LWVCO STUDY CONCERNING HYDROFRACTURING FOR OIL, GAS AND METHANE

STUDY PURPOSE: To investigate the impact of hydrofracturing for natural gas, oil, and methane on the State of Colorado and its citizens, and to discern what public policies are in place or need to be in place for this activity.

The following are study questions and background educational material for the local leagues to follow to conduct a unit meeting on hydraulic fracturing and come to consensus.

The Fracking Study Committee would like to acknowledge that much of the following information comes from the Colorado Oil and Gas Conservation Committee (COGCC), the primary regulatory agency for the oil and gas industry,[1] and from the Energy Institute at the University of Texas-Austin[2], in collaboration with the Environmental Defense Fund[3].

On their website, COGCC lists their Strategic Plan with the following goals:

- Promote the exploration, development and conservation of Colorado's oil and natural gas resources.
- Prevent and mitigate adverse impacts to public health, safety, welfare and the environment.
- Demonstrate balanced leadership in the regulation and promotion of oil and gas development in Colorado at the local, state and federal levels.

In addition, there are seven objectives to achieve these strategic plan goals, including ensuring compliance through enforcement programs, expediting the processing of oil and gas well drilling, serving as the primary government resource to the public, maintaining and developing COGCC information technology resources, developing and implementing business process management, providing administrative and technical support to assist COGCC in performing its policy, adjudicatory and rulemaking functions, and managing financial and personnel resources.

PROCESS AND IMPACTS OF HYDRAULIC FRACTURING

1. What is hydraulic fracturing?
2. What procedures do the drilling companies go through to obtain drilling rights?
3. Who gives permission from the state and/or the county?
4. What type of licenses/permits must they have?
5. Who enforces laws pertaining to these and related issues?

Hydraulic fracturing (referred to as fracking throughout this report) is defined by the Colorado Oil and Gas Conservation Commission as " …the process of creating small cracks, or fractures, in underground geological formations to allow oil or natural gas to flow into the well bore and thereby increase production. Prior to initiating hydraulic fracturing, engineers

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1 www.cogcc.state.co.us/

2 From the report "*Fact-Based Regulation for Environmental Protection in Shale Gas Development*" from the Energy Institute at the University of Texas, Austin: http://www.energy.utexas.edu/images/ei_shale_gas_regulation120215.pdf

3 http://www.edf.org/

and geoscientists study and model the physical characteristics of the hydrocarbon- bearing rock formation, including its permeability, porosity and thickness. Using this information, they design the process to keep the resulting fractures within the target formation. In Colorado, the target formation is often more than 7,000 feet below the ground surface and more than 5,000 feet below any drinking water aquifers.

The oil and gas industry uses the above definition for fracking, which is only one operation in the development of an oil or gas well; many lay people refer to the entire sequence of operations performed during well development, from the initial drilling of the well to the sealing and abandonment of the well, as fracking. This difference in definitions can result in confusion between the public, the industry and regulatory agencies. Some potential oil and gas development impacts of concern to the public happen outside of the actual fracking operation (during preparation for or cleanup after the fracking, or during transport of the fracking materials, for example). It is recommended, therefore, that when discussing the topic, one refer to “fracking and associated processes.

Before describing the fracking process, it is necessary to distinguish between vertical and horizontal drilling of oil and gas wells. All wells are initiated with vertical drilling. The well is created by drilling a hole 5 to 50 inches in diameter into the earth. After the hole is drilled, sections of steel pipe (casing), slightly smaller in diameter than the borehole, are placed in the hole. Cement is often placed between the outside of the casing and the borehole. According to the COGCC, the casing provides structural integrity to the newly drilled well bore, in addition to isolating potentially dangerous high pressure zones from each other and from the surface.

With these zones safely isolated and the formation protected by the casing, the well can be drilled deeper with a smaller bit, and also cased with a smaller size casing. Modern wells often have two to five sets of subsequently smaller hole sizes drilled inside one another, each cemented with casing. Once the vertical well is drilled to a substantial depth (5,000 feet to 9,000 feet) the drill can be turned horizontally and drilled a further distance, up to two miles[4.] Materials used may include drilling fluid (“mud”) which is pumped down inside of the drill pipe and then exits at the drill bit.

To fracture the formation, special fracturing fluids are injected under high pressure down the well bore and into the formation. These fluids typically consist of water, sand, and chemical additives. The pressure created by injecting the fluid opens the fractures. Sand is carried into the fractures by the fluid and keeps the fractures open to increase the flow of oil or natural gas to the well bore. The chemicals serve a variety of purposes, including increasing viscosity, reducing friction, controlling bacteria, and decreasing corrosion. Following the fracturing treatment, much of the fluid flows back up the well bore and is collected at the surface in tanks or lined pits.

This “flowback fluid” combines with saline water located in the fractured formation, and the mixture is known as “produced water”. Permanent storage of produced water is typically in surface evaporative ponds or in deep underground injection wells.

The Colorado Oil and Gas Conservation Commission, a sub-agency of the Department of Natural Resources, is the oversight agency for the oil and gas industry in our state. COGCC’s mission is to foster the responsible development of Colorado’s oil and gas natural resources. The agency has a very comprehensive website: one section deals with “Hot Topics/Hydraulic Fracturing”, and another includes information about the commissioners (two executive directors and seven additional commissioners), and describes their qualifications. Some of the commissioners must reside in specific areas of the state, some must be local

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[4] http://files.eesi.org/fracking_technology_120111.pdf

government officials, some must have experience working in oil & gas, and one has to have environmental or wildlife protection experience. The website lists all of the Colorado Revised Statutes and COGCC rules and regulations that govern oil and gas development in the state, as well as monitoring and enforcement information.

Anyone seeking to drill a natural gas or oil well in Colorado must submit a Form2, Application for Permit to Drill (APD), under COGCC Rule 303.a. The APD includes information on the well location, formations and spacing, and drilling plans and procedures, including the casing, cementing and blowout preventer. This information is reviewed by engineers and permit technicians at COGCC, and additional conditions are imposed where necessary to protect public health and the environment.

Applicants must also submit COGCC Form 2A, Oil and Gas Location Assessment, for the well pad and certain related facilities, under Rule 303.b. The Location Assessment contains information about the location, including information about the equipment to be used, nearby improvements, surface and ground water, access roads, current and future land uses and soils. This information is reviewed by the environmental professionals at COGCC, and conditions of approval can be imposed where necessary to protect the public health and environment.

