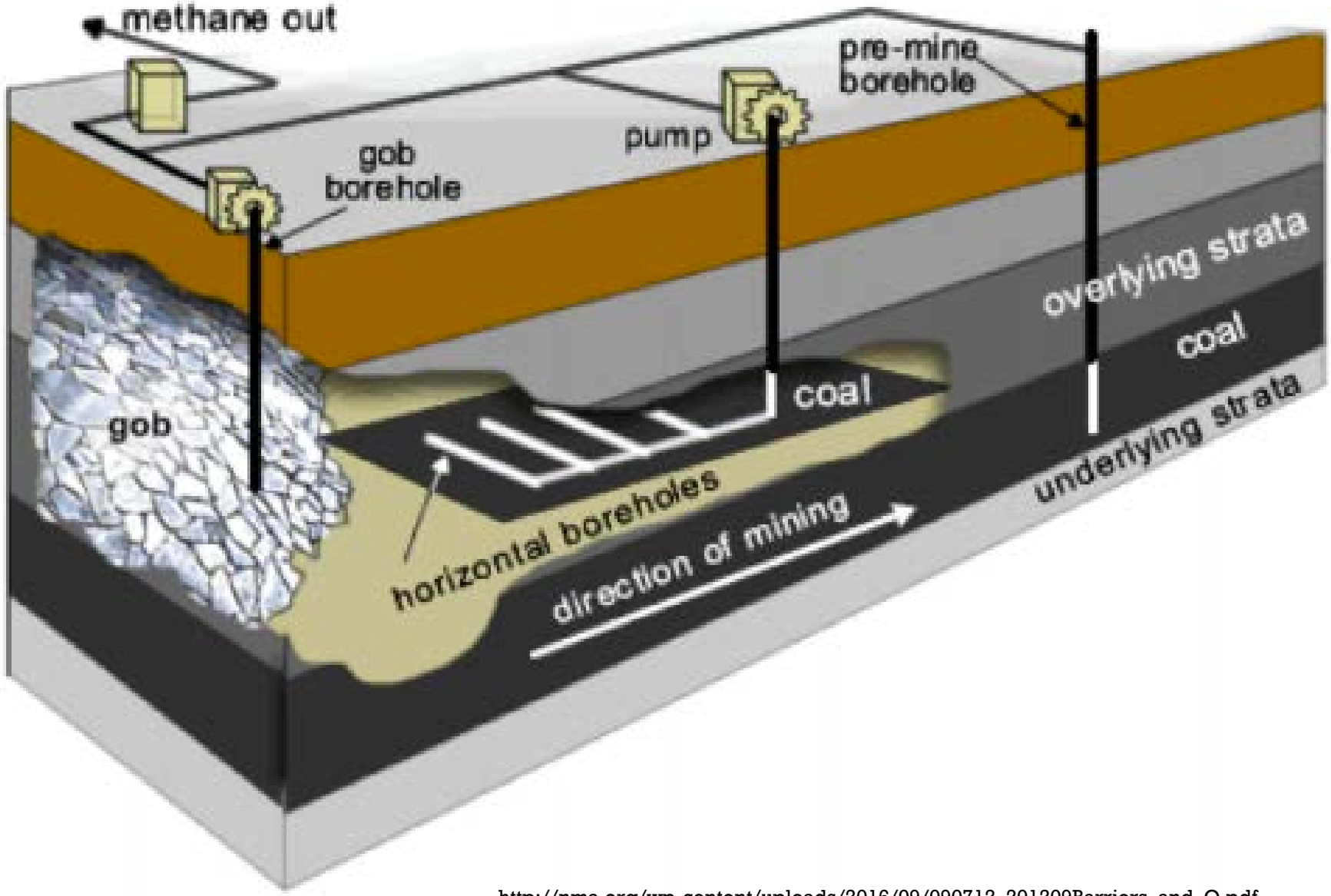
COAL MINE METHANE IN THE GUNNISON COUNTY'S NORTH FORK VALLEY: OPPORTUNITIES, OBSTACLES, & THE FUTURE

Chris Nutgrass

Advisor: Luke Danielson

Community Sponsor: Gunnison County Board of County Commissioners

WHAT



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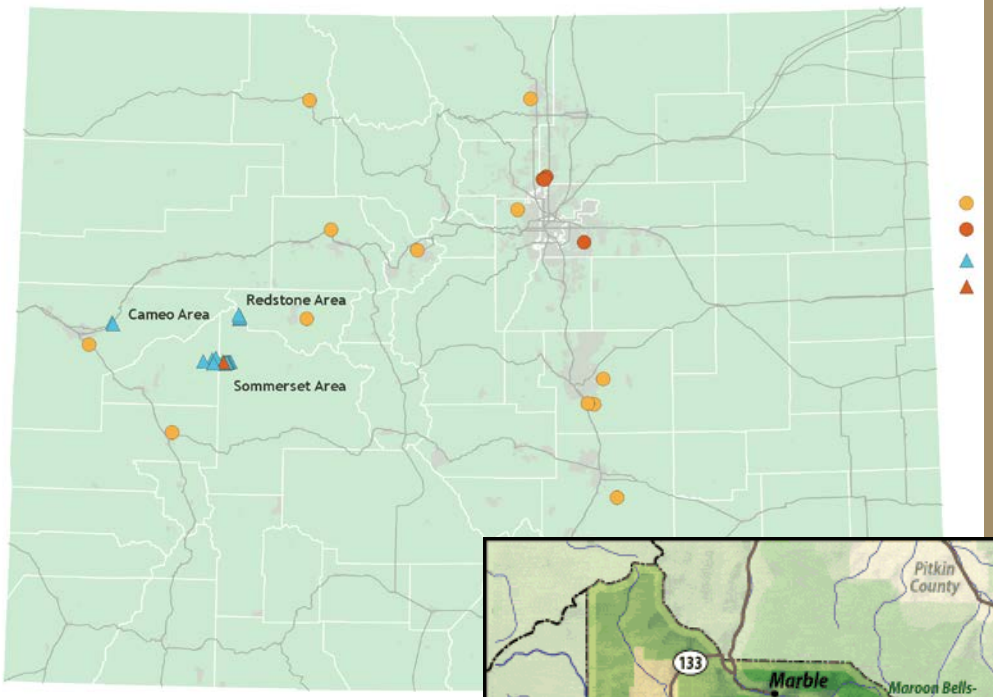
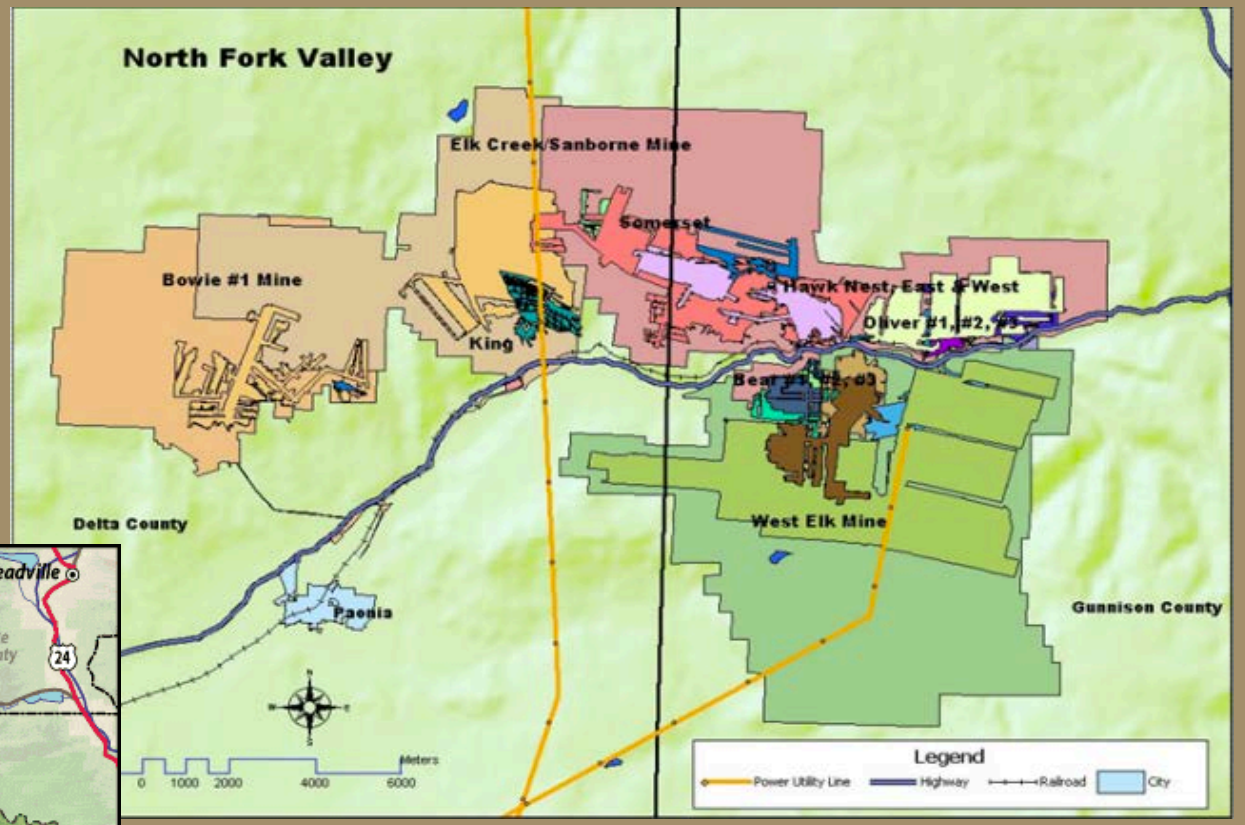


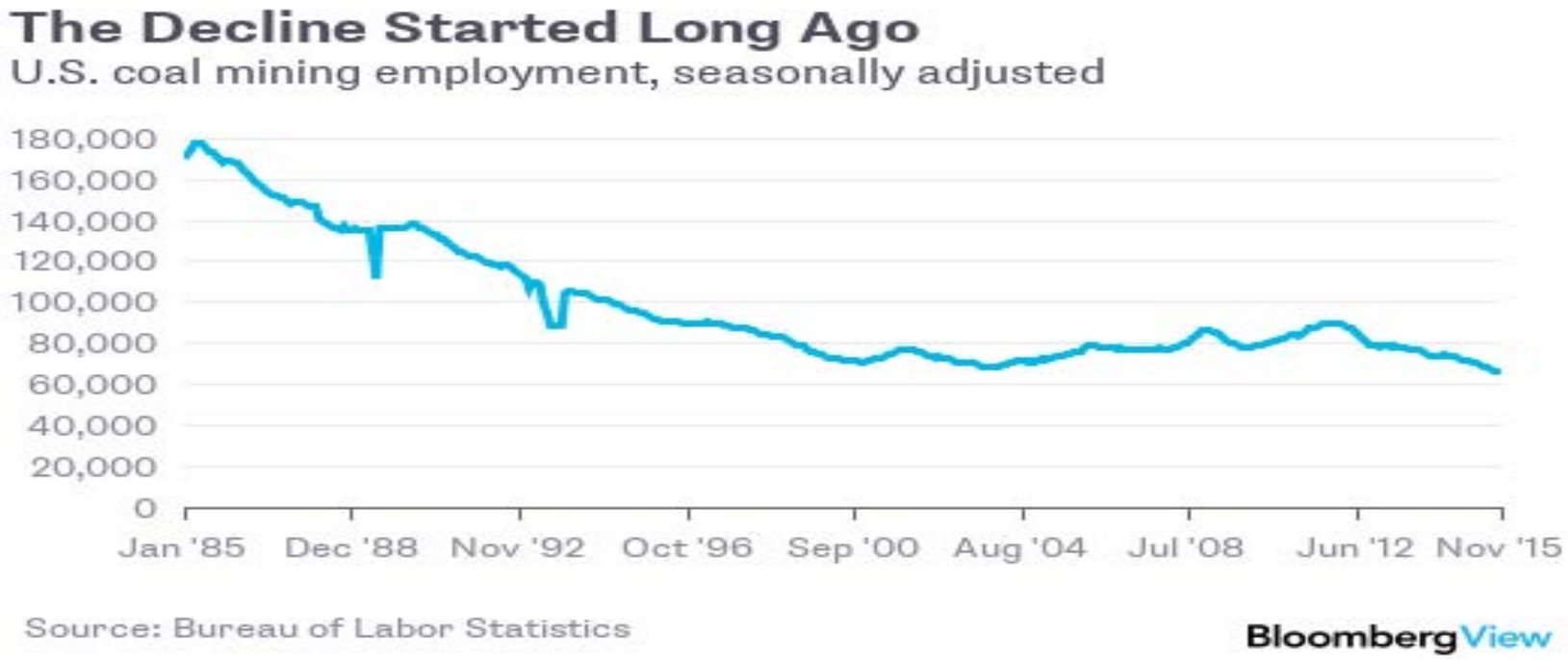
https://www.colorado.gov/pacific/energyoffice/methane-capture

