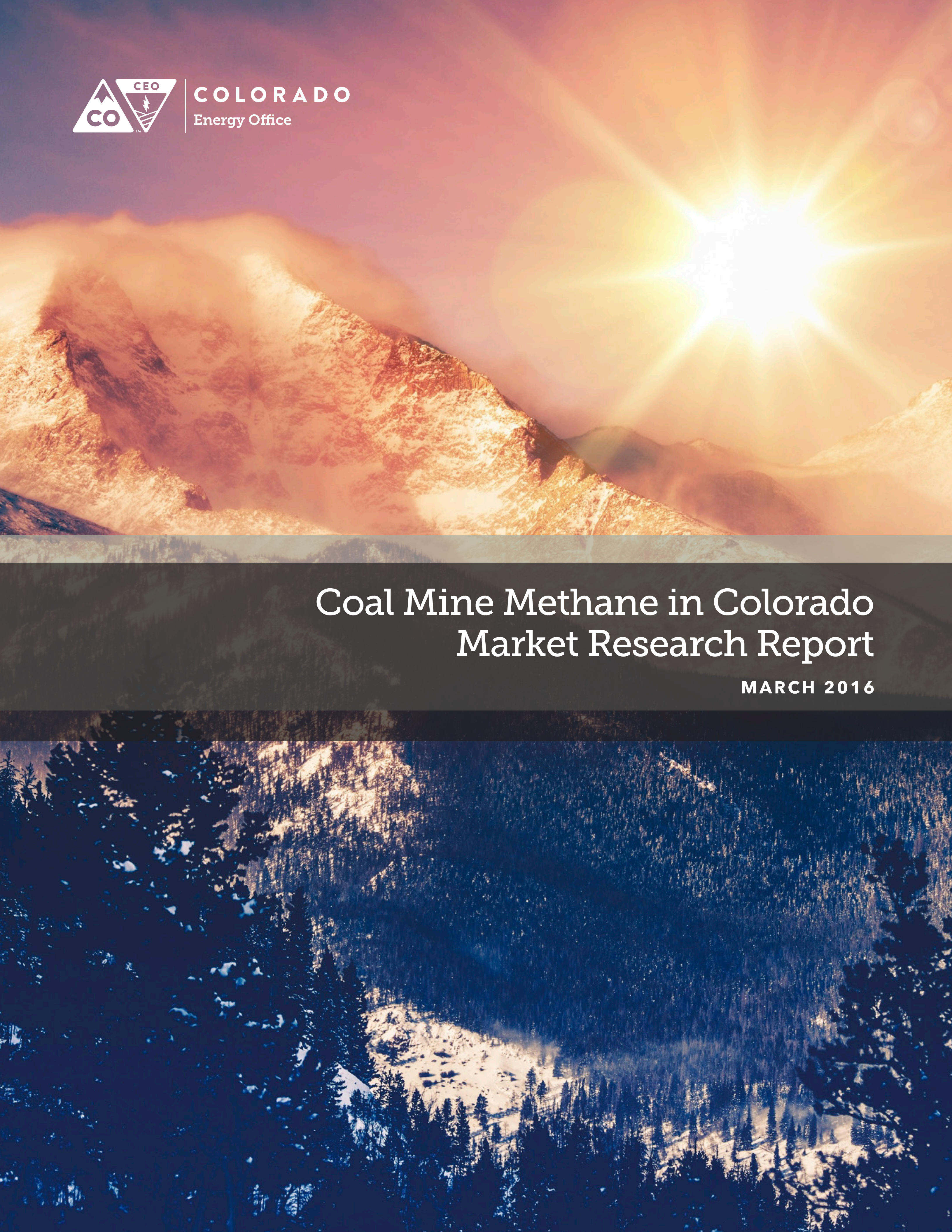
COLORADO
Energy Office



Coal Mine Methane in Colorado Market Research Report

MARCH 2016

Prepared by:

RUBY CANYON ENGINEERING

Ruby Canyon Engineering
743 Horizon Ct. Suite 385
Grand Junction, Colorado 81506
(970) 241-9298

Coal Mine Methane in Colorado Market Research Report

MARCH 2016

COLORADO Energy Office

PROJECT DESCRIPTION

The Colorado Energy Office (CEO) contracted Ruby Canyon Engineering, Inc. (RCE) (PO EFAA2016-1437) to prepare a Market Research Report ("Report") that identifies opportunities for using coal mine methane (CMM) captured at active and inactive coal mines as a fuel source to generate electricity. Among other things, the Report focuses on the Inclusion of CMM as an "eligible energy resource" under Colorado's Renewable Energy Standard (RES), with the passage of SB 13-252 in 2013.

In preparing the Report RCE investigated three main areas:

(i) An assessment of the current CMM resource opportunities in Colorado,

(ii) Data analysis of potential market size in Colorado, including a breakdown listing specific sites with high potential, and

(iii) Identification of key barriers to developing CMM projects in Colorado and potential solutions.

The Report includes a description of RCE's sources of information and the research methodology used to develop methane emissions estimates.

DISCLAIMER

This Report was prepared for CEO for internal use and information dissemination. CEO does not:

(a) Make any warranty or representation—expressed or implied—with respect to the accuracy, completeness, or usefulness of the information contained in this Report,

(b) Assume any liability with respect to—or damages resulting from—the use of the information disclosed in this Report, or

(c) Imply endorsement of the information mentioned in this Report.

Table of Contents

Executive Summary

In 2013, the U.S Energy Information Administration (EIA) ranked Colorado 11th among major coal producing states. Three coal basins in Colorado contain methane volumes sufficient enough to potentially generate commercial electricity: the Uinta Basin in western Colorado and the Raton Mesa Basin and San Juan River Basin in southern Colorado. The U.S. Environmental Protection Agency's (U.S. EPA) GHG Inventory for 2013 identified several gassy underground coal mines in western Colorado as the state's largest sources of CMM emissions.

Colorado's Renewable Energy Standard (RES) defines CMM as "methane captured from active and inactive coal mines where the methane is escaping to the atmosphere" (CRS 40-2-124 (1)(a)(II)). Including CMM as an "eligible energy resource" under the RES accomplishes several key public policy objectives. First, CMM optimizes the use of methane gas, an important energy resource, released during or as a result of coal mining operations. Second, utilizing CMM improves mine safety and reduces a major source of anthropogenic greenhouse gas (GHG) emissions that contribute to climate change. Third, CMM's RES inclusion promotes the development of smaller scale electrical generation and transmission capabilities at coal mines that can serve as distributed energy sources in remote rural areas.

The U.S. EPA's 2013 GHG Inventory divides methane emissions from coal mines into three subcategories: (i) CMM vented from active coal mines, (ii) ventilation air methane (VAM) from active coal mines, and (iii) abandoned mine methane (AMM) emissions. Total methane emissions from coal mines in Colorado as reported by the EPA have the potential to generate upwards of 89 megawatts (MW) of electricity while a more realistic and technically feasible value is approximately 34 MW.

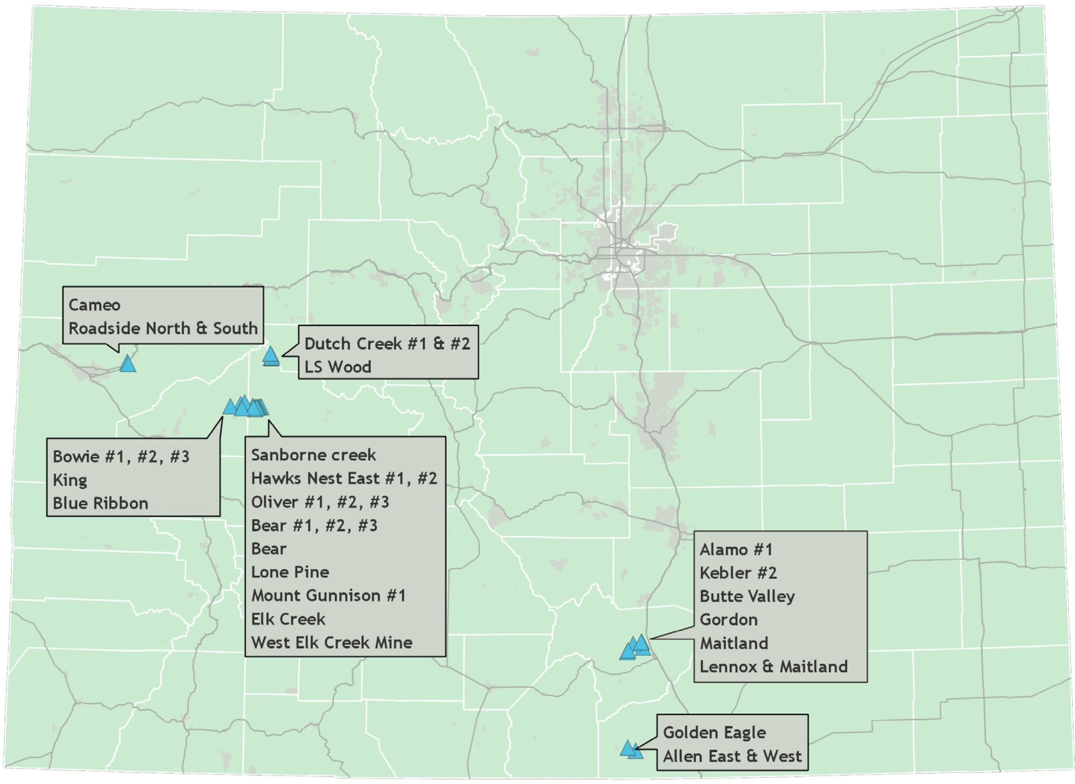
Initial capital and development costs of CMM generated power generally range from $700,000 to $1.5 million dollars per MW. This primarily depends on the quality and quantity of the CMM fuel resource as well as the capital and operation costs for the gas collection system, electrical generation, and transmission facilities. Based on market conditions, a rule of thumb for the economic feasiblity of a project is a $0.05 per kilowatt-hour levelized cost, excluding RES incentives, carbon credits, or other incentives.

A detailed inventory of over 30 active and inactive coal mines in Colorado with reported CMM emission volumes is included within the report. The impacted areas include six counties: Mesa, Delta, Gunnison, Pitkin, Huerfano, and Las Animas. Of all the mines evaluated, most of the "high value" CMM recovery targets are located within and around the North Fork Valley Coal Mining Area (Somerset) in Delta and Gunnison counties, and near the town of Redstone in Pitkin County. In the Somerset area, there are three active coal mines and 15 inactive or abandoned coal mines. The Somerset area mines estimated electrical generation potential from CMM (consisting of VAM, drainage, and AMM) emissions is about 76 MW, of which 25 MW may be economically and technically feasible to develop. The second area with highest potential is about 6 to 8 miles west of Redstone, where there are four abandoned mines with CMM emission volumes capable of generating in excess of 5 MWs. Permitting operations at these locations could be complicated, since a portion of the wellbores and gas gathering systems are located on or near public lands.

ESTIMATED ELECTRIC POWER GENERATION FROM VAM, CMM AND AMM EMISSIONS IN COLORADO (MW)

	VAM Emissions	CMM Emissions	AMM Emissions	Total
Potential	46	23	20	89
Feasible	10	12	12	34

LOCATION OF COLORADO'S ACTIVE AND ABANDONED COAL MINES WITH METHANE RECOVERY OPPORTUNITIES



While the potential economic and environmental benefits of CMM generated electricity are recognizable, an uncertain energy market and declining coal production impedes project development. Moreover, legal, regulatory, and technical challenges make CMM project business risks and commercial feasibility difficult to assess, particularly at active mines where production can be highly variable.

Image Courtesy of Vessels Coal Gas, LLC

1 | Coal

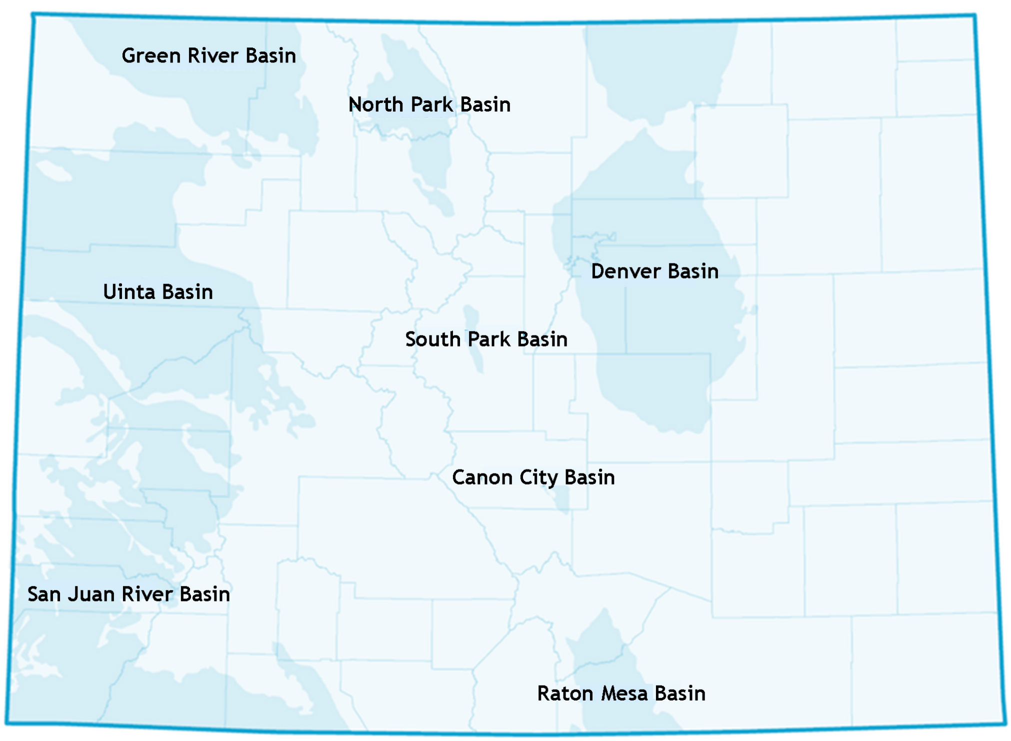
Coalification

Coalification is the formation of coal and associated methane from vegetation buried and subjected to extreme pressures and temperatures over a long period of time. Coal is classified with a ranking system based on the amount of metamorphism undergone by the vegetation. Lignite is the lowest ranking coal with low energy content and a light color while anthracite is the highest ranking coal with high energy content and a shiny black color. During coalification, methane becomes trapped and stored within the coal seam and surrounding strata. The quantity of the methane being stored is directly related to the rank and depth of the coal. A higher rank coal is higher in carbon content and contains a greater amount of methane while the deeper the formation of a coal seam, the greater the quantity of methane stored in the coal seam. As more material is deposited on the top of the coal seam, pressure in the seam increases and the associated strata has a greater capacity to store methane.