All Location Assessments and associated APD's are subject to public notice and at least 20 days (a 10 day extension may be requested) of public comment under Rule 305. Special notice should be provided to the local government, the surface owner, and across most of the state, the owners of surface property within 500 feet. COGCC has received complaints from local governments and individual landowners that notice has not always been received.

Operators are required to consult with the surface owner and the local government in locating certain facilities under Rule 306. If a proposed well pad is located in important wildlife habitat, then COGCC will consult with the Colorado Division of Wildlife. If the operator seeks a variance from certain environmental regulations or the local government requests, then COGCC will consult with the Colorado Department of Public Health and Environment (CDPHE).

Following staff review and any consultation and public comment, Location Assessments and APDs are approved by the COGCC Director. The COGCC may attach technically feasible and economically practicable conditions of approval under Rule 305, and, as noted above, the COGCC often does so to protect public health and the environment. In addition, applicants must provide financial assurance to the State under Rule 304 and the 700 Series of Rules. Following the drilling and completion of the well, additional reporting requirements apply under Rules 308A, 308B, and 309.

Each county/city in Colorado is entitled to name a Local Government Designee (LGD), who is entitled to receive from COGCC information related to drilling activities in that area. The COGCC requires that operators provide notice of an application to drill for oil and gas to the LGD, and the county/city has the right to consult with COGCC regarding the location of roads, production facilities and well sites prior to the commencing of operations with heavy equipment. The LGD may also request consultation with the Colorado Department of Public Health and Environment regarding concerns about public health, safety, welfare, or impacts to the environment.[5]

As many are aware, there has been considerable controversy in Colorado regarding the role of local governments in exercising local land use decisions. Gov. Hickenlooper appointed a Task Force during the 2012 legislative session to address this controversy, and

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[5] http://cogcc.state.co.us/RR_Docs_new/rules/300Series.pdf

the report from the group suggested COGCC work with the LGD'S. In addition, COGCC has added two positions to the agency staff, known as Local Government Liaisons. The establishment of working relationships between all of the above entities is still in development.

COGCC has a comprehensive website, including a list of Hydraulic Fracturing Rules. A sampling of these rules includes Rule 205, which requires an inventory of chemicals to be maintained at the drill site, and requires operators to provide this information upon request to COGCC and certain health care professionals. The Rule 205 series also requires the industry to disclose all fracking ingredients on a publicly-accessible website, FracFocus.org[6] (a non-governmental website managed by the Groundwater Protection Council[7] , of which Colorado is not a member, and the Intergovernmental Oil and Gas Compact Commission[8]), unless certain ingredients are entitled to trade secret status. Rule 317B mandates setbacks and enhanced environmental precautions near surface waters and tributaries that are sources of public drinking water.

COGCC enforces all aspects of well drilling, development, and closure; they require industry self-monitoring and reporting for much of their information. There are 34 field inspectors, engineers and location and environmental staff assigned across the state (for about 50,000 wells). These include a manager, a supervisor and three inspectors assigned to each of three geographical areas (northeast, northwest, and south) outside of Denver, and two environmental inspection specialists who focus on reclamation issues. Any of these employees can report violations seen in the field. Nearly all inspections are unannounced. Inspectors are equipped with laptop computers, global positioning system (GPS) devices, pressure gauges, range finders and cameras. During 2010, COGCC staff conducted 17,157 inspections.

OWNERS RIGHTS

1. What are individual owner's rights on properties being drilled?
2. What procedures are followed in approaching landowners?
3. Who represents landowners if a dispute arises?

In the United States, oil and gas rights to a particular parcel may be owned by private individuals, corporations, Indian tribes or local, state or federal governments. Oil and gas rights extend vertically downward from the property line. Unless explicitly separated by a deed, oil and gas rights are owned by the surface owner. Once severed from surface ownership, oil and gas rights may be bought, sold or transferred like any other real estate property.

In many cases, the surface rights and subsurface rights (such as the rights to develop minerals) for a piece of land are owned by different parties. This is known as a split estate. In these situations, mineral rights are considered the dominant estate, meaning they take precedence over other rights associated with the property, including those associated with owning the surface. However, the mineral owner must show due regard for the interests of the surface estate owner and occupy only those portions of the surface that are reasonably necessary to develop the mineral estate.

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[6] www.fracfocus.org

[7] http://www.gwpc.org/

[8] http://www.iogcc.state.ok.us/

Colorado law recognizes that access to the mineral estate from the surface estate is necessary in order to develop the mineral interest. The law provides for access to the mineral estate by allowing subsurface owners "reasonable use" of the surface estate.

When property is purchased, a title search is usually performed and title insurance is usually purchased. Often, this document will note any separate subsurface mineral owners. Prior to or when first approached by a company regarding drilling, a surface owner can review the property ownership documents to determine if she/he owns the mineral rights. If a deed is unclear, it may be necessary to hire an attorney to interpret the information. If there is a dispute between the owner and an oil or gas company, the landowner certainly will need to hire an attorney to help resolve the dispute.

The surface owner and the oil and gas company often reach a surface use agreement, which covers things like dust mitigation, burial of pipeline, making sure that drilling is not done too close to buildings and whatever other conditions can be agreed upon. There may also be a road use agreement in which companies agree to maintain a road on a surface property. In lieu of a surface use agreement, a company may post a bond for crop losses and/or surface damages with COGCC, but the agency prefers that the company and the surface owner come to an agreement.

Usually the negotiations between the oil or gas developer and the surface and mineral owners involve monetary payments. The surface owner is often offered some type of financial compensation for the use of and potential damage to the land; the mineral owner is often offered a lease signing bonus and some percentage of the production of the oil/gas as a royalty payment. If the surface and mineral owner are the same, both payments may apply.

PROCEDURE TO EXTRACT NATURAL GAS AND OIL IN COLORADO

1. What is the difference between coal bed methane and shale gas mining?
2. How is shale gas and coal bed methane production different from conventional gas production?
3. What chemicals are used in the fracking process and by what methods are they disposed?
4. Who regulates and monitors the drilling procedure and use of fracking chemicals?
5. How much water is used in the drilling and fracking process? Where does it come from?

