Quadrennial Technology Review 2015

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U.S. DEPARTMENT OF ENERGY

Quadrennial Technology Review 2015

Unconventional Oil and Gas

Chapter 7: Technology Assessments

Executive Summary

The United States will, for the foreseeable future, continue to rely heavily upon oil and natural gas to support our economy, national security, and energy security. Given the increasing reliance on unconventional oil and gas (UOG) resources, such as from shale, optimizing the public good of the nation's UOG endowment will require safe, efficient, and environmentally responsible UOG exploration and production systems. While science-based regulation and adherence to best practices can contribute significantly to achieving this goal, continued science and technology advancement is needed to maximize the national energy, security, and economic benefits of UOG development while minimizing the negative environmental impacts.

This Technology Assessment examines the current state of science and technology, as well as opportunities for future R&D, relative to five broad UOG topical areas: (1) resource recovery; (2) water quality protection; (3) water availability; (4) air quality protection; and (5) induced seismicity. These topics are recognized within the Federal Multiagency Collaboration on Unconventional Oil and Gas Research,[1] which also includes topic areas on ecosystem impacts and implications for human health.

Today, increased pad drilling and extended-reach horizontal wells are reducing the land impacts of drilling. Integration of "green completions" (new techniques to capture gas emissions during the well-completion process), increased recycling of flow-back and produced water, and improved disposal protocols are similarly reducing negative impacts to air and water. However, significant issues remain. Going forward, alternatives to water as the base fluid for fracture stimulation hold promise to relieve future burdens on water availability and on water handling and disposal. Clarifying the cumulative air quality impacts of UOG development and confidently determining the nature and source of emissions are needed so that corrective actions can be taken. The integrity of wellbores is unclear, particularly after the production life of the well has passed and in the context of dense populations of horizontal wells. Improved methods for evaluation and remediation are needed. While risks of subsurface fluid migration enabling contamination of shallow aquifers are likely very low in most settings, it is uncertain whether legacy wellbores play a role in enabling pathways. Modular, rapid, flexible, and large-volume produced water treatment technologies will be needed, as is the information and insight required to manage wastewater disposal in a manner that eliminates the risk of damaging levels of induced seismicity. Further, although UOG production is commercial in many regions, a large portion of the resource remains unviable with existing technologies. Many of the engineering paradigms that have historically guided oil and gas reservoir and field management simply do not apply in the new context of nanoporous reservoirs (reservoirs with pores of nanometer size). The fundamental science required to enable a practical understanding of the reservoir and its response to stimulation is lacking, and therefore, so is the potential for more efficient and less impactful recovery from alternative means.

UOG development has clearly provided substantial benefits to the nation; nonetheless, current approaches are not yet increasing resource utilization while reducing environmental impact. The U.S. UOG resource and the scale of future development that it can support (including the number and pace of wells to be drilled) remain highly uncertain, making assessment of cumulative benefits and impacts unclear. In the current environment of high industry activity levels, high public awareness, and strongly divergent views on the impacts of

development, there is need for: (1) objective science to inform sound policy; and (2) accelerated delivery of technological options that enable the most "prudent" use of natural resources. Further efforts in basic science and applied research can accelerate development of advanced technologies that enable the simultaneous achievement of the resource exploration and production and environmental impact reduction goals.

Introduction and Background

The United States now, and for the foreseeable future, relies heavily on oil and natural gas to support our economy and national security. Given the increasing U.S. and global reliance on UOG resources,[2] as these resources are increasingly tapped, the continued supply of these fuels will depend on the steady development of the science and technology required to enable safe, efficient, and environmentally responsible exploration and production systems.[3,4] The concept of "prudent development" describes the widely shared goal to optimally balance maximization of the national energy security and economic benefits of UOG development with minimization of any associated negative environmental impacts.[5] Success in this effort, and in other allied R&D efforts, will strengthen America's energy independence,[6] protect air and water quality, position the nation as a global leader in UOG resource development technologies, ensure that the maximum value of the nation's resource endowment is realized, and ease the optimal transition to the low-carbon energy systems of the future.[7] This document provides an assessment of the state of science and technology with respect to UOG resources.

Unconventional Oil and Gas Resources

Conventional oil and gas resources are those in which oil and gas can be economically produced given natural reservoir conditions. In other words, the hydrocarbons are housed at high concentrations in reservoirs of sufficient porosity and permeability such that natural subsurface pressure can drive the hydrocarbon into wells and to the surface at rates that result in profitable (commercial) production. In contrast, UOG resources—in their predevelopment state—are trapped in reservoirs that cannot be produced economically without the use of well "stimulation" to augment reservoir quality.[8,9] While coal-bed methane, shale gas, fractured reservoirs, tight oil, oil shales, tight gas, and gas hydrates are all considered unconventional resources, this Technology Assessment focuses primarily on those that have experienced rapid escalation in production in recent years ("shale" gas, tight oil, and tight gas) due to the widespread and effective use of hydraulic fracturing (HF).

