity. Table 4-1 lists the emission sources included in this study.

4.4 GHG Neutrality

GHG baseline and project emissions from each source identified in Table 4-1 are estimated using various equations that are implemented in the pyrolysis calculator. Tables 4-2 and 4-3 present baseline and project emissions equations, and define each of the parameters included for the data needs as inputs.

The main assumptions used to develop a calculator in response to Colorado's definition of pyrolysis and the requirements for GHG neutrality include:

- All syngas produced was assumed to be used to generate electricity.
- Pyrolysis technology vendors reported products from MSW pyrolysis (see MSW Pyrolysis Technology Landscape) as liquid fuels, including diesel and gasoline blend stock. The calculator assumes that these products are used to produce electricity rather than directly used or transformed into transportation fuels, which are reported as the likely markets by North American vendors (as opposed to burning the fuel to generate electricity).

TABLE 4-1: DEFINITION OF BASELINE EMISSIONS, PROJECT EMISSIONS, AND HOW THEY ARE CONSIDERED IN THE PROPOSED FRAMEWORK (ADAPTED FROM REF ID 1)

Baseline/Project	Sources Included	GHG	Justification/Explanation
Baseline Emissions	Emissions from decomposition of waste at a solid waste disposal site	CH ₄	Major source of GHG emissions in the baseline attributable to waste placement at a solid waste disposal site
	Emissions from electricity generation (optional)	CO ₂	Emission reductions resulting from the displacement of electricity
Project Emissions	On-site fossil fuel consumption due to the project activity other than for electricity generation	CO ₂	Includes heat generation for mechanical/thermal treatment process, start-up of the pyrolysis reactors, etc.
	Emissions from grid-based electricity use	CO ₂	Includes electricity consumed in order to manufacture synthetic fuels.
	Direct emissions from the waste conversion processes (waste-to-syngas and syngas-to-electricity).	CO ₂	CO ₂ emissions from combustion of fossil based pyrolysis products (syngas or syngas)
		N ₂ O	N ₂ O emitted from syngas production
	CH ₄	CH ₄ may be emitted from stacks from the pyrolysis process	

*If organic waste were included in the pyrolysis project, the CO₂ emissions would be considered carbon neutral (or biogenic)



Site specific values needed as inputs to the calculator include total amount of waste consumed in the pyrolysis process, auxiliary fuels usage for the production of synthetic fuels, grid electricity consumed, and the amount of fossil carbon in exhaust gas (or other waste emission stream). None of the vendors reported electricity generation as an end product. The calculator used electric energy conversion efficiencies to estimate theoretical electricity production if the end product fuels were combusted to create electricity. The calculator uses default emissions factors for the combustion of the pyrolysis fuels to generate electricity in order to estimate the GHG emissions.

Waste volume composition has a significant impact on the amount of methane that would have been generated at a solid waste disposal site in the absence of the project. MSW that breaks down easily (i.e. food waste) generates significant amounts of methane in landfills. MSW that does not break down (i.e. inerts, glass, plastics) generates little or no methane emissions from landfills. Fossil fuel based waste is also the main contributor to project emissions from combustion/conversion (exhaust gas or some other emission). These characteristics of plastics and tires compound the problem of proving carbon neutrality from pyrolysis projects as these waste types do

not decompose in landfills and do not contain biogenic carbon. Higher amounts of plastics and tires (the main components pyrolysis) used as pyrolysis feedstock results in lower avoided emissions from landfills and higher project emissions from the conversion process.

Other impacts on whether pyrolysis can be considered carbon neutral include auxiliary fossil fuel consumption, electricity consumption, pyrolysis product type and volume, carbon emissions from the pyrolysis process, electric energy conversion efficiencies, and project emissions from burning synthetic fuels to product electricity. All vendors reported mostly liquid fuels as the main end product. The calculation converts the synthetic fuels to an MMBtu/kilowatt hour value in order to estimate the avoided emissions from displacing grid electricity. Note that this is a very unlikely situation for pyrolysis as the liquid fuels generated are more valuable as a product than using said fuels to generate electricity. Syngas can be a secondary product, but represents only a small portion of the fuel outputs. Example pyrolysis data from six facilities is included in the calculator to illustrate functionality.