Coal bed methane is a form of natural gas extracted from underground coal beds. Typically these beds are located closer to the surface and are softer than shale gas formations. Shale natural gas is trapped within shale formations quite deep underground. Because coal beds are softer and shallower, coal bed methane is typically extracted using vertical wells only, not horizontal, and less pressure is required to release the methane, compared to shale formation gas. Extraction of shale gas requires horizontal fracking and much higher pressures than methane. Coal bed methane is more commonly found on the Western slope of Colorado, but shale formations can be found throughout the state.

Conventional gas reservoirs are created when natural gas migrates toward the earth's surface from an organic rich source formation into highly permeable reservoir rock, where it is trapped by an overlying layer of impermeable rock. Unconventional shale gas resources form within the organic rich shale source rock. The low permeability of the shale greatly inhibits the gas from migrating to more permeable reservoir cracks. Without horizontal drilling and hydraulic fracturing, shale gas production would not be economically feasible because the natural gas would not flow from the formation at high enough rates to justify the cost of drilling.[9]

[9] 7/9/12. "*What is shale gas and why is it important?*" Retrieved 8/18/12 from http://www.eia.gov/energy_in_brief/about_shale_gas.cfm

In 2011, COGCC regulation of the oil and gas industry underwent assessment by an independent group known as the State Review of Oil and Natural Gas Environmental Regulations (STRONGER)[10]. This group has assessed the performance of 21 other states. The STRONGER Board is made up of nine individuals throughout the US. They include three gas and oil representatives, 3 staff and 3 environmentalists. The Board works by consensus. The Colorado STRONGER report, which was published in the latter part of 2011, contained a number of suggestions regarding minimum and maximum surface casing depths for protecting fresh water aquifers, well completion reports, assessment of normally occurring radioactive material (NORM), and the adequacy of available water supplies.

Regarding the surface casing depth, the report recommends: “The setting of surface casing to an appropriate depth is critical for meeting anticipated pressures and for protecting fresh water aquifers. In determining minimum surface casing setting depths, the COGCC considers all available information, including: a state-wide ground water atlas and area-specific aquifer studies prepared by the Colorado Geologic Survey (CGS); a statewide database of water well information maintained by the Colorado Division of Water Resources (DWR); and oil and gas well electric logs on file with the COGCC. As part of this process, the COGCC reviews information on all water wells and one representative oil and gas well within at least one mile of the new well. The review team recommends that the COGCC work with stakeholders to review how available information is used to determine minimum surface casing depths and how those depths assure that casing and cementing procedures are adequate to protect fresh groundwater. This review should include a determination of the percentage of surface casing depths determined on the basis of existing water well depths, oil and gas well electric logs, area aquifer studies, or a combination of these sources of information. Additionally, this review should determine the percentage of wells in which the surface casing is set through the base of the freshwater aquifer.”

Regarding maximum surface casing depth, the report recommends “There is no standard for the maximum depth to which surface casing can be run. The review team recommends that the COGCC review any past instances where problems occurred in the setting or cementing of surface casing in a well to be hydraulically fractured, where casing or cement failures occurred during hydraulic fracturing, and other available relevant information, and consider whether establishing a maximum surface casing depth may be in order to prevent well control or cementing problems that may arise when lost circulation zones or gas-producing formations are penetrated before surface casing is set and cemented.”

Approximately 99.5% of fracking fluid volume is water and sand. In general the fluid is about 90% water, 9.5% proppant particles (like sand), and 0.5% chemical additives. The additives have a number of purposes, including reducing friction (as the fluid is injected), acting as a biocide (to prevent bacterial growth), scale inhibition (to prevent mineral precipitation), corrosion inhibition, clay stabilization (to prevent swelling of expandable clay minerals), gelling agent (to support proppants), surfactant (to promote fracturing), and cleaners. In December 2011, the COGCC approved a new rule that requires drillers to disclose all chemicals and their concentrations used in hydraulic fracturing, unless the operator has filed with COGCC for trade secret status for a specific chemical. This took effect April 1, 2012. For now, this list is to be filed with FracFocus; please see the attached addendum for the list of chemicals on the FracFocus website. COGCC will be reviewing the effectiveness of this website in 2013.

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[10] http://67.20.79.30/sites/all/themes/stronger02/downloads/Colorado%20HF%20Review%202011.pdf

Many of the chemicals used for fracking are the same as those used in industrial and household applications, and must be handled properly. For certain chemicals, safe work practices, proper site preparation and attention to handling are required to ensure that employees, the public, and the environment are protected. Some of the chemicals used in fracking include benzene, toluene and formaldehyde, which are known carcinogens. These warrant more study re: the effects on human health. The non-profit organization Earthworks provides a more cautious perspective on the use of fracking chemicals[11]

The COGCC requires an operator to maintain an inventory of the chemical products used down hole or stored at a well site for use down hole, including fracking fluid. Such chemicals must also have Material Safety Data Sheets (MSDS) readily available for review by all personnel at a central location on the job site. The MSDS outline the hazards associated with the chemicals and the appropriate steps to take to protect the user and the environment. The COGCC website maintains a listing of all violations of chemical handling, storage, and disposal regulations.

The COGCC regulates and monitors drilling procedures and the use of fracking chemicals; the agency delegates much of the monitoring and incident reporting to industry operators, and grants variances from certain monitoring, recording, and reporting requirements under appropriate circumstances.[12]

ENVIRONMENTAL IMPACTS OF HYDRAULIC FRACTURING

With the Energy Policy Act of 2005, Congress exempted the natural gas and oil industry from regulations in the Clean Water Act, the Safe Drinking Water Act, the Clean Air Act, the Resource Conservation and Recovery Act (RCRA), Superfund (CERCLA), and the National Environmental Policy Act (NEPA). These include:

- exemptions regarding the disposal of natural gas or "fluids or propping agents (other than diesel) pursuant to hydraulic fracturing operations related to oil, gas, …" in injection wells.
- exemptions from:
  - storm water discharge regulations.
  - consideration of fracking chemicals as "pollutants".
  - possible operator liability for solid waste contamination and triggering of a Superfund site.
  - consideration of well sites as sources of air pollutants.