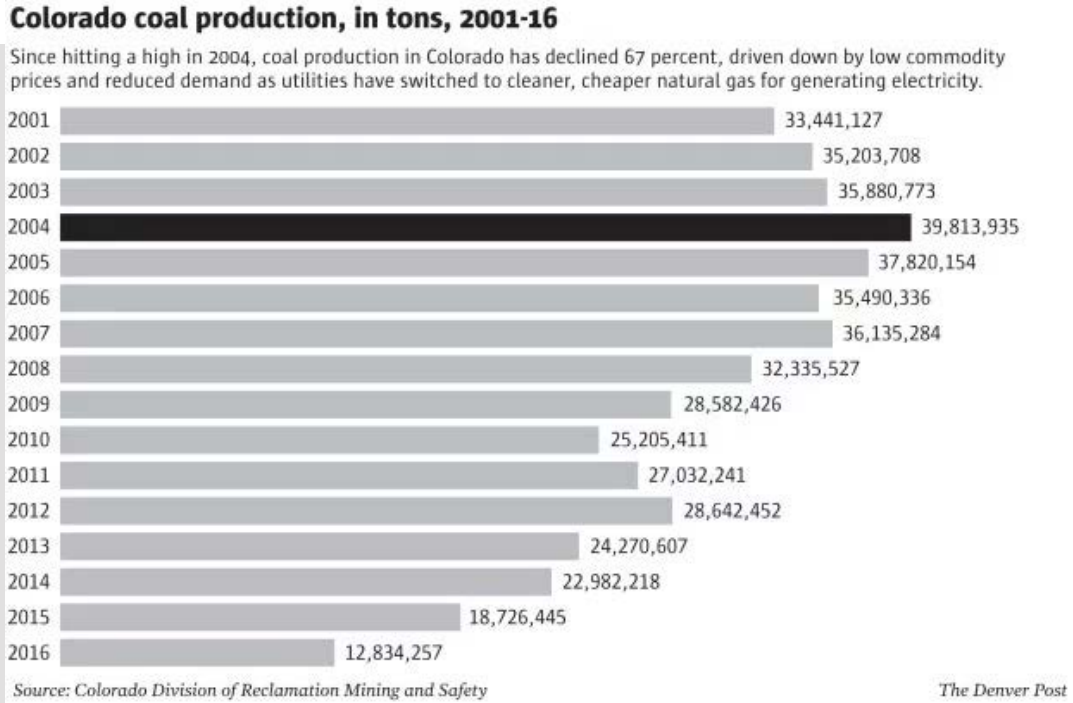


Coal Mine Methane in Colorado Market Research Report

http://www.bensonsothebysrealty.com/crested-butte-gunnison/area-maps/

WHERE





WHY

Coal is not what it once was

1990-2010 Colorado GHG Emissions by Sector ($MMTCO_2e$)

	1990	1995	2000	2005	2010
Electric Power	31	33	39	40	40
Transportation	20	24	27	31	30
Residential, Commercial & Industrial Fuel Use	15	18	20	25	27
Natural Gas and Oil Systems*	2	2	6	7	10
Agriculture	8	8	9	9	9
Coal Mining & Abandoned Mines	5	4	5	7	8
Industrial Processes	1	1	3	3	4
Waste Management	1	1	1	2	3
Grand Total	83	91	110	123	130

Exhibit 7-1: Summary of Colorado CH_4 Emissions From Coal Mining Activities ($MMTCO_2e$)

	1990	1995	2000	2005	2010
Total CH4 from Coal Mining	4.81	3.73	5.32	6.61	7.54
Coal Mining	4.16	3.06	4.36	5.49	6.63
Abandoned Coal Mines	0.64	0.67	0.96	1.12	0.90
Vented	0.04	0.03	0.10	0.07	0.05
Sealed	0.60	0.64	0.86	1.05	0.84
Flooded	0.00	0.00	0.00	0.01	0.00

Coal Mine Methane accounts for ~8% of Colorado methane emissions

Tables provided by Colorado Greenhouse Gas Inventory 2014

WHY

Target GHG reduction goals

	Mine Name	2013 Emissions ($MTCH_4$)	2014 Emissions ($MTCH_4$)	2015 Emissions ($MTCH_4$)	Total
	West Elk	30,084.88	26,049.05	19,404.3	75,538.23
SC-CH_4 (MTx$1000)		$30084880.00	$26049050.00	$19404300.00	$755 Million

Mine Name	Abandoned Date	Nearest North Fork Area Mine
Sandborn Creek Mine	10/1/2003	Elk Creek
Hawks Nest East	1/3/1986	Elk Creek
Somerset	2/16/1989	Elk Creek
Hawks Nest #1	6/30/1970	Elk Creek
Hawks Nest #3	6/30/1975	Elk Creek
Oliver #1 & #3	6/30/1960	Elk Creek
Oliver #2	6/30/1954	Elk Creek
Bear #1, #2, #3	4/1/1977	Elk Creek
Bowie #1	12/10/1988	Bowie #2
King	6/30/1974	Bowie #2
Blue Ribbon Coal	6/30/1984	Bowie #2
Bowie #3	6/30/2006	Bowie #2
Bear	5/27/1982	West Elk
Lone Pine	6/30/1965	West Elk
Mount Gunnison #1	6/30/1991	West Elk

WHY

Social Cost of Carbon and Methane

Even after closed, methane emissions continue at the coal mines

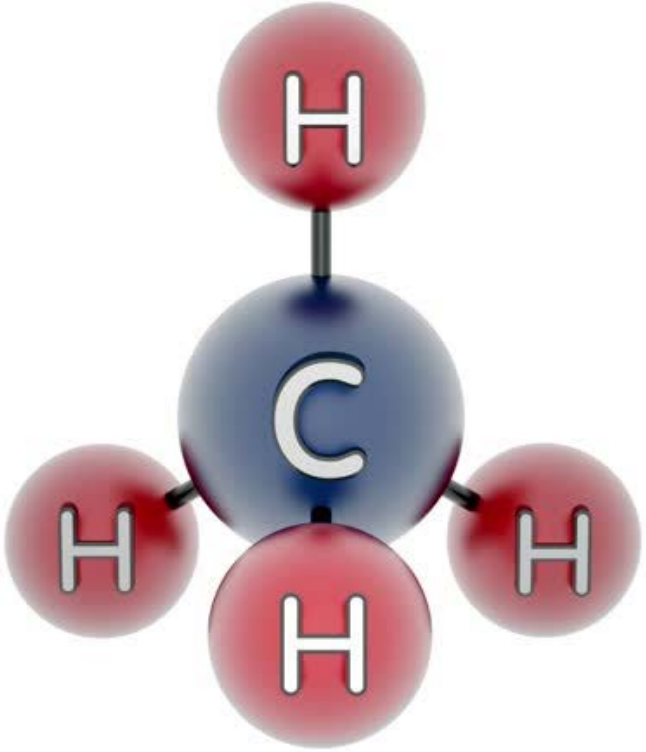
Local environmental changes

WHAT CAN WE DO?

Establish the baseline…

WHAT CAN WE DO?

- Electricity
- Compressed Natural Gas
- Pipeline Injection
- Industrial Feedstock
- Research Applications
- Flaring



ELECTRICITY

- Opportunities
  - Vessels project and why unique
  - Colorado Renewable Energy Credits (conditions)
  - Distributed, dispatchable power
  - Local light industry park or single purchaser
- Obstacles
  - Western electricity supply glut
  - Price
  - Power purchase agreements

http://koveva.com/portfolio/aspen-skiing-company/

COMPRESSED NATURAL GAS

http://crestedbuttenews.com/2016/01/rta-poised-to-transition-to-compressed-natural-gas/

- Opportunity
  - Gunnison fleet conversion
  - Local source to create RINS?
  - Decreased GHG emissions
- Obstacles
  - No pipeline
  - Don't currently qualify for Renewable Fuel Standard
  - Quality & Quantity of gas

FLARING

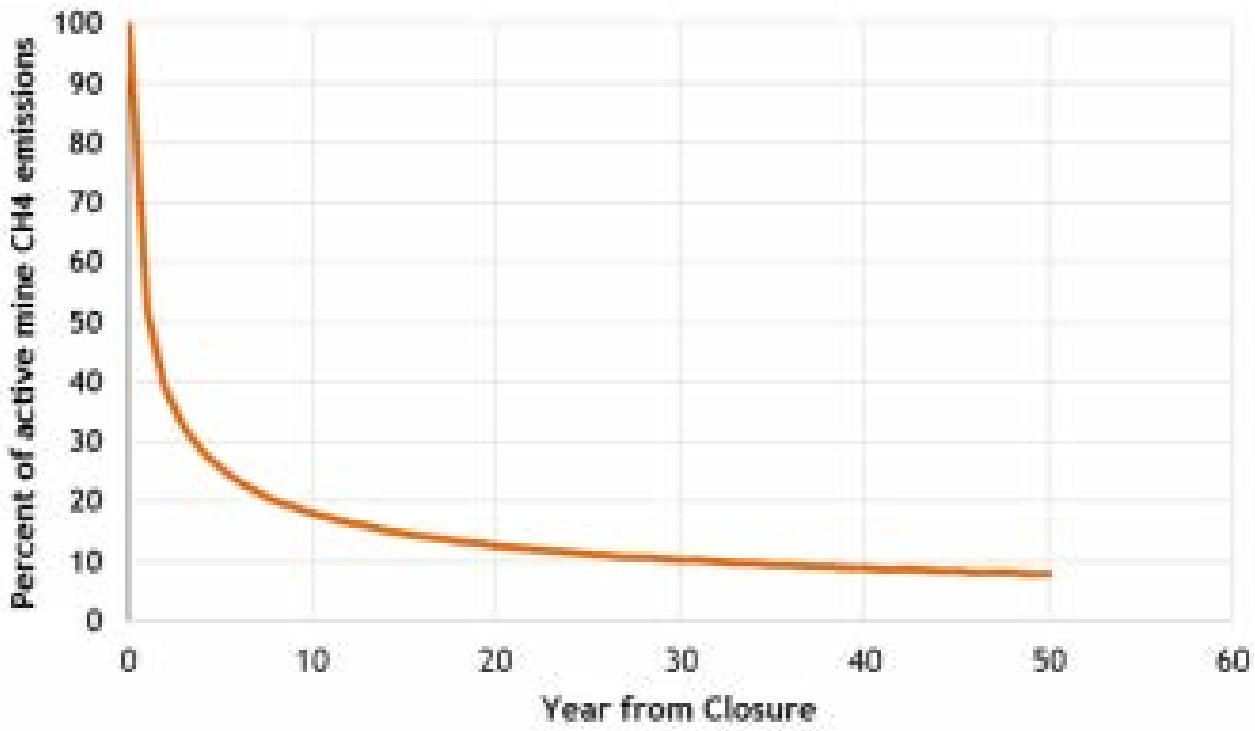
- Opportunities
  - Reduces methane now
  - Readily available technology
  - Carbon Offsets program (California Cap-and-Trade)

- Obstacles
  - Containment
  - Perception

http://www.gjsentinel.com/images/photos/imgkit_sized/Methane_power_plant_1_CPT_111812_600x400.jpg