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 can be lifted naturally to the surface, exposing coal layers to the atmosphere and creating outcrops. The decrease in pressure at the outcrop allows methane to flow more freely and escape to the atmosphere. Essentially, the same process releases methane to the atmosphere during surface mining when overburden is removed and pressure is reduced on the coal seam.

During the mining process, coal is dewatered and fractured, reducing the confining pressure and releasing methane. At underground mines, coal is removed by long-wall or room and pillar mining. Concurrently, the mine reduces methane concentrations in the mine workings by employing ventilation and degasification systems. The methane being vented from active underground mines is known as CMM while the ventilation air methane is referred to as VAM.

FIGURE 1: COAL BASINS OF COLORADO (AMUNDSON ET AL., 2009)



Russell L. and Lyn Wood Mining History Archive. Between 1930-1950. Coal Mine Town. Photograph. DSpace Repository. http://hdl.handle.net/11124/9981. Accessed February 2016.

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 from coal seams above and below the mined seam moves to the surface through poorly sealed shafts, boreholes, and fractures in the overburden.

Anthropogenic coal mine methane emissions are those that are liberated as a result of the extraction and storage of coal. All underground and surface mining liberates methane as part of normal mining operations. In 2013, U.S. coal mines liberated about 134 billion cubic feet (BCF) of methane from coal mining, enough to heat almost 2 million households for one year. The amount of methane released per ton of coal mined from active underground coal mines is significantly greater than that of surface mines. According to the 2013 U.S. EPA GHG inventory, methane emissions from active underground coal mines were about five times greater than emissions from surface coal mines while underground coal mines produced half as much coal as surface mines. The majority of underground mine emissions are emitted from the ventilation system.

Colorado Coal

Coal mining has been an integral part of Colorado's economy for over a century. In 2013, Colorado produced about 19.5 million short tons of coal from underground mines and about 5 million short tons of coal from surface mines. Colorado was ranked 11th among states for coal production from 10 mines and employed more than 2,000 people (EIA, 2015).

There are six major coal basins in Colorado (Figure 1) that contain large amounts of recoverable, high quality coal. Colorado's coal mining industry makes up 3.6 percent of total U.S. liberated CMM emissions. Current coal extraction is focused in the Green River, Piceance, and San Juan basins. Underground and surface mines operate in Colorado with underground mines producing 80 percent of the total coal extracted. Almost half of the coal mined for domestic consumption is used to produce Colorado electricity and most of the coal exported to other states also is used to produce electricity.

Coal Mine Methane

Methane gas, or CMM in coal, is released during or as a result of mining operations, creating a major safety hazard for miners. Although the Mine Safety and Health Administration (MSHA) and its state counterparts require mines with high levels of methane to be ventilated in order to protect miners, there are no requirements to either use or destroy CMM that is treated as a "waste gas" and emitted into the atmosphere during mining operations (Mandatory Safety Standard, 1996).

Methane is also a potent GHG that the scientific community considers to be a short-lived climate pollutant (SLCPs) (CCAC, 2014). Methane emissions in the atmosphere survive for 11 to 14 years (Myhre et al., 2013) compared to carbon dioxide emissions, which can have a much longer lifetime, upwards of a thousand years or more. The global warming potential of methane is 28 times that of carbon dioxide (EPA, 2015).

2 | CMM Ventilation and Degasification Systems

Active Underground Coal Mines

Ventilation Air Methane (VAM)

Methane in active underground mines is removed to protect the miners and maintain safe working conditions. MSHA and related state mine safety agencies require mine operators to maintain methane concentrations below 1 percent in mine working areas and 2 percent in all other locations. 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 in the United States.

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. While there is one active VAM abatement project operating in the U.S, the facility does not recover waste heat generated.

Drainage Systems

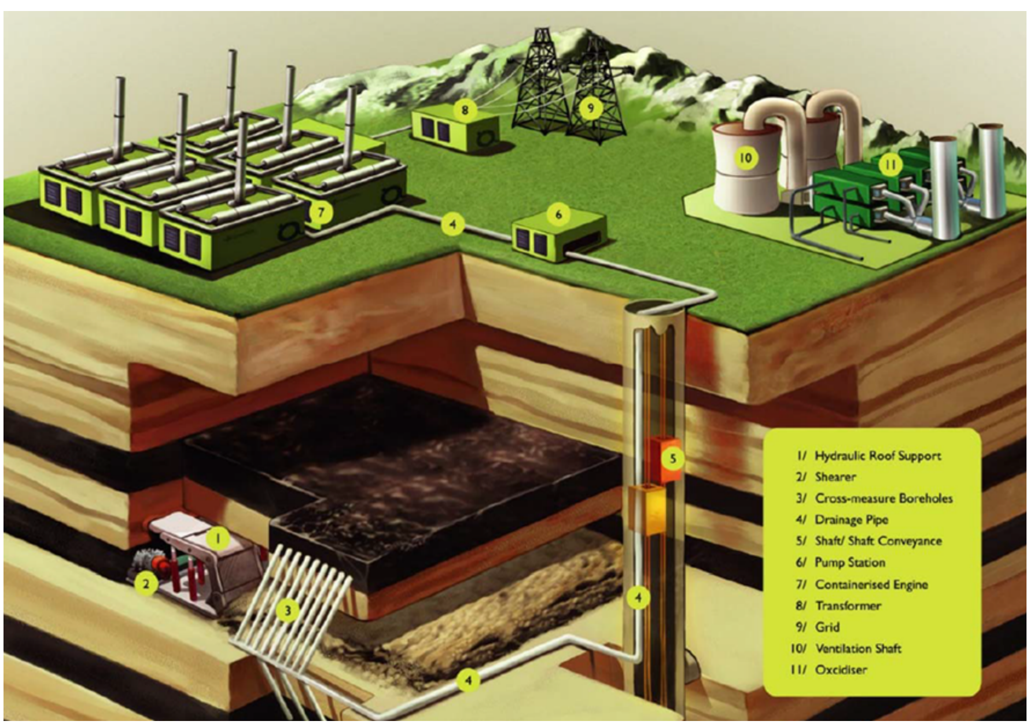
At particularly gassy mines, ventilation systems alone are not enough to maintain safe methane concentrations. Underground and surface drainage systems are employed to reduce methane quantities within the mine working areas by extracting gas from the surrounding strata before, during, and after mining 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 or pipeline sales. Several drainage techniques typically are employed at gassy active underground mines (Figure 2).

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. Recovering gas from pre-mining drainage systems

FIGURE 2: VERTICAL PRE-MINING DRAINAGE AND GOB WELLS, AND HORIZONTAL BOREHOLES (GREEN GAS INTERNATIONAL).



usually ensures that the methane is not contaminated with ventilation air and is of high quality (>80 percent). Production of methane may require fracturing of the coal seam, similar to methods utilized in oil and gas extraction. During the first several months of operation, these wells may produce large quantities of water and little methane; however, as water is removed, the hydrostatic pressure is lowered and gas production increases.

The quantity of gas a pre-drainage system will produce over its lifetime will depend on site-specific conditions of the coal seam (i.e. gas content, permeability) and on the number of years the wells are in operation before mining activities encroach into the well's effective radius. For example, 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 would normally 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. Wells typically are short lived – less than two years, and up to 1,000 feet in length. Like other pre-mine degasification wells, horizontal boreholes produce high quality gas.

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 or commercial pipeline sales. 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 releases. To manage gob gas, degasification wells typically 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.

Cross-Measure Boreholes

For particularly gassy longwall areas of a coal mine, cross-measure boreholes are drilled in any direction from inside the mine to the gob area or overlaying and underlying strata. Cross measure boreholes are typically less than 600 feet in length with a gas quality similar to production of surface gob wells. This drainage technique is more commonly used outside the United States.

Active Surface Coal Mines

In general, opportunities for methane recovery at surface coal mines are somewhat limited compared to underground mines. This is in large part because coals have low gas contents at the shallow depths of surface mining operations. An overburden-to-coal thickness ratio usually determines the economics of a surface mine operation, and usually once the overburden exceeds 250 feet, the mining operation switches to an underground mining operation.

However, there are exceptions to the depth-to-coal rule, such as the Powder River Basin (PRB) in eastern Wyoming and southeastern Montana. Commonly referred to as the "Saudi Arabia of Coal," the PRB is the largest coal producing basin in the U.S. With coal seams more than 60 feet thick, the PRB also has been a major source of commercial CBM production. Relatively, low-cost shallow CBM wells were drilled into the large highly permeable coal seams in advance of mining operations. Before producing the methane from the coal, however, substantial volumes of water had to be removed from the coal seam in order to reduce the hydrostatic pressure holding the gas in the coal matrix. Dewatering operations typically took an average six to 12 months before gas could be produced in commercial quantities.

Abandoned Coal Mines

Once the coal resource is recovered, mines close and become abandoned. Even though operations have terminated, methane or CMM continues to be released from the mine's remaining coal bearing strata. As many of the safety issues associated with active mining operation are no longer concerns, abandoned coal mines can offer an excellent opportunity for methane recovery. Prior to abandonment, shafts and portals are filled and sealed, and boreholes and wells are plugged. Depending on the mine's location and gassiness, some mines are allowed to vent in order to prevent methane build up from making its way into surface structures.

Following abandonment, mines have been shown to release methane at a declining rate for an extended period of time. However, mines that become flooded from surface or ground water infiltration will produce methane for only a few years until the mine void is full of water, blocking methane from the remaining coal and from entering the flooded area.

There are several factors used to determine the potential methane volumes being produced at abandoned mines:

- Time since abandonment;
- Gas content and adsorption characteristics of the coal;
- Methane flow capacity of the mine related to the methane emission rate during active mining;
- Mine flooding;
- Presence of vent holes; and
- Mine seals.

Commonly, wells are drilled vertically into the mine workings to extract the gas. However, open vents remaining after abandonment also can be used. 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 70 percent to 90 percent. If the atmospheric gasses are drawn into the mine, the methane content can degrade to the point of not being usable as an energy source (<25 percent).

The Golden Eagle Mine, in southern Colorado, has been producing methane for pipeline sales since its closure in 1995. Other abandoned mine CMM projects in the U.S., United Kingdom, and Germany have shown similarly long lives.

United States Bureau of Mines. Date Unknown. Miner starting fan after blasting. Photograph. DSpace Repository. http://hdl.handle.net/11124/6116. Accessed February 2016.

3 | Coal Mine Methane Utilization Options

Depending on methane content and volume recovered, CMM can be used in a variety of applications, such as electricity generation, pipeline sales, or for the mining operation as a fuel source for heating or cooling. With the 2013 amendment to the RES, Colorado now joins five other historic coal producing states by including CMM as an alternative energy, clean energy, or a renewable energy fuel source in each state's energy portfolio standards. The other states are Pennsylvania (Alternative Energy Portfolio Standard 2004), West Virginia (Alternative and Renewable Energy Portfolio Standard 2009), Ohio (Alternative Energy Resource Standard 2009), Utah (Energy Resource Procurement Act 2010), and Indiana (Comprehensive Hoosier Option to Incentivize Clean Energy 2011).

Power Generation – Mandatory Purchase Obligations and RES

CMM can be used to generate power for onsite use or sale to local utilities. Power can be generated with a lower concentration of methane than that required for commercial pipeline gas sales. Reciprocating engines generate electricity using mine gas with a minimum heat content as low as 350 Btu/cf (approximately 35 percent methane). There are 122 power generation projects in operation worldwide with 70 projects at active mines and 52 at abandoned mines. The projects are located in Australia, China, and throughout European countries (GMI, 2015).

Vertical degas wells, gob wells, and in-mine boreholes are all acceptable methods of recovering CMM for generating power. Gas turbines, internal combustion (IC) engines, and boiler/steam turbines can be adapted to generate electricity from CMM. Fuel cells also may prove to be a promising power generation option. Currently, the most likely generator choice for a CMM project is an IC engine. Boiler/steam turbines generally are not cost effective in sizes below 30 MW, while gas turbines are not the optimal choice for projects requiring 3.0 MW or less. However, when used in the right applications, gas turbines are smaller and lighter than IC engines, and have had lower historical operation and maintenance costs.

Since the 1970s, federal and state legislative and regulatory actions have promoted the development of certain small power production facilities using renewable energy and waste fuels with little or no commercial value, such as CMM. At the federal level, under the Public Utility Regulatory Policies Act of 1978 (PURPA), utilities are obligated to purchase electricity from qualifying small power production or cogeneration facilities to which a utility is directly or indirectly connected. Under PURPA, a "small power production facility" or "qualifying facility" is a generating facility of 80 MW or less whose energy source is a renewable (hydro, wind, or solar), biomass, *waste*, or geothermal resource. [emphasis added] A "qualifying facility" must either be self-certified or certified by the Federal Energy Regulatory Commission (FERC). For a CMM project to be eligible under PURPA, the CMM fuel source must fit the definition of "waste" in the regulations, which includes certain gaseous fuels that exist in the absence of a qualifying facility. For example, such fuels may include CMM volumes at an active or inactive coal mine (18 CFR §§ 292.101 et seq. (2015)).

On June 18, 2015, FERC issued an Order in Delta-Montrose Electric Association (DMEA), EL15-43-000, stating that DMEA was required under PURPA to purchase power from a qualifying facility (to-be-built) in its service area notwithstanding any conflicting provisions DMEA may have in its power supply contract with Tri-State Generation and Transmission Association, Inc. (Tri-State). FERC's decision could enable CMM project developers to overcome industry barriers by securing reasonable power supply contracts with utilities in Tri-State's service area in western Colorado, where most of the "high value" CMM emission targets are located.

A major benefit of being a qualifying facility under PURPA is that the project developer may have the right to sell energy or its capacity to the host utility for either the utilities "avoided costs" or a negotiated rate. "Avoided costs" are the incremental costs the host utility would otherwise incur to generate or purchase the power from another source. Typically, the state public utilities commission establishes the method for calculating avoided costs (18 CFR §§ 292.101 (b)(6) (2015)).

At the state level, Colorado's RES requires qualifying retail service providers, cooperative electric associations, and municipally owned utilities to achieve percentage targets for generating electricity sales from "eligible energy resources" that now include CMM. The State's RES requirements are coupled with a range of possible incentives to make near-term eligible energy resource project development commercially feasible. Depending on the specific circumstances for each CMM project developed with a qualifying retail utility, potential incentives may include, among other things: (i) accelerated cost recovery; (ii) opportunities for the qualifying retail utility to earn extra profit or its most recent authorized rate of return; or (iii) retail rates sufficient to recover all just and reasonable costs associate with an eligible energy resource contract. The combination of federal and state requirements coupled with the right incentives provides an important synergy in promoting CMM recovery and use for power generation.