These are known as the Halliburton Loophole. At this time, only the states have jurisdiction over the above hydraulic fracturing and other associated processes.[13]

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[11] http://www.earthworksaction.org/issues/detail/hydraulic_fracturing

[12] COGCC rule 341: http://cogcc.state.co.us/Announcements/Hot_Topics/Hydraulic_Fracturing/Rule341.pdf

[13] http://docs.nrdc.org/air/files/air_07103101a.pdf See also "*2.3.1.2 Exemptions from Federal Regulations*", from the report "*Fact-Based Regulation for Environmental Protection in Shale Gas Development*" from the Energy Institute at the University of Texas, Austin: http://www.energy.utexas.edu/images/ei_shale_gas_regulation120215.pdf

Much of the following information comes from the report “Fact-Based Regulation for Environmental Protection in Shale Gas Development” from the Energy Institute at the University of Texas, Austin.[14]

In regard to fracking there are a number of environmental impacts that need to be addressed. The operational areas we will include are: drill pad construction and operation, blowouts, erosion control and polluted runoff to surface waters, leaks and spills from drilling operations, emissions from drilling rigs, contamination to groundwater , and water supply and consumption.

Drill pad construction and operation, which is permitted by COGCC with local government approval, can create impacts on unimproved areas, such as gravel roads, by creating soil erosion and transport of sediment into surrounding water bodies during heavy rain events. Most drilling operations should have a storm water management plan in place, as required by the state, which will address these impacts. The industry needs to make sure that there are Best Management Practices (BMPs) in place for sediment control measures, such as seeding, filter fences, terraces, check dams and use of straw bales. Agreements with local governments addressing dust from operations should be dealt with prior to drilling; at times, local governments may require watering operations to control dust under various circumstances.

The National Energy Technology Laboratory (NETL) has sponsored research into the impacts on ecology due to drilling and provides information on improved road designs and minimizing impacts to sensitive birds and wildlife

One very important area of concern relative to well construction is the cement casings that are constructed within the well bore. These must be done correctly and in accordance with COGCC regulations. There is much evidence that the majority of the seepages and leaks from oil and gas wells occur from poorly constructed wellhead casings. This is an area which the STRONGER report noted needs more oversight from the industry and permitting agencies.

Another important area of concern for Colorado is the quantity of water required for natural gas production. Greater emphasis is being placed on recycling and reuse of production water for later fracking, not only to reduce water requirements, but also to reduce the volume of flowback wastewater that must be managed.

Once hydraulic fracturing has been completed in a shale gas well, the fluid pressure is relieved and a portion of the injected fluid returns to the well bore as “flowback”, which is brought to the surface for treatment, recycling, and/or disposal. Flowback water contains some or all of the following: sand and silt particles, clay particles which remain in suspension, oil and grease from drilling operations, organic compounds from the hydraulic fracturing fluids and producing shale and total dissolved solids (TDS) from the shale. The fluid withdrawn from the well consists of a mixture of the flowback water and saline water already present in the formation; this mixture is referred to as “produced” water.

The return of hydraulic fracturing fluid is important: if water recycling was to increase in the industry, a higher rate of return of flow back water would reduce the total water requirements of shale gas production. (This reduction would not, however, reflect a reduction in the amount of underground water withdrawn from the formation).

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[14] http://www.energy.utexas.edu/images/ei_shale_gas_regulation120215.pdf

HYDRAULIC FRACTURING AND GROUNDWATER CONTAMINATION

With the increase in natural gas and oil well numbers and production across the state, there is great concern about the potential for groundwater contamination from the chemicals used for fracking. A contributing factor to the level of controversy may well be the location of some wells in proximity to urban centers and other highly densely populated areas, resulting in closer contact with the general public than in previous oil and gas operations.

The possible routes of escape of fracking chemicals may be through gas-well induced fractures outside of the target zone and into aquifers, the intersection of induced fractures with natural underground fractures that lead to aquifers through abandoned and improperly plugged oil and gas wells, or upward in the well bore through the annulus between the borehole and the casing.

The greatest potential for impacts from a shale gas well appears to be from failure of the well casing integrity, with leakage into an aquifer of fluids that flow upward in the annulus between the casing and the borehole. Well integrity issues resulting in leakage can be divided into two categories. In annular flow, fluids move up the well bore, traveling up the interface between the rock formation and cement or between the cement and the casing. Leak flow is flow in a radial direction out of the well and into the underground formation. In general, a loss of well integrity and associated leakage has been the greatest concern for natural gas, leading to home explosions.

The STRONGER report recommended that Rule 341 require operators to monitor and record bradenhead annulus pressure during hydraulic fracturing operations and to promptly report to COGCC increases in pressure greater than 200 psig. These requirements help ensure that groundwater is protected and that prompt action is taken if conditions arise that could lead to the subsurface release of hydraulic fracturing fluids.

Regarding the surface casing depth, STRONGER recommends: “The setting of surface casing to an appropriate depth is critical for meeting anticipated pressures and for protecting fresh water aquifers. In determining minimum surface casing setting depths, the COGCC considers all available information, including: a state-wide ground water atlas and area-specific aquifer studies prepared by the Colorado Geologic Survey (CGS); a statewide database of water well information maintained by the Colorado Division of Water Resources (DWR); and oil and gas well electric logs on file with the COGCC. As part of this process, the COGCC reviews information on all water wells and one representative oil and gas well within at least one mile of the new well. The review team recommends that the COGCC work with stakeholders to review how available information is used to determine minimum surface casing depths and how those depths assure that casing and cementing procedures are adequate to protect fresh groundwater. This review should include a determination of the percentage of surface casing depths determined on the basis of existing water well depths, oil and gas well electric logs, area aquifer studies, or a combination of these sources of information. Additionally, this review should determine the percentage of wells in which the surface casing is set through the base of the freshwater aquifer.”[15] In general, the STRONGER team has concerns that certain well casings do not extend below the aquifer, but rather end within it, thus allowing contamination of the aquifer.

The STRONGER report also addressed maximum surface casing depths (there are no standards for maximum depth in the industry) and recommended that the COGCC review any past instances where problems occurred in the setting or cementing of surface casing in a well to be hydraulically fractured, where casing or cement failures occurred during hydraulic fracturing, and other available relevant information. Consider whether establishing a maximum

[15] http://67.20.79.30/sites/all/themes/stronger02/downloads/Colorado%20HF%20Review%202011.pdf

surface casing depth may be in order to prevent well control or cementing problems that may arise when lost circulation zones or gas-producing formations are penetrated before surface casing is set and cemented.