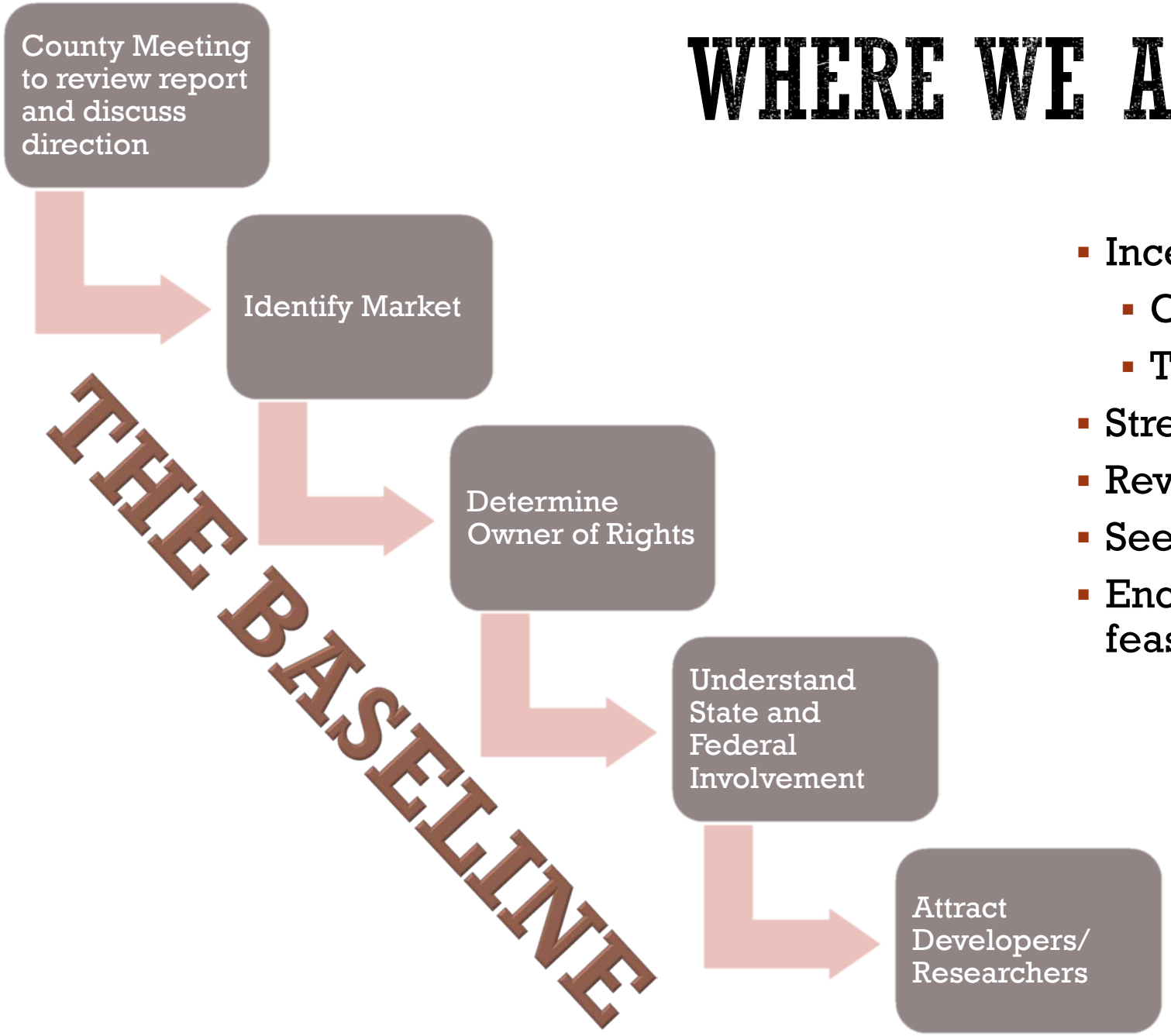
TIME TO MAKE A CHOICE

- Baseline established
- Utilizing a wasted product
- Reduced GHG emissions
- Sustain economic activity in the area



Colorado Coal Mine Methane Market Research Report/ California Air Resources Board

WHERE WE ARE & WHERE TO GO



- Incentivize capture and use
  - Carbon tax
  - Tax credits
- Streamline permitting
- Revise Land Use Regulations
- Seek grants for community development
- Encourage further research to determine feasibility

THANK YOU

- A special thank you to all those involved especially:
- Luke Danielson
- Jonathan Houck
- Tom Vessels
- John Cattles
- Mike McBride
- Emily Peters
- Family and Friends

QUESTIONS?

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Christopher Nutgrass

Western State Colorado University
MEM- Sustainable and Resilient Communities

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Executive Summary

The Gunnison County Board of County Commissioners is interested in understanding the resource potential of coal mine methane in the North Fork Valley. Coal has been a valuable commodity in Gunnison County for decades. Previous generations of mines worked in this area for the last century, with the current mines in the North Fork Valley operating since the 1980's. All area mines have now closed except one.[1]

Those mines have provided jobs for hundreds of Gunnison and Delta County residents as well as revenue to Gunnison and Delta Counties in the form of tax dollars (local, state, and federal) and local development grants.[2] The century of coal mining in the valley has provided significant benefits. But those benefits have not come without negative environmental consequences, which future generations will be forced to address.[3]

The Gunnison County Board of County Commissioners recognizes both the costs and benefits generated from coal mining in the North Fork Valley. The BOCC is eager to capitalize on an opportunity surrounding an historically wasted resource - coal mine methane.

Methane is a potent greenhouse gas (GHG). It has a global warming potential of 28-36 times that of CO_2 over 100 years and 84-88 times CO_2 over a 20-year period. The increased global warming potential over the shorter timeframe translates to more acute effects.

Methane is hazardous in underground coal mines because of its combustibility.[4] That same combustibility lends itself to many uses including generating electricity, becoming a vehicle fuel source in the form of compressed natural gas (CNG), or affording carbon credits when flared. Outside of combusting the gas, it can serve as a feedstock to many industrial processes. It is the goal of the BOCC to determine which of these uses might be technically and economically feasible.

This report serves as a guide to narrowing the options for methane utilization. It identifies potential project, obstacles, and recommendations for Gunnison County. Generation of electricity and compressed natural gas are discussed in greater depth than the other identified options for reasons detailed below.

The economic feasibility of the options for methane utilization studied as part of this report has not be fully determined. At present, it appears that without shifts in policy at the state and federal levels any project will be delayed. Incentives could be created to encourage methane capture and utilization.

The situation is similar to the difficulties associated with running effective recycling programs in areas that allow free disposal at landfills. Making the landfill option available without cost is a subsidy to waste generation, and undermines the economics of recycling.

In the case studied here, there is currently no price attached to methane emissions in the coal industry, allowing coal mines to emit methane into the atmosphere without any cost. This is clearly a subsidy to the coal industry and not just in the United States. The issue is a global one: The International Monetary Fund projected total world energy subsidies at $5.3 trillion (6.5 percent of global GDP) in 2015.[5] The coal industry is the biggest single recipient of such subsidies. In this same study, U.S. subsidies to the coal industry were estimated at over $200 billion per year.[6]

The best current estimate is that the cost to society of allowing a ton of methane to enter the atmosphere is about $1000, as discussed below. Where a commercial operation imposes this cost on society without charge or payment, the public is subsidizing it.

The current system is an intergenerational wealth transfer. Economic activity that benefitted past and present generations will impose a price, economically and environmentally, on future generations of Gunnison County, Colorado, United States, and global citizens.

Introduction

Gunnison County is well endowed with natural resources—both renewable and non-renewable, and the local economy reflects an array of economic activities based on environmental services. Historically, people were attracted to this area for its mineral reserves and later for the opportunity to raise cattle.[7] These two activities can still be seen throughout the county today albeit less dominant in the economy than they once were. Current attractions come predominately from opportunities such as biking, hiking, fishing in the summer months and skiing, snowmobiling, and skating in the winter. The economy has shifted. However, mining, especially the coal resource in the North Fork Valley, has remained an important generator of economic activity, though one that has declined in recent years.

One of the by-products of coal mining is the release of methane into the atmosphere. Gunnison County's coal mine are no exception. In fact, they are some of the gassiest mines in Colorado.[8] This has presents a danger to miners and has negative environmental consequences. Because the coal mines continue to produce methane long after they have closed, Gunnison County (and others) wonder if there is not a way to make economic use of this potential resource.

The United States has been the leader in coal mine methane (CMM) projects. At the end of 2012, there were a total of 38 projects at active and abandoned coal mines. The majority of these projects occur at active mines east of the Mississippi River and primarily inject methane into existing natural gas pipelines.[9] There are also projects being completed in China, India, Germany, and Poland to name a few.[10] A number of these global projects are flaring the gas and burning it as a greenhouse gas (GHG) emissions reduction strategy, since the resulting carbon dioxide has much less global warming potential than the methane itself.

The Gunnison County Board of County Commissioners has requested assistance in understanding how best to make use of a local methane resource. A full feasibility study of one or more of the options is necessary before any project can be built and implemented. Feasibility studies typically cost between $80,000-$100,000 and take a team of financial and technical experts months to complete. This project is in the nature of a pre-feasibility report, attempting to provide some answers to questions posed in the in-depth feasibility studies as a way for the county to rule out unfeasible options and identify viable ones for more detailed studies.

A project on this scale requires expertise and input from many different sources and disciplines. Although coal mine methane is used globally, its use is not yet widespread. This has led to a complex regulatory structure that is often unclear. For any productive use, collaboration between entities is paramount.

This report provides some background as well as next steps to be completed for Gunnison County to best make use of the methane resource. It identifies the principal questions that need to be answered for a project to be designed, while also providing contacts for individuals to answer those questions. This is not meant to be a prescriptive document but an explanation of options.

There is much interest in a coal mine methane project from Gunnison County, developers, and potential buyers. Gunnison County would like to see beneficial CMM production to reduce emissions, retain a revenue stream, and encourage economic activity in the North Fork Valley.

Current developers of CMM projects such as Vessels Coal Gas Inc. want to expand operations but - as is the case with any private business - need the project to be profitable. For the project to be profitable, a consistent purchaser of the finished product needs to be in place. This role could be satisfied by one of the electrical cooperatives or potentially by Gunnison County in the case of vehicle fuel.

Federal, state, and local agencies and regulations allow for or deny the utilization of CMM as a resource. Because the resource is primarily located on federal land, the Bureau of Land Management and United States Forest Service will also be involved in the leasing of the resource, royalty collection, and stipulations imposed by the Colorado Roadless Rule. Colorado Department of Public Health and Environment permits will be required in addition to complying with federal regulations.

What is Coal Mine Methane?

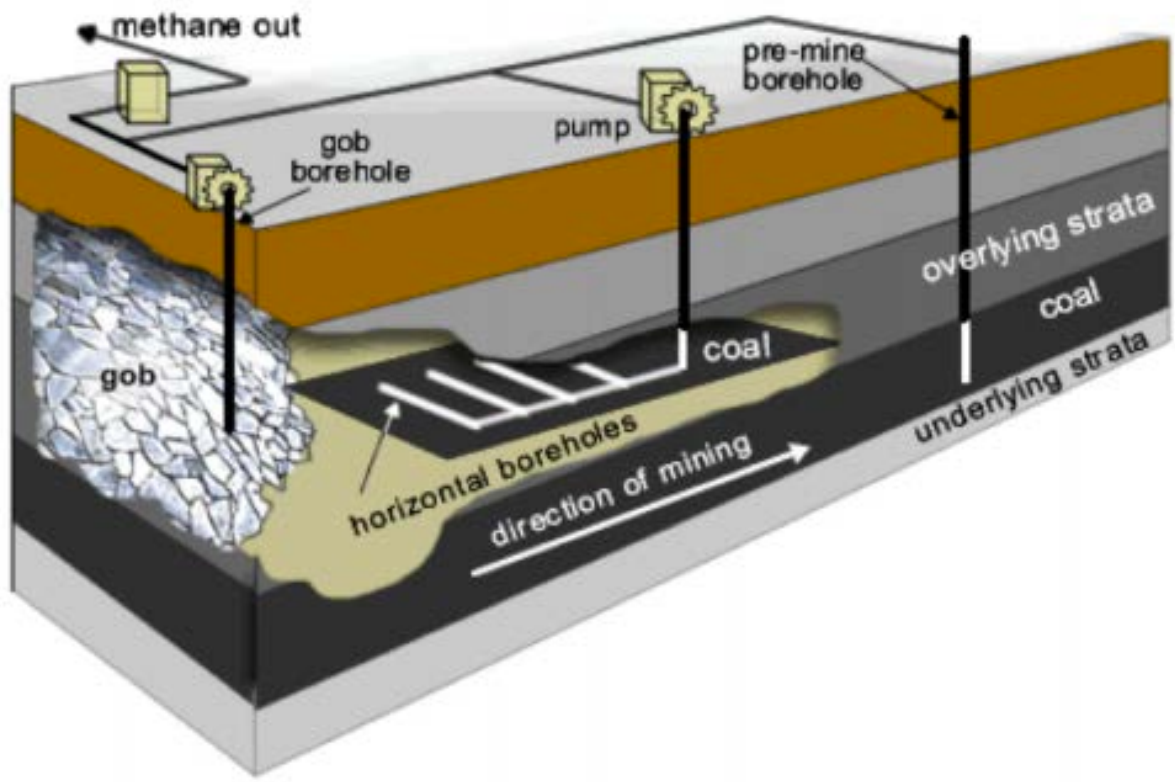
Methane is the major component of what we use as natural gas. Some 95% of typical natural gas is methane. The difference between commercial natural gas and coal mine methane is the purity. Pipeline quality gas has a methane content over 95% while the methane content of coal mine methane (CMM) varies considerably. It might range from <10% to >90%. If conditioned, methane from coal mines is potentially useable for any of the purposes for which natural gas is used. However, because as it comes from the mine it is commingled with other gases, it may need considerable processing before it can be applied to commercial uses.

That is the challenge that separates CMM from natural gas. If what was coming out of the mine was useable in the same way as natural gas, basing some economic activity on it would be viable. However, there are additional steps of gathering the gas and concentrating the methane to a useful level that add to cost.

Methane in coal mines is a danger to coal miners and is a potential hindrance to mine operations.[11] Where it reaches excessive concentrations, it can cause explosions, fires and loss of life. In order to operate, companies need to stay within safe limits of methane concentration in underground air. Failure to meet those limits can cause the mine to be in violation of its permit and be closed. Therefore, most underground mines, including those in the North Fork, need to have ventilation systems that exhaust the methane to keep concentrations within safe regulatory limits. This ventilation system is regulated by the Mining Safety and Health Administration and produces Ventilated Air Methane (VAM) which can be harnessed for different uses.