Pipeline Injection

High quality CMM can be commercially sold and delivered to natural gas companies through an extensive network of interstate pipelines and local distribution companies in and near coal mining regions. In order to be sold in the natural gas markets, CMM must meet pipeline quality, volume, and deliverability standards. Vertical degas wells are the preferred recovery method for producing pipeline quality methane from coal seams because the recovered methane is not contaminated with ventilation air from the working areas of the mine. Gob wells, in contrast, generally do not produce pipeline quality gas as the methane is frequently mixed with ventilation air. However, it is possible to enrich gob gas to pipeline quality by using technologies that remove carbon dioxide, oxygen, and nitrogen.

Horizontal boreholes and longhole horizontal boreholes also can produce pipeline quality gas when the integrity of the in-mine piping system is closely monitored. However, the amount of methane produced from these degasification systems often warrants a financial investment. In cases where mines are developing utilization strategies for larger amounts of gas recovered from vertical or gob wells, it may be possible to use the gas recovered from in-mine boreholes to supplement production.

Waste Heat Recovery from Thermal Oxidation

Typically, the methane content in CMM released to the atmosphere by a mine ventilation system is below 1 percent and cannot be used. VAM constitutes the largest source of CMM methane emissions. In 2013, approximately 60 percent of the all CMM released from underground mines was released through mine ventilation shafts.

The U.S. EPA identified two technologies for destroying or beneficially using VAM: (i) a thermal flow-reversal reactor, and (ii) a catalytic flow-reversal reactor. Both technologies employ similar principles to oxidize methane in mine ventilation airflows; however, the catalytic reactor operates at lower temperatures. Waste heat from a thermal flow-reversal reactor has been used to generate 5 MW of power at an Australian coal mine, but at a significant additional capital cost.

In addition, a variety of other conventional technologies such as boilers, engines, and turbines may use ventilation airflows as combustion air. At least two other technology families may prove to be viable candidates for beneficially using VAM: volatile organic compound (VOC) concentrators and new lean fuel gas turbines.

Local Use

Most large underground coal mines have surface preparation plants and administrative and maintenance facilities, which may use coal mined on site to provide energy for surface operations. CMM recovered from the mine can be used as a fuel source in addition to or as an alternative to coal. Other local uses could include selling recovered methane to nearby industrial or institutional facilities. A mine's ideal gas customer is located within 5 miles of the mine to reduce gas transportation costs and requires a continuous fuel supply for a variety of uses, such as fuel for a cogeneration system, to fire boilers or chillers, or to provide space heating.

Flaring

From a climate change standpoint, emitting carbon dioxide is much less harmful on the environment than a mine's direct emission of methane into the atmosphere. Accordingly, flaring methane, which converts the residual gas emission to carbon dioxide, has nearly the same environmental impacts as using methane to generate electricity or heat. Generally, flaring yields GHG reductions equal to about 87.5 percent of those achieved through CMM recovery and use.

Although flares recently have been employed at the Elk Creek Mine in Colorado, flaring to reduce CMM emissions has not been implemented on a widespread basis at active mines because of safety concerns. Of particular concern is the distance between the surface flare and the wellhead CMM collection point in the mine because of the potential for the flame to propagate back down to the mine and cause an underground explosion. A properly engineered, manufactured, and operated flare with redundant safety systems can fully address these concerns.

4 | Benefits

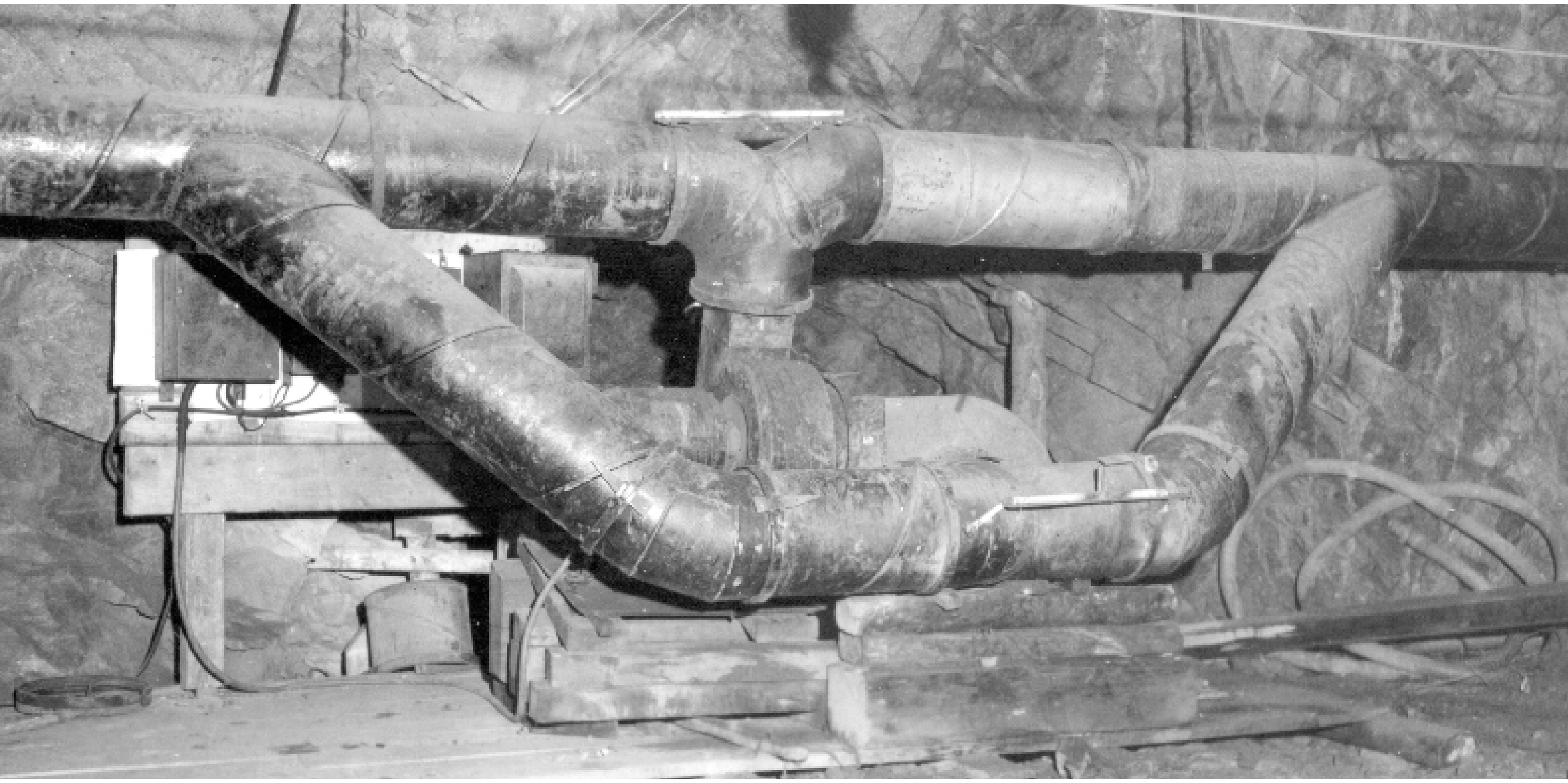
Major benefits from CMM recovery and use at active coal mines include energy resource conservation, improved gas management and mine safety practices, and climate change mitigation. Achieving these benefits is possible in the near term, since the CMM resource has a known location (boreholes, pipes, or vents), and the quantity routinely is monitored and measured. In addition, capturing the mine gas technically is feasible with off-the-shelf equipment and limited infrastructure. As a result, in the right situations, CMM capture and use can contribute meaningfully to either reducing mine operating costs (self-generation) and/or generating additional revenues (electricity sales).

Similarly, at inactive or abandoned underground coal mines, methane emissions can be reduced or eliminated through drilling into underground mine workings and voids and pumping the gas to the surface where it can be used or flared with fewer safety concerns than at active mines. Because the mine is a network of tunnels and roadways, only two to three boreholes or extraction wells need to be drilled to drain an abandoned mine that may cover several thousand acres.

Landfill and livestock waste methane projects are similar to CMM in that the volume of methane in the waste stream is quantifiable. CMM, however, is generally a cleaner gas that does not contain corrosive sulfur compounds and carbon dioxide and an acid gas that must be dealt with for the machinery to operate effectively. CMM contains methane, nitrogen, and small amounts of carbon dioxide and oxygen, which modern IC engines can burn efficiently.

CMM is recovered from shallow wells at atmospheric pressure, while conventional (and unconventional) natural gas generally is recovered from deep wells under high pressure (hundreds or thousands of psi). For site specific uses, the economic investment required to capture and use CMM can compare favorably with developing or using conventional natural gas to provide energy for mining operations.

One of the primary environmental benefits of capturing and using CMM as a fuel is the reduction in GHG emissions. Using or destroying CMM achieves that objective, and may qualify for GHG emission reduction credits or offsets.



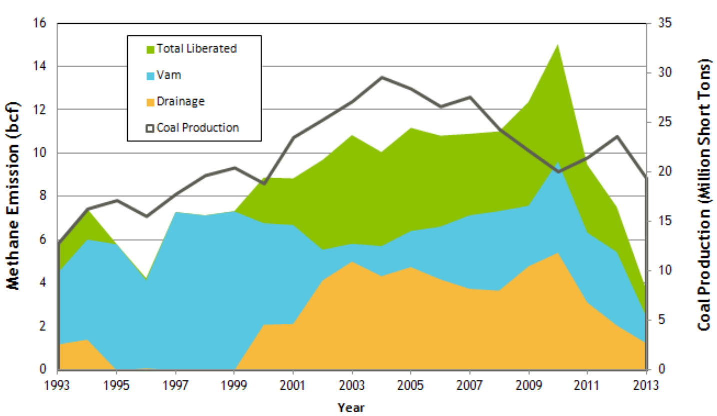
Petersen, Max S. United States Bureau of Mines. 1945. Newport Mine, vent air blowers. Photograph. DSpace Repository http://hdl.handle.net/11124/6494. Accessed February 2016.

Historical CMM Emissions in Colorado

As previously noted, Colorado's largest source of CMM emissions historically have been VAM from underground coal mines, which peaked in 2010. As Figure 3 shows, CMM emissions do not necessarily correlate with coal production on a year-over-year basis, although this is a contributing factor. Beginning in 2000 and peaking in 2010, degasification systems produced a significant portion of Colorado's active underground mine emissions

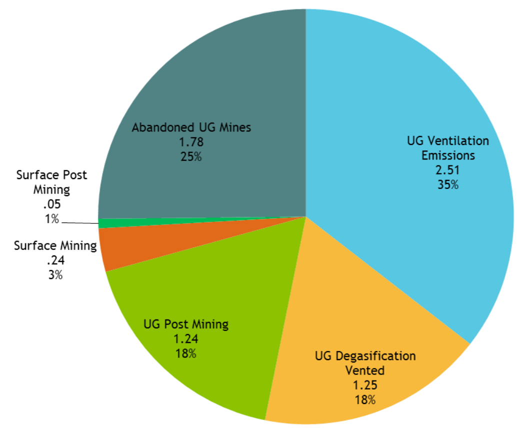
The quality and volume of CMM is determined by coal depth, methane content, permeability, and thickness. In Colorado's mountainous areas, coal depth from the surface can differ significantly, thereby creating fluctuations in CMM liberation rates. Changes in mining operations underground, such as longwall machine movement to a new panel, can also reduce emission rates for weeks at a time. Figure 3 below shows a significant increase in CMM emissions after 1999, primarily because the operating coal mines in the Somerset area were mining deeper underground, often at depths greater than 2,000 feet.

FIGURE 3: COLORADO ACTIVE UNDERGROUND MINE EMISSIONS, 1993-2013



In 2013, Colorado mines reported 7.06 BCF of CMM emissions. Based on the U.S. EPA's methane inventory for 2013, Figure 4 shows BCF sources of CMM emissions for underground (UG) and surface mines. Emissions data for abandoned underground coal mines were calculated using the methodology presented in section 5.4.1 below. Values for underground and surface post-mining emissions are based on emission factors using the volume of methane per ton of coal mined. The estimated methane volumes are then adjusted to take into account CMM emitted during transportation and storage of the coal after leaving the mine site; post-mining emissions are considered non-recoverable.

FIGURE 4: COLORADO COAL MINING METHANE EMISSIONS BY SOURCE.



Active Underground Coal Mines – CMM

Methodology

The U.S. EPA's mandatory reporting rule enables the public to have data on CMM emissions. As of 2013, six mines reported CMM emissions data to EPA: Foidel Creek (also known as Twentymile Mine) in Routt County, Deserado Mine in Rio Blanco County, McClane Canyon Mine in Garfield County, Bowie #2 Mine in Delta County, and the West Elk and Elk Creek Mines in Gunnison County. Table 1 shows reported CMM emissions for the six mines. For the purposes of this study, the lower 3 methane emitting mines were not considered as their respective CMM emissions volumes were projected to generate less than 1 MW.

In order to develop an estimate of the power generation potential from the three highest emitting mines (all in and around the Somerset area), the three-year average VAM emissions and gas drainage volumes were used. The Somerset area mines are the only mines in the state with gas drainage systems that can deliver usable concentrations of methane directly to power generators. Power generation estimates from VAM are based on waste heat recovery/ steam turbine from a thermal oxidizer that destroys VAM.

ESTIMATED ELECTRIC POWER GENERATION FROM VAM, CMM AND AMM EMISSIONS IN COLORADO (MW)

	VAM Emissions	CMM Emissions	AMM Emissions	Total
Potential	46	23	20	89
Feasible	10	12	12	34

Opportunities & Energy Potential

Additional assumptions for estimating energy potential from captured CMM include the use of IC engines for drainage gas, which operate at a 38 percent electrical efficiency and 90 percent availability. VAM emissions are assumed to be used in a combustion steam turbine operating at a 30 percent electrical efficiency and 90 percent availability. Based on these assumptions and 100 percent CMM recovery factor, the forecasts are optimistic. As seen from Table 1, CMM emissions rates vary greatly on an annual basis. Based on the CMM being emitted to the atmosphere, the total electric power generating potential for the three mines would be about 69 MW with the gas drainage portion (23 MW) offering the greatest CMM recovery and use opportunities.

