U.S. House of Representatives
Committee on Transportation and Infrastructure
Washington, DC 20515

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November 10, 2011

MEMORANDUM

TO: Members of the Subcommittee on Water Resources and Environment

FR: Bob Gibbs
Subcommittee Chairman

RE: Hearing on "Hydraulic Fracturing of Shale Beds: Ensuring Regulatory Approaches that Will Help Protect Jobs and Domestic Energy Production"

PURPOSE OF HEARING

The Water Resources and Environment Subcommittee is scheduled to meet on Wednesday, November 16, 2011, at 10:00 a.m. in 2167 RHOB, to receive testimony from federal and state regulators and industry representatives on regulatory approaches to the hydraulic fracturing of shale beds.

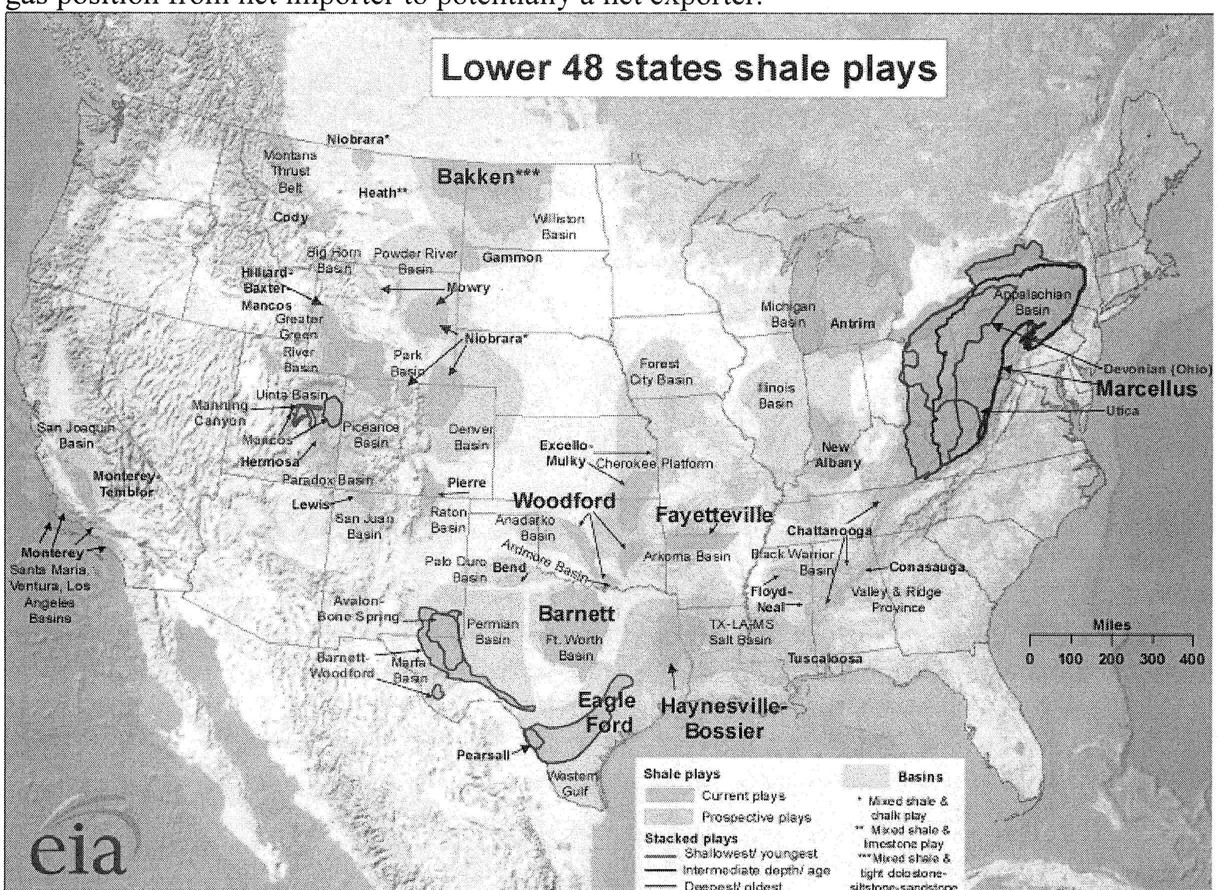
BACKGROUND

Natural gas is a plentiful, inexpensive and emerging source of domestic energy. A 2010 Congressional Research Service (CRS) study titled "Global Natural Gas: A Growing Resource" found that in 2009, almost 84% of the natural gas the United States consumed was from domestic production. According to a 2011 Massachusetts Institute of Technology (MIT) study, natural gas has gained market share on an almost continuous basis over the past half century, growing from some 15.6% of global energy consumption in 1965 to approximately 24% today. In absolute terms, global natural gas consumption over this period has grown from around 23 trillion cubic feet (Tcf) in 1965 to 104 Tcf in 2009, a more than fourfold increase. The United States Environmental Protection Agency (EPA) found that production from shale formations has grown from a negligible amount just a few years ago to almost 15% of total U.S. natural gas production and is expected to triple in the coming decades.

Traditionally, unconventional sources of natural gas, and particularly shale gas, will significantly contribute to the nation's future energy supply and CO2 emission reduction efforts. Unconventional gas has proven to be difficult to precisely define because what was un-conventional yesterday may, through some technological advance or ingenious new process, become conventional tomorrow. In the broadest sense, unconventional natural gas is gas that is more difficult or less economical to extract, usually because the technology to reach it has not been developed fully, or is too expensive. Assessments of the recoverable volumes of shale gas in the U.S. have increased dramatically over the last five years and continue to grow. According to EPA Administrator Lisa Jackson, America's potential natural gas resource is nearly 50 % larger than it was believed