Coal mine methane is a category of coal bed methane (CBM) that is associated with the release of methane from coal mining activities. CBM has a broader definition that typically refers to methane associated with a coal seam. Figure 1 represents a typical longwall mining operation like the ones found in the North Fork Valley. There are numerous projects in the western U.S. exploiting CBM. CBM is treated more like a typical natural gas deposit because the coal resource is being left intact.

Figure 1. Methane Drainage in an Underground Coal Mine (EPA)



Coal mine methane (CMM) can be subdivided into four categories. The distinguishing features are where the methane is collected, what technologies are used, the quality of the gas, and the status of the mine at the time of capture. There are projects utilizing each of these forms of CMM.

The four categories are: (1) pre-mine drainage methane (2) ventilation air methane (VAM (3) coal mine methane referred to as waste mine methane while coal is in production, and (4) coal mine methane captured post coal resource exhaustion sometimes referred to as abandoned mine methane.

Pre-Mine Drainage Methane

In some areas of the country, such as Appalachia and Alabama, methane can be collected prior to mining through **pre-mine drainage wells**. These wells are drilled ahead of the mining activity to drain the area of water and methane and can also be referred to as coalbed methane wells. These wells produce gas with very high concentrations of methane (>80%) and are very similar to natural gas wells. This means that the gas can be used for economic uses such as direct pipeline injection or utilized onsite for electricity and heat generation. Pre-mine draining does not occur in the North Fork Valley to produce CBM due to the variability of coal depth and

surface contours. The landscape and Roadless designation makes it very difficult to set-up this type of well ahead of mining.

Ventilation Air Methane

Ventilation air methane is the byproduct of ventilating the outside air to reduce methane concentrations below 1% as required by the Mining Health and Safety Administration (30 CFR Part 75 Subpart D). VAM has very low concentrations of methane due to the high volumes of air ventilated through an underground mine. Thermal oxidation is a process by which methane is converted into carbon dioxide and water. It is the most widespread technology utilized to treat methane from the source. This technology is designed for pollution reduction but the heat generated can be used to heat the mine.

Waste Mine Methane

Methane drainage wells in place behind the mined area of an active mine produce waste mine methane. These wells are referred to as gob wells. As the mining progresses through the seam, methane is released into the fractured rock above the coal. Methane continues to be released and is vented into gob wells connected to the surface behind the active face. They are typically in place for a short time and removed and reclaimed soon after the area beneath the wells is mined.

Abandoned Mine Methane

In addition to active mine ventilation, methane can also be captured from abandoned mines. Accessing areas of the mine that are closed can provide opportunities for capturing methane that may otherwise be escaping through subsidence fissures, cracks in the surrounding rock resulting from surface subsidence. As the methane accumulates in open spaces of previously mined areas, it becomes possible more accurately to determine lifespan and measure production quality. This fourth kind of methane capture utilizes the mine's existing structure to direct the methane into areas to be captured. As the concentration increases, the number of potential uses increases.

Each of these types of methane poses different challenges to use. In this case, the focus is on **abandoned mine methane** but **VAM** and **waste mine methane** may provide opportunities while coal is still in development.

Gunnison County Context

The extraction of North Fork Valley coal has provided jobs, infrastructure, and tax revenue for a century. The most recent generation of mines has been in operation since the early 1980s. As recently as 2013, direct employment in coal mining in the North Fork exceeded 1000 jobs.[8] The two mines located in Gunnison County have been the County's largest taxpayers for many years; Gunnison County has received millions in severance and property tax revenue from these mines since they were established. This tax source appears to be lessening as demonstrated by a 2014 severance tax receipts of $914,000 and only $235,050 in 2016.[9] Severance tax revenue does include oil and natural gas, coal, and metallic and non-metallic mining revenues, but the downward change is evident and related to coal mine closures. In the past five years, two of the three operating coal mines in the North Fork have closed resulting in the loss hundreds of jobs. These job losses are tied directly to the decreased demand and production of coal. Along with these direct and indirect job losses, a loss of tax revenue to Gunnison County has also occurred.

Coal mines have been and continue to be a major source of methane emissions. Methane is a potent greenhouse gas (GHG) with a global warming potential of 28-36 times that of CO_2 over 100 years and 84-88 times CO_2 over a 20 year period.[10] Reduction of methane emissions from this source would be a major step toward Gunnison County's goal of reducing its GHG emissions (Gunnison County Carbon Policy Task Force, 2010).[12] The Gunnison County Strategic plan calls for a reduction of carbon dioxide equivalent (CO_2e) emissions by 20% of 2005 levels by 2030.[13] Methane's higher global warming potential means that smaller actual reductions lead to larger general reductions.

The Environmental Protection Agency along with other Federal agencies use a metric known as the Social Cost of Carbon (SC-CO_2) to estimate, in monetary figures, the damage done by a ton of carbon released into the atmosphere. The price per ton increases over time to account for incremental increases in the damages. In 2015, the Social Cost of Carbon was set at $36/ton. The agencies also calculate a Social Cost of Methane (SC-CH_4). Because of methane's higher global warming potential, the price per ton in 2015 was $1000. Monetary figures are used to quantify the environmental and social damages of climate change with this metric. [14]

Gunnison County's economy is becoming more focused on tourism that relies on providing access to public lands. Changes in rain and snowfall are already being observed as well as higher temperatures. Hotter summers coupled with uncertain precipitation could affect the growing land-based tourism economy and lead to increased risks of fire further, endangering citizens and their property.

There is currently a project utilizing abandoned mine methane in Gunnison County. The project is located at the Elk Creek mine. Vessels Coal Gas Inc. in association with Gunnison Energy generate 3 MW of electricity and flare approximately 900MCF/day. The electricity is sold to Aspen Skico via Holy Cross Energy and contributes to their green energy portfolio. The methane that is flared is then sold as offsets to the California Cap-and-Trade system. There is potential for expansion at this project as well as the surrounding abandoned coal mines.

3MW Generating and Flaring Facility located at Elk Creek Mine

What is the resource?

There are a number of abandoned mines in the North Fork including one long term underground coal mine fire, at the Oliver Mine.

Table of abandoned mines in North Fork Area

Mine Name	Abandoned Date	Nearest North Fork Area Mine
Sandborn Creek Mine	10/1/2003	Elk Creek
Hawks Nest East	1/3/1986	Elk Creek
Somerset	2/16/1989	Elk Creek
Hawks Nest #1	6/30/1970	Elk Creek
Hawks Nest #3	6/30/1975	Elk Creek
Oliver #1 & #3	6/30/1960	Elk Creek
Oliver #2	6/30/1954	Elk Creek
Bear #1, #2, #3	4/1/1977	Elk Creek
Bowie #1	12/10/1988	Bowie #2
King	6/30/1974	Bowie #2
Blue Ribbon Coal	6/30/1984	Bowie #2
Bowie #3	6/30/2006	Bowie #2
Bear	5/27/1982	West Elk
Lone Pine	6/30/1965	West Elk
Mount Gunnison #1	6/30/1991	West Elk

Some of the older, inactive mines may well have methane production potential. And it is very likely that their methane is being vented into the atmosphere through old ventilation wells, subsidence fissures, or other routes. However, the main interest has focused on three underground mines that have been operated in recent years. Of these, two are in Gunnison County, and one just over the county line in Delta County. Brief profiles of each of these mines are outlined below:

The Elk Creek Mine

Elk Creek Mine is located in Gunnison County. It was closed in late 2013 after a fire with hopes of one day reopening. In 2016, Oxbow Mining moved to permanently close the Elk Creek Mine. The 3MW electricity generation project and flare were constructed in 2012 at this site and provide electricity to Holy Cross Energy which in turn sells the power to Aspen Skico.

The site has seen emissions reduction of 1,119,192.8 metric tons (MT) CO_2e 2012-2015 from a combination of CMM utilization and the halt of coal mining.[15]

In 2015, Elk Creek reported total emissions of 34,759 $MTCO_2e$ The majority of emissions from this mine in 2015 were carbon dioxide. Methane, which is mostly captured, accounts for less than 1/1000th of a percent of total CO_2e emissions in 2015. Vessels Coal Gas, Inc. believes it will be able to continue producing electricity at its current rate for at least the duration of its 15 year power purchase agreement and potentially longer.

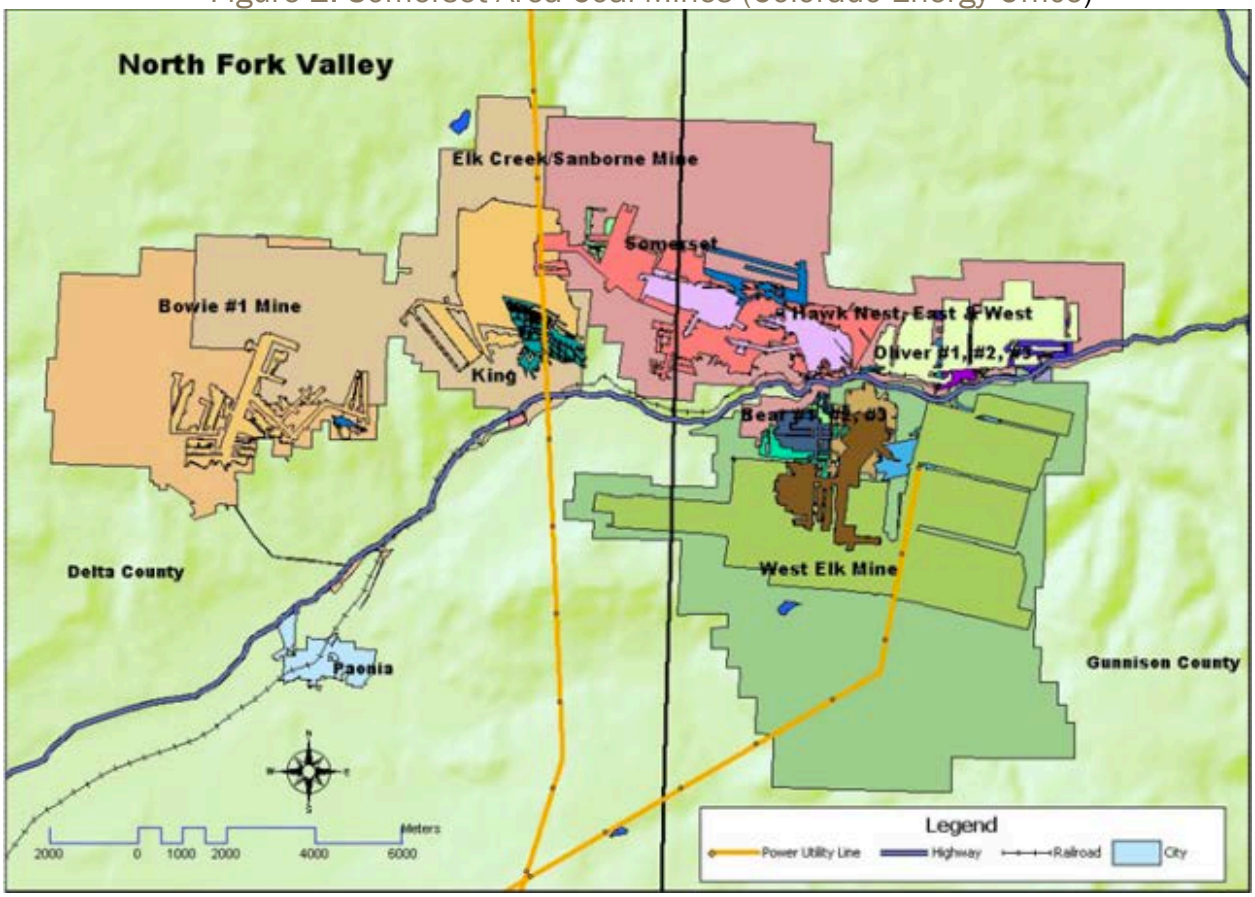
The West Elk Mine

The only remaining operating mine in the area is the West Elk Mine owned by Mountain Coal Company and located in Gunnison County. As of January 2017, West Elk produced 467,716 tons of coal and employed 220 people. From 2012 to 2015 West Elk saw CO_2e emissions reduced by 444,829.9 $MTCO_2e$. Of the 492,398 $MTCO_2e$ emitted in 2015, 98.5% can be attributed to methane, thus there is a real opportunity for a methane project at this site.[16]

Bowie

Bowie #2 mine, in Delta County, was also operating until 2016. According to the Environmental Protection Agency (EPA) data Bowie #2 saw an increase in emissions over the 2012-2015 timeframe. In 2015 all of its recorded emissions were from methane to the amount of 514,703 $MTCO_2e$.[17] Bowie Resources LLC, the owner of the mine, recently cancelled a 2016 proposal for a coal gasification plant to produce syngas at the site for unknown reasons.