The generic term "shale" actually refers to a wide range of fine-grained, low-permeability lithologies, including fine-grained carbonates, true (clay-rich) shales, and mudstones. Reservoir lithology can also vary significantly within any given play (a set of known or postulated oil and gas accumulations sharing similar geologic, geographic, and temporal properties, such as source rock, migration pathway, timing, trapping mechanism, and hydrocarbon type).[10] The formations most amenable to HF[11] are commonly those deep (more highly pressured) shales that are relatively rich in organic matter, particularly "brittle" due to high concentrations of non-clay constituents, and relatively undeformed (so as to not have been excessively drained of hydrocarbon through natural pathways).

The term "hydraulic fracturing," while commonly used for referring to the entire UOG development activity, technically refers only to one part of the full life cycle. This confusion has led to miscommunication on the nature and risks of development. Specifically, HF refers to the process of generating permeability in ultra-low-permeability, hydrocarbon-bearing rocks through the creation of fractures via the injection of high-pressure fluids and fracture-propping agents ("proppant") such as sand.[12] In contrast, the full life cycle of UOG development includes the following primary stages: (1) geological and geophysical exploration, often including acquisition of seismic survey data; (2) site development (pads, road, impoundments construction); (3) drilling, often in separate stages and using separate equipment for the vertical and horizontal portions of the well and including handling and disposal of drilling wastes such as cuttings; (4) completion stimulation, including the assembly of fracture fluid and necessary equipment on site and the hydraulic fracturing of the wellbores; (5) production, including installation of necessary gas and water gathering and handling infrastructure; (6)

wastewater management; (7) well site reclamation; and (8) other supporting activities conducted elsewhere, such as mining, fabrication, and transportation of proppants; water acquisition and transportation; and construction and transportation of fracture fluid additives.

History of Hydraulic Fracturing

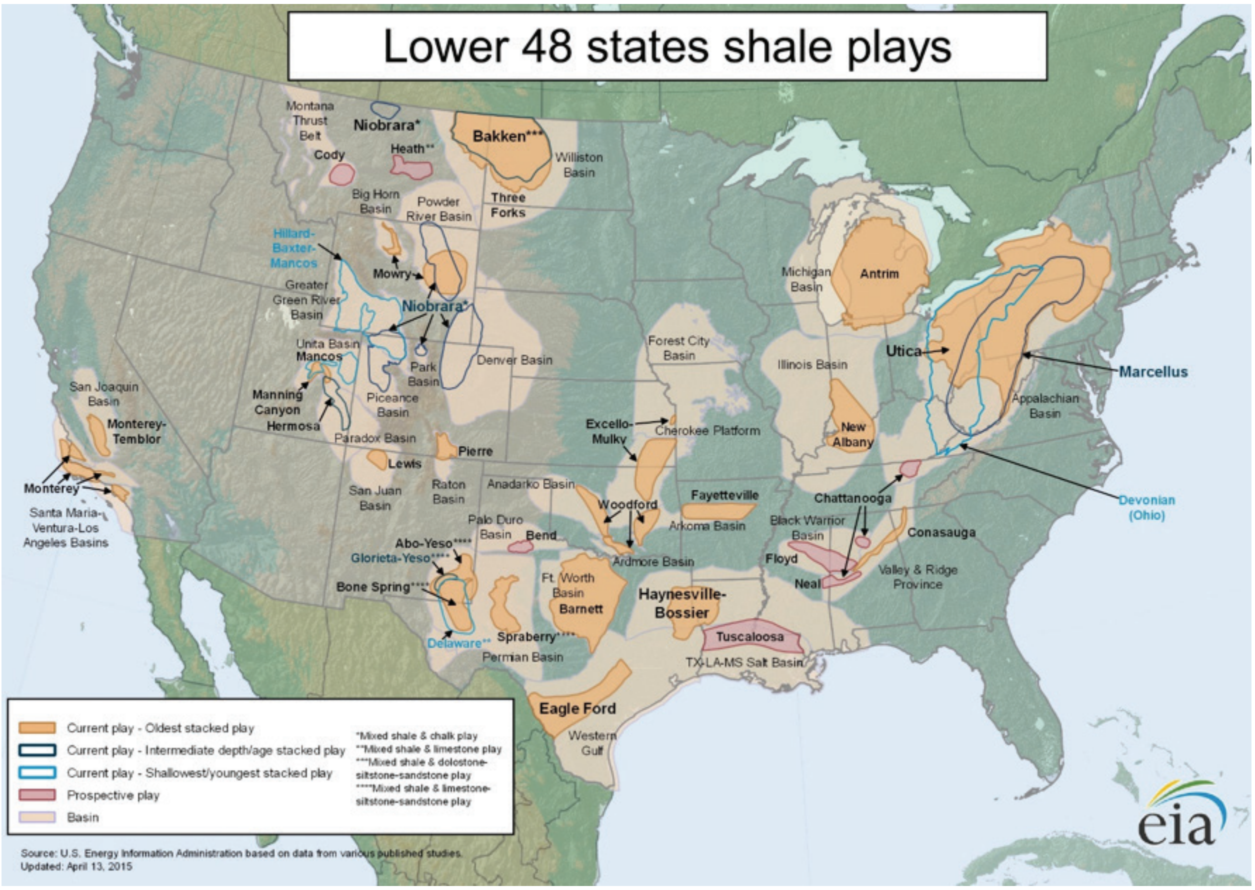
Hydraulic fracturing has been a part of UOG development for more than half a century.[13] It was first applied in select low-permeability formations in the mid-continent region in the late 1940s, and HF—using water as the primary fluid—soon became a common stimulation process for a variety of unconventional formations. Beginning in the mid-1970s, recognition of very low recovery factors and the massive remaining in-place resources in UOG reservoirs (primarily gas shales in the eastern United States and tight sands in the western United States) resulted in public-private R&D partnerships including industry, DOE, and the Gas Research Institute (GRI).[14] These R&D programs contributed to many advances in deep horizontal drilling, natural fracture detection, and the application of horizontal drilling and massive hydraulic fracturing in shales. The development of improved drilling bits, composite drill pipes, downhole drilling motors, downhole mud-pulse telemetry equipment, microseismic monitoring, and other technologies that were advanced through these partnerships has played a key role in enabling expanded UOG production.[15,16,17] While HF has been around in one form or another for a long time, it is not widely appreciated that shale development is even older. Initial large-scale development of shale gas fields in the United States began in the 1920s in the Upper Devonian Huron Shale (Big Sandy Field) of eastern Kentucky and southern West Virginia (Figure 7.G.1). This early production was enabled by numerous means of formation stimulation, primarily explosive fracturing with gelatinized nitroglycerin. Use of water became common in the 1950s. From the 1970s onward, development of the Huron Shale—a relatively shallow, clay-rich, and intensively naturally fractured unit—has been primarily conducted through nonaqueous (usually nitrogen) fracturing[18] because of the negative (i.e., clay swelling) permeability impact water injection has on clay-rich formations. The application of multistage hydraulic fracturing accelerated greatly after field trials in the Barnett Shale conducted by Mitchell Energy in the 1990s successfully combined deep horizontal drilling and large-scale (massive) hydraulic fracturing technologies.[19] By 2005, the approach was exported to the Fayetteville, Haynesville, Marcellus, Woodford, Eagle Ford and other "shale" gas reservoirs, as well as to "shale" oil plays such as the Bakken, Niobrara, and a variety of Permian Basin formations. Through 2010, approximately 1 million wells had been hydraulically fractured in the United States. However, while fracture stimulation is a process with a long history, the manner in which it is being deployed at present—featuring massive, slickwater hydraulic fractures in extended-reach and closely spaced horizontal wells—is fundamentally new[20] and therefore poses both new opportunities and challenges.[21,22]