just a few years ago due to advances in drilling technology, such as hydraulic fracturing. The Potential Gas Committee of the Colorado School of Mines states the estimated natural gas reserves within the U.S. have grown by 77% since 1990. Although the development of shale technology has grown rapidly in the past few years, there are still scientific, technological and regulatory challenges to overcome before this very large resource base is optimally developed.

Prevalence of Shale Gas Formations in the U.S.

In the U.S., unconventional natural gas reserves and production, particularly shale gas, have grown rapidly in recent years. In 2009, shale gas reserves increased 76%, while production rose 47%, according to a recent U.S. Energy Information Administration (EIA) report. Between June and July the EIA boosted its own forecast for 2012 liquids production by a startling 170,000 Barrels Per Day (BPD). The newly extractable shale gas resources have changed the U.S. natural gas position from net importer to potentially a net exporter.

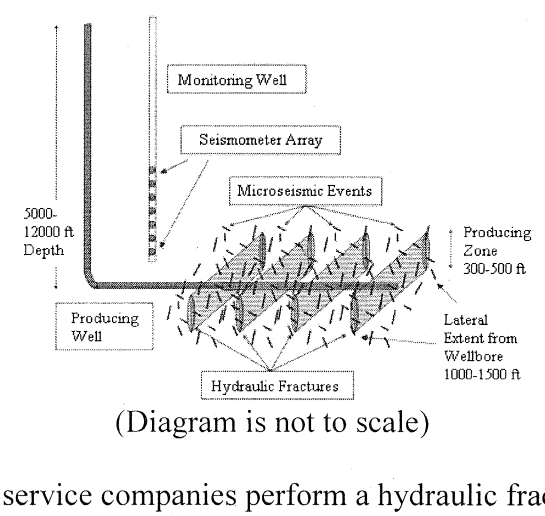


Source: Energy Information Administration based on data from various published studies.
Updated: May 9, 2011

As the map above shows, shale gas basins, also referred to as plays, can be found throughout the county. According to "Unconventional Gas Shales: Development, Technology, and Policy Issues", a 2009 Congressional Research Service document, there are at least 21 shale basins in more than 20 states. According to EIA research, 86 % of the total 750 trillion cubic feet of technically recoverable shale gas resources identified are located in the Northeast, Gulf Coast, and Southwest regions, which account for 63 %, 13 %, and 10 % of the total, respectively. In the three regions, the largest shale gas plays are the Marcellus (410.3 trillion cubic feet, 55 % of the total), Haynesville (74.7 trillion cubic feet, 10 % of the total), and Barnett (43.4 trillion cubic feet, 6 % of the total). The Barnett Shale play is reportedly the most active natural gas play in the United States with as many as 173 drilling rigs at work in 2008. The United States Geological Survey (USGS) estimated that as much as 26.7 tcf of natural gas could be present in continuous accumulations as non-associated gas trapped in strata of two of the three Barnett Shale Assessment Units (AU)—the Greater Newark East Frac-Barrier Continuous Barnett Shale Gas AU and the Extended Continuous Barnett Shale Gas AU. The Ohio Department of Natural Resources reports that hydraulic fracturing has been used in more than 1 million wells throughout the country.