Tables 4-2 and 4-3 show the parameters included in the GHG emission reduction calculations that determine GHG neutrality over a five-year time frame.

TABLE 4-2: BASELINE EMISSIONS CALCULATION EXAMPLE

Variable	Description	Units	Comments
Baseline Emissions (Equation 1.1: Ref ID 1 Equation 19 Revised)			
$BE = BE_{CH_4,SWDS} + BE_{EN}$			
BE	Baseline emissions	Metric tonnes CO ₂ e	
BE _{CH₄,SWDS}	Methane produced in a landfill in absence of project	Metric tonnes CO ₂ e	Plastics do not decompose in solid waste disposal sites and therefore do not produce methane emissions.
BE _{EN}	Energy gen. emissions that would have been generated in the baseline in the absence of the project	Metric tonnes CO ₂ e	
Baseline Emissions from Displaced Energy (Equation 1.2: Ref ID 1 Equation 23)			
$BE_{EN} = BE_{Elec} + BE_{Thermal}$			
BE _{Elec}	Baseline emissions from electricity generation that would have been produced in the baseline in the absence of the project	Metric tonnes CO ₂ e	
EG	Net electrical generation from project tonnage	MWh	
CEF	Carbon emission factor for displaced electricity	Metric tonnes CO ₂ e/MWh	
Carbon Emission Factor for Displaced Electricity			
$CEF = EF_{grid,BM} \times W_{BM} + EF_{grid,OM} \times W_{OM}$			
EF _{grid,BM}	Build margin CO ₂ emission factor	Metric tonnes CO ₂ e/MWh	Estimated
EF _{grid,OM}	Operating margin emission factor	Metric tonnes CO ₂ e/MWh	eGRID 2012 data for the state of Colorado. 1,668.72 pounds of CO ₂ per MWh converted to metric tonnes CO ₂ per MWh.
W _{BM}	Weight of build margin	50%	UNFCCC Methodological Tool to calculate emissions factors for an electric system
W _{OM}	Weight of operating margin	50%	UNFCCC Methodological Tool to calculate emissions factors for an electric system
Amount of Methane Produced (Equation 1.6 Ref ID 5 Equation 1 Revised)			
$BE_{CH_4,SWDS} = \varphi \times GWP_{CH_4} \times (1 - OX) \times \frac{16}{12} \times F \times DOC_f \times MCF \times \sum_{x=1}^y \sum_j ((1 - f_x) \times W_j \times DOC_j \times e^{-k_j(x-1)} \times (1 - e^{-k_j}))$			
φ	Model correction factor	Unitless	
OX	Soil oxidation factor	Fraction	Fraction of methane naturally oxidized by soil bacteria
F	Fraction of methane in solid waste disposal site gas	Fraction	IPCC default
DOC _f	Decomposable fraction of degradable organic C	Fraction	IPCC default
MCF	Methane correction factor	Unitless	Default for an anaerobic solid waste disposal site (assumed for Colorado landfills)
x	Year for which CH ₄ emissions are calculated	Year	
y	Final year of crediting period	Year	A five-year forecast according to PUC regulations.
f _x	Fraction of methane captured and flared	Fraction	
W _j	Amount of waste prevented from landfill disposal	Metric tonnes	The amount of feedstock consumed in the pyrolysis project
DOC _j	Fraction of degradable organic carbon in MSW	Fraction	Varies; however only plastics considered as a feedstock for pyrolysis projects. Plastics do not degrade under normal solid waste disposal site conditions
k _j	Decay rate for waste type j	Fraction	Varies; however only plastics considered as a feedstock for pyrolysis projects. Plastics do not degrade under normal solid waste disposal site conditions