Factors Affecting UOG Recovery

UOG reservoirs commonly extend across large regions and therefore represent extremely large "in-place" resources. However, even with the application of advanced technologies, UOG reservoirs typically exhibit a low recovery factor (RF; the ratio of produced gas to total gas residing in-place). While well-documented estimates of recovery efficiency are scarce, values of 10% or less are often cited for liquid-rich shales, 25%–35% for gas-rich shales.[23] In addition, because the nature of recovery is highly dependent on the effective application of technology, per-well production is not readily estimated from geologic information as it is in conventional reservoirs. Instead, production is highly sensitive to the nature and effectiveness of the interaction between the stimulation process and variable reservoir conditions, resulting in production that can be highly variable within a play, among the wells on a given pad, or within the various zones stimulated within a single well. Evaluation of UOG production, particularly in shale reservoirs, is further complicated because the reservoir engineering concepts and approaches that have been developed over a century of conventional oil and gas development—and successfully extended to tight gas sands—do not apply well in the unique, nanoscale context of "shale" reservoirs.[24] Further, the nature, efficiency, and potential environmental impacts of

Figure 7.G.1 Map of Shale Plays in U.S. (https://www.eia.gov/oil_gas/rpd/shale_gas.pdf)

Credit: U.S. Energy Information Administration



UOG development will differ significantly among and within UOG resource areas due to geographic (climate, topography, population density, etc.), geological (depth, extent of natural fracturing, reservoir lithology, etc.), and operational (nature of technology utilization, etc.) variability.[25] In addition, the consideration of impacts from UOG development must focus not only on near-term implications of individual processes but on cumulative impacts across the UOG life cycle over long time frames.[26]

R&D Drivers and Federal Role

UOG development is occurring at a high rate in many regions of the country and is substantially contributing to increased national energy security and local and regional economic development, as described in Chapter 1 of the QTR. The motivations for federally funded R&D associated with UOG development include enabling objective science, resource conservation, and environmental protection.

Enabling Objective Science refers to the need to build public confidence that policies, including regulations, are based on the latest and most reliable scientific information. As this assessment documents, many key unknowns and uncertainties related to UOG development remain, most notably with respect to environmental implications for water quality, water availability, air quality, and induced seismicity. Public sector science organizations have reported that gaining access to the sites of UOG operations for the purpose of evaluating potential impacts[27] is a high priority in the advance of science and technology in the public good.