What is hydraulic fracturing?

Hydraulic fracturing, also referred to as "fracking," was first used in the late 1940s and has since become a common technique to enhance the production of low permeability formations, especially in unconventional reservoirs such as tight sands, coal beds, and deep shales. Gas shale refers to any very fine-grained rock capable of storing significant amounts of gas. Hydraulic fracturing is required to extract valuable natural gas from the dense shale. The process creates small cracks, or fractures, in horizontal underground rock formations of up to 2 miles below ground level to extract gas from shale. The fracturing process entails the pumping of fracture fluids, primarily water with sand proppant and some chemical additives, at a calculated, predetermined rate and enough pressure to generate fractures or cracks in the target formation. The sand proppant is needed to "prop" open the fractures once the pumping of fluids has stopped. The below diagram illustrates a sample horizontal well fracture.

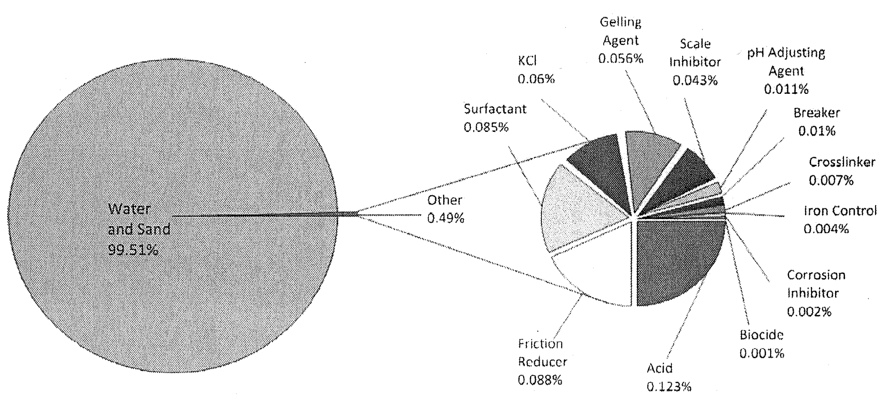


(Diagram is not to scale)

Before operators or service companies perform a hydraulic fracture treatment of a well (vertical or horizontal), a series of tests is performed. These tests are designed to ensure that the well, well equipment, and hydraulic fracturing equipment are in proper working order and will safely withstand the application of the fracture treatment pressures and pump flow rates. After the testing of equipment has been completed, the hydraulic fracture treatment process begins.

Hydraulic fracturing is performed in stages. Lateral lengths in horizontal wells for shale gas development may range from 1,000 feet to more than 5,000 feet. Because of the length of exposed wellbore, it is usually not possible to maintain a down hole pressure sufficient to stimulate the entire length of a lateral in a single stimulation event and hydraulic fracture treatments are usually performed by isolating smaller portions of the lateral, sequentially beginning with the section at the farthest end of the wellbore, moving uphole as each stage of the treatment is completed until the entire lateral well has been stimulated. By fracturing discrete intervals of the lateral wellbore, the operator is able to make changes to each portion of the completion zone to accommodate site-specific changes in the formation. After hydraulic fracturing is complete, gas begins to flow out of the well to the surface, where it is processed, compressed, and typically transported to markets through pipelines.

The addition of friction-reducing chemicals to fracturing fluids allows this "slickwater" to be pumped to the target zone at a higher rate and reduced pressure than if water alone were used. Slickwater increases water pressure in these microfractures, inducing shear-slip, or micro-seismic events that generally have magnitudes of less than -1.5 on the Richter scale—about as much energy as released by a gallon of milk dropped from chest height to the floor. In addition to friction reducers, other additives include: Biocides to prevent microorganism growth and to reduce biofouling of the fractures; oxygen scavengers and other stabilizers to prevent corrosion of metal pipes; and acids that are used to remove drilling mud damage within the near-wellbore area. These fluids are used not only to create the fractures in the formation but also to carry a propping agent (typically silica sand) which is deposited in the induced fractures. The graph below demonstrates what the mixture may include; each well may have a unique fluid makeup to address specific geological and hydrological concerns.