West Elk

The West Elk Mine, operated by Mountain Coal Company, is an underground longwall mine producing about 6 million tons of coal per year. Mountain Coal has operated the coal mine since the early 1980s. In late 1990, while mining the B seam, the mine began to deploy degasification wells to manage the methane. The mine deployed a variety of techniques including vertical gob wells and in-mine horizontal boreholes. Because of the remote location of the surface gob wells, CMM was used to power the blowers extracting methane at each wellhead. In addition, nearly 50 percent of the drainage gas was recovered from the in-mine efforts and brought to the surface at a single location. In 2003, West Elk began utilizing CMM from in-mine wells to operate mine ventilation air heaters during the colder months from October to April. In 2009, West Elk moved the mining operation from the B seam to the higher (and less gassy) E seam. Total methane liberation rates from E seam mining have been about one half that of the B seam operations for the previous 10 years. West Elk continues to use methane from a sealed gob area of the mine for mine air heating, and in 2013 reported 88 MMcf of CMM usage.

Bowie Mine (Recently Idled)

The Bowie #2 mine is an underground longwall mine operated by Bowie Resources, LLC. The mine began coal production in 1998 and produces up to 5 million tons per year. From 2008 to 2010, Bowie #2 mined in much deeper areas (~2,500 ft.) of their coal lease, and found the need to deploy gas drainage systems in order to manage their methane. The mine primarily used vertical gob wells to extract the excess CMM. Since 2011, the mine has moved to shallower areas and their total methane liberation rates are only about one-fifth of the methane emissions generated from the deeper areas. Bowie #2 does not use its drained gas except to fuel the blowers used to vent the gob areas. In February 2016, Bowie Resource Partners announced that Bowie #2 would be idled while the market for its coal is further evaluated.

Elk Creek (Idled)

The Elk Creek Mine is an underground longwall mine operated by Oxbow Mining, LLC. The mine began producing coal in 2002, shortly after the closure of Oxbow's Sanborn Creek Mine. Elk Creek has deployed degasification wells

TABLE 1 - 2013 CMM EMISSIONS FROM ACTIVE UNDERGROUND COAL MINES IN COLORADO

Mine	VAM Emissions (MW)	Drainage CH4 (MW)	Total (MW)	Households powered per year*
West Elk	17	10	27	28,382
Elk Creek (Idled)	24	11	35	36,792
Bowie No. 2 (Recently Idled)	5	2	7	7,358
Total	46	23	69	72,533

*Megawatt hours per year is based on capturing 100 percent of VAM and drainage gas at 90 percent operating capacity.
The households powered per year in Colorado are based on 7.5 MWhr/year (EIA, 2009).

since its initial development, primarily vertical gob wells. Beginning in 2011, the mine began degassing CMM from behind sealed gob areas using an in-mine gathering system that delivered gas to the surface at a single location. Later that year, Elk Creek used a portion of the CMM to heat mine ventilation air in the winter months. In 2012, Elk Creek began using CMM for both a 3 MW power generation and a flaring facility (see case study below). Annual coal production was approximately 6 million tons per year before the mine was as abruptly idled in January 2013.

Case Study – Elk Creek Mine

In 2012, Vessels Coal Gas, Inc. (Vessels) officially began generating GHG emission reductions from the project under the Climate Action Reserve. Vessels had The Elk Creek Coal Mine Methane Destruction and Utilization Project verified, registering the first offset credits via the Climate Action Reserve in September of 2014 (CAR, 2015). Currently, the mine sends drainage gas to a thermal oxidizer and three 1 MW electrical generating engines with the potential to install additional engines. The mine modified the borehole that drained coal mine gas in 2010 in order to combust the CMM through heaters that warmed mine intake air. The project has destroyed about 1 BCF of CMM via heaters, an enclosed flare, and three 1 MW reciprocating engines since its inception in June of 2011 (Figure 5).

A series of equipment processes the CMM through chilling, dehydrating and finally compressing the gas prior to engines combusting the CMM. The generated electricity is sent through a small substation connected to the Delta-Montrose Electric Association (DMEA) grid. The power is wheeled to another rural electrical utility, Holy Cross Energy. The Project produces approximately 24,000 MWhs annually (Blevens, 2012).

Surface Coal Mines

Currently, there are four surface coal mines operating in western Colorado. In 2013, the mines produced about 5 million tons of coal and generated about 240 mmcf of methane emissions. However, the methane emissions are emitted diffusely from the exposed coal face and not considered to be of recoverable volumes.

Abandoned Coal Mines – AMM

The Colorado Geological Survey developed a database of Colorado coal mines in 2002 (Historic Coal Mines of Colorado Information Series 64), which was updated in 2009. The database provides the mine name, historical ownership, location, geologic setting, coal quality, and production information. Of the 1,751 mining permits listed in the database, 11 are active mines. Of the remaining mines, 1,122 reported producing greater than 1,000 tons of coal and are abandoned. Of those, 32 mines were selected for further evaluation as to their potential to produce power over a 10 year period. These mines are estimated to have approximately 20 MW of electric generating capacity.

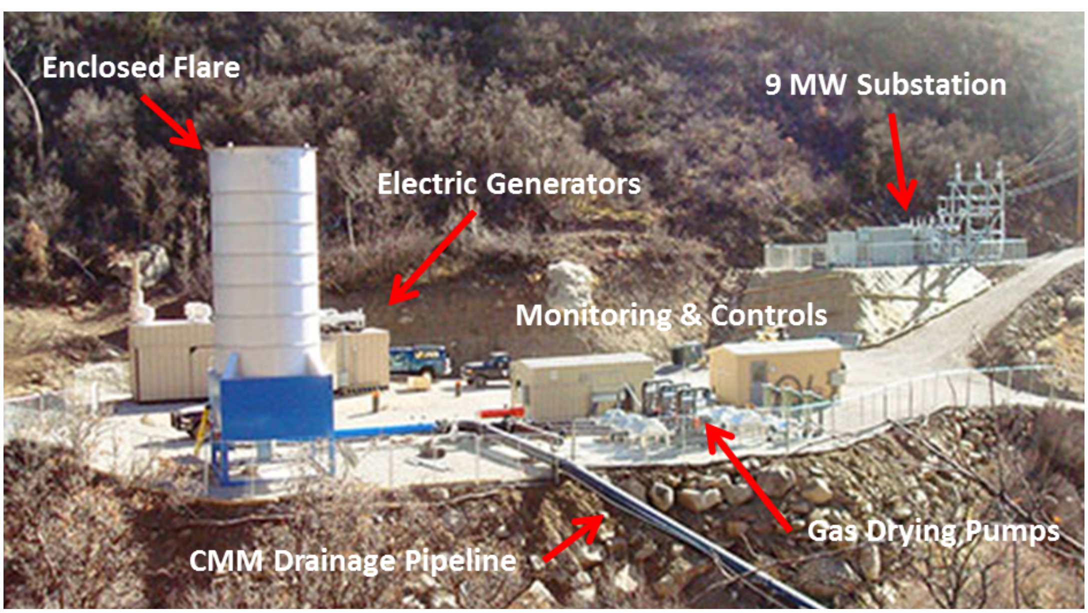
Methodology

In order to prioritize the mines for evaluation the following parameters were used:

- Mine Size;
- Mine gassiness;
- Years from mine closure;
- Reported gas explosions; and
- Mine groupings.

FIGURE 5: ELK CREEK MINE PROJECT SITE

(COURTESY OF VESSELS COAL GAS, LLC)



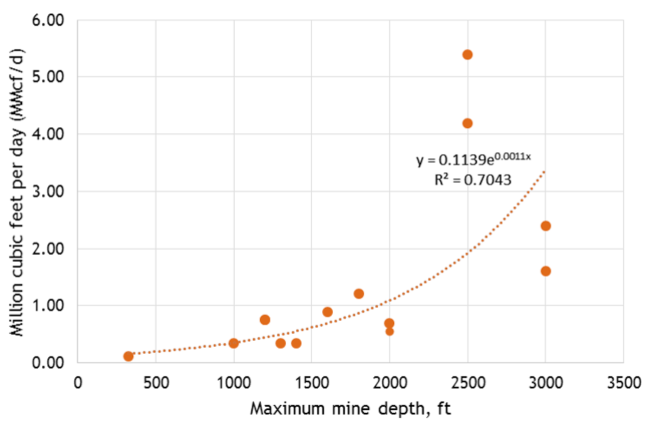
Mine Size

Larger mines cover more area and have larger void areas to hold gas and deliver gas at high rates. There is also more exposed coal surface area in the mine, which allows methane remaining in the coal to desorb into the void areas. However, to recover that gas, larger mines also may require more degasification wells and gas collection infrastructure.

Mine Gassiness

The methane emission rate is expressed in cubic feet per day (cfd) or in cubic feet per ton of coal mined. The rate provides a good indicator of the total amount of gas originally contained in the coal as well as the ability of the gas to move through the coal to the mine workings or void area. This can be correlated with the depth of the mine where the greater the depth, the greater the emission rate. This is shown in Figure 6, which shows the relationship of mine depth with emission rate, where the emission rate is known for more recently closed mines.

FIGURE 6: CORRELATION OF COAL MINE DEPTH TO METHANE EMISSIONS AT COLORADO COAL MINES



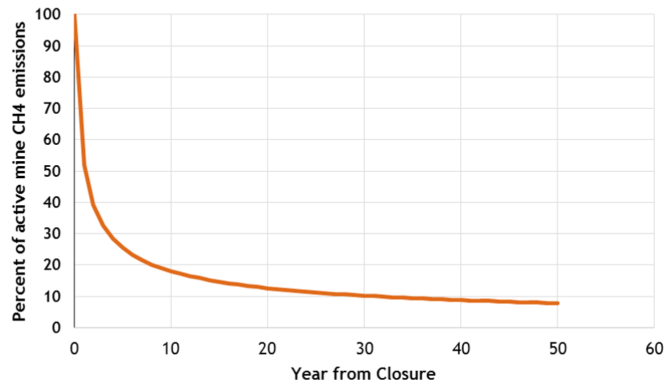
This correlation was used to assign estimated emission rates for mines that did not have documented active mining emission rates.

Years from Mine Closure

It is generally accepted in the mining industry that abandoned mines emit methane at the surface, either through poorly sealed shafts and boreholes or as diffuse emissions through the overlaying strata that has been fractured as the result of mining. The emission rate from abandoned mines also has been shown to decrease over time as the reservoir of methane remaining in the coal is depleted (much like the depletion of a natural gas well).

The California Air Resources Board (CARB) has recognized abandoned mine methane emission reduction projects as an emission offset project type and has accepted the emission rate decline curve shown in Figure 7 as the generic baseline emission rate from an abandoned mine. This decline curve is based on the active mine emission rate and the elapsed time from abandonment.

FIGURE 7: CALIFORNIA AIR RESOURCES BOARD BASELINE NATURAL EMISSION DECLINE CURVE FOR ABANDONED MINES



Assuming similar CMM emission rates while active, a more prospective mine for CMM recovery will be the one closed more recently. However, given the uncertainty of the gassiness of some mines, the efficiency of the shaft, and the efficiency of the borehole seals, this estimate may not apply to any given mine. Indeed, some mines can build methane pressure up to several pounds per square inch, and therefore have more recoverable methane than the decline curve suggests. Also, this curve is based on passive emissions under atmospheric pressure, whereas AMM projects normally extract the gas under vacuum and therefore accelerate gas recovery.

Reported Gas Explosions

Gas explosions during active mining can be an indicator of gassy mines. However, it is just one factor to be considered because older mines may not have the safety infrastructure and procedures in place as newer mines now have.

Mine Groupings

It is not uncommon for several abandoned mines to be near each other within a mining district. This can be important to establishing a power generation project because often a single mine may not provide the amount of gas necessary to economically establish a power generation project. Aggregating several mines into a project by networking the recovered gas through pipelines to a common site can supply the economies of scale that can make the project profitable.

Although there are several abandoned coal mines in the Boulder/Weld, Canyon City, Colorado Springs, Crested Butte, Durango, and Yampa coal fields, these were not included in the evaluation list because they were generally low gas, smaller, and poorly grouped mines. Appendix C shows the mines evaluated by group (A through H) which occur in the Book Cliffs, Carbondale, Somerset, Trinidad, and Walsenburg coal fields.

Opportunities & Energy Potential

Based on the above criteria for selecting abandoned coal mines with potential power generation capacity, this study divided the mines into seven groups based on coal field and geographical mine groupings. A brief discussion of each group's characteristics follows each table.

GROUP A – REDSTONE AREA

Primary Mine Name	Abandoned Date	Estimated Area (acres)	Est. 10 year production from current Mcf	MW potential
Dutch Creek #1	10/4/1992	1,403	1,887,303	2.30
Dutch Creek #2	7/1/1988	477	1,528,557	1.86
LS Wood	12/2/1985	705	837,777	1.02
Coal Basin	2/27/1981	185	521,202	0.63
Total		**2,770**	**4,774,839**	**5.81**

Group A mines are at located high altitude 9,900 to 11,000 ft. above the town of Redstone. They were large gassy mines, and abandoned fairly recently in the 1980's and 1990's. The mines are located on a combination of federal and private land.

GROUP B – SOMERSET

Primary Mine Name	Abandoned Date	Estimated Area (acres)	Est. 10 year production from current Mcf	MW potential
Sanborn Creek Mine	10/1/2003	874	2,811,412	3.42
Hawks Nest East	1/3/1986	371	314,595	0.38
Somerset	2/16/1989	3,285	257,505	0.31
Hawks Nest #1	6/30/1970	136	211,823	0.26
Hawks Nest #3	6/30/1975	145	200,710	0.24
Oliver #1 & 3	6/30/1960	118	192,264	0.23
Oliver #2	6/30/1954	118	182,780	0.22
Bear #1, 2, 3	4/1/1997	917	151,564	0.18
Total		**5,965**	**4,322,653**	**5.26**

Mines located in the Somerset area were split into three groups based on their relative positions to active coal mines. The Group B (Somerset mining district) area has been active since 1903 and has been known for its thick section of very gassy but tight (low permeability) coal. As many as six different coal seams have been mined in the area. It may be possible to extract methane from numerous abandoned mines that overlay each other with a minimum number of boreholes. The project developer at the Elk Creek CMM project has plans to add Sanborn Creek abandoned mine gas to the project in 2015.

The mines are located on a combination of federal and private land. The gas rights to the methane on the federal land in this group are controlled by the Oxbow Group company, Gunnison Energy, LLC. Another Oxbow Group company, Oxbow Mining LLC, owns and operates the nearby active Elk Creek Mine.