There is at present little evidence of groundwater contamination from hydraulic fracturing of shales at normal depths. A possible explanation for this is that after fracturing is completed, the fluid flow is toward, not away from the well, as gas enters the well bore during production. However, the EPA is currently conducting a two year study on the impacts of hydraulic fracturing on drinking water. One site in the Raton Basin in Colorado is part of the study, as well as sites in Texas, Pennsylvania, Louisiana and North Dakota.

CONCERNS ABOUT FRACKING FLUIDS

There are over 450 different chemicals used for fracking. The overall composition of fracking fluid varies among companies and the properties of the shale being treated. The detailed composition of the additives has been controversial because the industry feels this is proprietary information. There needs to be a clearer understanding of what are the key chemicals of concern for environmental toxicity and their chemical concentration in the injected fluid. Over the last two years, voluntary disclosure and state based disclosure laws have resulted in increased openness. The COGCC implemented mandatory fracking fluid disclosure requirements for Colorado operators in April, 2012. This reporting is done on the FracFocus website. COGCC did allow for the industry to claim trade secret status for certain chemicals in fracking fluids, thereby exempting them from mandatory disclosure. The agency plans to review the effectiveness of the FracFocus.org website in January 2013.

Many of the fracking chemicals are also used in the manufacture and use of commercial products and other applications utilized in everyday activities. According to the Waxman Committee Report[16] there are four compounds of particular concern. They are:

- 2-BE (a surfactant noted in the report for destruction of red blood cells, and dangerous to the spleen, liver, and bone marrow) is widely used in many commercial products, such as solvents, paints, polishes, pesticides, household cleaners, and brake fluids. As a result of the production and use of 2-BE it is now widely dispersed in a natural environment. This is being replaced in hydraulic fracturing with a new product having low toxicity and with properties requiring use of a much lower volume of product.
- Benzene is a known human carcinogen. Additional exposures to benzene take place through use of consumer products and in a number of workplace environments, as well as from fumes from gasoline, glues, solvents and some paints. Cigarette smoking and secondhand smoke are significant sources of benzene exposure, accounting for about 50% of benzene exposure in the general population in the US.
- Naphthalene (a probable human carcinogen), is a major component of mothballs and toilet bowl deodorizers. It is relatively biodegradable (half life of a few weeks in sediment).
- Polyacrylamide (PAM) is widely used as a consumer product in non-stick pan sprays, biomedical applications, cosmetics and textiles, as well as flocculants, thickening agents and soil conditioners. Although some risk assessment research has been done for several environmental applications, it has generally been assumed that PAM is safe.

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[16] http://democrats.energycommerce.house.gov/sites/default/files/documents/Hydraulic%20Fracturing%20Report%204.18.11.pdf

Although the release of more of these chemicals into the environment by hydraulic fracturing is not necessarily acceptable, their use should be evaluated in the framework of other broad uses and environmental releases as well as the depth of release, which is typically several thousand feet below the surface.

IMPACTS OF FRACKING ON WATER WELLS.

The issue of impacts on water wells from hydraulic fracturing activities is a major controversy. The majority of the claims involve methane, methane constituents (iron, manganese, etc.), arsenic, and physical properties such as color, turbidity, and odor. In many cases, these conditions were present in water wells before shale gas development, but often there is insufficient baseline (pre-drilling) sampling or monitoring to establish the impacts of drilling. Iron and manganese are common naturally occurring constituents in groundwater that are higher in concentration in some aquifers, particularly in areas underlain by gas-producing shales. Methane migrates out of the shales under natural conditions and moves upward through overlying formations.

Such naturally occurring methane in water wells has been a problem in shale gas areas decades before shale gas drilling began. It appears that many of the water quality changes observed in water wells in a similar time frame as shale gas operations may be due to movement of constituents that were already present in the wells by energy (vibration and pressure pulses) put into the ground during drilling and other operations, rather than by hydraulic fracturing fluids or leakage from the well casing. As the vibrations and pressure changes disturb the wells, accumulated particles of iron and manganese oxides, as well as other materials on the well casing and well bottom may become agitated into suspension, causing changes in color (red, orange or gold), increasing turbidity and release of odors.

In December of 2011, the U.S. EPA issued a press release regarding the results of a three-year study it had conducted in the Pavilion, Wyoming area. The study was conducted at the request of Pavilion residents who had concerns about water quality from their private drinking water wells. These results indicate that ground water in the aquifer contained compounds likely associated with gas production practices, including hydraulic fracturing. From the report:

"EPA constructed two deep monitoring wells to sample water in the aquifer. The draft report indicates that ground water in the aquifer contains compounds likely associated with gas production practices, including hydraulic fracturing. EPA also re-tested private and public drinking water wells in the community. The samples were consistent with chemicals identified in earlier EPA results released in 2010 and are generally below established health and safety standards. To ensure a transparent and rigorous analysis, EPA is releasing these findings for public comment and will submit them to an independent scientific review panel. The draft findings announced today are specific to Pavilion, where the fracturing is taking place in and below the drinking water aquifer and in close proximity to drinking water wells – production conditions different from those in many other areas of the country."[17]

In a subsequent news release in March of 2012, EPA stated:

"The EPA, the State of Wyoming, and the Tribes recognize that further sampling of the deep monitoring wells drilled for the Agency's groundwater study is important to clarify questions about the initial monitoring results. The EPA will partner with the State and the United States Geological Survey (USGS), in collaboration with the Tribes, to complete this

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[17] http://yosemite.epa.gov/opa/admpress.nsf/0/ef35bd26a80d6ce3852579600065c94e?OpenDocument

sampling as soon as possible and will collaborate with the State and other stakeholders in designing the sampling methodology, the quality assurance plan, and other features of the next phase of testing.

In order to ensure that the results of this next phase of testing are available for the peer review process, to which the Agency has committed, the EPA has agreed to delay convening the peer review panel on the draft Pavilion report until a report containing the USGS data is publicly available. The State of Wyoming and the Tribes appreciate this decision. In the meantime, EPA's draft report will continue to be open to public comment."[18]

The Independent Petroleum Association of America has questioned the EPA study in its publication "Energy in Depth".[19]

When a mineral rights holder wants to develop their rights they approach the surface rights owner, and one of the negotiating tools for the surface rights owner is to have the company do pre- and post- testing of water wells. Many oil and gas companies are willing to do this. A number of environmental groups feel independent testing of water wells would be preferable to testing by industry producers.

SPILL MANAGEMENT AND SURFACE WATER PROTECTION.