TABLE 4-3: PROJECT EMISSIONS CALCULATION EXAMPLE

Variable	Description	Units	Comments (as needed)
Total Project Emissions			
$PE = PE_{elec} + PE_{fuel} + PE_i$			
PE_{elec}	Emissions from on-site electricity consumption	Metric tonnes CO ₂ e	
PE_{fuel}	On-site fossil fuel combustion emissions	Metric tonnes CO ₂ e	
PE_i	Emissions from waste & aux. fuel combustion	Metric tonnes CO ₂ e	
Project Emissions from Plant Electricity Use (Equation 2.2: Ref ID 1 Equation 2)			
$PE_{Elec} = EG_{PJ,FF} + eGRID_{ef}$			
$EG_{PJ,FF}$	Grid electricity consumed by project activity	MWh	
$eGRID_{ef}$	Grid carbon emission factor	Metric tonnes CO ₂ e/ MWh	Based on the U.S. EPA eGRID emissions factor for the State of Colorado
Project Emissions from Fossil Fuel Use including pyrolysis products (Equation 2.3: Ref ID 1 Equation 3)			
$PE_{Fuel} = \sum F_{Cons} \times HHV_{Fuel} \times EF_{Fuel}$			
F_{Cons}	Fossil fuel consumption (gallons, standard cubic feet etc.)	Varies	
HHV_{Fuel}	Net caloric value of fossil fuel	Mega joule/unit	2015 Climate Registry Default Emission Factors
EF_{Fuel}	CO ₂ emission factor of fossil fuel	Tonnes of CO ₂ / mega joule	2015 Climate Registry Default Emission Factors
Process Emissions from Waste-to-Fuel Conversion (Equation 2.4-2.6 Ref ID 1 Equation 11, 14 and 16)			
$PE_i = PE_{i,CO_2} + A_{MSW} \times (EF_{N_2O} \times GWP_{N_2O} \times CF_{N_2O} + EF_{CH_4} \times GWP_{CH_4} \times CF_{CH_4}) \times 10^{-6}$			
PE_{i,CO_2}	Fossil-based waste fuel CO ₂ process emissions	Metric tonnes CO ₂	Measured via continuous emissions monitoring system or by sampling of biogenic fraction of carbon in stack gas
A_{MSW}	MSW consumed to produce synthetic fuels	Metric tonnes	Facility specific
EF_{N_2O}	Emission factor of N ₂ O	Grams N ₂ O/metric tonne of waste	Facility specific
GWP_{N_2O}	Global warming potential of N ₂ O	298	IPCC 4 th assessment report (AR4)
CF_{N_2O}	Conservativeness factor for N ₂ O	Unitless	
EF_{CH_4}	Emission factor of CH ₄	Grams CH ₄ /metric tonne of waste	Facility specific
GWP_{CH_4}	Global warming potential of CH ₄	25	IPCC 4 th assessment report (AR4)
CF_{CH_4}	Conservativeness factor for CH ₄	Unitless	

4.5 Applicability of GHG Neutrality Calculator

Given the Colorado statutory definition of MSW pyrolysis and established GHG project protocols for determining emission reductions, neutrality will be governed by baseline emissions: (1) the developer’s ability to offset methane emissions from MSW landfill(s) and (2) the avoided emissions generated from offsetting grid electricity consumption by end users. The calculator allows the user to include or exclude the avoided emissions.

Project emissions will be significant from the pyrolysis process and combustion of pyrolysis products (i.e. synthetic diesel, gasoline, naphtha and crude oils) to produce electricity. Typically, only syngas is used for electricity generation, but the calculator allows any product to be