Source: ALL Consulting based on data from a fracture operation in the Fayetteville Shale, 2008

Since the make-up of each fracturing fluid varies to meet the specific needs of each area, there is no one-size-fits-all formula for the volumes for each additive. In the classification and regulation of fracturing fluids and their additives, it is important to realize that service companies providing these additives have developed a number of compounds with similar functional properties to be used for the same purpose in different well conditions. The difference between additive formulations may be as small as a change in concentration of a specific compound.

Wastewater Management

After each fracturing stage, the fracturing fluid along with water originally present deep underground in the shale formation is forced back through the wellbore to the surface. The flowback period can last from a few hours up to several weeks, although some injected water can continue to be produced along with gas for several months after production has started. A USGS study of the waters associated with oil and gas extraction found that flowback and water produced during a well's lifetime can contain naturally occurring formation water that is millions of years old and therefore can display high concentrations of salts, naturally occurring radioactive material (NORM), and other constituents including arsenic, benzene, and mercury. On the other hand, some wells produce water that is nearly potable in quality. Many oil-field waters are particularly rich in chloride, and this enhances the solubility of other elements that might be present including the naturally occurring radioactive element radium. The possible contamination of this water requires that it be disposed of in a responsible manner.

Flowback water is dealt with differently in various shale plays across the country. In the Barnett, Fayetteville, Haynesville, Woodford, Antrim, and New Albany Shales, the primary disposal method has been injection into underground saline aquifers, such as the Ellenberger Limestone that underlies the Barnett formation. Underground Injection Control (UIC) Class II wells provide a means for disposing produced water by re-injecting them back into their source formation or into similar formations. UIC Class II wells are governed by Sections 1422 and 1425 of the Safe Drinking Water Act. According to EPA, the approximately 144,000 Class II wells in operation in the United States inject over 2 billion gallons of brine every day. Most oil and gas injection wells are in Texas, California, Oklahoma, and Kansas. There are tens of thousands of licensed injection wells in Texas, but because of geological and political constraints, many fewer exist in the Marcellus Shale states. According to the EPA, Pennsylvania had only 10 of these Class II Underground Injection Control (UIC) wells in 2008. The emerging Utica Shale play appears to be favorable for the extensive use of UIC wells.

If UIC wells are not feasible, it is likely that a service company will have to transfer the wastewater off-site to an industrial treatment facility or a municipal sewage treatment plant that is capable of handling and processing the wastewater. In this case, the operator of the publicly owned treatment works (POTW) or industrial treatment facility would assume responsibility under the Clean Water Act (CWA) for treating the waste before discharging it into a nearby receiving water in compliance with effluent limitations contained in the facility's discharge permit. Currently, wastewater associated with shale gas extraction is prohibited from being directly discharged to surface waters.

One potential alternative to off-site disposal may be on-site treatment and reuse of flowback and produced water. Some companies are reportedly considering on-site treatment options such as advanced oxidation and membrane filtration processes. On-site treatment technologies may be capable of recovering 70%-80% of the initial water to potable water standards, thus making the water immediately available for reuse. The remaining 20%-30% is very brackish and considered brine water. A portion may be further recoverable as process water, but not at potable water standards. In other cases, companies send the briney water off-site for treatment and disposal. The economics of any such options are critical, and site factors such as available power and final water quality are often the determinant in treatment selection.

Recycling the water is another option, but will require new technological developments. In one case, Devon Energy Corporation (Devon) is currently using water distillation units at centralized locations within Texas's Barnett Shale play to treat produced water from hydraulic fracture stimulations. As of early 2008, Devon had 50 wells using recycled water. Devon reports that the program is still in its testing and development stages. With further development, such specialized treatment systems may prove beneficial, particularly in more mature plays such as the Barnett; however, their practicality may be limited in emerging shale gas plays. New approaches and more efficient technologies are needed to make treatment and re-use a wide-spread reality.

According to MIT's study of natural gas and hydraulic fracturing, every year the onshore U.S. industry safely disposes of approximately 18 billion barrels of produced water. By comparison, a high-volume shale fracturing operation may return around 50 thousand barrels of fracture fluid and formation water to the surface. The challenge is that these volumes are concentrated in time and space.