Resource Conservation refers to the maximization of a range of public economic and energy security benefits obtained from optimal and efficient (nonwasteful) development of a natural resource. At present, the low recovery efficiencies inherent in UOG development practices leave substantial resource quantities in the ground. Furthermore, because of the extraction method, which includes the injection and permanent emplacement of large volumes of water within fine-grained reservoirs, those untapped resources may reside in a degraded state, challenging attempts at further recovery. While industry can profitably develop certain regions within the resources (the "sweet spots") despite this inefficiency, the phenomenon limits public benefit, including lost taxes and royalties, degraded productive life (and therefore reduced economic value), and lost production capacity (and therefore reduced energy security). Therefore, even a modest increase in recovery efficiency (for example, from 10% recovery to 15% recovery) could greatly expand (by 50% in this case) the economic benefits associated with the nation's UOG endowment.

Although UOG resources are significant, it should not be assumed that the "shale revolution" equates to a vast surplus of available energy such that low recovery efficiency is acceptable or of no practical import. Instead, it is a key role of the federal government to consider issues of public good and resource management over long time frames. For example, present EIA estimates (EIA, 2014) suggest that the recent advances in UOG recovery have increased total domestic gas resources by approximately 70% (from 1000 trillion cubic feet (pre-shale) to ~1700 trillion cubic feet [tcf]). However, at the same time, predictions indicate that domestic gas utilization is expected to grow by ~100% (from less than 20 tcf/y in 2010 to nearly 40 tcf/y in 2040), suggesting that even with the recent expansion of UOG resources, the lifetime for affordable domestic gas availability may be contracting, and not extending.

In addition, continuing evaluation of UOG resources shows potential limits to natural gas availability due to a range of factors. Shale resource estimates by EIA continue to be refined as more data is collected in plays such as the Marcellus and the Woodford. Large portions of currently producing plays, particularly the lower-pressure areas of liquid-rich plays, cannot be effectively produced with existing technologies. Other promising plays, most notably the Monterey Shale, are being determined to be too structurally complex to be economic with existing technology. As a result, the EIA has reduced the resource estimate for the play by more than 95%, from 13.7 to 0.6 billion barrel.[28] Recent studies that attempt to consider the geologic heterogeneity within the leading shale gas formations[29] suggest resource projections require further study and contain plausible scenarios that may be less favorable for long-term shale gas sustainability than those portrayed in the current EIA estimates.

Environmental Protection refers to the widely accepted federal role in funding research to mitigate negative externalities of oil and natural gas development activities. With regard to UOG resources, the potential environmental impacts are broad, including risks to soil, water, and air, as well as those impacts associated with induced seismicity.[30] Overall, the cumulative impacts of development are most effectively mitigated via avoidance. At present, industry is having success in increasing per-well and per-unit-area resource recovery, and development practices such as pad drilling and extended horizontal well reach are translating to reduced environmental impacts—in this case, reductions in land disturbance. Similarly, increased flowback water recycling and changes in produced water disposal are reducing freshwater usage burdens. New Source Performance Standards are also expected to reduce methane emissions and other air quality impacts from upstream UOG development.[31] Nonetheless, significant potential for continuing and substantial cumulative impact exists, perhaps most closely related to water issues, including water use and the implications of water disposal for water quality and induced seismicity. The future scale and intensity of these impacts will be determined by numerous factors, including future regulation, operating practice, market conditions, technology advancement, and the scale and pace of development. At present, it is difficult to ascertain the potential numbers of wells yet to be drilled or the time frames over which they will be drilled; however, recent trends in industry toward reduced well spacing and multilevel (stacked) reservoir development suggest that drilling intensity may significantly exceed current expectations.

The impact on water resources (surface and groundwater) includes both (1) the withdrawal (and permanent removal from the shallow hydrologic cycle via ultimate deep injection disposal) of freshwater resources required for HF and (2) the potential for contamination during the drilling, completion, and subsequent well cleanup and fluid transport processes.[32] While not a new technology, the manner in which HF is being widely used today—multiple-stage, large-volume treatments within large numbers of closely spaced, extended-reach, horizontal laterals—is new. The scale of UOG development generates the potential for acute and cumulative/chronic environmental impacts that may differ from those associated with prior oil and gas development practices as related to industrial activity across the full development life cycle. Although the widespread public conception is that unintended subsurface migration of hydraulic fracture fluids (along with their chemical constituents) represents the primary risk to groundwater resources, the most critical risks are those associated with (1) loss of wellbore integrity through inadequate placement of seals (cements) or progressive deterioration of seals and infiltration of shallow potable groundwater with production fluids; and (2) surface releases and spills during impoundment, handling, transportation, and disposal of produced waters. For both these aspects, although actual incident/release rates may be low, given the large and accelerating scale of development, significant impacts are possible—particularly over long time scales. Subsurface migration of fluids may be an important risk as well in certain settings where abundant natural pathways (pervasive faulting and fracturing) are present in areas of relatively shallow shale development or where man-made pathways (such as improperly abandoned oil and gas "legacy" wells) are present.