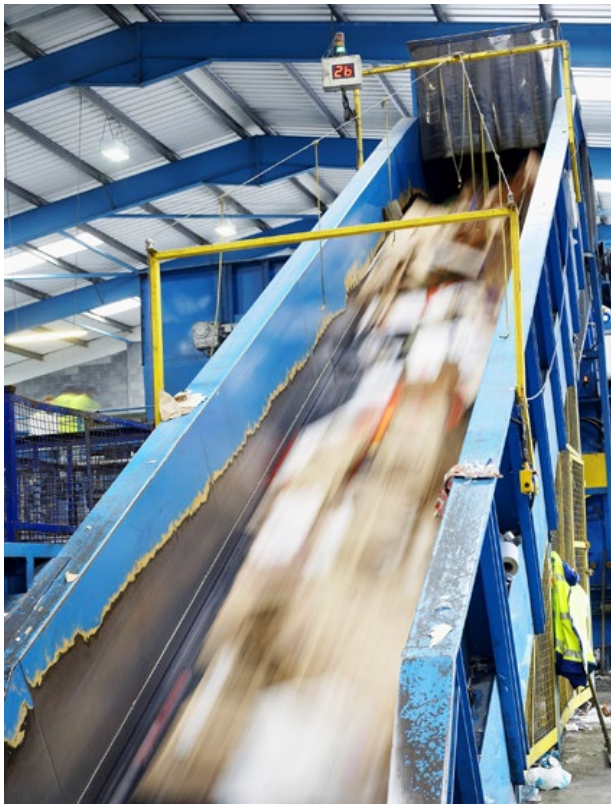
used including liquid fuels. Also, project emissions from grid electricity consumption and auxiliary fuel can impact the outcome of calculating GHG neutrality; however these impacts were small as surveyed sites did not use substantial amounts of energy for the pyrolysis process.

Regarding avoided landfill GHG emissions, the research into MSW pyrolysis and communication with technology vendors (whose data are included in the calculator’s generic dataset) found that vendors typically accept only the plastics fraction of the MSW stream. Because plastics do not degrade in landfills (and subsequently produce little or no methane), these technologies will not generate landfill GHG emissions avoidance benefits. This baseline scenario makes it nearly impossible for such technologies to achieve GHG neutrality.

Avoided GHG emissions from displaced grid-based electricity generation needs to be included in the calculation to even consider pyrolysis technologies achieving GHG neutrality. For example, the blue line in Figure 4-1 illustrates a scenario where offsets of baseline GHG emissions from conventional electricity generation are considered. However, because the avoided methane emissions from landfills are zero for plastic or tire waste (orange line), pyrolysis projects never can be above the grey line (project emissions) to achieve GHG neutrality. The possibility exists that a pyrolysis technology may be developed that can accept some type of bio-waste from MSW landfills as a portion of its feedstock. The GHG calculations require both baselines to be significant in order to result in positive emissions reductions and/or GHG neutrality.

Key sources of uncertainty in the generic data used to produce these results include:

- The use of proxy, literature-based heating values for the syngas and liquid fuels that were reported by the technology vendors.
- The use of proxy, literature data for the conversion efficiencies of plastics/tires to energy products (liquids and gaseous), and conversion of these energy products to electricity. MSW pyrolysis vendors whose data is included in the calculator's generic data set reported liquid or gaseous fuels, rather than electricity, as their main products.



There exist a number of protocols and methodologies for the purpose of quantifying GHG emission reductions from various waste management projects. The development of this framework involved utilizing relevant equations and information from the most applicable protocols. The protocols and methodologies utilized are identified in the following list.