GROUP C – TRINIDAD

Primary Mine Name	Abandoned Date	Estimated Area (acres)	Est. 10 year production from current Mcf	MW potential
Golden Eagle	5/30/1996	1,548	3,185,193	3.88
Allen-East and West Portals	6/10/1982	3,949	248,682	0.30
Total		**5,497**	**3,433,875**	**4.18**

The Golden Eagle Mine is the subject of the case study which follows. The neighboring Allen mine was re-entered to develop a new adjacent mine called the New Elk Mine in 2010. However, in 2012, the New Elk Mine was idled due to poor coal market conditions. The methane potential of the New Elk mine is unknown at this time, and not included in the energy potential assessment. These mines are located within an active coalbed methane field and operations, and multiple gas leases. XTO Energy, Inc. currently owns the gas leases and operates the Golden Eagle AMM wells.

GROUP D – SOMERSET

Primary Mine Name	Abandoned Date	Estimated Area (acres)	Est. 10 year production from current Mcf	MW potential
Bowie #1	12/10/1998	1,113	546,329	0.67
King	6/30/1974	190	308,016	0.38
Blue Ribbon Coal	6/30/1984	114	252,444	0.31
Bowie #3	6/30/2006	1,281	594,541	0.72
Total		**2,698**	**1,701,331**	**2.07**

Group D mines are located between the towns of Paonia and Somerset, near the Bowie #2 mine and west of the Group B and E mines. As with other mines in the area, they are located on a combination of federal and private land. Gunnison Energy controls much of the gas rights to federal land of the group.

GROUP E – SOMERSET

Primary Mine Name	Abandoned Date	Estimated Area (acres)	Est. 10 year production from current Mcf	MW potential
Bear	5/27/1982	388	248,548	0.30
Lone Pine	6/30/1965	44	201,357	0.25
Mount Gunnison #1	6/30/1991	752	163,639	0.20
Total		**1,183**	**613,544**	**0.75**

These mines are on the south side of Highway 133, adjacent to the West Elk Mine and across the river from the Group B mines, and also are located on a combination of federal and private land. Private gas leases exist on a portion of the group area.

GROUP F – BOOK CLIFF – CAMEO

Primary Mine Name	Abandoned Date	Estimated Area (acres)	Est. 10 year production from current Mcf	MW potential
Cameo	6/30/1982	677	341,106	0.42
Roadside No. & So. Portals	4/25/2000	1,678	257,615	0.31
Total		**2,354**	**598,721**	**0.73**

These two mines, the Cameo on the north side of the Colorado River and Roadside Mines which are north and south of the river, supplied coal to a mine-mouth power station up until 2000. The coal-fired power station eventually was dismantled by Xcel Energy in 2013. They were considered relatively gassy mines and are near existing power infrastructure and along Interstate 70.

GROUP G – WALSENBURG

Primary Mine Name	Abandoned Date	Estimated Area (acres)	Est. 10 year production from current Mcf	MW potential
Alamo No.1	6/30/1936	125	179,552	0.22
Gordon	6/30/1965	605	88,242	0.11
Maitland #1	6/30/1962	540	85,786	0.10
Kebler #2	6/30/1953	836	83,958	0.10
Lennox and Maitland	6/30/1953	651	79,465	0.10
Butte Valley	6/30/1952	145	78,843	0.10
Totals		**2,901**	**595,845**	**0.73**

The mines in the Walsenburg area mostly have been closed since the 1950's and 1960's and were reportedly not as gassy as the Somerset and Carbondale mines, limiting their potential. Much of the abandoned mine locations are on private or fee land. Elk Creek Mine project developer, Vessels Coal Gas, LLC, owns gas leases at several on the mines in Group G.

Case Study – Golden Eagle

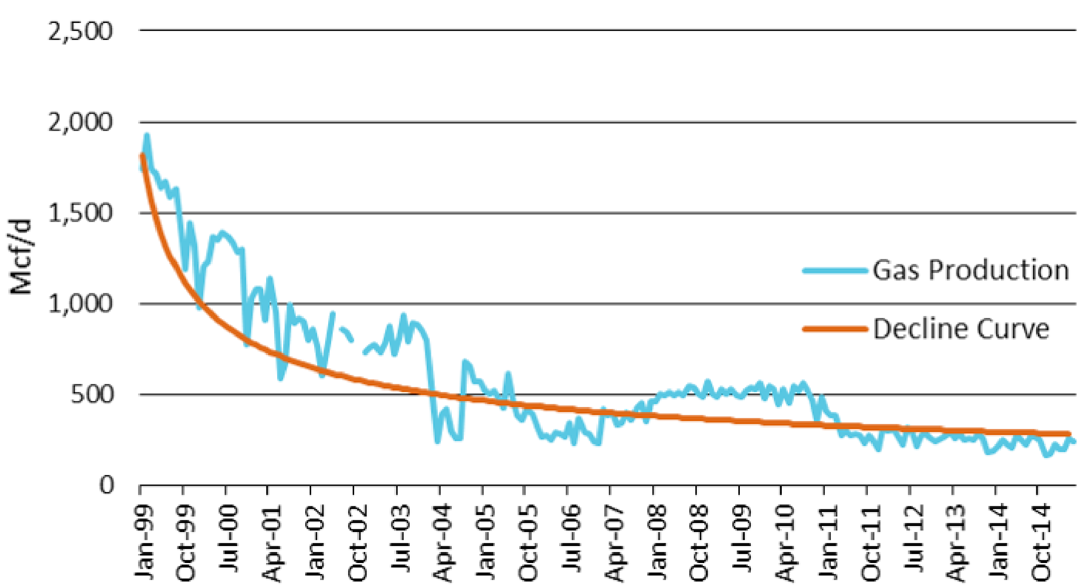
Golden Eagle Mine is an abandoned underground coal mine located in south-central Colorado, just west of Trinidad. Coal production began in 1978 and ceased in 1995. Golden Eagle produced coal from the Maxwell seam in the central portion of the Raton Basin. The seam thickness ranges from less than 5 feet to 10 feet and the overburden thickness ranges from 500 feet to nearly 1,200 feet. The mine workings are split into north and south sections, bisected by the Purgatoire River and Colorado Highway 12. The estimated area of the abandoned mine is 1,548 acres. During operation, Golden Eagle drained mine methane from gob wells as a gas control method.

In 1996, shortly after the mine closure, Stroud Oil Properties Inc. (Stroud) started the AMM recovery project. Stroud converted the already existing gob wells, boreholes, and mine shafts into drainage wells, drastically reducing the cost of methane recovery. Compressor pumps and gathering lines were installed to convey the methane to the nearby Colorado Interstate Gas line for sale. Initially, Stroud produced methane only from the south section of the mine to test for sustainability. Gradually, other gob wells and boreholes were added to the system. From 1999 to 2012, six wells produced methane for pipeline sales. Currently, there are only two wells in the north section and one well in the south section still producing methane. Figure 8 below displays the total methane recovered over time as well as the forecasted baseline methane emissions decline curve.

Stroud faced several operational challenges during the project. Maintaining the optimal vacuum pressure on the wells has been difficult due to limitations in methane desorption and diffusion. Stroud continuously adjusts the compressors for maximum methane recovery void of oxygen. Another challenge was gas communication between the north and south sections; when the north wells were first connected to the system, production of the south wells decreased equally. The wells needed to be far enough outside each adjacent well's radius of influence. The final challenge was that the methane being produced was slightly below pipeline quality and required blending with nearby high quality coalbed methane.

Through trial and error, Stroud managed to create a successful coal mine methane recovery project. Over the years, approximately 3.5 BCF (Figure 8) of methane that would have been vented to the atmosphere was recovered and used. The success of this project suggests there may be opportunities for other AMM project in Colorado and the United States.

FIGURE 8 GOLDEN EAGLE AMM PRODUCTION 1999 TO 2015.
The red line is the theoretical decline curve for the Golden Eagle mine.



6 | Applicability to PUC regulations

CMM RES Eligibility

On December 1, 2004, Colorado was the first state in the nation to enact by popular vote a renewable energy standard (RES) when it adopted Amendment 37. The RES, which is set forth in CRS 40-2-124, requires providers of retail electric service to more than 40,000 customers to generate a percentage of their retail electricity sales from certain "eligible energy resources." The RES subsequently has been increased by the Colorado General Assembly through HB07-1281, HB10-1001, SB13-252, and SB13-252.

Most recently, SB13-252, signed by Governor Hickenlooper in 2013, amended the RES to include as a nonrenewable "eligible energy resource" CMM captured from active and inactive coal mines that is escaping into the atmosphere. As previously noted, there are obvious potential benefits to utilizing CMM as an energy source, including providing distributed electrical generation primarily to rural populations and reducing a major source of GHG emissions.

It should be noted that in order for a CMM project at an active or inactive/abandoned coal mine to be RES eligible under the statute the Public Utilities Commission (PUC) must determine the following:

- The electricity generated is GHG neutral (discussed further below in Section 6.2);
- The extent to which methane vented in the normal course of active mine operations is naturally escaping to the atmosphere;
- The extent to which the CMM electrical generation technologies utilized in an optional pricing program may be used to comply with the RES.

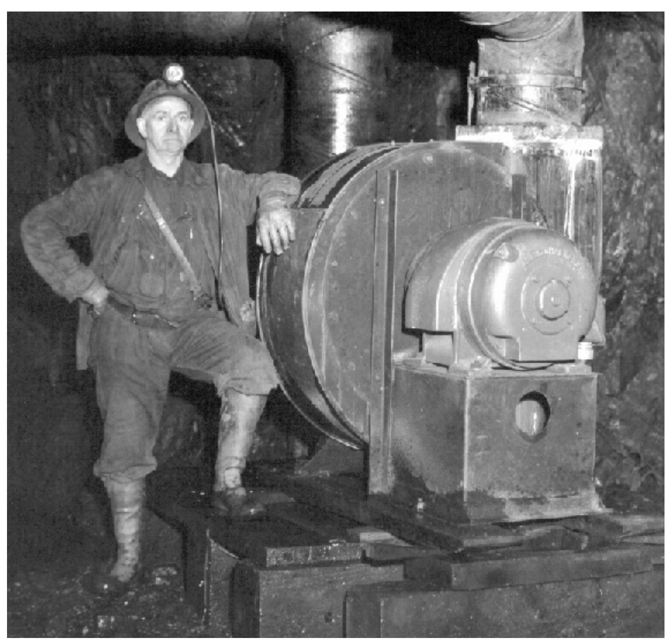
Greenhouse Gas Neutral

For electricity generated from CMM to meet the renewable energy standard, CRS 40-2-124 expressly requires the PUC to determine that the use of CMM as a fuel source is "greenhouse gas neutral." The statute defines "greenhouse gas neutral" as:

> "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." (C.R.S. §40-2-124(1)(a)(IV) (2013))

On August 21, 2013, the PUC issued a Notice of Proposed Rulemaking (NOPR) (Proceeding No. 13R-0901E) to revise and clarify the RES rules contained in 4 Code of Colorado Regulations (CCR) 723-3-3650, et seq., in order to conform to SB13-252. Among other things, the NOPR included amendments to Rule 3668, Environmental Impacts, to provide that "greenhouse gas neutrality" should be determined on a case-by- case basis for CMM electric generation projects.

On April 2, 2014, the PUC adopted Rule 3668(d), which requires an evidentiary hearing for each CMM project to determine whether it complies with the greenhouse gas neutral standard as defined in SB13-252 (Decision No C14-0390). While the amended RES Rules incorporate the statutory definition of "greenhouse gas neutral," they have not provided a framework or protocol for certifying GHG neutrality or permitting CMM projects. It is important to note that because of the significant GHG emission reduction benefits of destroying fugitive methane like CMM, GHG neutrality will not be difficult to demonstrate. However, the methodologies and data inputs for determining GHG neutrality for active vs. abandoned coal mines are likely to be different.



Petersen, Max S. United States Bureau of Mines. 1944. Spies-Virgil Mine Fan. Photograph. DSpace Repository http://hdl.handle.net/11124/6481. Accessed February 2016.

7 | Potential Project Barriers

Distributed power and self-generation
Large-scale power generation serves large populations, requiring direct access to large quantities of fuel. Distributed power generation, in contrast, ranges from a few kilowatts up to 30 MW and can best benefit areas where electricity prices and peak-demand usage are high (40-2-124 C.R.S). Distributed generation differs from self-generation in that distributed generation projects typically are placed close to a limited number of consumers to enhance the capability of the existing power grid. Many of Colorado's large coal mines are located in relatively remote regions with limited load growth and generally low electricity prices compared to the rest of the country. Those factors combined can negate some of the direct economic and service benefits of distributed generation.

Other barriers for using CMM as a fuel source to generate electricity are the capital cost of equipment and operation and maintenance costs. Certain fixed fees such as electric grid interconnect fees can be burdensome for projects smaller than 10 MW. Also, existing power supply agreements between local utilities purchasing power from wholesale utilities historically have been barriers to new small renewable power generators seeking to enter the market. The recent FERC decision in the DMEA case may create a pathway under PURPA for qualifying facilities, which may include CMM power generation.

Active coal mines are large consumers of electricity. While CMM power projects can help reduce a mine's electricity needs, CMM and power generating equipment will incur downtime on occasion due to certain mining activities or equipment maintenance. Electricity reliability at coal mines is paramount because of underground mine safety requirements. Utilities typically charge a standby fee to coal mines that self-generate in order to have available the grid-based electricity. Such fees can negatively impact the economics of CMM electric power project for self-generation.

Methane quantity and quality
Through effective CMM gas management, a stable quantity of usable quality CMM can be supplied to a small-scale power generation facility. Due to mining variations and degas well types, the quantity and quality of CMM will vary. Post-mining gob well methane concentrations can vary significantly through time from the lower limit of use (~30 percent) up to 90 percent. Gob wells can produce large quantities of methane at high rates initially then decline steeply in rate and concentration. Therefore, it is common to move a gathering system from well to well as mining progresses.

Improved engineering and new technology for in-mine drainage systems enables mines to tap into sealed gob areas and produce high quality gas. System improvements eliminate the need to move surface pipelines and blowers from place to place as mining progresses. These systems are monitored closely to ensure that the gas pressure behind the seals is balanced with the working area pressure and that there is never an explosive mixture of gases behind the seals.

Underground degasification systems can be left in-place after mine abandonment to drain the methane that continues to be released into the gob areas, enabling a project to produce electric power long after mine closure. Most of the gas produced from abandoned mines will generally be at concentrations between 50 percent to 85 percent methane. However, if there are boreholes open to the atmosphere, air ingress can contaminate the gas reducing methane concentration. Therefore, it is important to identify and adequately plug all sources of dilution.

Today's small-scale power generation equipment can use CMM as a feedstock throughout the 30 percent to 90 percent methane concentration range. While equipment such as IC engines can operate on CMM with methane concentration as low as 30 percent, turbines and micro turbines require at least 60 percent methane concentrations. Assessing a CMM power project's size requires an analysis of historical CMM emission rates and mining activities. Many commercial projects are constructed below the peak capacity of CMM volumes while flaring the excess methane as part of the project.