The impact of UOG development on air quality includes cumulative, life-cycle issues related to general increases in industrial activity, truck traffic, etc.; gas flaring in regions of limited gas gathering and transportation infrastructure; and methane emissions during development, production, and transmission. Recent and impending changes in drilling and completion methods ("green completions") and a growing number of studies suggest that the primary remaining risks to air quality from methane emissions reside in the activities of natural gas compression and mid- and downstream transmission of natural gas (a topic being addressed within the Department's midstream and infrastructure program).

Various recent technical papers reporting measurements of atmospheric methane have suggested that methane emissions are such that, on a life-cycle basis, UOG development results in greater greenhouse gas (GHG) impacts than those of the coal-fired power plants that the increased natural gas supply is actively displacing.[33] This finding is far from being a consensus view, however, as the bottom-up accounting of detailed measurement of emissions from specific UOG processes suggests much lower emission levels.[34,35]

Additional implications of UOG development, such as ecosystems impacts, land impacts,[36] and impacts on quality of life[37] are also potential topics for investigation[38] but are not treated further here.

It will be complex to maximize the utilization of these national resources for the economic and national security benefits, while minimizing any negative environmental impacts of that development. For example, a primary driver for current increases in recovery is the implementation of more intensive development processes, including more and more closely spaced ("down-spaced") wells, more HF stages per well, and others.

Because many environmental impacts scale directly to the intensity of resource development, technology that enables development of a given resource with fewer wells will translate directly into reduced (avoided) environmental impacts. In the context of considering development intensity, it is important to recognize that UOG development via HF remains in the early stages. Projections contained in the Energy Information Administration's (EIA) 2014 Annual Energy Outlook[39] suggest that shale gas will continue to expand in coming decades and will approach one-half of total U.S. natural gas production by 2035. For example, while drilling in the prolific Marcellus shale has reached a total of ~10,000 wells since the initial wells in 2004, the extent of the regional resource suggests that this may be less than 10% of the total number of wells that may ultimately be drilled in that play.[40]

Stakeholders in UOG Research and Development

Key stakeholders with strong interest in research and development as it relates to UOG development include, but are not necessarily limited to, the following:

- **The public**, which expects that industrial operations permitted near homes, schools, and businesses will not adversely affect their health, their property value, or the environment, either in the short term or in the long term, while still providing the energy they need at an acceptable cost.
- **Policymakers and permitting entities** (at the local, state, and federal levels), which want to ensure that policy and regulatory frameworks are science-based and broadly acceptable to the public and stakeholders.
- **Oil and gas producing companies**, which desire to maximize the value of their leases, conform to regulations, be good neighbors and citizens in the areas in which they operate and who expect regulatory decisions affecting their activities to be based on objective science.
- **Academia and the National Laboratories**, which desires the opportunity to improve the efficiency and environmental performance of unconventional resource development through advances in science and technology and who have made significant past contributions and investments in the capabilities and relationships required to conduct the R&D.
- **Technology providers**, which may develop potential paradigm-changing technologies but who often lack access to field testing and demonstration opportunities that are a prerequisite for utilization by industry.
- **Nongovernmental organizations**, which desire to inform the public debate with focused science on issues of great concern and uncertainty.
- **Other federal agencies**, which desire to coordinate R&D activities and share R&D results effectively with the Department of Energy.

The latter five of the categories listed above also support R&D efforts related to UOG resources. Industry supports R&D internally, and via external collaborations, on a variety of topics. However, much of this research is proprietary and aimed toward operational efficiency, cost reductions, increased recovery, and regulatory compliance. The primary technological advancements reported by industry in recent years deal with (1) practices to streamline drilling operations such that more wells/footage can be drilled within a given time using a given rig fleet and (2) increased per-lease productivity, including efforts to optimize well spacing and stimulation spacing and approaches.[41]

R&D in UOG resources issues is also conducted and supported within numerous federal agencies. Budget formulation and work allocation within the executive branch is coordinated through a steering committee consisting of representatives from DOI (USGS), DOE, and EPA with additional input from HHS, NSF, and others.[42] In addition to R&D within the DOE Fossil Energy program, important activities through this group include a wide range of sampling, modeling, and analytical activities within EPA's "hydraulic fracturing drinking water study;"[43] ARPA-E's "Monitor" program, which addresses technological development related to midstream fugitive methane emission detection and mitigation; the USGS's ongoing program of resource assessment and characterization; and the crosscutting Subsurface Technology and Energy Water Nexus initiatives, which involve several DOE programs.