- Ref id 1: UNFCC Approved baseline and monitoring methodology AM0025, Avoided emissions from organic waste through alternative waste treatment processes (available at https://cdm.unfccc.int/EB/033/eb33_repan08.pdf);
- Ref id 2: Current MSW Industry Position and State-of-the-Practice on LFG Collection Efficiency, Methane Oxidation, and Carbon Sequestration in Landfills," prepared for Solid Waste Industry for Climate Solutions (SWICS) (available at: <http://www.scsengineers.com/scs-white-papers/current-msw-industry-position-and-state-of-the-practice-on-lfg-collection-efficiency-methane-oxidation-and-carbon-sequestration-in-landfills-prepared-for-solid-waste-industry-for-climate-solution>); and
- Ref id 3: Local Government Operations Protocol For the quantification and reporting of greenhouse gas emissions inventories, Version 1.0, September 2008 (available at: http://archive.iclei.org/fileadmin/user_upload/documents/Global/Programs/CCP/Standards/LGOP_USA_2008.pdf).
- Ref id 4: UNFCC Methodological tool, Tool to calculate the emission factor for an electricity system, Version 04.0 (available at: <https://cdm.unfccc.int/methodologies/PAmethodologies/tools/am-tool-07-v4.0.pdf>).
- Ref id 5: UNFCC Annex 14 Methodological tool "Tool to determine methane emissions avoided from dumping waste at a solid waste disposal site" (available at: https://cdm.unfccc.int/EB/026/eb26_repan14.pdf).

Appendix A. Gasification

Gasification is the partial oxidation of carbon-based feedstock to generate syngas. The process is similar to pyrolysis, except that oxygen (as air, concentrated oxygen, or steam) is added to maintain a reducing atmosphere, where the quantity of oxygen available is less than the stoichiometric ratio for complete combustion. Gasification forms primarily carbon monoxide and hydrogen, but potentially other constituents such as methane, particularly when operating at lower gasification temperatures. Gasification is an endothermic process and requires a

heat source, such as syngas combustion, char combustion, or steam. The primary product of gasification, syngas, can be converted into heat, power, fuels, fertilizers or chemical products, or used in fuel cells. Figure A-1 illustrates the main processes, inputs and outputs to and from MSW gasification.

Table A-1 provides a list of currently active gasification vendors in the North American region and their general characteristics.

FIGURE A-1. MSW GASIFICATION MAIN PROCESSES, INPUTS AND OUTPUTS
 NOTE: THICKER-BORDER SHAPES INDICATE THE MAIN CONVERSION PATHWAYS AND PRODUCTS.