Figure 2: Somerset Area Coal Mines (Colorado Energy Office)



What are the applications?

Coal mine methane can be used in many of the same ways as natural gas because methane is the primary constituent of natural gas. This means CMM can be used to produce electricity by burning it, as a fuel for vehicles, injected into a pipeline, or processed into more complex hydrocarbons for plastics productions.

Even flaring – just burning the gas without any economic use and simply turning methane into CO_2 and water - has a beneficial effect on greenhouse emissions. This is because CO_2 is a far less potent GHG than methane.[18] For the purposes of this document, CMM usage has been broken into broad categories: (1) electricity production, (2) vehicle fuel, (3) flaring, and (4) other. It could be necessary to combine multiple uses to make a project more appealing economically, socially, or environmentally.

There is potential for expansion of the 3 MW Vessels project at Elk Creek and increased electricity production. As recently as 2016, the Colorado Energy Office commissioned a report on the market viability of CMM citing the North Fork Area coal mines as prime candidates.[19]

Aside from generating electricity, it seems that only compression for CNG vehicles and flaring are as viable options. Applications such as plastics or fertilizer production were not analyzed in depth due to what appear to be prohibitive costs and infrastructure development requirements.

Recommendations for pursuing the utilization of coal mine methane are contingent on many factors. For every opportunity, there are also obstacles that must be overcome. The following sections review the most promising methods of utilization, identify barriers, offer solutions, and explain what makes each option potentially viable. This report serves as a guide for Gunnison County to determine which method of utilization it would like to support as it works towards its goals to create a more sustainable and resilient community.

Electricity

The generation of electricity from coal mine methane is the most obvious potential use, because the infrastructure already exists for transmission, and it has been demonstrated by the Vessels project to work. In Colorado, CMM qualifies as a part of the renewable energy portfolio, allowing recognition of renewable energy credits.[20] At present, natural gas outcompetes coal as the preferred fuel for electricity generation. CMM for the generation of electricity has many advantages here in Colorado.

Natural gas is a cleaner option than coal fired power plants. While CMM is not pure natural gas, if concentrated it can be burned, and burning it has less adverse greenhouse impact than releasing the methane into the atmosphere.

The turbines currently in use at the plant at Elk Creek are not the most efficient. Greater efficiency and a lower electricity price would be gained at more megawatts. A bigger plant would be more efficient. There is enough CMM to drive a bigger and more cost-effective plant if there is a market for the electricity. Using the gas to generate electricity onsite eliminates the transportation costs and transportation related emissions. A life-cycle analysis is needed to determine the actual GHG savings.

The methane concentrations found in CMM that are typically much lower than natural gas from a traditional well. An additional step is required before CMM can be used similarly to natural gas.

There are several technologies that are able to generate electricity from the lower concentration of methane in CMM. Each project must consider variables such as methane concentration, predicted lifespan, and flow variability to choose the proper method of generation. See the Colorado Energy Office's report *Greenhouse Gas Neutrality Assessment of Coal Mine Methane and Waste-to-Energy Pyrolysis Projects* for more information on technologies used and associated advantages and disadvantages.[21]

The Colorado Renewable Energy Standards require utilities, both owner-operated and cooperatives, to source a minimum amount of electricity from renewable sources. The federal Public Utilities Regulatory Policy Act of 1978 also mandates that utilities purchase electricity from "qualifying facilities". Most potential CMM electricity generation facilities would be considered small power production facilities which produce less than 80 MW from renewable sources. (The existing generator in the North Fork is only 3 MW). These qualifying facilities receive special rate and regulatory treatment, such as the Vessels project at Elk Creek.[22]

In addition to the 3 MW currently being generated at the Oxbow facility, the Colorado Energy Office concluded there is potential for a combined 66 more megawatts from Elk Creek, West Elk, and Bowie #2 alone.[23] This potential gives the North Fork Valley a unique advantage to develop CMM as a resource. The three 1 MW turbines being used now experience efficiency losses that could be remedied by larger, more efficient models whose purchase may be facilitated by multi-county or utility partnerships.

There are several rural electric coops distributing electricity in the area surrounding these mines. **Delta-Montrose Electric Association (DMEA)** is the closest cooperative to the methane resource and provides electricity to the North Fork Valley. DMEA's service area covers Montrose and Delta Counties as well as a portion of Gunnison County.

Gunnison County Electric Association (GCEA) services Gunnison, Hinsdale, and parts of Saguache Counties. A third cooperative, Holy Cross Energy, is the current purchaser of the 3 MW project at Elk Creek and provides services primarily to Pitkin and Garfield counties. Each of these cooperatives is a potential purchaser of electricity produced from CMM.

Before launching into the analysis of this market, it is necessary to explain the relationship of two of these three rural electric coops to Tri-State Generation & Transmission. None of these rural cooperatives is a major generator of electricity. They are each primarily distribution cooperatives which take electricity generated by others and sell it to retail customers. Historically DMEA and GCEA have obtained most of their electricity from Tri-State Generation & Transmission.

In order to help Tri State finance new coal fired generators in the early 2000s, each of these local cooperatives signed, at Tri-State's request, a contract committing to purchase almost all of its electricity needs from Tri State for the next 40 years. Similar contracts were signed by about three dozen cooperatives in this region.

One of the conditions of the contract limits the amount of electricity that can be generated or purchased from any source other than Tri-State. This of course includes independent hydro, solar, wind, and coal mine methane projects. This condition limits the purchase from other sources to 5% of the total sales essentially limiting coops in their ability to generate electricity locally,[24] or to buy from others who do.

Alternative energy sources such as wind are priced at a lower rate per kilowatt hour (kWh) but generate electricity intermittently. Coal fired power plants currently serve to provide base load (or "dispatchable") power that fills the gaps when other sources are not generating. There are costs associated with backing up that intermittent power that is not reflected in the kWh price. Coal mine methane can also provide base load, "dispatchable" power and therefore is potentially a valuable addition to the local generating mix.

The controversial Tri State contract provision has implications far beyond the CMM projects that are the focus of this report. Among these are:

First, it appears that electrical demand in the area served by Tri-State is somewhat stagnant. Projections of robust demand growth in the area have not

materialized. Much of this trend is associated with greater energy efficiency measures taken by communities.

Second, the price of electricity generated by natural gas, solar and wind have been falling. There may be a growing disparity between the price of Tri-State's coal generated power and the price at which the various regional cooperatives could buy other forms of power. Local customers, in some scenarios, would be captive for many years to above market electrical rates. The potential effects on regional economic development are unknown but should be researched further.

Third, some of the cooperatives are getting restless and are attempting to leave the Tri-State system. If they succeed in doing so, the cost of supporting Tri State's capital investments could be spread over a smaller and smaller number of cooperatives, making the prospect even more alarming.

Fourth, while Tri State is now moving to add some renewable sources to its portfolio (approximately 700MW since 2009) It may be a case of "too little too late." And it is not that clear how Tri State can deal with the large investment in its coal fired capacity.

The current system therefore may be an obstacle to innovation, and to a transition to renewable power, and could prove very expensive over time. These are serious issues, potentially affecting development in this region, that go far beyond the scope of this report.

Delta-Montrose Electric Association (DMEA) is the closest cooperative to the potential sources of coal mine methane in the North Fork, which makes it the likely first option for purchasing. DMEA is a Tri-State cooperative but is currently exceeding its allowable 5% purchases from other sources.

The Federal Energy Regulatory Commission (FERC) has ruled that local electrical cooperatives are required to purchase from "qualifying facilities" under the Public Utilities Regulatory Policies Act (PURPA). DMEA recently won a legal proceeding before the Federal Energy Regulatory Commission (FERC) upholding DMEA's obligation to buy power from what are termed "qualifying facilities." Thus, they have established that the 5% limit may not bind them.

However, DMEA is awaiting another ruling from FERC on whether DMEA must pay a surcharge to Tri-State. The FERC Board is currently unable to meet because numerous commissioners have resigned leading to a lack of a quorum. Thus, all decisions are delayed, and it is uncertain when FERC will again be able to function as a federal agency. Until that final ruling is made, DMEA will be hesitant to enter any

new contracts that may expose them to a surcharge when and if FERC again becomes functional and rules.

Gunnison County Electric Association (GCEA) is also a potential buyer of this electricity. GCEA is a much smaller distribution cooperative than DMEA, which means lower operating margins and potentially higher costs to consumers for premium electricity.

GCEA has not done any rigorous analysis of the potential use of CMM from the North Fork, but is essentially frozen into inaction by a number of uncertainties. Those uncertainties include: possible increased costs due to "wheeling" fees - fees paid to transmission and distribution companies for the added load over their lines - which would be charged to transmit the power over DMEA and Western Area Power Administration lines and the potential cost of challenging Tri-State for increased generation rights.

It does not appear that GCEA has done a rigorous analysis of the potential cost of electricity generated by CMM in the North Fork, or that it has developed clear numbers to show the extent of any concern. GCEA does have a proposal from a potential CMM developer but cannot share details at this time. The North Fork is outside GCEA's coverage area and other projects located nearer have received more attention. It has been thinking about the potential of adding a hydropower generator to the Taylor Dam and is exploring another hydro project in Hinsdale County, which would take GCEA near the 5% limit of what Tri-State's contract would permit, leaving little or no room for other sources of generation so long as the Tri-State arrangement is in place. GCEA is currently leaning toward the hydro projects because of projected costs compared to the potential CMM development.

Holy Cross Energy is the third cooperative in the immediate area that could be a potential purchaser. It is the purchaser of the 3 MW currently being produced at Elk Creek. This cooperative is different from the other two in that it is able to purchase renewable energy from distributed sources without repercussions because is it not under contract to Tri-State. Its primary energy provider is Xcel. Holy Cross is currently accepting proposals for solar installations and in personal correspondence has expressed openness to more CMM power. "Wheeling" fees are also likely to impact the economics of electricity generation from CMM from the North Fork coal mines.

A fourth potential purchaser could be a single private customer that can consume the electricity produced on or near site: perhaps the new industry so many communities would like to attract. This scenario avoids multiple "wheeling" fees that a sale to distant cooperatives would incur but may be subject to other regulations. Consumption by a private industry – possibly one attracted to the County by the possibility of an attractively priced, dedicated electrical supply -- may also circumvent

the need to purchase power from one of the coops and be subject to Tri-State's power purchase agreements. This option has not been explored in depth due to the number of variables associated with attracting industry to an area such as who would generate the electricity and if sold to what regulations would the generator be subject. But a concept might be something like this:

- Gunnison and Delta counties partner to seek economic development grant funds.
- These funds are then used to help finance an efficient 10 MW methane fired power plant in the North Fork, with the capacity to draw CMM from any of several local mines.
- The availability of inexpensive electricity is then used to attract one or more light industrial plants to this area, which has been economically hard hit by coal mine closure.

Use of CMM for electricity provides many opportunities to diversify the source of electricity to create a more resilient system. It has a value that wind and solar lack, because it can provide baseload, 24-hour capabilities. As with every opportunity, there are challenges to implementation. In the case of CMM, the challenges are regulatory and market based rather than technical.[25]

It is a mistake to focus on the risks of a new system without focusing on the risks of the existing system, or to pretend that the existing arrangement with Tri-State is without risk to local electricity consumers. There are some real economic, regulatory and policy risks associated with tying the County's energy future to a single energy source and a single generator. Coal is currently more expensive than other options.[25] In light of climate concerns, its future is clouded by immense policy and regulatory uncertainties. Lastly, Tri-State has begun adding more renewable generation to its portfolio (approximately 700 MW since 2009), but in many ways as failed to adapt quickly enough to the changing energy market.

Although the price of electricity has seen a slight rise over the last year it is relatively inexpensive in the Mountain West.[26] On the wholesale market prices of $20-$30/MW are common as the price of renewables is falling. This makes investors and project developers reluctant to begin new projects. According to studies conducted by West Elk mine in 2009 and personal correspondence with project developers, a price of seven cents/kWh (or $70/MWh) is needed to make any CMM project economically feasible. Renewable energy credits as well as efficiency gained with larger projects could help to bring these costs down.

The other major obstacle to these projects are the power purchase agreements and uncertainty in litigation. Power purchase agreements have been signed between

the local distribution coops and Tri-State until 2050. Until the recent DMEA ruling, these contracts limit the amount of renewable energy that can be purchased from other providers.[27] DMEA is awaiting another ruling from FERC that will clarify what costs Tri-State is entitled to recover. Because the FERC board currently has only two of five members and cannot reach quorum, no decision is expected until FERC has a full board. Uncertainty is the primary hindrance for investment in electricity generation.

The tangled web of changing market conditions, local utilities' contractual relationship with Tri-State, and future rulings of the Federal Energy Regulatory Commission are likely to take a long time to sort out. If Gunnison County wants to move forward with generating electricity from CMM in the North Fork, the "single customer" concept, or the light industrial park with several users, are probably a clearer and more certain route than becoming entangled in utility politics and regulatory issues.