Within nongovernmental organizations, active efforts include the Environmental Defense Fund's (EDF) study of "Methane Emissions from Shale Gas Wells" being conducted in collaboration with the University of Texas and others;[44] the Nature Conservancy's investigation of the cumulative, long-term implications on ecosystems, habitat fragmentation, and other land use issues;[45] periodic reports from Resources for the Future (RFF), such as their recent report "Impact of UOG development on Property Values;"[46] and the Health Effects Institute's (HEI) ongoing review of potential human health impacts from UOG development in Appalachia.[47]

Academia has developed a number of research consortia that feature extensive industry participation (funding, data provision, field research opportunities). Examples include the Colorado School of Mines Unconventional Natural Gas and Oil Institute's (UNGI) Coupled Integrated Multi-scale Measurements and Modeling Consortium (CIMMM); induced seismicity and basic shale geomechanics research conducted by the Stanford Rock Physics and Borehole Physics Industrial Affiliates Consortium; the Unconventional Shale Research and Shale Gas Simulator consortia at The University of Oklahoma; the Marcellus Center for Outreach and Research (MCOR) and the Marcellus Educational Consortia at Penn State; the Energy and Environmental Research Center (EERC) at the University of North Dakota, which conducts field programs and analyses in collaboration with industry related to efficient utilization of Bakken Shale resources; the Induced Seismicity Consortium at the University of Southern California; and the University of Texas–Austin's FRAC (Fracture Research and Application Consortium) and SUTUR (Shell/UT Unconventional Resources) programs. Universities are also conducting a wide range of focused studies on shale gas issues, often with support from foundations, philanthropic organizations, NGOs, the National Science Foundation, other federal and state sources (including DOE), and university funds. Examples include the University of Texas–Austin/Bureau of Economic Geology's studies on the sustainability of key shale basins;[48] Duke University's drinking water studies;[49] and many others.

UOG Technology Areas, Challenges, and Research Needs

In this Technology Assessment, the primary R&D needs identified include technologies to enable resource extraction in a manner that minimizes environmental impact as well as technologies that can improve the efficiency of unconventional oil and gas development such that vast stores of public resources are not left unused (and degraded) in the ground. R&D in improved UOG development efficiency specifically targets those opportunities to enable gas recovery from fewer and less impactful wells. Opportunities exist to provide a fuller understanding of the basic petrophysical nature of UOG reservoirs as well as the fundamental geomechanics of their stimulation such that both the reach of individual wells and the production efficiency (the ratio of produced resource to resource existing in-place) of the resource can be maximized. In addition, science and technology to document, mitigate, and avoid (where feasible) the negative environmental impacts of UOG development on air quality, surface and groundwater quality and availability, induced seismicity, and ecosystems would also enable broader and better access to these resources. This assessment discusses R&D opportunities within six technology areas that encompass 15 specific (but not exclusive; many R&D opportunities are related to multiple topics) research topics as shown in Table 7.G.1. The following sections provide science and technology assessments for each "technology area," along with a review of ongoing R&D efforts within the DOE/FE program, and remaining science and technology development opportunities.

Science and Technology Assessment – Scale and Nature of Resource Development

The environmental impact of UOG development is dependent largely on the nature of the development process and the geologic and geographic setting where the development occurs. Specific impacts on air, water quality, water availability, and induced seismicity are described in separate sections. However, the nature of both near-term and cumulative long-term impacts will be driven by the nature and pace of the development. Assessing the location and potential size of different UOG resources around the country, the evolution in development processes, and the nature of subsurface physical processes is a requirement for understanding the potential scale and impacts of development. These same factors are critical as well in assessing recovery efficiency. Therefore, the general area of "Subsurface Footprint" includes four topic areas: (1) fundamental science; (2) resource characterization and assessment; (3) recovery efficiency; and (4) development intensity.

Table 7.G.1 UOG Technology Areas, Challenges, and Research Needs

Technology Area	Situation and Challenges	Primary Research Needs
Scale & Nature of Resource Development		
Fundamental Science of UOG Reservoirs	■ Uncertain nature of porosity at nanoscales ■ Hydraulics, thermodynamics at nanoscales ■ Traditional evaluation/engineering/field management paradigms do not work ■ Geomechanics in heterogeneous media	■ Assessment and characterization of reservoir phenomena at various scales ■ Development of new petrophysical geomechanical thermodynamic algorithms of UOG behavior
Resource Assessment	■ Geology no longer drives recovery ■ Technically recoverables are prone to significant temporal and spatial variability ■ Sustainability of key plays in question ■ Tools for modeling resource development process/implications do not exist	■ Evaluation of future additions to technically recoverable resources in both established and emerging plays as a function of technology ■ Tools for evaluation of impacts and potential for technology-based impact mitigation
Improved Recovery	■ Recovery Factor (RF) is low, poorly known, highly variable ■ Inability to access hydrocarbon in unstimulated matrix ■ Secondary recovery potential unknown ■ Large regions of existing plays currently not produceable	■ Improved stimulation technology development, testing, and demonstration
Reduced Development Intensity	■ Unconstrained future well counts and steadily increasing development intensity ■ Inability to image or control Stimulated Rock Volume (SRV) as desired (size, shape)	■ Dynamic control of HF ■ Go beyond microseismic for mapping of SRV ■ Optimal spacing of wells (maximum EUR from fewer wells)
Water Quality		
Wellbore Integrity	■ Inability to diagnose cement condition through time ■ Unknown causes of annular gas migration ■ Potential long-term degradation of cements ■ Difficult intervention, repair	■ New cement formulations ■ Approaches for evaluating cement condition over time ■ Case studies for loss in cement integrity ■ Cost-effective mitigation approaches