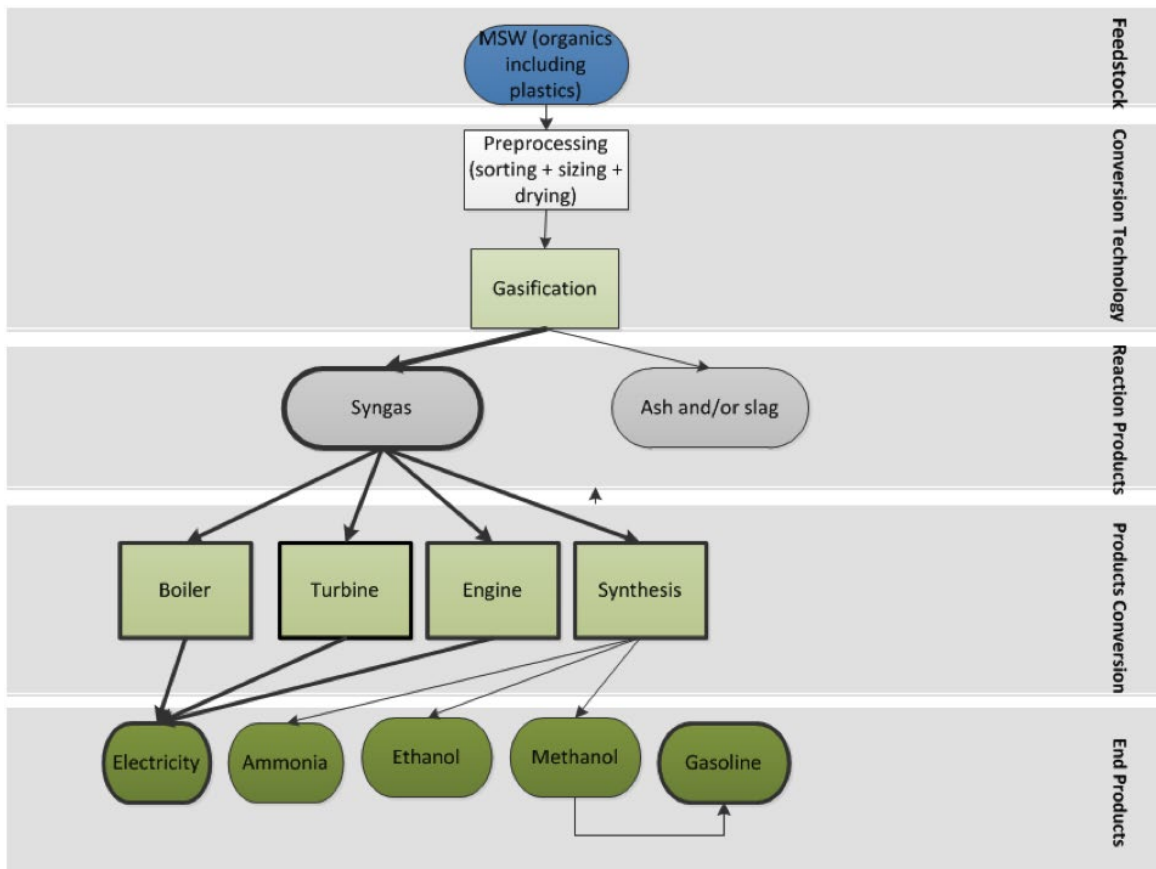


TABLE A-1. GASIFICATION TECHNOLOGY—NORTH AMERICAN VENDORS

Vendor Name	Status	Feedstock	Location	Main Product	Source (Sites accessed in October 2015)
Alter NRG	Pilot	MSW	Madison, PA	Syngas	http://www.alternrg.com/
Coskata	Pilot	Building waste, forest waste, and MSW	Warrenville, IL	Ethanol	http://www.coskata.com/
Covanta Cleergas					http://www.covanta.com/services/technologies/cleergas.aspx
Enerkem	Commercial	MSW	Alberta, Canada Westbury, Canada	Syngas, methanol, acetates, second generation ethanol	http://enerkem.com/about-us/technology/
InEnTech, LLC	Demo	MSW	Richland, WA	Syngas	http://www.inentec.com/
PHG Energy	Commercial	wood trimmings and sewer sludge	Covington, TN	Syngas	http://www.phgenergy.com/case-study/covington-tenn
Plasco Energy	Demo	MSW	Ottawa, Canada	Syngas	http://www.plascoenergy.com/
Renewable Energy Management Inc. (REM)/EnYrch	Permitted	MSW	Huntington Beach, CA	Syngas	http://www.rem-energy-solutions.com/
Sierra Energy	Demo	MSW	Fort Hunter Liggett, CA	Syngas	http://www.sierraenergycorp.com/fastox-gasifier/
Taylor Biomass	Commissioned	paper, fiber, food residuals, leather, some textiles and wood products from MSW	Montgomery, NY	Syngas	http://www.taylorbiomassenergy.com/
Hybrid: Gasification + Fermentation					
Fulcrum Bioenergy	Commercial	Post-recycled MSW	City of McCarran, NV	Syngas	www.fulcrum-bioenergy.com
Ineos Bio	Commercial	Pre-processed MSW and ag waste	Indian River County, FL	Ethanol	www.powersenergyofamerica.com

Appendix B. Pyrolysis Vendors Case Examples

The following presents examples of technology vendors with facilities at a commercial demonstration or commercial stage in the United States. These examples were selected to correspond to the Plastics-to-Fuel & Petrochemistry Alliance led by the American Chemistry Council. The Plastics-to-Fuel & Petrochemistry Alliance works to increase awareness of the benefits of plastics-to-fuel technologies, enhance the industry’s voice through expanded membership, and demonstrate broad support for plastics-to-fuel technologies through an expanding network of allies.