Ownership and Control
Colorado has a rich mining and oil and gas history dating back to the 1800's. However, mineral ownership and much of the natural resource production in Colorado is complicated by the fact that the state's largest landowners are the federal and state governments. Each has its own separate administrative policies and procedures, management practices, rules, and regulations relating to the acquisition and development of mineral rights. In addition, they also are responsible for environmental and operational permitting and regulatory compliance on both public and private lands in the state.

To put this in perspective, Colorado covers over 66 million acres. About 24 million acres is federal land (36 percent), most of which is managed either by the Department of Agriculture's United States Forest Service (USFS) or the Department of Interior's Bureau of Land Management (BLM). The BLM primarily is responsible for mineral

operations on federal land. However, all mineral revenues received by BLM essentially are divided 50/50 between the federal government and host state (Gorte et al., 2012).

The Colorado State Board of Land Commissioners (State Land Board) owns and manages mineral rights to about 4,000,000 acres held in trust for the benefit of public schools and institutions. The State Land Board has a dual mandate of producing reasonable and consistent revenues over time for the trusts and promoting sound stewardship of the trust assets (Colo. Const. art. IX, § 10).).

The situation further is complicated by the fact that responsibility for determining title to mineral or property rights to resources such as CMM rests with the judiciary. It is not surprising that as a result of a dispute over coalbed methane gas ownership, in 1999, the U.S. Supreme Court held in the case of *Amoco Production Company v. Southern Ute Indian Tribe,* 526 U.S. 865 (Amoco), that the 1909 and 1910 Homestead Acts enacted by Congress did not intend to include the conveyance of methane gas in a coal seam with the conveyance of the coal, thereby severing the methane from the coal estate. The issue of gas ownership further was complicated in the case by the fact that the Court held a coal owner or mine operator he unrestricted right to freely vent methane (now determined to be part of the gas estate) during the normal course of mining operations in order to protect the safety of the miners.

The Amoco decision gave rise to a number of cases throughout the country relating to disputes over CMM ownership. Cases in the western U.S. dealing with large federal land holdings typically have followed the reasoning in the Amoco decision and held that the methane gas in coal is part of the gas estate and not part of the coal estate. Cases in the eastern U.S. on private fee lands typically have held that the gas in the coal is part the coal estate. Predictably, there are a number of exceptions to these general rules, so CMM project developers have to seek legal advice on the applicable federal or state law pertaining to title to CMM where the project is located. Since the Amoco decision, the BLM has worked to develop procedures to resolve conflicts between coal and gas lessees and operators over rights to CMM (which they refer to as Waste Mine Methane (WMM)). On April 29, 2014, the BLM published in the Federal Register an Advance Notice of Proposed Rulemaking (ANPR) for WMM Capture, Use, Sale, or Destruction, seeking public comment. Comments received from the public in response to the ANPR are still being reviewed by the BLM as of August 2015.

In dealing with the CMM title issues resulting from the Amoco decision, the Colorado State Land Board and the Colorado Oil and Gas Commission modified the State's standard Oil and Gas Lease form to allow the coal lessee to produce, save, or sell CMM from mineable coal seams. The lease also provides that CMM, which is uneconomic, can be produced or flared during mining operations.

Issues concerning CMM ownership are separate from matters pertaining to project permitting and regulatory compliance. While CMM permitting requirements are highly site and project specific and generally beyond the scope of this Report, there are several key starting points to keep in mind when conducting a preliminary assessment:

- Proponents of projects on state and private lands generally prepare preliminary environmental assessments to identify, among other things, the specific site location, potential direct and secondary environmental, economic, and physical impacts of the proposed project, and federal, state, and local agencies that may have responsibility for the project's regulatory compliance. While the environmental assessment is intended to develop a concise project description and scope, it is important to note that Colorado does not have a comprehensive state-specific environmental protection act like California's California Environmental Quality Act or "CEQA" that requires a detailed project description and analysis.
- At active or inactive coal mines on federal or Native American lands, obtaining approvals and permits for CMM project development likely will require a federal action triggering a National Environmental Protection Act (NEPA) analysis by the appropriate federal land management agency, which is generally BLM or USFS. The level of analysis can range from a Finding of No Significant Impact (FONSI) to a full-blown Environmental Impact Statement (EIS) that fully evaluates actions or operations that may have a significant impact on the environment and measures required to mitigate those impacts. Examples of federal action that triggers a NEPA analysis specifically include:
    - If the project involves CMM emissions from federally owned coal, assuming the gas has not already been leased to a third party, the BLM may have to amend the existing coal lease to enable the mine operator or its designee to use or sell methane gas removed from the coal. The act of amending the existing coal lease probably will require a NEPA type analysis.
    - If the project involves federal surface lands managed by either BLM or USFS, a request for a federal agency to issues an access agreement, right of way, or surface lease resulting in any surface disturbing activity, such as site clearance or road or power line construction.
    - In addition, at an active mine that includes both federal and state lands, if a CMM project involves amending any of the mine's existing permits, such as an air quality permit, surface management plan, or the design and operation of an underground ventilation system, the relevant federal and state agencies will all will be actively involved in a collaborative permitting program.

While the environmental assessment and permitting process can be complicated, depending on the location and ownership of the site, it is intended to be transparent and to disclose important information and plans to decision makers, stakeholders, and the general public. In Colorado, where agricultural, recreational, and industrial users frequently seek to use property for different purposes, the permitting process provides an opportunity to obtain meaningful citizen input.

Institutional challenges

One of the biggest challenges to developing a CMM project at an active coal mine is addressing the mine operator's business risk. Mine managers have concerns that CMM projects can pose a risk to maintaining the mine's productivity and profitability. In general, the profits from any small-scale CMM power project are a fraction of the coal mine's revenue. Also, coal mine operators are not typically in the business of generating power as part of their core business activities, and can be reluctant to engage in CMM utilization as a result. In order to mitigate these risks, CMM project developers must establish a close working relationship with the mine operator to ensure that the CMM project will not distract or interfere with mining operations, and/or reduce the mine's ability to change their future mine plans.

Location of Abandoned Mines

While all the gassy active coal mines are in the North Fork Valley Mining Area, over 1,500 abandoned coal mines are located across the six major coal basins. Abandoned mine development has the advantage of not having to interface with active coal mining operations and limitations. A number of abandoned mine candidates are in relatively remote locations, while others are situated near cities, facilities, electric substations, etc. In order for a project to be economically viable, it is essential that abandoned mine locations be in close proximity to electric power infrastructure.

Abandoned mines generally produce a fraction of the methane generated when the mine was producing coal. As a result, individual mines may not be large enough to sustain a viable AMM recovery and use project by themselves. Therefore, combining the methane produced from several nearby abandoned mines (or an active mine) is an important consideration.

8 | Potential Solutions to Barriers

Aggregating Coal Mine Methane

Three active coal mines in Colorado all have power generating capacities ranging from 2 MW to 11 MW from their CMM gas drainage systems. As few as five abandoned coal mines in the state may have the ability to generate greater than 1 MW of electricity. Because of economies of scale, the most viable project opportunities will result from combining AMM from several abandoned mines or from combining AMM with nearby active mine CMM. This study finds four abandoned mine groups that could potentially generate 2 MW to 5 MW of electricity, of which two of the groups are located in the Somerset area. Moreover, 15 of the 29 abandoned mines identified are in the Somerset area near each of the three gassy active coal mines. This area of high abandoned mine concentration together with active mining operations offers the greatest opportunity for successful CMM project development.

Additional Abandoned Mine Assessment

The estimated methane emissions and resulting energy potential from abandoned mines is based on modeling because abandoned mine emissions are difficult to measure and quantify. The modeling uses a decline curve approach that has been calibrated against actual AMM vents and methane production rates from recovery and use projects. The 17-year decline curve-actual methane production comparison shown in the Golden Eagle case study speaks to the validity of using the modeling approach. The model contains an uncertainty range of approximately 20 percent. Actual AMM production cannot truly be assessed until after a well is drilled into the mine void and flow tested.

Prior to drilling high risk AMM wells, additional technical due diligence is recommended along the lines of identifying (and possibly measuring) any methane seeps originating from abandoned mine workings and assessing the degree of flooding that may have occurred over time. Mine flooding can greatly impact a mine's ability to emit or produce methane. Methane seeps can be identified from field studies at ground level or via remote sensing. Evidence of mine flooding is difficult to assess from the surface without the benefit of monitoring wells, but an investigation of mining records and permits can show the water discharge rates or incidences of flooded during active mining operations.

State Policy Recommendations

The state should consider the following potential next steps:

1. To the extent legally feasible, develop a range of RES financial incentives such as CMM offset protocols for GHG credits, RECs, and other financial and tax incentives, which can be essential to drive CMM project development in the near term.
2. Work with Colorado's PUC to establish a clear framework and procedures for:
   - i. Confirming that at active coal mines, methane vented in the normal course of mine operations is naturally escaping to the atmosphere so as to fully qualify as an eligible energy resource under the RES.
   - ii. Utilizing standard decline curves for establishing CMM residual resources and historic and projected future emission estimates at inactive/abandoned coals mines similar to the decline curves developed and adopted by EPA and CARB.
   - iii. Certifying GHG neutrality for CMM electrical generation technologies with the objective of seeking to reduce unnecessary delays and costs of Rule 3668(d)'s case-by-case analysis.
3. Advocate for the adoption of the BLM's WMM rulemaking that resolves CMM ownership issues on federal lands and incentivizes, rather than requires, major capital investment in CMM electrical generation. Having an economic incentive based system is important to encourage all existing coal mine operators to consider CMM project development where they do not presently have any legal obligation to do so. For example, a possible incentive could include limited federal coal royalty relief to accelerate the recovery of project capital and operating costs and expenses.
4. Promote better coordination of federal and state land management leasing and permitting programs. This can provide a clear pathway for the acquisition of CMM rights, and expedite permit issuance and other approvals. For example, including in future federal gas and coal leases a provision similar to the provision in the State Oil and Gas Lease form granting the coal lessee rights to the gas in the coal could avoid ongoing uncertainty over rights to ownership and control of CMM on federal lands.
5. Support CMM project developers, mine operators, and local utilities efforts to obtain FERC approval for treating CMM as a qualifying "waste" under PURPA. This will enable CMM electrical generation projects to have viable opportunities for securing long-term power supply contracts on reasonable terms.

9 | Conclusions

This study concludes that there may be potentially up to 89 MW of electric power generating capacity from active and abandoned coal mine methane emissions. This is based on current and historic methane emission rates. Approximately half (46 MW) of this energy potential originates from VAM recovery and use projects. Unfortunately, there has been only one successful commercial-scale VAM power plant (6 MW) ever constructed at an Australian coal mine. Including the cost of the VAM oxidation equipment, the installed cost for power generation is five times that of using high methane content drainage CMM with IC engines rendering it uneconomic at this time. There is currently one VAM abatement project of similar size operating at a West Virginia coal mine. Based on its capacity, it is technically feasible to install VAM abatement equipment and recover approximately 20 percent of the VAM emissions found at Colorado mines.

For CMM at active mines, it may be technically feasible to capture 25 percent to 75 percent of the emissions. The largest obstacle is often gathering the gas from dozens of surface wells (sometimes with short two-to-five-year lives) through difficult terrain in western Colorado. Other operational challenges include U.S. BLM land approvals, moving temporary pipelines and operating equipment in harsh winter conditions.

In general, there is a large degree of uncertainty in assessing AMM potential. The decline curve estimation approach applied for this study contains uncertainties of about ±25 percent. Moreover, approximately one-third of all underground coal mines eventually become flooded, thus negating their methane liberation potential. Additional assessment work may be necessary to reduce the AMM uncertainty in the state. Slightly over half of the 29 identified abandoned mines are located in the Somerset area adjacent to the three active mines (representing 8 MW of the total 20 MW potential). Other areas of high AMM potential are located near Redstone, Palisade, Walsenburg, and Trinidad, CO.

This study concludes that while up to 89 MW of energy potential exists at Colorado mines, a more realistic and technically feasible value is approximately 34 MW. Of this amount, nearly 80 percent (or 26 MW) originates from the Somerset area mines. Clearly, efforts to promote coal mine methane-to-energy projects in this region would be considered the greatest opportunity in the state.

ESTIMATED ELECTRIC POWER GENERATION FROM VAM, CMM AND AMM EMISSIONS IN COLORADO (MW)

	VAM Emissions	CMM Emissions	AMM Emissions	Total
Potential	46	23	20	89
Feasible	10	12	12	34

References

Amundson, A., Greenman, C., & Stover, B. (2009*). Subsidence Above Inactive Coal Mines: Information for the Homeowner*. State of Colorado, Department of Natural Resources, Colorado Division of Reclamation, Mining & Safety and the Colorado Geological Survey. Denver, Colorado.

Blevens, J. (2012). Aspen Skiing Co. partners with coal mine for methane power. *The Denver Post.* Retrieved on 8/14/2015 from http://www.denverpost.com/ci_21966674/aspen-skiing-co-partners-coal-mine-methane-power

Burns Robert & Rose Kenneth, *PURPA Title II Compliance Manual* (March 2104) sponsored by American Electric Institute, Edison Electric Institute, National Association of Public Utility Commissioners, National Rural Electric Cooperative Association from http://www.publicpower.org/.../PURPA Title II Manual Final_w- cover.pdf

The Climate Action Reserve (CAR). (2014). Project Database. Climate Action Reserve. Retrieved from http://www.climateactionreserve.org

Coalbed Methane Outreach Program (CMOP). (1999). *White Paper: Opportunities for Coal Mine Gas Projects Created by Electric Industry Restructuring*. Washington, DC. March 15, 1999.

CMOP. (2008a). *U.S. Abandoned Coal Mine Methane Recovery Project Opportunities*. Retrieved 8/11/2015 from http://www.epa.gov/cmop/resources/abandoned_underground.html

CMOP. (2008b). *Abandoned Coal Mine Methane Opportunities Database*. Retrieved 8/11/2015 from http://www.epa.gov/cmop/resources/abandoned_underground.html

CMOP. (2008c). *U.S. Surface Coal Mine Methane Recovery Project Opportunities*. Retrieved 8/11/2015 from http://www.epa.gov/cmop/resources/active_surface_mines.html

CMOP. (2009). *Identifying Opportunities for Methane Recovery at U.S. Coal Mines: Profiles of Selected Gassy Underground Coal Mines 2002-2006*. Retrieved 8/11/2015 from http://www.epa.gov/cmop/resources/active_underground.html

COLO. REV. STAT. § 40-2-124 (2013)

Colorado Division of Reclamation Mining & Safety. (2012-2014). *GIS Data*. Retrieved from http://mining.state.co.us/Reports/Pages/GISData.aspx

Colorado State Board of Land Commissioners. (2014). *Income & Inventory Report: Fiscal Year 2013-14*. Annual review of income generated by state trust lands.