Vehicle Fuel (Compressed Natural Gas)

While electricity generation may be a long-term opportunity for CMM utilization, a potential short-term goal could be the production of compressed natural gas (CNG) as a fuel source for Gunnison County's vehicle fleet. The County has already made the commitment to converting its fleet as well as the Rural Transportation Authority (RTA) to this alternative fuel.[28] That satisfies an essential requirement of any project: to identify a demand. However, this project will require further analysis.

While the major obstacles to the generation of electricity is finding a purchaser for the product, CNG presents an opportunity if there is a buyer. There are currently no projects utilizing CMM for compressed natural gas in the United States. If the economics are viable, Gunnison County could be the first locally sourced CMM CNG fleet. Gunnison County may not be the only possible purchaser of this resource. Grand Junction and the Roaring Fork Transportation Authority both currently use CNG powered vehicles.

Two potential obstacles to using CMM for CNG are impurity removal and transportation of the product. The gas would need to be at least 52% methane, less than 48% CO_2, and contain less than 5% nitrogen to be viable for BioCNG systems. Other impurities could then be removed before being compressed. After compression, the CNG would then need to be transported from the production site to Gunnison County.

The technology exists but the costs are undetermined. The CNG would probably have to get to users on trucks since no rail or pipelines are available to deliver the gas to Gunnison from the North Fork Valley. In addition to CNG stations, it is possible

to refuel vehicles directly from a tanker truck. This option could make it feasible to convert the Crested Butte bus service to CNG creating additional demand. Compressed natural gas from CMM may have the demand needed to make a project viable.

A feasibility study of this option could be conducted by a number of qualified firms. This option could be particularly attractive if CMM is considered under the Renewable Fuel Standards and eligible to produce Renewable Identification Numbers (RINs). Fossil fuel companies are (at least under current regulations) required to produce or purchase RINs to offset GHG emissions from their products.[29] Examples of RIN generating activities are growing corn for ethanol production, harnessing bio-waste on a hog farm, landfill gas capture, or even using the methane from wastewater treatment plants.

One such facility that is certified under the Renewable Fuel Standard and has the capability of producing RINs is the Persigo Wastewater Treatment Plant in Grand Junction. That facility can produce RINs because it uses a bio digester to convert organic material into methane. The facility then compresses the methane it once flared to be utilized as CNG.[30] Although CMM does not currently qualify under the Renewable Fuel Standards, it could be worthwhile to investigate this potential.

Pipeline

The majority of CMM capture projects in the United States inject the excess methane directly into natural gas pipelines.[31] This gas is of high enough quality or minimally conditioned to meet pipeline qualifications. West of the Mississippi River, there are no projects of this kind. Pipeline injection projects most often occur in Appalachia and Alabama where the coal has greater concentrations of gas than in Gunnison. Coal mines in those areas often utilize pre-mine drainage wells and extract a purer product. The feasibility of pipeline injection has been analyzed by Mountain Coal Company in its West Elk E-Seam Gas Economic Evaluation Report from 2009 and was found to be too expensive. It would also disturb 15 miles of surface in an effort to reach the Bull Mountain Pipeline. Aside from surface disturbance, the estimated costs exceeded $35 million.[32] CMM from this area appears to be too low in quality (30-80% CH_4) to make pipeline injection a feasible option.

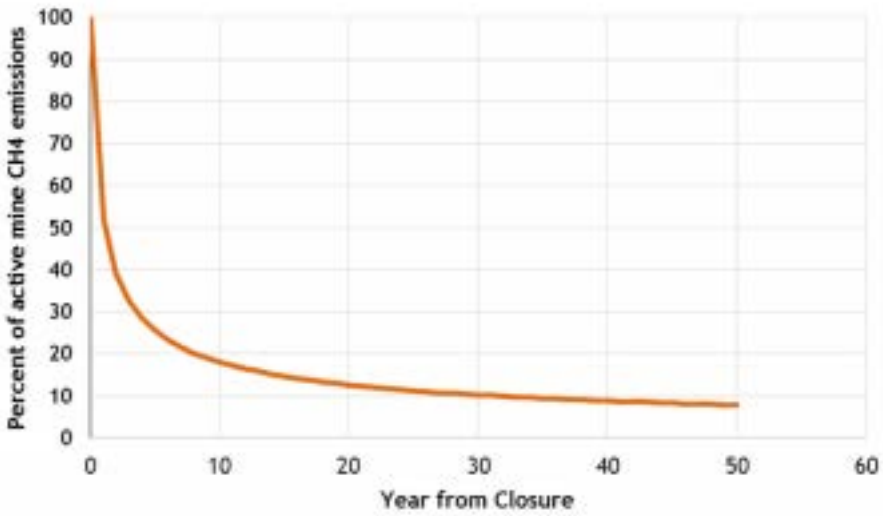
Other

There are many other potential uses for natural gas and CMM. These applications, such as use for industrial feedstock to create plastics or fertilizer, were not investigated in as great of detail. Factors including increased infrastructure, price of natural gas, and lifecycle emissions contributed to this decision.

Methane can be used as an industrial feedstock. This first requires the methane to undergo a chemical reaction yielding ethylene (C_2H_4 or CH_2). Ethylene is used in an array of industrial activities including as ethanol, ethylene glycol for antifreeze, or for polymer chains to form plastics.[33] There is research currently being conducted at the University of Wyoming to improve efficiency of this process. This application did not receive in-depth analysis due to the abundance of cheap natural gas being produced in other areas of the country. The production of plastics could provide a local source of packaging for Delta and Montrose area agriculturalist but impacts should be examined in more detail. It is possible to imagine a plant making plastic bags for Western Colorado agricultural products, or other similar uses.

Another use of methane is to produce ammonia based fertilizer. Natural gas is the primary source due to high hydrocarbon content relative to other sources. This characteristic makes CMM attractive yet obstacle prone. CMM containing high methane concentrations may be attractive for fertilizer production but over time the methane content of CMM will decrease. A decreasing methane concentration yields lower returns. See Figure 3 for the methane decline curve. More information is needed to determine feasibility.

Figure 3: Natural Emission Decline Curve for Abandoned Mines[34]



Locally produced fertilizer could assist area agriculturalists by reducing transportation costs of the input, but it could also mean greater GHG emissions in total. Studies such as "Life Cycle Assessment: a review,"[35] provide important considerations for the production and use of different fertilizers. Life cycle analysis is an important tool to implement when determining the overall environmental impacts of an action, especially when one of the goals is GHG reduction.

In-depth analysis is needed to determine the feasibility of other required infrastructure investments such as factories, in addition to the barriers identified for cleaning and transporting the gas. There are also high quantities of natural gas already on the market making any payback periods too long for serious consideration. If a large manufacturer of plastics or fertilizer were planning to develop a site in the neighboring communities of Paonia or Hotchkiss alternative utilizations may warrant greater attention. Contact information for industry professionals and academic institutions associated with alternative uses has been included so that they may serve as a future resource.

Flaring

Flaring is the destruction of methane through combustion. Although not typically thought of as a use, it does reduce the overall GHG impact, because the resulting CO_2 has much less greenhouse effect that the original methane. Flaring technology is also readily available from the oil and gas sector, as well as companies specializing in coal mine methane reduction.

Flaring methane can result in the production of carbon offsets and can be sold to different carbon trading schemes, such as the California Cap-and-Trade. In 2010, it was believed that a federal cap-and-trade system would be implemented but that never came to fruition. The ability to sell offsets to California businesses allows projects to diversify their income. Coal mine methane qualifies under the Mine Methane Capture Projects Compliance Offset Protocols.[36] Although flaring is a technique to reduce methane emissions, it should be coupled with some kind of economic use when possible. Options for flaring coupled with other uses may provide the best avenue for projects to be economically feasible.

So, while gas flaring would create a net environmental benefit compared to simply letting the methane enter the atmosphere, it is often thought of as an undesirable practice because of the economic waste involved. There is even a world program to reduce it, the Global Gas Flaring Reduction Partnership.

> "The World Bank Group has a leadership role in gas flaring reduction through the Global Gas Flaring Reduction Partnership (GGFR), a public-private initiative comprising international and national oil companies, national and regional governments, and international institutions. GGFR works to increase use of natural gas associated with oil production by helping remove technical and regulatory barriers to flaring reduction, conducting research, disseminating best practices, and developing country-specific gas flaring reduction programs."[37]

All potential uses are bound by common factors. Economic costs associated with construction of gathering systems and purification are the largest obstacle. Following those is time. As the methane content of the gas decreases over time (Figure 3), the economics of a project will be affected. Strategies such as placing equipment on skids rather than permanent pads can help to reduce the permanency of the project allowing for reclamation as well as a way for the developer to transfer the investment to another location.

Regulatory structures

One of the key issues is from whom the rights to the methane need to be obtained. Whether it is a utility, a small independent operator like Vessels Coal Gas Inc., or someone else, whoever wants to use the CMM has to obtain the right to it.

This section will outline the current federal, state, and local regulations that govern the development of coal mine methane in the North Fork Valley. Gunnison County and the State of Colorado have demonstrated a willingness to adjust policy for beneficial outcomes. Regulations should not be viewed as an insurmountable barrier, but they must be considered in the process.

The coal mine methane in the North Fork Valley is located primarily on federal public lands. CMM in the North Fork Valley requires a mixed approach due to the complexity of how mineral rights are determined and leased. Where the federal government leases coal (much of the North Fork coal is federal) there is a question as to whether the owner of the coal lease owns the methane in the coal bed, or whether the ownership of the gas stays with the federal government, and those wanting to exploit it must obtain a separate federal oil and gas lease.

The Bureau of Land Management (BLM) is the responsible agency for leasing the coal or natural gas on federal public lands. There has been some ambiguity whether methane contained in the coal deposit and surrounding strata constitute a separate deposit.[38] An internal administrative decision by the BLM's Internal Board of Land Appeals holds that gas associated with a coal deposit is not a separate deposit. This only applies to methane that is released due to the mining of coal and allows an active coal mine to enter an agreement with another entity to utilize the methane released for economic gain.

In the January 2017 Instruction Memorandum, the BLM authorizes the capture of waste mine methane (methane released from coal mining) for productive use when it does not endanger the miners.[39] This memorandum creates an addendum to permit applications allowing capture but does not require it.

The BLM, which controls the coal or gas deposit requiring leasing, and the United States Forest Service (USFS) that manages the surface impacts. Adding to the complexity where any mining is involved, is the Mining Safety and Health Administration (MSHA) under the Department of Labor. Additionally, the Environmental Protection Agency also participates in monitoring air and water quality associated with mineral development. These agencies sometimes differ regarding whether CMM is part of the coal deposit or a separate gas deposit. This difference is also highlighted by regional variations influenced by politics and markets.

Federal Agencies and Regulations

Under the Surface Mining Control and Reclamation Act (SMCRA) the Office of Surface Mining, Reclamation and Enforcement (OSMRE) is responsible for regulating coal mining activity in the USA. Although OSMRE is primarily responsible, 30 CFR Chapter VII of SMRCA allows a state primacy after it develops a regulatory framework. OSMRE and associated state agencies implement reclamation more than mining activity in progress. Individual mine and reclamation plans will need to be reviewed to determine how CMM may impact those timelines. The state of Colorado assumes primacy of regulatory plans in Colorado under delegation from OSMRE.

The United States Forest Service (USFS) is responsible for conducting the Environmental Impact Statement (EIS) associated with mining actions on lands that it manages. The USFS does not directly regulate the extraction of coal or gas but must give consent for the BLM to lease the minerals. Typically, the USFS is the leading agency in preparing the EIS for leasing and permit applications. Activity associated with CMM capture must comply with USFS management plans in the area. The North Fork Area Coal Mining Exception to the 2012 Colorado Roadless Rule is one such regulation that will allow methane capture and transport through the Sunset Roadless Area.

The Colorado Roadless Rule is an exceptionally important regulation because it includes an exception (North Fork Coal Mining Area Exception) for the construction of roads for activities related to coal mining in a designated roadless area. Much history and conflict surrounds the exception. Within the regulation is a provision that allows for the collection and transport of methane in right-of-ways developed for coal mining related activities. It is the aim of this provision to allow a method of capture and utilization for economic benefit while reducing environmental impact. This provision does not allow for the exploration or capture of coal bed methane without coal mining.