Agilyx: Tigard, Oregon

In December 2013, Agilyx began operations at a pilot scale PTF facility in Tigard, Oregon. The self-financed facility

represents the Gen 6 technology, the company’s feature offering. Agilyx’s Gen 6 is a continuously fed, non-catalytic pyrolysis system that includes a heated, self-cleaning dual-screw reactor. The facility currently is processing an average of 10 TPD of waste plastics on a continuous basis. Currently, the pilot facility produces light sweet synthetic crude oil, of which it has sold 600,000 gallons to a local refinery. The system has an up-time of 92 percent.

Process Details

Feedstock arrives at the system pre-prepared by feedstock suppliers. Feedstock is shredded to a dimension of ½”. In future commercial applications, Agilyx will seek to co-locate near an MRF, where pre-processing systems are

already in place to minimize front-end costs. Once at the system, plastic feedstock is placed in storage bags on the stock floor. Each batch is tested in a bench scale system onsite to determine feedstock composition. Prepared plastics feedstock is placed on a hopper and loaded onto conveyor belts.

Once on the conveyor, a magnet pulls most remaining ferrous metals out of the input stream. Material is continuously fed into the system at automated 30–40-second intervals. Input material enters the reactor where heated dual screws rotating forward and backward at slightly different speeds feed it through several different heating zones. The relative movement of the screws creates a self-cleaning action. Any residues scraped off the cartridge flights in this stage are collected as char. Plastics move through several heating zones and are converted into hydrocarbon gases. These pass into a condensing tower chamber, which uses a cold water spray to condense the majority of the gases into heavy oil. The oil and water emulsion is sent into a coalescing tank, where the oil and water are separated. The light hydrocarbons exit from the top of the condenser as gases and are subsequently condensed in a chiller as light oil, which is sent directly to storage. The heavy oil is conditioned to adjust pH, remove particulates, and lower organic salts before it is sent to storage as well.

Vadxx: Danville, Pennsylvania

Vadxx's proprietary continuous pyrolysis technology converts recyclable and non-recyclable plastic waste into synthetic oil (generally used as a blending fuel with ultra-low sulfur diesel), syngas, and char, with no hazardous by-product. The process runs with off-the-shelf equipment including extruder, boiler, condenser, and closed piping, with the cooking of the plastic taking place in a closed vessel similar to a pressure cooker. Their facility in Ohio has received a final permit as a true minor emitter, Ohio EPA's lowest possible emissions rating.

For every 10 pounds of waste plastic Vadxx's process produces an estimated one gallon of synthetic oil, two pounds of syngas, and one pound of inert char. Its first commercial plant, in Akron, Ohio, is designed to process 60 tons of plastic per day. The company counts on feedstock from Ohio, Indiana, and Pennsylvania.

Process Details

Vadxx's process' biggest advantage is that it is a continuous process. Chopped cable and wire insulation are fed into an extruder, which outputs a toothpaste-like consistency hot plastic. This plastic is then transferred through a pipe to a rotary kiln, which uses the plastic as a plug in the back end. Inside this chamber, the plastic is melted and depolymerized, at which point it vaporizes.

The vapor goes through a condenser where hydrocarbons are captured as a synthetic crude, comparable to the light end and middle cuts of a conventional distillation column. The system is highly automated and requires only four people to operate.

Its Akron, Ohio, facility is capable of processing 60 tons of plastic waste per day out of which five to six tons of char per day will be produced as well as 300 barrels of liquid fuel. The syngas produced during the process is reused in the process and provides up to 80 percent of the heat required in the plastic melting process.

RES Polyflow: Perry, Ohio

RES Polyflow uses a patented process to convert mixed polymer waste into a light, sweet, liquid fuel known as PyGas. The technology uses a lightly sorted and unwashed feedstock in order to reduce pre-process labor and capital requirements. The company's first full scale processing facility is located in North Perry, Ohio.

RES Polyflow is a thermal depolymerization process, continuously fed, that can produce up to 202 gallons/ton of crude oil. An advantage of RES Polyflow's process is the ability to accept mixed plastic/rubber with minimal pre-sorting and cleaning without affecting the end product. Rigid and film plastics #1–7, carpet, and tire shreds all are accepted. Polyethylene terephthalate (PET) and polyvinyl chloride (PVC) contaminated material is rejected.