Code of Colorado Regulations (CCR). (2004). Public Utilities Commission 4 CCR 723-3. *Renewable Energy Standard 3650-3668, Amendment 37: Renewable Energy Requirements*. December 2004.

Colorado Geological Survey. (2009). *Data: Historical Coal Mines*. Access database file. Retrieved on 8/11/2015 from http://coloradogeologicalsurvey.org/publications/free-downloads/data/

Colorado Oil & Gas Information System (COGIS). (2015). *Facility Inquiry Database*. Retrieved on 8/12/2015 from http://cogcc.state.co.us/cogis/FacilitySearch.asp

Energy Information Administration (EIA). (2009). *Residential Energy Consumption Survey*. Retrieved from www.eia.gov/consumption/residential/

EIA. (2015). Colorado State Profile and Energy Estimates. Retrieved from http://www.eia.gov/state/?sid=CO

Environmental Protection Agency (EPA). (2015a). *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2013*. Retrieved 8/11/2015 from http://www.epa.gov/climatechange/ghgemissions/usinventoryreport.html#fullreport

EPA. (2015b). *Greenhouse Gas Reporting Program (GHGRP): Flight*. Retrieved from http://www.epa.gov/ghgreporting/

Global Methane Initiative (GMI). (2015). Global Methane Initiative International Coal Mine Methane Projects Database. Retrieved on 8/18/2015 from http://projects.erg.com/cmm/projects/ProjectFind.aspx

Hupp, K., Bibler C., & Pilcher., R. (1999). *Recovery of Methane from the Abandoned Golden Eagle Mine Property*. 1999 International Coalbed methane Symposium.

Mandatory Safety Standards, 30 CFR, pt. 75 (1996).

Mine Safety and Health Administration (MSHA). (2015). Data Transparency at MSHA. *Mine Safety and Health Administration*. Retrieved from http://www.msha.gov

Myhre, G., D. Shindell, F.-M. Bréon, W. Collins, J. Fuglestvedt, J. Huang, D. Koch, J.-F. Lamarque, D. Lee, B. Mendoza, T. Nakajima, A. Robock, G. Stephens, T. Takemura and H. Zhang (2013). *Anthropogenic and Natural Radiative Forcing Supplementary Material*. In: Climate Change 2013: The Physical Science Basis. Contribution of Working Group I to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change [Stocker, T.F., D. Qin, G.-K. Plattner, M. Tignor, S.K. Allen, J. Boschung, A. Nauels, Y. Xia, V. Bex and P.M. Midgley (eds.)]. Available from www.climatechange2013.org and www.ipcc.ch.

Gorte, R, Vincent, C., Hanson, L., & Rosenblum, M. (2012). Congress Research Service, R42346, *Federal Landownership: Overview and Data*. Retrieved from http://fas.org/sgp/crs/misc/R42346.pdf

Svaldi, A. (2013). Elk Creek Mine in Somerset will go idle. *The Denver Post.* Retrieved on 8/14/2015 from http://www.denverpost.com/business/ci_24640773/elk-creek-mine-somerset-will-go-idle

The Climate and Clean Air Coalition to Reduce Short-Lived Climate Pollutants (CCAC). (2014). *Time to Act to Reduce Short-Lived Climate Pollutants*. Retrieved 8/11/2015 form http://www.unep.org/ccac/Publications/Publications/tabid/130293/language/en-US/Default.aspx

Turney, J., & Murray-Williams L. (1983a). *Colorado Front Range Inactive Coal Mine Data and Subsidence Information Huerfano County*: Plate 8. Colorado Geological Survey Department of Natural Resources. Retrieved from http://coloradogeologicalsurvey.org/wp-content/uploads/2013/08/HuerfanoCounty.pdf

Turney, J., & Murray-Williams L. (1983b). *Colorado Front Range Inactive Coal Mine Data and Subsidence Information Las Animas County*: Plate 11. Colorado Geological Survey Department of Natural Resources. Retrieved from http://coloradogeologicalsurvey.org/wp-content/uploads/2013/08/LasAnimasCounty.pdf

U.S. Energy Information Administration (EIA). (2015). *Annual Coal Report 2013*. U.S. Department of Energy, Washington, D.C. April 2015.

Appendix A

WEST ELK MINE

Mine Status: Active

Drainage System: Yes

Use Project: Heaters

GEOGRAPHIC DATA

Basin: Piceance   State: CO   Coalbed: B Seam   County: Gunnison

CORPORATE INFORMATION

Current Operator: Mountain Coal Company, LLC

Owner/Parent Company: Arch Coal Inc.

Previous Owner(s): Atlantic Richfield/ITOCHU Corp

Parent Company Website: www.archcoal.com

Previous or Alternative Name of Mine: Mt. Gunnison

MINE ADDRESS

Physical Address: 5174 Highway 133

Mailing Address: P.O. Box 591 | Somerset , CO | 81434

Phone Number: (970) 929-5015

GENERAL INFORMATION

Number of Employees at Mine: 384

Year of Initial Production: 1982

Life Expectancy: 2020

Depth to Seam (ft): 0 – 2,300

Mining Method: Longwall

Primary Coal Use: Steam

BTUs/lb of Coal Produced: 11,700

Seam Thickness (ft): B:8-16, E:7-15, F:6-8

PRODUCTION, VENTILATION, AND DRAINAGE DATA

	2011	2012	2013
Coal Production (short tons/year):	5,896,402	6,852,136	5,826,798
Estimated Total Methane Liberated (million cf/year):	2,747	2,491	2,347
Emission from Ventilation Systems:	2,060	1,483	1,605
Estimated Methane Drained:	687	1,008	742
Estimated Specific Emissions (cf/ton):	466	364	403
Methane Used (million cf/year):	0	28	88

Estimated Current Drainage Efficiency: 32%

Drainage System Used: Horizontal & Vertical Gob Boreholes with Pumps

POWER GENERATION POTENTIAL

Utility Electric Supplier: Delta-Montrose Electric Association

Parent Corporation of Utility: Touchstone Energy Cooperatives

Nearest Transmission Line: On site

	MW	GWH/YEAR
Mine electricity demand 2006	37.4	144.3
Generating capacity assuming 50% CH4 Recovery Efficiency:	4.5	35.5

ELK CREEK MINE

Mine Status: Temporarily Idled

Drainage System: Yes | Use Project: Flare/generator/heater

GEOGRAPHIC DATA

Basin: Uinta | State: CO

Coalbed: D Seam | County:Gunnison

CORPORATE INFORMATION

Current Operator: Oxbow Mining LLC | Parent Company Website: www.oxbow.com

Owner/Parent Company: Oxbow Carbon & Materials Inc.

Previous Owner(s): None | Previous or Alternative Name of Mine: None

MINE ADDRESS

Physical Address: 3737 Highway 133 | Phone Number: (970) 929-5122

Mailing Address: P.O. Box 5535 | Somerset, CO | 81434

GENERAL INFORMATION

Number of Employees at Mine: 11 | Mining Method: Longwall

Year of Initial Production: 2002 | Primary Coal Use: Steam

Life Expectancy: 2014 | BTUs/lb of Coal Produced: 12,128

Depth to Seam (ft): 200 – 1,200 | Seam Thickness (ft): D:6-19, D2:14

PRODUCTION, VENTILATION, AND DRAINAGE DATA

	2011	2012	2013
Coal Production (short tons/year):	3,007,833	2,958,014	436,381
Estimated Total Methane Liberated (million cf/year):	5,852	4,182	544
Emission from Ventilation Systems:	3,687	3,217	179
Estimated Methane Drained:	2,165	965	365
Estimated Specific Emissions (cf/ton):	1,946	1,414	1,247
Methane Used (million cf/year):	0	17	360

Estimated Current Drainage Efficiency: 67%

Drainage System Used: Vertical Gob Boreholes with Pumps

POWER GENERATION POTENTIAL

Utility Electric Supplier: Delta-Montrose Electric Association | Nearest Transmission Line: One site

Parent Corporation of Utility: Touchstone Energy Cooperatives

	MW	GWh/year
Mine electricity demand 2013	31.9	123.1
Generating capacity assuming 100% CH4 Recovery Efficiency:	4.4	34.7

BOWIE NO. 2

Mine Status: Recently Idled

Drainage System: Yes

Use Project: No

GEOGRAPHIC DATA

Central Rockies

B & D Seams

State: CO

County: Delta

CORPORATE INFORMATION

Current Operator: Bowie Resources LLC

Owner/Parent Company: Bowie Resources Partners LLC

Previous Owner(s): Bowie Resources Limited

Parent Company Website: www.bowieresources.com

Previous or Alternative Name of Mine: None

MINE ADDRESS

Physical Address: 43659 Bowie Rd

Mailing Address: None | Paonia, CO | 81428

Phone Number: (970) 527-7786

GENERAL INFORMATION

Number of Employees at Mine: 207

Year of Initial Production: 1997

Life Expectancy: unknown

Depth to Seam (ft): 450 – 2,000

Mining Method: Longwall

Primary Coal Use: Steam

BTUs/lb of Coal Produced:12,128

Seam Thickness (ft): 12 – 20

PRODUCTION, VENTILATION, AND DRAINAGE DATA

	2011	2012	2013
Coal Production (short tons/year):	2,235,055	3,430,291	3,320,696
Estimated Total Methane Liberated (million cf/year):	725	736	667
Emission from Ventilation Systems:	457	642	527
Estimated Methane Drained:	268	94	140
Estimated Specific Emissions (cf/ton):	324	215	201
Methane Used (million cf/year):	0	0	0

Estimated Current Drainage Efficiency: 21%

Drainage System Used: Vertical Gob Boreholes with Pumps

POWER GENERATION POTENTIAL

Utility Electric Supplier: Delta-Montrose Electric Association

Parent Corporation of Utility: Touchstone Energy Cooperatives

Nearest Transmission Line: One site

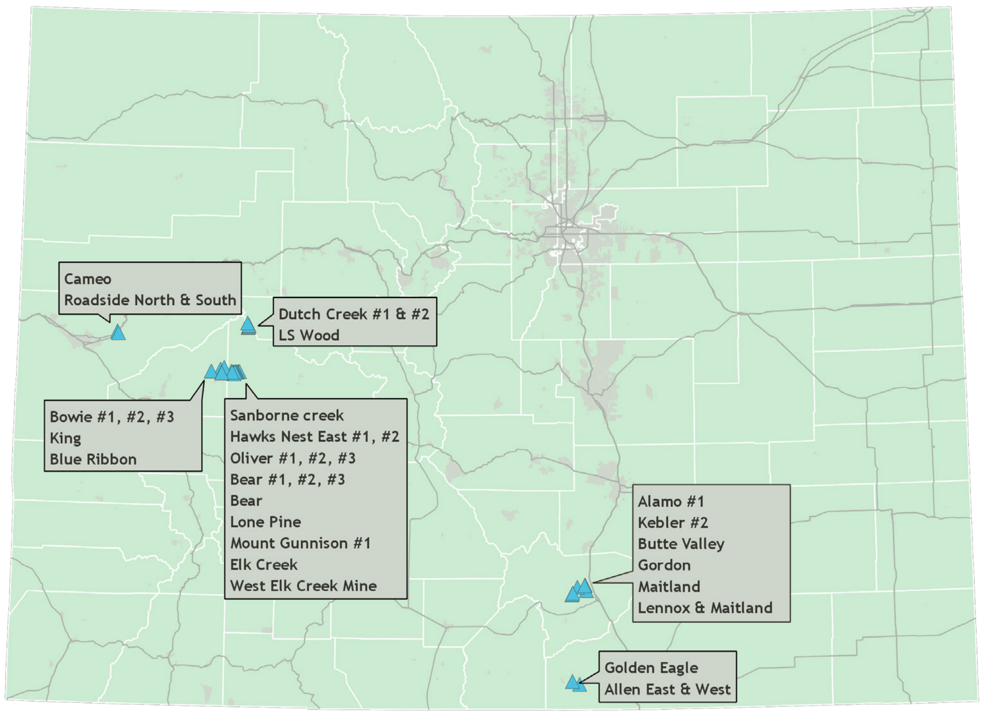
	MW	GWh/year
Mine electricity demand 2006	27.5	106.1
Generating capacity assuming 50% CH4 Recovery Efficiency:	1	7.9

Appendix B

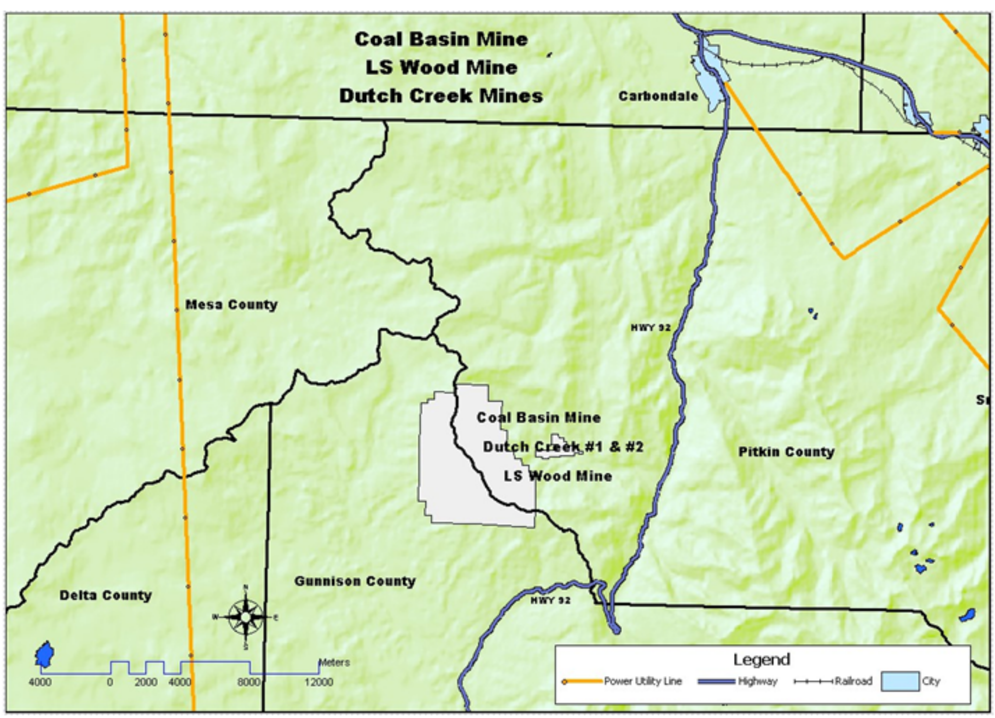
Utility	Web Address	County	Mine
Grand Valley Power / Excel Energy	http://gvp.org/ http://www.xcelenergy.com/	Mesa	Cameo, Roadside, North and South Portals
Holy Cross Electric / Excel Energy	https://www.holycross.com/ http://www.xcelenergy.com/	Pitkin	Dutch Creek #1 Dutch Creek #2 LS Wood Coal Basin
Delta Montrose Electric Association	http://www.dmea.com/	Gunnison	Sanborn Creek Mine Hawks Nest East Somerset Hawks Nest #1 Hawks Nest #3 Oliver #1 & 3 Oliver #2 Bear #1, 2, 3 Sanborn Creek Mine Bear Lone Pine Mount Gunnison #1
		Delta	Bowie #1 King Blue Ribbon Coal Bowie #3
		Las Animas	Golden Eagle Allen-East and West Portals
San Isabel Electric Association	http://www.siea.com/	Huerfano	Maitland #1 Lennox and Maitland Alamo No.1 Gordon Kebler #2 Butte Valley