The EPA is responsible for “protecting human health and the environment” according to its mission statement. EPA regulations enforce the Clean Water Act, Clean Air Act, and Endangered Species Act; each of which must be considered for CMM utilization. The EPA is the primary source for GHG emissions reporting, lending the data needed to determine the carbon neutrality of proposed CMM projects; an important step in generating renewable energy credits. In addition to the GHG emissions data, the EPA provides guidance for reductions of pollutants under the Clean Air Act. The mines in the North Fork Valley do not currently need to obtain a Title V (Tailoring Rule) permit but some utilization methods such as electricity production may. [40]

The Mining Safety and Health Administration (MSHA) supports miners through regulations regarding safety and working conditions. MSHA requires that mines vent

methane to a level below 1% for safe operations. Methane becomes flammable between 5-15% and creates an explosion hazard. Reducing the amount of methane present has been the priority for MSHA. While a mine is active, special care must be taken to remain in compliance with MSHA. In especially gassy mines, "waste" methane must be vented. There is no requirement to flare or to use it. [41]

Office of Natural Resource Revenue is located within the Department of Interior. Its main function is the collection and distribution of royalty payments from natural resources produced on public lands. Royalty rates vary for surface mined and underground coal and depend on the intended use. For example, royalties of 12.5% are levied for CMM used for electricity generation or carbon credit sales. Royalty rates for gas are assessed on a sliding scale of 12.5% for production under 5,000 Mcf and 16.6% over 5,000 Mcf.[42]

The Federal Energy Regulatory Commission (FERC) oversees the transmission or transportation of energy resources across state lines. Although an electricity generation project or CNG project would not move CMM across state boundaries, FERC will need to be consulted. In the case of electricity generation, the most promising buyers are members of an interstate energy coops (Tri-State and Xcel). FERC currently does not have a quorum to make decisions causing uncertainty in the regulatory framework of electricity generators and providers.

State Agencies and Regulations

At the state level, there is another layer of regulation and associated agencies. Colorado has progressive restrictions on the venting of natural gas from oil and natural gas wells but no restrictions or incentives for coal mines. Rule 912 of the Colorado Oil and Gas Conservation Commission prohibits the "unnecessary or excessive venting or flaring of natural gas."[43]

Methane is a major contributor to GHG emissions in Colorado. The 2014 Colorado Greenhouse Gas Inventory reported methane emissions from coal mining accounted for 6% of total Colorado emissions in 2010 in comparison with 8% for oil and natural gas production (Figure 4).[44] The state has taken regulatory action to curb natural gas associated emissions. Coal mining seems like the next regulatory step.

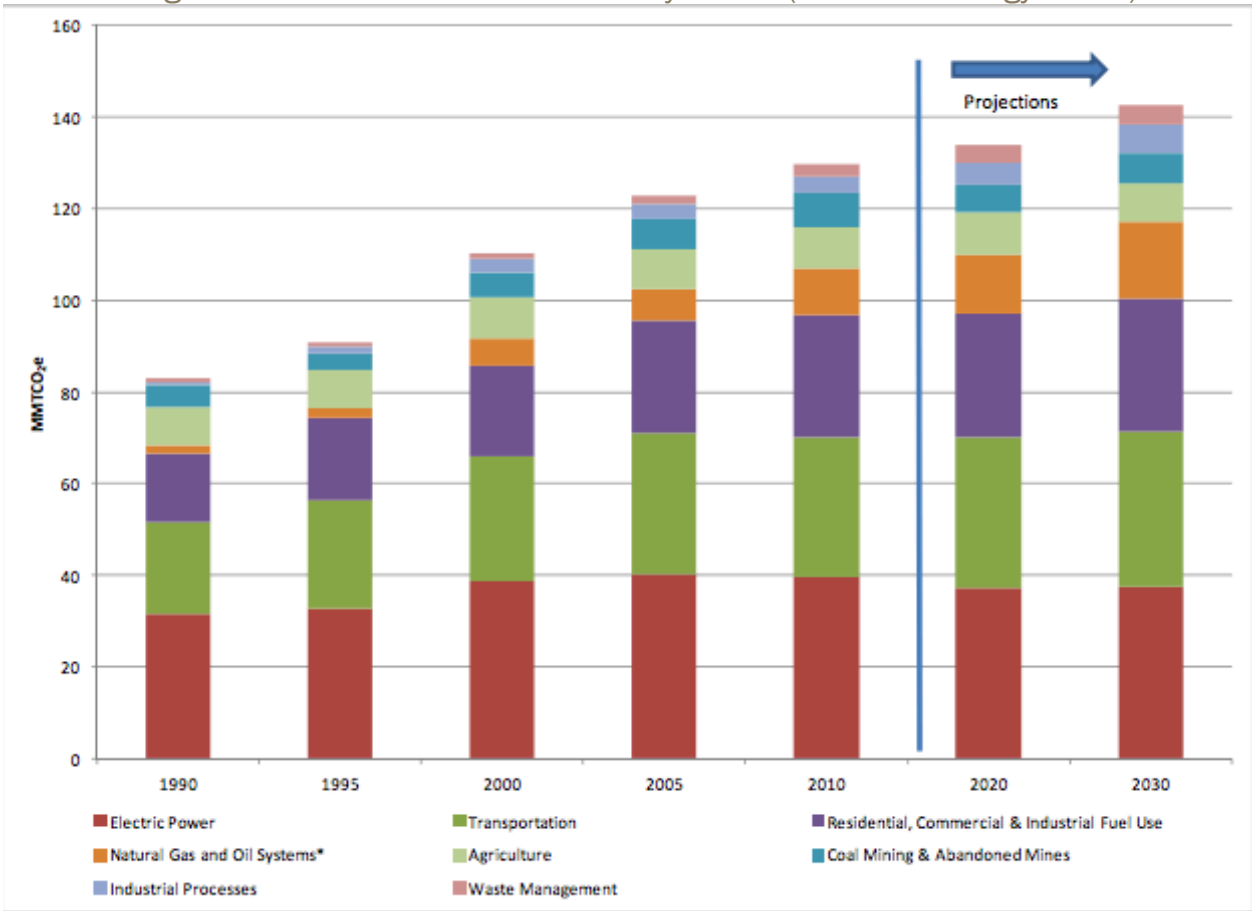
The Colorado Renewable Energy Standard took effect in 2004 to increase the amount of wind, solar, and other renewables in the electricity mix. Since 2013 CMM has also been recognized as qualifying for renewable energy credits. Section 40-2-124(1)(a)(II), C.R.S., qualifies methane as a renewable energy source when defined as, "methane captured from active and inactive coal mines where the methane is escaping to the atmosphere. In the case of methane escaping from active mines,

only methane vented in the normal course of the mine operations that is naturally escaping to the atmosphere is coal mine methane for purposes of eligibility under this section."

This is the same definition the Public Utilities Commission uses. Colorado Senate Bill 13-252 also requires cooperative utilities (such as Tri-State) to generate 20% of their electricity from renewables by 2020. These are both efforts to reduce the state's overall GHG emissions; a goal more easily accomplished by utilizing CMM.

One of the primary challenges to electricity generation and distribution is the availability of on-demand, baseload power. The ability of CMM to qualify for renewable energy credits while producing baseload power is very attractive. In contrast, solar and wind projects produce intermittent power. When the power is able to be generated on-demand it is considered "dispatachable" and can fill any gaps in intermittent production and peak demand.

Figure 4: Colorado GHG emissions by sector (Colorado Energy Office)[45]

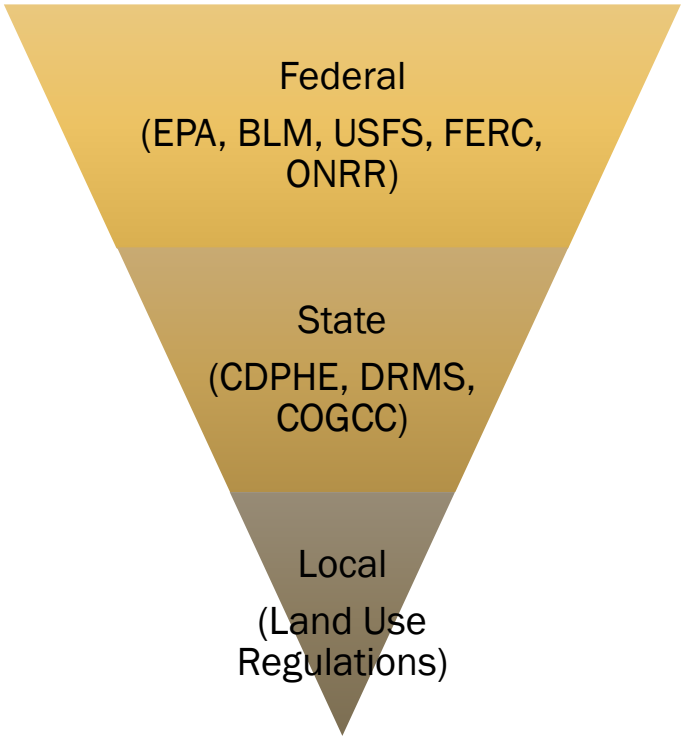


Under SMCRA the state of Colorado has primacy in enforcement of mine planning and reclamation. Mining companies are required to file permits with the Division of Reclamation and Mining Safety. Its mission is "to protect the public, miners and the environment during current mining operations, restore abandoned mines, and to ensure that all mined land is reclaimed to beneficial use."[46] Special considerations for reclamation planning to incorporate CMM would be filed with DRMS. DRMS does not regulate the oil and natural gas industry.

The Colorado Oil and Gas Conservation Commission is responsible for the development of oil and natural gas in Colorado. The Commission and DRMS are housed in the Department of Natural Resources.

Local Agencies and Regulations

In addition to Federal and State regulations, Gunnison County has specific land use regulations. These Board of County Commissioners has the greatest amount of influence on these regulations. Division 9-400 of the Gunnison County Land Use Resolution concerns "Exploration, Extraction and Processing of Minerals and Construction Materials."[47] Gunnison County also has regulations on Oil & Gas Development included in the Land Use Resolution. A special set of regulations apply to the North Fork Valley for development of the coal resource.[48] By altering these regulations, Gunnison County can streamline the process for potential developers.



Recommendations

If getting the North Fork coal mine methane into productive use were easy, someone would already be doing it.

The two primary options are electricity generation and production of CNG. The problem in either case is that these are uses for which natural gas is suited. And compared to natural gas, CMM requires some additional steps to improve quality before it can be put to these uses.

Both need more rigorous study to determine feasibility. Both options will require political leadership and regulatory change to incentivize CMM capture. In the following section, recommendations are provided to potentially navigate some obstacles. Proactive action is needed to curtail this resource waste and avoid negative environmental consequences.

Electricity Generation

The obvious idea for electrical generation is to distribute the electricity through one of the utilities.

This idea appears to be currently unfeasible for several reasons:

- **Market Conditions**: There is no electricity shortage in this region; indeed there is a good deal of power available at attractive prices. Electricity generated from CMM in the North Fork would be competing against a variety of other potential sources.
- **Regulatory and Legal Uncertainty**. Local utilities' contractual obligations to Tri-State, whether there are exceptions for Qualifying Facilities under the Public Utility Regulatory Policies Act (PURPA), whether utilities buying such power need to compensate Tri-State, and related issues all create considerable uncertainty.
- **Price risk**. Any decision creates a risk that could cost electrical consumers more.

But inaction is not without risk. Indeed, sometimes inaction creates the greatest risks. It may be more detrimental to consumers if utilities fail to act and invest in alternative energy sources, as the differential between coal generated electricity and these alternatives continues to widen. Inaction could result in utilities and their customers being responsible for millions of dollars in stranded assets in the form of uncompetitive coal fired power plants. Given the current uncertainties, it seems that it may be easier, rather than trying to convince local utilities to get involved, to form a partnership with Delta County, and together seek funding for a project to generate

electricity on a scale that would be large enough to realize economies of scale and thus lower electricity prices. It seems that is reached at approximately 10 MW allowing to the use of larger, more efficient generators. The Vessels project for example is producing 3 MW by using three 1 MW generators.

This power could then be offered at discount to either a single large potential customer, like Aspen Skico, or tenants of a light industrial park. Selling the electricity incurs additional regulatory costs to be considered within a contract.

Compressed Natural Gas

One novel use could be compressed natural gas for vehicle fuel. Gunnison County is already making strides to create a more environmentally friendly public transportation and vehicle fleet service by converting to compressed natural gas. By 2020, Gunnison County will be using 60,000 gas gallon equivalent per year. When combined with other committed fleets, Gunnison County is projected to use 126,000 gas gallon equivalent/year.[49] If the methane from the North Fork coal mines qualified for the Renewable Fuel Standard, the County could decrease its impact on new natural gas development, while also making the project more attractive for developers.

In addition to facilities needing to be developed on site, delivery of the gas is an issue. If the CNG were to be trucked or railed then trucked, vehicles could refuel from the transport container. Having the CNG trucked may also allow the Mountain Express buses in Crested Butte and Mt. Crested Butte to convert to CNG, producing additional demand for the product.

For CNG to be a realistic option, a policy change by the EPA of what qualifies under the renewable fuel standard is needed. The Gunnison County BOCC can leverage its position along with Colorado's representatives to achieve this goal. The County needs to begin creating a pathway for CMM to qualify and the facility to generate Renewable Identification Numbers (RINs). RINs have become more valuable as the Renewable Fuel Standard increases each year providing a growing market for producers.

The actual molecules may not need to be used as fuel. Financial mechanisms exist that allow for the trading of energy and fuel credits. In this scenario the gas could be used to produce renewable energy credits then traded for RINS. More research is needed to determine if the quality and quantity of gas would allow for a project to be feasible.