Regulation of Fracking

The development and production of oil and gas in the U.S., including shale gas, are regulated under a complex set of federal, state, and local laws that address every aspect of exploration and operation. The EPA administers most of the federal laws, although development on federally-owned land is managed primarily by the Bureau of Land Management (part of the Department of the Interior) and the U.S. Forest Service (part of the Department of Agriculture). The Clean Water Act governs the wastewater from hydraulic fracturing activities, including the discharge to surface water bodies or sewage treatment plants; the Safe Drinking Water Act regulates the underground injection of fluids into wells; and the Clean Air Act limits air emissions from engines, gas processing equipment, and other sources associated with drilling and production. The National Environmental Policy Act (NEPA) requires that exploration and production on federal lands be thoroughly analyzed for environmental impacts. Most federal laws have provisions for granting "primacy" to the states who also thoroughly analyze environmental impacts (i.e., state agencies implement the programs with federal oversight).

State and local agencies not only implement and enforce federal laws, but also have their own sets of laws to administer. The States have broad powers to regulate, permit, and enforce all shale gas development activities—the drilling and fracture of the well, production operations, management and disposal of wastes, and abandonment and plugging of the well. State regulation of the environmental practices related to shale gas development, usually with federal oversight, addresses the regional and state-specific character of the activities. Some of these location-specific factors include: Geology, hydrology, climate, topography, industry characteristics, development history, state legal structures, population density, and local economics. State laws often add additional levels of environmental protection and requirements to the already strict federal requirements. Several States also have their own versions of the federal NEPA law, requiring environmental assessments and reviews at the State level and extending those reviews beyond federal lands to State and private lands.

Rules and regulations developed by state agencies such as the Oklahoma Corporation Commission, Colorado Oil & Gas Conservation Commission, the Texas Railroad Commission, or the Pennsylvania Department of Environmental Protection govern the specifics of gas production, requiring producers to obtain permits before drilling, and requiring certain standards and practices to be used during well construction, hydraulic fracturing, waste handling, and well plugging. State regulations also deal with tanks and pits as well as any chemical or waste water spills.

Beyond government regulation, stakeholder groups provide industry-wide best practices reviews. One group, STRONGER, an acronym for State Review of Oil and Natural Gas Environmental Regulations, was formed in 1999 to reinvigorate and carry forward the state review process begun cooperatively in 1988 by the EPA and the Interstate Oil and Gas Compact Commission (IOGCC). This diverse group that includes industry representatives, environmental groups, federal and state agencies meets to study and review state practices and make recommendations as needed. This activity provides a validation of state regulation practices.

Future Regulation Possibilities

In March 2010, EPA announced its intention to conduct a study of hydraulic fracturing in response to a request from Congress. Since then, the agency has held a series of public meetings across the nation to receive input from states, industry, environmental and public health groups, and individual citizens. The initial research results and study findings will be released to the public in 2012, with the final report scheduled for 2014. The final study plan looks at the full cycle of water in hydraulic fracturing, from the acquisition of the water, through the mixing of chemicals and actual fracturing, to the post-fracturing stage, including the management of flowback and produced or used water as well as its ultimate treatment and disposal.

On October 20, 2011, EPA announced a plan to develop national standards specifically for wastewater discharges produced by natural gas extraction from underground coalbed and shale formations. EPA will consider standards based on demonstrated, economically achievable technologies, for shale gas wastewater that must be met *before* going to a treatment facility. At the current time, the date of implementing these standards is unknown, but EPA is looking to propose a rule for shale gas in 2014. EPA needs time to gather sufficient comparable data on shale gas activities. In particular, EPA will be looking at the potential for cost-effective steps for pretreatment of this wastewater based on practices and technologies that are already available and being deployed or tested by industry to reduce pollutants in these discharges. The effluent guidelines program, which sets national standards for industrial wastewater discharges, is based on best available technologies that are economically achievable. EPA is required to publish a biennial outline of all industrial wastewater discharge rulemakings underway. EPA has issued national technology-based regulations for 57 categories of industries, including oil and gas development, since 1972.

Benefits of Natural Gas Production

As noted earlier, a 2010 CRS study found that in 2009, almost 84% of the natural gas the United States consumed was from domestic production. Domestic energy production is safe and secure – not subject to international turmoil. According to MIT, in the U.S., around 30% of natural gas is consumed in the electric power sector. Within the power sector, gas-fired power plants play an important role, due to their inherent ability to respond rapidly to changes in demand. In 2009, natural gas plants represented over 40% of the total generating capacity. The U.S. gas market is mature and sophisticated, and functions well, with a robust market. Domestically, the price of oil (which is set globally), compared to the price of natural gas (which is set regionally), is very important in determining market share when there is an opportunity for substitution. Abundant domestic natural gas production ensures consistently low-cost energy for American consumers.