Appendix C

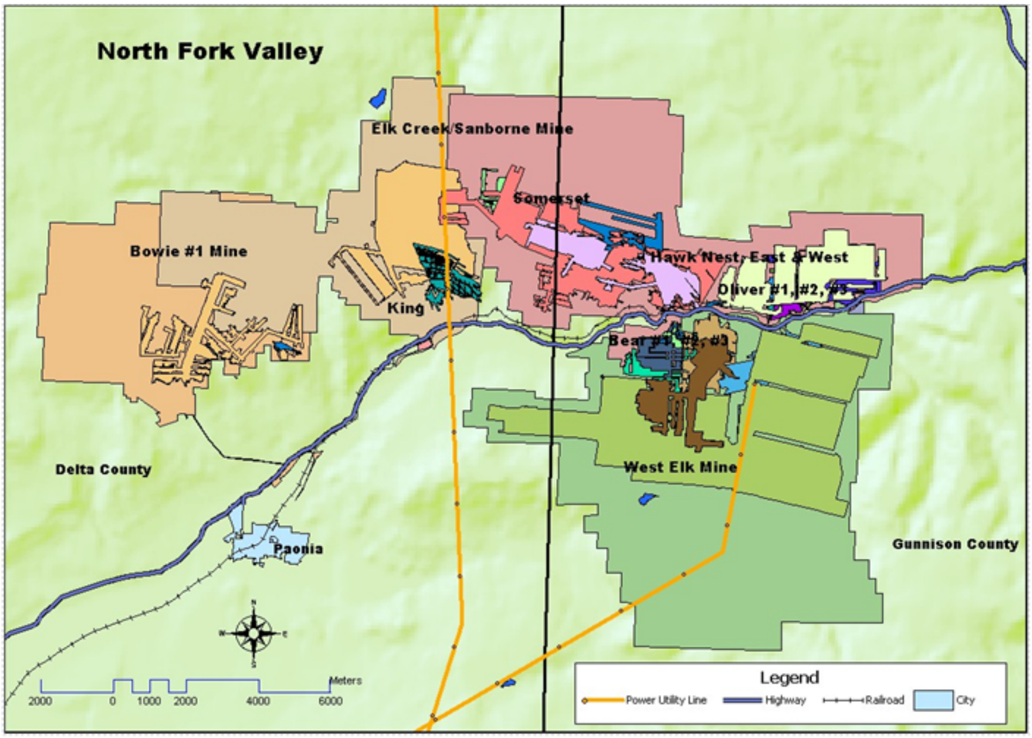
Colorado's Active and Abandoned Coal Mines with Methane Recovery Opportunities



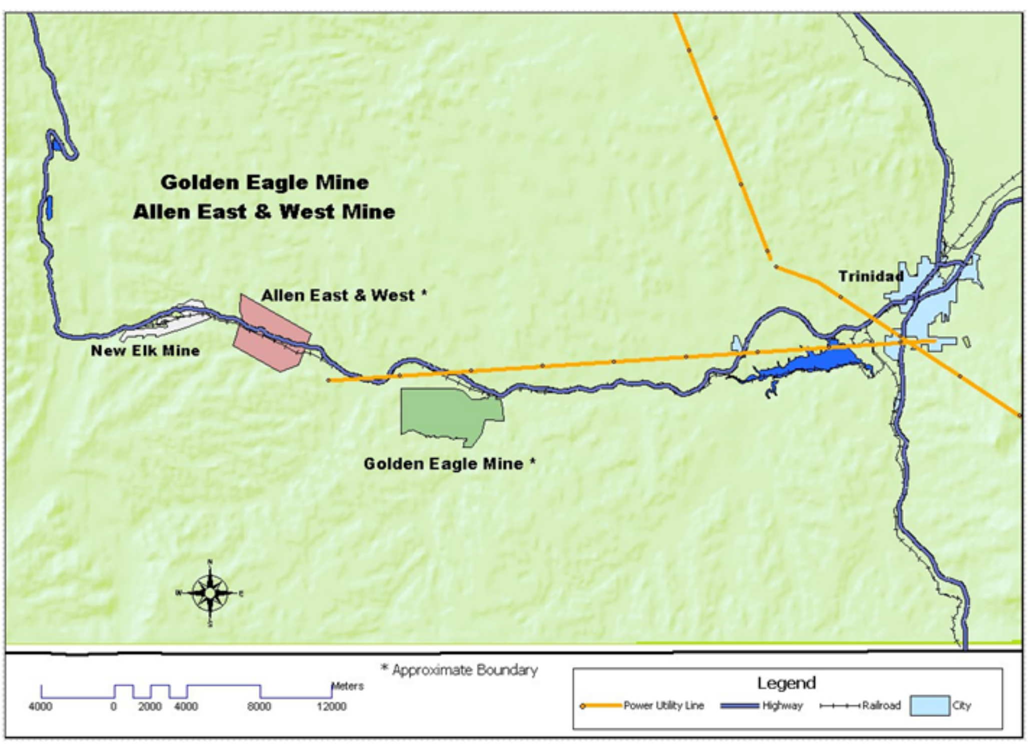
Group A – Carbondale – Redstone Area



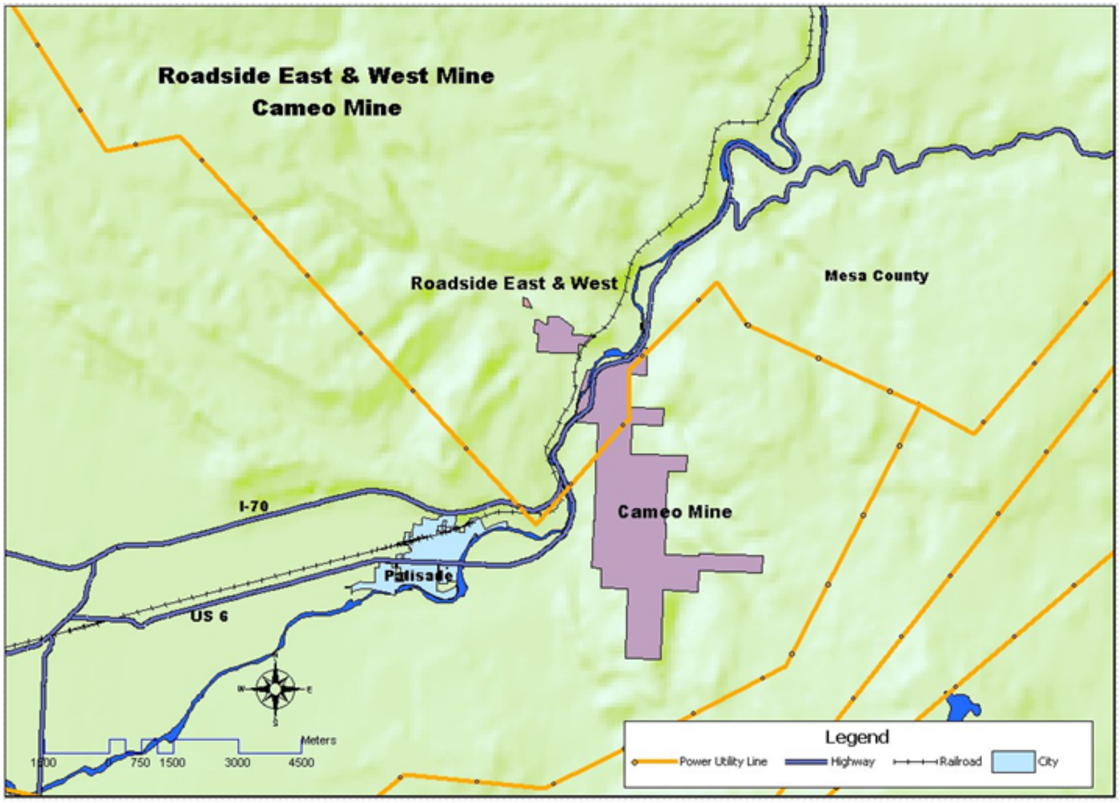
Group B, D, E – Somerset



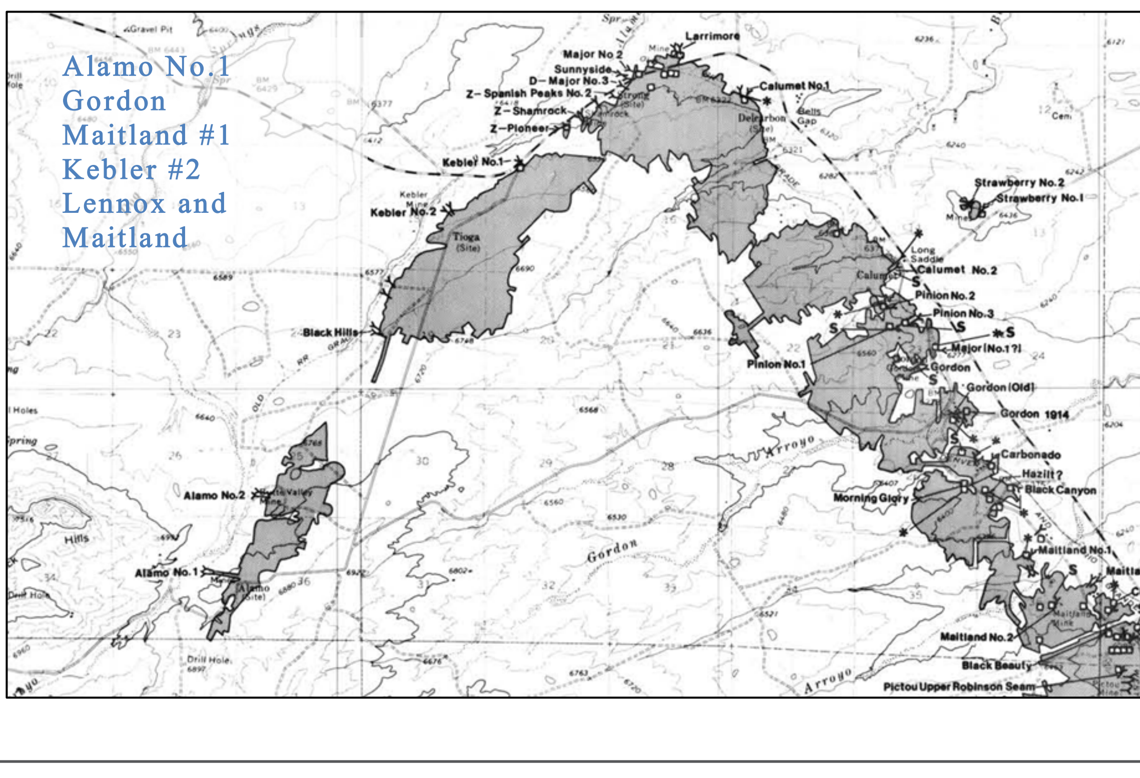
Group C – Trinidad



Group F – Book Cliff – Cameo



Group G – Walsenburg



Appendix D

Mine Name	Status	CMM 3-yr average for active AMM 10-yr average for abandoned			VAM active only		
		MCF/day	MW potential	MW Feasibility	MCF/ day	MW potential	MW Feasibility
West Elk Mine	Active	2,226	10.5	5.2	4,702	17.4	3.49
Elk Creek Mine	Active (idled)	2,504	11.8	5.9	6,468	24.0	4.79
Bowie No 2 Mine	Active (idled)	459	2.2	1.1	1,485	5.5	1.10
McClane Canyon Mine	Active	N/A	0	0	286	1.1	0.21
Foidel Creek Mine	Active	N/A	0	0	123	0.5	0.09
Deserado Mine	Active	N/A	0	0	103	0.4	0.08
Dutch Creek #1	Abandoned	517	2.3	1.38			
Dutch Creek #2	Abandoned	419	1.9	1.14	Feasible recovery estimates		
LS Wood	Abandoned	230	1.0	0.60	Drainage	VAM	Abandoned
Coal Basin	Abandoned	143	0.6	0.36	50%	20%	60%
Sanborn Creek Mine	Abandoned	770	3.4	2.04			
Hawks Nest East	Abandoned	86	0.4	0.24			
Somerset	Abandoned	71	0.3	0.18			
Hawks Nest #1	Abandoned	58	0.3	0.18			
Hawks Nest #3	Abandoned	55	0.2	0.12			
Oliver #1 & 3	Abandoned	53	0.2	0.12			
Oliver #2	Abandoned	50	0.2	0.12			
Bear #1, 2, 3	Abandoned	42	0.2	0.12			
Golden Eagle	Abandoned	873	3.9	2.34			
Allen-East and West Portals	Abandoned	68	0.3	0.18			
Bowie #3	Abandoned	163	0.7	0.42			
Bowie #1	Abandoned	150	0.7	0.42			
King	Abandoned	84	0.4	0.24			
Blue Ribbon Coal	Abandoned	69	0.3	0.18			
Bear	Abandoned	68	0.3	0.18			
Lone Pine	Abandoned	55	0.2	0.12			
Mount Gunnison #1	Abandoned	45	0.2	0.12			
Cameo	Abandoned	93	0.4	0.24			
Roadside, No. & So. Portals	Abandoned	71	0.3	0.18			
Alamo No.1	Abandoned	49	0.2	0.12			
Gordon	Abandoned	24	0.1	0.06			
Maitland #1	Abandoned	24	0.1	0.06			
Kebler #2	Abandoned	23	0.1	0.06			

COLORADO
Energy Office