Hydraulic fracturing chemicals in concentrated form (before mixing) at the surface present a more significant risk above ground than as a result of injection in the deep subsurface. Leaks and spills associated with shale gas development may occur during transport to the drill site, at the drill pad or during handling and transport of chemical waste materials. The primary risk of uncontrolled releases is generally to surface water and groundwater resources. On-site and off-site releases may occur because of accidents, inadequate facilities management or staff training, or illicit dumping. Wastewater from flowback and produced water is typically temporarily stored in on-site impoundments before removal by trucks or pipelines for reuse, treatment or disposal. These impoundments may be another source of leaks or spills. Lining of pits for flowback water depends on company policies and regulatory requirements, which can vary from state to state. COGCC rules in the 400, 500, and 900 series deal with these issues.

There are three characteristics of a spill that determine the severity of the consequences. They are:

- Volume— depending on toxicity, smaller releases generally have lower impact than larger spills.
- Toxicity—the higher the degree of toxicity the greater the severity. Even small spills with high toxicity can be severe.
- Containment—effective containment is key to minimizing the impact of a spill on human health and the environment

Little information is available on the short or long term consequences of surface spills. Regulatory reports on spill investigations do not necessarily include information that would allow evaluation of environmental damage or the effectiveness of remedial responses. Data is not readily available from regulatory agencies on the frequency of spills and other releases.

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[18] http://yosemite.epa.gov/opa/admpress.nsf/d0cf6618525a9efb85257359003fb69d/17640d44f5be4cef852579bb006432de!opendocument

[19] http://www.energyindepth.org/six-questions-for-epa-on-pavillion/

The FracFocus website is reporting these incidences in Colorado. The COGCC "Hot Topics" section (found on the home page) also has information on spills. Continual checks will see if they are all recorded.

Many states require Spill Prevention Control and Contingency (SPCC) plans at well pad sites, which specify the best practices to be used in the event of a release. Spill management and remediation should be accomplished based on contingency plans that are prepared in advance and are developed jointly with regulatory agencies and emergency responders. Rapid communication of the nature, volume and toxicity of a spill is essential to effective emergency response.

WATER QUANTITY CONCERNS

Water consumption for hydraulic fracturing is one of the most contentious issues for natural gas development in the West. The drilling and fracturing of natural gas wells requires significant quantities of water for mixing drilling mud, extraction and processing of proppant sands, testing natural gas transportation pipelines, gas processing plants, and other uses. The amount of water used varies due to the material the gas is in (coal or shale). In shale gas drilling, specifically, consumption is greater for fracking than for other uses. The specific amount of water varies considerably, as fracking of shale gas has become dominated by more complex, multi-staged horizontal wells.

The methane found in coal is held in place by water. The procedure, therefore, is to remove the water from the methane in order to release it. Also, the softer coal can collapse with horizontal drilling, so this method is not used with coal; only vertical drilling is used. Shale is a much harder substance so the amount of water used is greater. The Colorado State Engineer reports that it takes approximately 500,000 gallons to frack a vertical well and 5 million gallons to frack a horizontal well. The Energy Institute at the University of Texas reports that typically 4 to 6 million gallons are needed for fracking of a shale gas well. Natural gas wells can be and often are fracked multiple times.

Energy Water intensity (volume of water used per unit of energy produced) is the most popular metric to measure the quantity of water used. It appears that the water intensity of shale gas is relatively small compared to other types of fuels. The US EPA has estimated that if 35,000 wells are hydraulically fracked annually in the US, the amount of water consumed would be equivalent to that used by 5 million people

The Colorado Division of Water Resources, COGCC and the Colorado Water Conservation Board (CWCB) have recently released a report concerning the amount of water used and projected to be used in fracking. The following information is summarized largely from this report on the COGCC website[20:]

- Factors that influence the amount of water needed include economic conditions, oil and gas prices, capital availability, corporate strategies and technological innovations (p.1 of report). The COGCC has attempted to predict the amount of water that will be used and needed from 2010 to 2015. (p.2). Their assumptions are that new gas wells, number of drilling rigs and number of new wells drilled will remain flat. However, the number of horizontal wells drilled will increase, and the number of vertical wells drilled will decrease proportional to the increase in horizontal wells drilled. The projections on demand for water for hydraulic fracturing in acre feet will grow from 13,900 in 2010 to 18,700 in 2015. These projections were based on information provided for each

[20] http://cogcc.state.co.us/Library/Oil_and_Gas_Water_Sources_Fact_Sheet.pdf

county in the state. (This information does not distinguish water use for fracking by river basin.)

According to the report, the average amount of water currently (2010) diverted for beneficial use for all uses in Colorado is:

		Acre feet/yr	% of state total
Total		16,359,700	
	Agriculture	13,981,100	85.5%
	Municipal/industrial	1,218,600	7.4%
	Total all others	1,160,000	7.1%

Of "Total", Hydraulic fracturing uses 13,900 AF or 0.08% of the total. An acre-foot equals 326,000 gallons of water. One acre-foot of water supplies a family of five for one year. Five million gallons of water equals 15.3 acre-feet.

Water for natural gas wells may be obtained from surface water, groundwater aquifers, municipal supplies, reused wastewater from industry or water treatment plants and recycling water from earlier fracturing operations. The primary concerns are that the withdrawals will result in reduced stream flow or will deplete groundwater aquifers. There is need for more information to document sources of water used for hydraulic fracturing.

The question of whether or not the projections done statewide on the amount of water demanded for oil and gas drilling are realistic is a concern for Colorado in general, and for the eight Designated River Basins specifically. After the severe drought of 2002, the Colorado legislature passed the Colorado Water for the 21st Century Act (2005), which established the InterBasin Compact Committee (IBCC) and nine Basin Roundtables. The Roundtables are administered by the IBCC, and are charged with facilitating locally driven collaborative solutions to water supply challenges within and between the basins.

Demand for water used for fracking varies due to market conditions. The most reasonable approach to assessing water usage is to evaluate the impact it has on the local community and the local environment both in the short and long term. An important distinction among water sources is whether the water usage is sustainable (renewable); surface water usage is likely to be more sustainable than groundwater usage. It is important to realize that the waste water from fracking operations is injected into deep underground wells, stored in evaporative ponds above ground, or in a few operations, recycled for additional fracking. Unless this water is recycled for further fracking, it is permanently disposed of and is removed from the hydrologic cycle, unlike water used for agriculture, municipal consumption, and recreation.