Table 7.G.1 UOG Technology Areas, Challenges, and Research Needs, continued

Technology Area	Situation and Challenges	Primary Research Needs
Produced Water Treatment and Management	■ Disposal by injection is cost-effective ■ Lack of modular devices for rapid treatment of large volumes of water ■ Produced water chemistry/volume varies with time/well/play ■ Recycling options will decline as plays mature	■ High-volume, mobile systems ■ Technologies for reduced water production ■ Enabling expanded recycling and beneficial use
Risk of Groundwater Contamination	■ Shallow gas mobilization during drilling ■ Characterizing the risks of fracturing out-of-zone and vertical migration of fluids ■ Identifying/mitigating legacy well risks ■ Additives needed (biocides, viscosifiers)	■ New technologies for monitoring of HF extent ■ Demonstrate effective location and characterization of legacy wells
Water Availability		
Alternative Water Sources	■ Freshwater is cheap and best for HF make-up water ■ Compromised waters can result in flow degradation via fouling, scaling ■ Freshwater availability varies regionally and seasonally	■ Reduce freshwater use through protocols that allows effective use of brines, brackish waters, and other non-potable waters
Less-Water-Intensive HF	■ Many HF stages consume water but contribute little production ■ Water emplacement degrades reservoir quality ■ Clay-rich shales do not respond well to water ■ HF designs are not optimized to varying geology	■ Tools and insights to determine optimal zones for HF to more effectively tailor HF design to variable reservoir geology
Waterless Stimulation	■ Cheapness and availability of water ■ Excellent proppant-carrying properties of water ■ Safety and equipment for hydrocarbon-based fluids ■ High costs for CO_2 for CO_2+ stimulations ■ Limited reach for “explosive” fracturing	■ Identify most promising, play-specific, waterless approaches ■ Demonstrate effectiveness in variety of geologic settings

Table 7.G.1 UOG Technology Areas, Challenges, and Research Needs, continued

Technology Area	Situation and Challenges	Primary Research Needs
Air Quality		
Measurement and Attribution	■ Conflicting research findings from various approaches that require reconciliation ■ Difficulty in differentiating emissions between UOG and other regional methane sources ■ Green completions ■ Emerging consensus that primary contributors are mid-stream sectors, small number of large emitters	■ Complete ongoing efforts to gather colocated "top-down" and "bottom-up" measurement, modeling, and attribution in active plays ■ Update life cycle assessments to further refine most promising technological options/targets for emission mitigation
Impact Mitigation	■ Identifying leak sources quickly and efficiently	■ Technologies for the rapid identification of system upsets and quantification of unintended emissions
Induced Seismicity		
Analysis and Attribution	■ Data availability and management ■ Difficulty in differentiating induced from background seismicity ■ Difficulty in linking seismicity to specific engineering actions	■ Detailed review and analysis of data in regions of increased seismicity ■ Develop correlations between geologic and UOG activity factors
Prediction and Avoidance	■ Poor geologic characterization of geology and geomechanics in injection reservoirs ■ Limited ability to characterize the occurrence and condition of faults	■ Evaluation of potential for predictive models and calibration through back-casting with historical data in well characterized fields
Crosscutting		
Regional Field Laboratories	■ Lack of field access for objective science ■ Lack of field access for technology development and demonstration ■ Lack of field access for integrated studies across R&D Focus Areas ■ Regional heterogeneity of UOG resources	■ Establishment of multiple, multiyear, regional field sites for comprehensive monitoring of UOG development (initial focus) ■ Seek sites for collaborative field testing and demonstration of alternative advanced surface and subsurface development approaches (evolving focus)

Current State of the Art and R&D Drivers

Fundamental Science: Despite the significant growth in the production of UOG resources, much has yet to be learned about their basic physical structure and behavior. For the past century, reservoir engineering has developed within the context of conventional reservoirs. However, in the nanoscale, organic-matter-rich context of shale reservoirs in particular, basic reservoir petrophysical properties (porosity, hydrocarbon saturation, and others) are determined by phenomena occurring across a broad spectrum of spatial scales.[50] Further, unlike conventional reservoirs, production response is not primarily controlled by the nature of the reservoir, but instead is a complex interaction between the reservoir and the nature of the well stimulation.[51] Therefore, in UOG settings, neither the in situ nature of hydrocarbon occurrence nor the resultant flow properties of the stimulated reservoir are well known, and neither lends itself to ready diagnosis from standard analyses of log, core, or production data.[52,53]

Resource Assessment/Characterization: In conventional reservoirs, the most basic resource calculation, the volume of in-place resources, employs a relatively simple equation:

Gas in place = area x thickness x porosity x saturation x formation volume factor

(FVF: translates subsurface volumes to those present at surface pressure and temperature conditions).