Electricity, water, natural gas/propane for startup, and a catalyst all are used as input to the process. In addition to the reactor, housed in a 20,000 ft² building, a 75,000 ft² building for front-end processing is required and one-to-two acres for upgrading and ancillary systems/ materials handling.

Its main products are naphtha blend stock, distillate blend stock, and heavy oil. The blend stocks are planned for sale to fuel blenders and the heavy oil for sale to fuel consolidators or directly to an end user such as a refinery. The plans are to operate under a design, build, own and operate model to achieve proof of concept. This model is a vertical integration of all aspects of project development through which the suppliers take on exclusive risk for the development and operations of a plant. Another projected business model is to offer a licensing arrangement, through which they provide intellectual property for the development of a system for a fee (fixed or yearly).

By-products/residues from the process, in percentage of the feedstock, include 20 percent syngas, 10 percent of solid waste other than char, three-to-five percent char, and 5 percent waste water by volume. It is not clear how much of the syngas is used to fuel the process.

Appendix C. Survey Data of Pyrolysis Vendors

Parameter	Value 1	Value 2	Value 3	Value 4	Value 5	Value 6	Units
Throughput	8,030	14,600	14,600	18,250	21,900	21,900	tons
Waste composition:							
Food	0	0	0	0	0	0	Fraction composition, wet basis
Paper	0	0	0	0	0	0	Fraction composition, wet basis
Wood	0	0	0	0	0	0	Fraction composition, wet basis
Textiles	0	0	0	0	0	0	Fraction composition, wet basis
Rubber & Leather	0	0	0	0	0	0	Fraction composition, wet basis
Plastics and tires	1	1	1	1	1	1	Fraction composition, wet basis
Metal	0	0	0	0	0	0	Fraction composition, wet basis
Glass	0	0	0	0	0	0	Fraction composition, wet basis
Other Inorganic	0	0	0	0	0	0	Fraction composition, wet basis
Electricity consumption	7	0.5	8	10	6	8	Mwh
Auxiliary fuels	5,898	112,625	70,728	88,410	15,978	14,529	kCu.Ft
Products:							
Syngas	4	116			111,690		MMBTU
Product 1 production (diesel)	158,571	330,488			216,666	631,811	MMBTU
Product 2 production (gasoline blendstock)					303,332		MMBTU
Product 3 production (synthetic crude oil)			488,224	610,280			MMBTU
Product 4 production (kerosene)	26,375				86,666		MMBTU
Product 5 production (naphtha)	52,910	130,000					MMBTU
Conversion efficiencies:							
Syngas to electricity conversion efficiency	0.43	0.43	0.43	0.43	0.43	0.43	Fraction
Diesel to electricity conversion efficiency	0.31	0.31	0.31	0.31	0.31	0.31	Fraction
Gasoline blendstock to electricity conversion efficiency	0.31	0.31	0.31	0.31	0.31	0.31	Fraction
Synthetic crude oil to electricity conversion efficiency	0.31	0.31	0.31	0.31	0.31	0.31	Fraction
Kerosene to electricity conversion efficiency	0.31	0.31	0.31	0.31	0.31	0.31	Fraction
Naphtha to electricity conversion efficiency	0.31	0.31	0.31	0.31	0.31	0.31	Fraction
Total electricity produced	21,843	42,301	44,834	56,042	69,787	58,019	MWh
Emissions from waste conversion, fuel combustion to generate electricity and auxiliary fuel combustion							
Total measured CO ₂ mass emissions	22,121	36,440	43,024	53,780	68,876	53,753	ton CO ₂
Fossil C fraction of total carbon	1	1	1	1	1	1	fraction
Measured CH ₄ emission factor	1.1	4.5	0	0	0		g/ton waste
Measured N ₂ O emission factor	4,536	64				9,072	g/ton waste

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