If private water wells are used, the water rights continue to prevail on the use of well water. That water withdrawn must follow rules governing it, which generally does not include the use for oil and gas construction. To use ground water diverted from wells depends on whether the wells are outside or inside Designated Ground Water Basins, or in nontributary aquifers. The nontributary aquifers most used are of the Denver Basin along the Front Range, primarily the Dawson, Denver, Arapahoe and Laramie Fox Hills.

With the drought occurring in about 55% of the United States in 2012, there is a greater push for the oil and gas industry to recycle the water used during production. It is about 50% to 75% more expensive to recycle frack water than to send it into deep injection wells (a practice which has been linked to earthquakes). In Texas there is increased use of brackish water in oil and gas production. And there are indications that more natural gas companies are being responsible and are using treated or recycled water.

FLOWBACK AND PRODUCED WATER MANAGEMENT.

After hydraulic fracturing has been completed in a shale gas well, the fluid pressure is relieved and a portion of the injected fluid returns to the well bore as "flowback" water, which is brought to the surface for treatment, recycling and/or disposal. The fluid consists of a mixture of flowback water and saline water from the shale formation, the combination of which is referred to as “produced” water. As withdrawal proceeds, the fluid becomes more saline as the relative contribution of produced water to the flowback increases. The point in time when produced water dominates the flow has been a subject of controversy. The amount of injected fluid returned as flowback ranges widely, from 20% to 80%, due to factors that are not well understood.

The ratio of ultimate water production after fracturing to the volume of fracturing fluid injected varies widely in different shale areas. The return of hydraulic fracturing fluid is important because as recycling increases in the industry, a higher rate of return reduces the water requirements of shale gas production. Greater emphasis is being placed on recycling and reuse not only to reduce water requirements, but also to reduce the volume of flowback wastewater that must be managed. At this time in Colorado, a minimal amount of produced water is recycled, due to the high cost to the industry. Management of the combined flowback and produced water streams has become a major controversy, both from the standpoint of uncontrolled releases and the treatment, recycling and discharge of the fluid as a wastewater stream. Disposal of the flowback water has historically been in permitted injection wells, open pits, and rarely to publicly owned treatment works (none in Colorado).

In Colorado there are several methods of disposal of produced water from drilling operations. In some counties (Weld, for example), it is temporarily stored in above-ground tanks. Produced water is permanently transferred either into deep underground injection wells or surface evaporative pits; it can also be discharged to the surface with a permit from the Water Quality Control Division (WQCD) of the Colorado Department of Public Health and Environment (CDPHE).

La Plata County is crisscrossed with underground pipelines which transport most of the county’s produced water to injection wells. These wells are far underground (8,000-9,000 feet). A small amount of water is transported by truck to the injection wells when the pipelines are not available. There are about 300 disposal wells in La Plata County.

Flowback water contains some or all of the following: sand and silt particles (from shale or returned proppants), clay particles that remain in suspension, oil and grease from drilling operations, organic compounds from the hydraulic fracturing fluids and the producing shale, and total dissolved solids (TDS) from the shale. This composition reflects the mixed origin of the fluids from hydraulic fracturing and produced shale water. The average TDS of flowback water has considerable range for the different shale areas – 13,000ppm for Fayetteville to 120,000 ppm for Marcellus.

Of the chemicals found in fluids related to shale gas development, the ones that appear to be of greatest concern are naturally-occurring arsenic and radioactive material. Although arsenic is not uncommon in domestic water wells where no hydraulic fracturing has taken place, it has become a source of strong allegations in Texas and Pennsylvania.

In their 2011 report to the COGCC, the STRONGER review team recommended that the COGCC include an evaluation of normally-occurring radioactive material (NORM) in wastes associated with hydraulic fracturing operations, a part of the study recommendations of the 1996 review.

These concerns over produced water management have resulted in demands for increased regulation.

BLOWOUTS.

Blowouts are uncontrolled fluid releases that occur during the production or completion of oil and gas wells. They typically happen when unexpectedly high pressures are encountered in the subsurface or because of failure of valves or other mechanical devices. Blowouts may take place at the wellhead or elsewhere at the surface, or may involve movement away from the well in the subsurface. Many blowouts happen as a result of the failure of the integrity of the casing or the cementing of the casing, such that high pressure fluids escape up the well bore and flow into subsurface formations. Blowout preventers (BOPs) are used to automatically shut down fluid flow in the well bores when high pressures ("kicks") are encountered, but are known to fail infrequently.

Blowouts are apparently the most common of all well control problems, and they appear to be under- reported. There is limited data available on the frequency. Surface blowouts at the wellhead are primarily a safety hazard to workers and may also result in escape of drilling fluid or formation water to nearby surface water sources. Subsurface blowouts may pose both safety hazards and environmental risks. In the latter instance consequences depend mostly on three factors:

- The timing of the blowout relative to well activities (determines the nature of the released fluid);
- Occurrence of the escape of contaminants through the surface casing or deep in a well; and
- The risk receptors, such as freshwater aquifers or water wells that are impacted.

Blowouts due to high gas pressure or mechanical failures happen in both conventional and shale gas development. Shale gas wells have the incremental risk of potential failures caused by the high pressures of fracturing fluid during hydraulic fracturing operations. An environmental example is an incident in Ohio, not involving shale gas drilling, where high pressure natural gas was encountered and moved up the well bore and invaded shallow rock formations. Within a few days gas bubbling was observed in water wells and surface water and the floor of a basement in a home was uplifted. Fifty families were evacuated. The well was brought under control and capped a week later. Though these examples are rare, they can be addressed most effectively through proper well construction and ensuring well integrity.

ATMOSPHERIC EMISSIONS.

Air emissions from natural gas operations occur at the drill site during drilling and fracturing and ongoing production and at ancillary off-site facilities such as pipelines and natural gas compressors. The on-site emissions include dust, diesel fumes, fine particulate matter, and methane. Air emissions have become a major component of the shale gas controversies. A principal concern for natural gas emissions is related to the volatile organic carbon (VOC) compounds. VOCs are typically rich in the BTEX (benzene, toluene, ethylene, xylene) compounds. However, the role of VOCs as smog producers, as they combine with nitrous oxide (NOx) in the presence of sunlight to form smog, is the main source of concern. Ozone, a primary constituent of smog, and NOx are two of the five "criteria pollutants" of the Clean Air Act (CAA). The role of VOCs in forming smog and their contribution to elevated levels of ozone is the reason for the focus on VOC emissions from shale gas activities. There is much controversy over the amounts of VOCs in the atmosphere and what the sources are. The public concern over air quality and the need for more precise information has led to more focused emissions studies sponsored by governments or private foundations.