Natural gas is also the fuel of choice for a wide range of industries, including pulp and paper, metals, chemicals, petroleum refining, and food processing. According to the EIA, these five industries alone account for almost three quarters of industrial natural gas use. For many products, there is no economically viable substitute for natural gas and a major disruption to availability or price would negatively affect many sectors of the economy.

Natural gas also has environmental benefits, emitting only half as much Carbon Dioxide and other air pollutants and as coal and approximately 30% less than fuel oil. With these facts, it is generally considered to be central to energy resource plans focused on the reduction of greenhouse gas emissions. The current emphasis on the potential effects of air emissions on emissions, and air quality solidifies that cleaner fuels like natural gas are an important part of our nation's energy future.

Natural gas is a cornerstone of the current Administration's efforts to reduce environmental impacts of energy consumption. EPA Administrator Lisa Jackson stated "The president has made clear that natural gas has a central role to play in our energy economy. That is why we are taking steps – in coordination with our federal partners and informed by the input of industry experts, states and public health organizations -- to make sure the needs of our energy future are met safely and responsibly."

Economic Impacts of Domestic Shale Gas Development

Natural gas is an increasingly valuable commodity. In future projections from the International Energy Agency, demand increases by 44% between 2008 and 2035 – an average rate of increase of 1.4% per year. Growth in demand for gas far surpasses that for the other fossil fuels due to its more favorable environmental and practical attributes, especially given the constraints on how quickly alternative low-carbon energy technologies can be deployed. China's gas demand growth accounts for more than one-fifth of the increase in global demand through 2035. The largest single use of natural gas continues to be power generation, where it is used as a low cost, environmentally friendly alternative to coal. Future demand increases could stem from the growth of clean natural gas fueled vehicles.

Domestic energy production fuels economic growth. A 2011 Pennsylvania State University study on the economic benefit of the Marcellus Shale forecasted major economic development throughout the Marcellus Shale region because of extraction activities. Marcellus producers plan to spend significantly more in 2011 and 2012, generating more than $12.8 billion in value added in 2011 and another $14.5 billion during 2012. This higher economic activity generates almost $2.6 billion in additional state and local tax revenues during those same years. Employment in the State of Pennsylvania is projected to expand to over 180,000 jobs during 2012 in Marcellus related and supporting jobs. This dramatic increase in Marcellus drilling activity has occurred even during a period of slow economic growth and relatively low natural gas prices. Natural gas production from the Pennsylvania Marcellus will likely average 3.5 billion cubic feet per day during 2011 and could exceed 6 billion cubic feet per day during 2012.

The emerging Utica shale is spurring statewide economic development in Ohio. More than 204,000 jobs will be created or supported by 2015 due to exploration, leasing, drilling and connector pipeline construction for the Utica Shale reserve. With the substantial pace of development, economic output will increase by over $22 billion and wages by $12 billion by 2015. In the year 2015, local government wage tax revenues from Utica related activities may amount to $240 million. This estimate does not count the severance or ad valorem taxes that will be levied upon producers of crude oil and natural gas.

Beyond the drilling and extraction professions, hydraulic fracturing provides employment opportunities in many other fields including pipeline construction, research and development, and chemical processing. For example, ethane is produced when processing plants remove the natural gas liquids found in "wet gas" from methane. The ethane is then "cracked" to form ethylene, the basis of plastics. West Virginia, which rests above the Marcellus Shale, is working to attract an ethane cracking plant. According to a March 2011American Chemistry Council analysis titled "Shale Gas and New Petrochemicals Investment: Benefits for the Economy, Jobs, and US Manufacturing" an ethane "cracker" would represent an investment of $1.5 billion or more. If West Virginia attracts a cracker, about $3.2 billion would be invested in the downstream chemical facilities that would make products like dyes, paints, coatings and plastics, and according to the Council's analysis would generate $7 billion in additional chemical industry output in that state. Overall about 12,000 jobs would be created in the chemical industry and throughout the supply chain in West Virginia, the Council estimated. Regional job growth, such as the potential manufacturing jobs created by ethane cracking, requires that investors and communities have a strong level of certainty that domestic natural gas extraction will continue to be economically viable and thriving.

WITNESSES

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