University Research

Methane's role as a greenhouse gas is a global issue that is receiving attention from academic institutions across the United States. Much of the research on possible uses is being conducted within the oil and gas departments as well as chemical engineering departments. These researchers may be interested in CMM as a source of methane for their research. Gunnison County could attract large institutions or form a partnership with Western State Colorado University to help sponsor research initiatives. Attracting researchers and engaging students bolsters Gunnison County's reputation as a leader in integrated environmental management and sustainable energy applications.

Flaring

Flaring is the least favorable option unless coupled with one or more of the other technologies. The goal of this report is to provide a blueprint for economic utilization while also reducing methane emissions. Flaring meets the first requirement by generating carbon credits that can be sold in Cap-and-Trade systems. It also reduces the amount of methane entering the atmosphere but only by converting it into CO_2, another greenhouse gas with lower Global Warming Potential. This option may also be the most attractive to active mining operations because flares can be attached to the methane drainage wells in use and be moved as needed. Although flaring is less than favorable when considered alone, it is a useful tool to make other projects more feasible.

Next Steps/Plan of Action

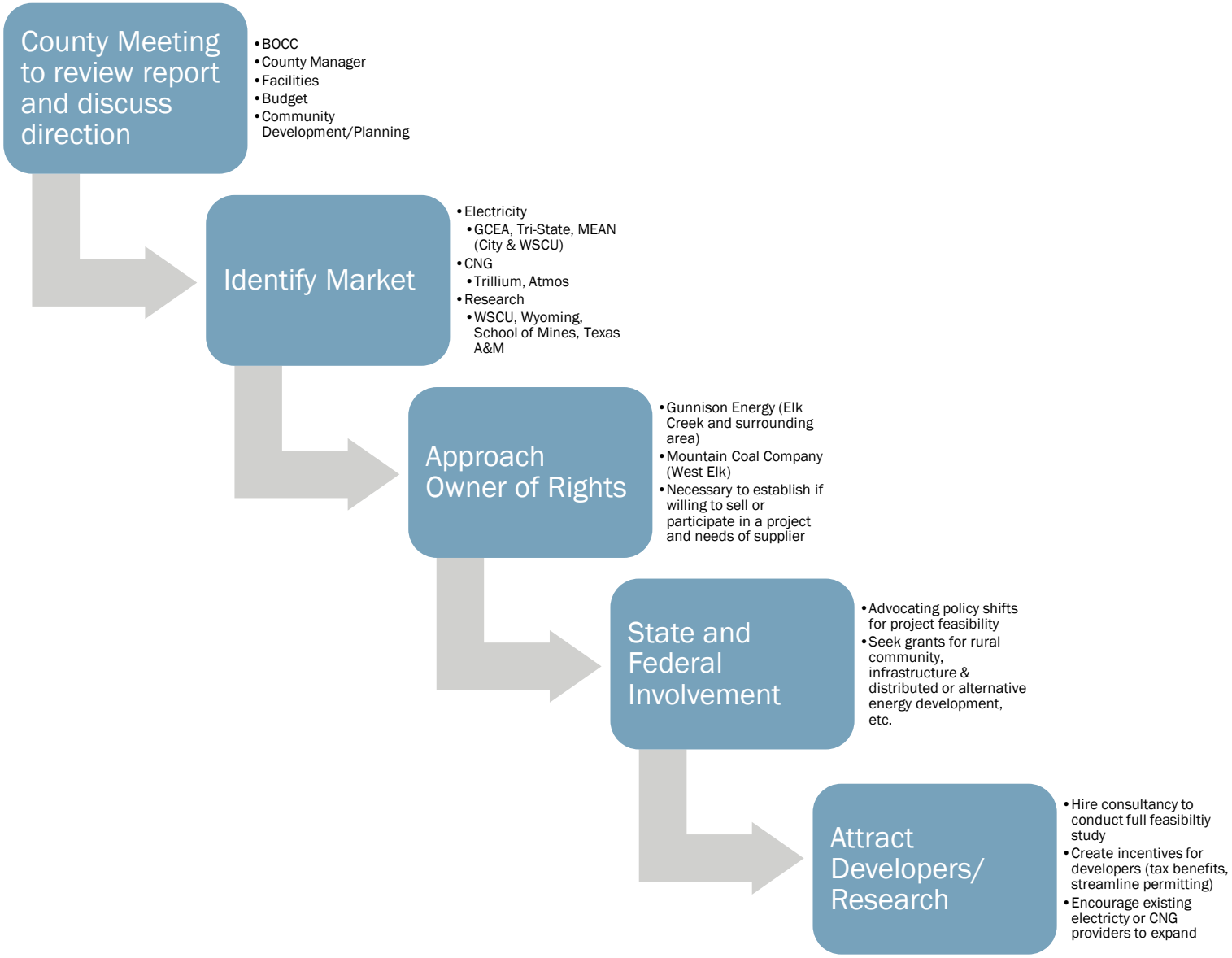
This section provides action items and steps to continue the momentum behind coal mine methane capture and utilization. While the immediate capture and utilization for the above-mentioned purposes does not appear to be feasible, a more in depth review is needed. The action items suggested here serve as incremental goals that may help to make a project feasible in the future.

At minimum, a review of each utilization technique should be conducted when market or regulatory conditions change. Such triggers may include:

- the opening or closing of a coal mine in the area,
- the expansion of mining activities
- changes in the natural gas market
- changes in Federal regulations concerning methane emissions or classification of coal mine methane
- Federal Energy Regulatory Commission rulings

The following is a list of concrete actions Gunnison County could take to create a more resilient energy or fuel mix:

- Advocate for a carbon tax (put a price on pollution)
- Advocate for CMM inclusion in Renewable Fuel Standard
- Create grant program to subsidize project construction or assist in updating feasibility studies performed by potential developers
- Advocate for the greater freedom of electricity choices
- Create tax exemption for beneficial use of waste mine methane
- Approach Western State Colorado University/City of Gunnison as potential buyer to subsidize costs
- Subsidize costs of voluntary flaring in short term for sale to California Cap and Trade
- Design and implement a GHG neutrality tool that can be used for future projects to determine if a project qualifies as renewable under SB 13-252
- Work with Colorado Department of Public Health & Environment to streamline air quality applications
- Conduct a Life-Cycle Analysis on each alternative


County Meeting to review report and discuss direction
• BOCC
• County Manager
• Facilities
• Budget
• Community Development/Planning
Identify Market
• Electricity
• GCEA, Tri-State, MEAN (City & WSCU)
• CNG
• Trillium, Atmos
• Research
• WSCU, Wyoming, School of Mines, Texas A&M
Approach Owner of Rights
• Gunnison Energy (Elk Creek and surrounding area)
• Mountain Coal Company (West Elk)
• Necessary to establish if willing to sell or participate in a project and needs of supplier
State and Federal Involvement
• Advocating policy shifts for project feasibility
• Seek grants for rural community, infrastructure & distributed or alternative energy development, etc.
Attract Developers/ Research
• Hire consultancy to conduct full feasibiltiy study
• Create incentives for developers (tax benefits, streamline permitting)
• Encourage existing electricty or CNG providers to expand

Resources

There are many resources available to developers of coal mine methane projects. The most useful are detailed below.

EPA Coalbed Methane Outreach Program[50]

The Environmental Protection Agency provides assistance through its Coalbed Methane Outreach Program (CMOP). Although the name suggests only coalbed methane there is a section dedicated to coal mine methane. This resource includes maps of potential project areas, reports produced by the EPA, technical assistance and emissions reporting data.

Two of the most valuable tools are the CMM Cash Flow Model and list of Industry Contacts. The CMM Cash Flow Model is a tool designed to determine financial viability of a project. It requires mine specific information to conduct analysis on the viability from abandoned mine wells, gob wells, or ventilation air for a variety of uses. It includes parameters for CNG and electricity generation in the newest version.

Global Methane Initiative[51]

The Global Methane Initiative is a non-profit organization with the goal of reducing methane emissions and promoting it as a clean energy source. The Global Methane Initiative is partnered with the EPA as well as many other countries, development banks, and nongovernmental organizations. GMI provides a global network of projects as well as tools and resources for CMM projects. GMI is primarily focused outside the US but with much of its support coming from the EPA.

Colorado Energy Office[52]

In 2016, the Colorado Energy Office produced two reports on coal mine methane. The Coal Mine Methane in Colorado Market Research Report followed by the Greenhouse Gas Neutrality Assessment of Coal Mine Methane and Waste-to-Energy Pyrolysis Projects. Both of these serve as great resources to understanding the potential benefits for capturing CMM in Colorado. They can provide a broader context to CMM outside the North Fork Valley. Ruby Canyon Engineering of Grand Junction, CO compiled the reports for the Colorado Energy Office.

The Market Research Report is a source of much of the information found within this report although this report focused on the North Fork Valley. The Market Report emphasizes electricity generation without considering other options.

West Elk Feasibility Assessment[53]

Mountain Coal Company, owner of the West Elk Mine, investigated the feasibility of capturing methane from the E-seam in its 2009 lease modification applications (Federal Coal Lease Modifications COC-1362 & COC-67232). Appendix A of this report includes information on flaring, gathering to then produce pipeline quality gas, and the potential for onsite electricity generation. The appendix is a good resource to understand some of the numbers associated with a project of this scale.

California Air Resources Board[54]

The California Air Resources board oversees carbon emissions and offsets in the Cap-and-Trade scheme.[55] The Compliance Offset Protocol Mine Methane Capture (MMC) section provides a FAQ section as well as a manual outlining requirements for qualification. Mine Methane from the North Fork Valley qualifies under this program as demonstrated by the project at the Elk Creek Mine.

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Contacts:

Name	*Company*	*Contact*	*Area of Expertise*
Tom Vessels	Vessels Coal Gas, Inc.	tvessels@VESSELSCOALGAS.COM	Electricity and Flaring at Elk Creek Mine Project
Brad Robinson	Gunnison Energy	Brad.Robinson@OXBOW.COM	Gas rights and Oxbow representative at Elk Creek Mine Project
Mike McBride	Gunnison County Electric Association	mmcbride@gcea.coop	CEO GCEA
Chris Morgan	GCEA	cmorgan@crestedbutte.net	GCEA and Tri State Board member
Kathy Welt	Mountain Coal Company	kwelt@archcoal.com	Environmental Engineer at West Elk Mine
Desty Dyer	BLM, Montrose Field Office	970.240.5300 (Montrose Field Office)	Mining Engineer, Coal progam
Lucas Eckenrod	USFS, Paonia Ranger District	970.557.4131	
Ben Apple	Environmental Commodities Corporation	ben.apple@envcomcorp.com	Carbon Credit trading/Flaring
John Gavan	Delta-Montrose Electric Association, Tri-State	john@thegavans.com	
Jim Heneghan	DMEA	Jim.heneghan@dmea.com	Renewable Energy
Phil Zimmer	DMEA	Phil.zimmer@dmea.com	Energy Services
Dr. Alexei Milkov	Colorado Geological Society, School of Mines	amilkov@mines.edu 303.273.3887	Coal Bed Methane geology, non-traditional well design
Dr. Maohong Fan	University of Wyoming	mfan@uwyo.edu	Coalification, Syngas, Life-cycle analysis, Pollution control, Aromatics

Michael Coté	Ruby Canyon Engineering	970.241.9298 ext. 11	Environmental engineering, CMM feasibility
Dan Tonello	Persiogo Wastewater Treatment Plant, Grand Junction	970.256.4171	Bio-gas CNG
John Cattles	Facilities Manager, Gunnison County	jcattles@gunnisoncounty.org	Gunnison CNG fleet conversion
Andrew Sand	Colorado Energy Office	Andrew.sand@state.co.us 3030.866.2206	Assistant Director of Policy and Legislation
Samantha (Sammy) Reifer	Colorado Energy Office	Sammy.reifer@state.co.us 303.866.2418	Research and Outreach Associate
Matt Shmigelsky	Clean Energy Economy for the Region (CLEER), Garfield Clean Energy	mshmigelski@cleanenergyeconomy.net 970.704.9200	Local Energy Solutions
Trish Thibodo	Delta County Economic Development, Inc.	trish@deltacountyed.org 970.874.4992	Economic diversification
Dr. Christopher Greene	Western State Colorado University, ICE Lab	cgreene@western.edu 970.943.2300	ICE Lab Project Director
Robert Drexel, Vincent Rogalski, Paula Swenson	Region 10		Western Slope Economic Development
Ben Cappa	CDPHE- Air Pollution Control Division	Ben.cappa@state.co.us 303-692-3162	Compliance and Enforcement Program (Coal)
Kay Turgeson	BioCNG	biocnginfo@biocng.us 630-410-7202	CNG system
Brian Johnson	Sheldon Kye Energy LLC	brian@sheldonkye.com 303.962.2496	Energy Project Development