In February, 2012, National Oceanic and Atmospheric Administration (NOAA) scientists published a study of air emissions in Weld County and concluded that emission of contaminants can be directly related to oil and gas development, and that the levels are higher than previous estimates indicated.[21] The report noted that the Denver and Northern Colorado Front Range region had already been officially designated in December of 2007 as a Federal Non-Attainment Area (NAA) for repeated violation in the summertime of the ozone National Ambient Air Quality Standard.

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[21] http://blogs.edf.org/energyexchange/files/2012/02/Petron_Colorado_Front_Range_2011.pdf

Modeling studies indicate that 70 to 80% of benzene is from fugitive emissions of natural gas, but that other VOC constituents are from motor vehicles. In Wyoming, air emissions from oil and gas activities are the largest source of VOCs and related high ozone levels. For example in Sublette County, WY, ozone levels in the winter routinely exceed the EPA 8-hour standard resulting in air quality that is sometimes worse than in Los Angeles. The relative contribution of shale gas activities in relation to conventional oil and gas development and other sources such as vehicle exhaust emissions must be taken into account in reports such as those from Wyoming.

Emissions of methane have caused public concerns over global climate change since methane is a strong greenhouse gas. Venting or flaring of natural gas may take place during the fracturing and flowback phase of shale gas well development. However, many operations use “green completions” to capture and sell rather than vent or flare methane produced with flowback water. Onsite fugitive emissions of methane may take place from other sources such as pressure relief valves of separators, condensate tanks, and produced water tanks. It is not known in the public realm the extent to which Best Management Practices (BMPs) (e.g. low-emissions completions, low-bleed valves) result in reduced methane and fugitive losses of methane.

HEALTH EFFECTS.

Potential health effects are a primary concern for natural gas operations. Several chemicals used in shale gas wells and natural gas infrastructure have potential for negative impact on human health. Among these are benzene and other VOC compounds as well as endocrine disruptors. The main sources are air emissions and surface and underground releases of fluids such as hydraulic fracturing fluids and flowback and produced water. In order for health effects to be determined for natural gas activities, not only must the types and toxicity of releases be known, but also the chain of events from the point of release. The transport, possible attenuation, and exposure of toxic substances to receptors must be established in order for health risk to be evaluated. Although there are a number of reports, many are anecdotal with no scientific investigation. Our society faces a problem in that benzene, (and other VOCs), polynuclear aromatic hydrocarbons (PAHs) hazardous air pollutants (HAPs), and a variety of endocrine disruptors are wide spread pollutants in our environment. For most of the population individual exposure to benzene and other VOC compounds is dominated by exposure to tobacco smoke, highway driving, time spent at gas stations, and time spent in urban environments.

Very few risk assessments of health effects of natural gas activities have been conducted. Most references have been made to other similar operations, such as refineries and chemical plants. A short term study of VOC levels in a sample of the population of Dish, Texas has been the only health related study that is focused specifically on the possible impact of shale gas extraction. The results appear to have been interpreted in a somewhat misleading manner. In April, the EPA released rules designed to limit the release of smog forming chemicals and other toxic substances that escape into the atmosphere. However, with great pressure from the industry, these rules are delayed for implementation until January, 2015. Until 2015, companies will be required to burn off emissions by flaring the natural gas, a common industry practice.

Although there have been claims of impacts on water wells by natural gas activities, there has not been evidence shown of chemicals found in hydraulic fluid additives. Most claims have involved naturally occurring groundwater constituents such as iron and manganese, which may form particles in water wells that are released as a result of vibrations and pressure pulses associated with nearby shale gas drilling operations.

Water wells in shale gas areas have historically shown high levels of naturally occurring methane long before shale gas development began. Methane observed in water wells with the onset of drilling may also be mobilized by vibrations and pressure pulses associated with the drilling. It would be beneficial to have pre and post testing of water wells to assess the impact of drilling operations. The COGCC claims that since 2000 they have required pre and post development water quality testing on 1900 wells in the San Juan Basin. They have tested an additional 1900 wells in other basins. There are individual operators who are including pre and post testing of well water when negotiating with surface rights owners.

There are many other regulations or policy topics that deal with environmental impacts. There is a need for more research to assess impacts and change regulations for individual well site construction and operations, effects on human health, and for large scale regional impacts of land clearing and loss of habitats. Colorado has one of the toughest requirements for disclosure of chemicals used for hydraulic fracturing in the country, and this will enable more complete analysis of the potential impacts on public health and the environment. However, there is a lack of funding from any source to address all aspects of gas drilling research. “Right now, the kind of comprehensive research that’s needed just hasn’t started,” said Bernard Goldstein, professor emeritus at the University Of Pittsburgh School Of Public Health.

Other areas that need research or monitoring include:

- management of flowback water, a component of produced water, as a wastewater stream.
- increased use of recycled water to minimize the quantity of water required for fracturing and to be disposed of after fracturing is completed.
- continued disclosure of chemicals present in hydraulic fracturing fluid additives to better assess their impact.
- management of leaks and spills at the well pad site and at off-site facilities.
- emissions of VOCs for air quality, particularly in ozone non-containment areas.
- methane releases during shale gas operations which has a greater impact on greenhouse gas than carbon dioxide.

CONCLUSION

Oil and gas extraction has been conducted in the U.S. since the late 1800’s. Hydraulic fracturing has been used by the oil and gas industry for decades, although horizontal drilling and subsequent fracking are only about twenty years old. With the increased demand for natural gas as a cleaner fuel source, the industry is moving drilling operations beyond their original fields, thereby pushing them closer to populated areas. Although the COGCC has begun to address some of the issues being brought forward by the public, the process needs to be evaluated to decide if the rules and regulations are sufficient to address their concerns about health and environmental impacts. This is a continually evolving issue, so information in the League’s study is relative to current material available. Those who desire to monitor the industry and the evolving practice of fracking will want to consult the information sources noted in the Important Links addendum to this report, as well as other sources of information identified in their research processes.