Such a calculation is complex in UOG reservoirs, as well-log data do not readily reveal reliable estimates of porosity or saturation, among other complications. Calculation of technically recoverable volumes (the subset of the in-place resource that is practically available for production using existing technologies) is similarly subject to great uncertainty. In conventional reservoirs, technically recoverable resources (TRR) can be determined by TRR in-place resources x recovery factor. However, most groups that conduct assessments obtain TRR from observed well performance and do not attempt to estimate in-place resources. In shale reservoirs, observed well performance is often not indicative of reservoir potential because of the strong reliance of production on what technology is applied and how well-matched it might be with the particular geology found in any specific well. Even where technology is uniformly applied, the nature of technology as it is applied to UOG resources evolves rapidly, meaning that any well is, at best, a snapshot of potential TRR at that particular point in time (or point in the development of technology). Furthermore, development typically proceeds from sweet-spots to more challenging areas, meaning early wells may not be fully indicative of larger regions. As a result, published assessments of resources in UOG plays have a limited "shelf life" and are prone to substantial revision as new data are obtained (as illustrated by the evolution of Marcellus Shale resource estimates: USGS, 2002; USGS, 2012; EIA, 2012). Such uncertainty within a formation that has experienced the drilling and production of the Marcellus suggests that assessed values in other emerging UOG plays are likely prone to similar uncertainty. For example, the EIA recently revised the recoverable resource assessment for the Monterey Shale of California from 13 billion to 600 million barrels based on recent well results indicating that particular play is not as readily amenable to existing technology as plays such as the Bakken.[54] Such substantial revisions—both positive and negative—should be expected, as the first substantive drilling information from emerging basins becomes available and many key factors, such as recovery factors, the potential areal variability in well performance, the impact of sustained low prices, development practices, and the potential impact of future technology, become better understood.

Improved Recovery Efficiency: Very little is known, in detail, about recovery efficiency in UOG reservoirs. The limited information that is available, which is often anecdotal, suggests that recovery efficiency is typically quite low, perhaps 20% in gas-rich shale reservoirs and less than 10% in liquid-rich plays. It is unclear if even the concept of recovery factor can be readily applied to shale plays. In general, RF is simply the ratio of volume recovered by prevailing production practice to the total volume in place. While volume recovered is readily measured, it is very difficult to constrain the reservoir area (both laterally and vertically) from which that volume was derived. The standard assumption (from conventional resource development) of some relatively regular drainage radius (often envisioned as a circle or an ellipse) simply does not apply in the HF-shale context. Instead, complex determinations of the "stimulated rock volume" (SRV) must be obtained or assumed, often using microseismic data.[55] While microseismic is widely accepted to be a relatively reliable indicator of the extent of hydraulic fractures,[56] it is much less conclusive in determining what portion of the reservoir may or may not be contributing to production.[57]

In conventional resource development, increased areal recovery efficiency is often enabled through secondary recovery and infill drilling. However, because of complexities of the impact of injected water, SRV geometry, complex induced variations in pressure, etc., concepts for infill drilling, secondary recovery, and even restimulation of primary UOG wells are very poorly developed.[58] As a result, there is a great motivation to properly/optimally stimulate[59] and space the primary wells.[60] The goal of these efforts is to produce a more predictable and controllable SRV so that wells can more effectively drain a given reservoir volume.[61] Therefore, ongoing efforts to assess and improve RF will focus on four primary issues. First, how can restimulation and other approaches for enhanced (secondary and tertiary) hydrocarbon recovery be most effective?[62] Such work will require significant advances in the fundamental understanding of the nature of UOG reservoirs and the changes imparted to them during primary production, followed by applied research and field demonstrations. Second, to what extent is recovery occurring within the SRV? This is an issue of the pervasiveness of fractures at varying scales and the extent to which those fractures provide access to hydrocarbon from the adjoining, undeformed matrix. Third, how can stimulation produce more uniform and pervasive SRV? At present, it is generally accepted that many hydraulic fracturing stages contribute little to production.[63] Significant potential for improvement is held in the wider adoption of "engineered completions" (in lieu of "geometric completions" or "factory development") that are enabled by advanced down-hole data collection that allows completions to be tailored to the specific geology within any given borehole[64] and to be controlled to create more pervasive and appropriately distributed stimulation along wellbores.[65] Fourth, from a field development standpoint, to what extent do the highly irregular SRVs from numerous wells interact to fill the available reservoir area, and how can more predictable and expansive SRVs be developed so that a given area can be effectively drained with fewer wells? At present, the ongoing transition to engineered completions can be expected to result in modest increases in recovery efficiency per unit; however, this success will likely be incremental and will come at the expense of escalating intensity of the subsurface development footprint. To counter this trend will require finding the means to dynamically control fracture size and orientation so that larger and more predictable SRVs can be reliably created.

At present, UOG technology has enabled the effective production of a certain subset of the shale gas resource—in particular, those that are relatively deep (and therefore higher-pressure), organic rich, and "frackable" (referring to a relatively brittle, clay-poor lithology). However, large portions of many of these plays, especially regions that are at lower pressures, are not economically viable with current technologies despite housing significant resource volumes. Other plays, such as the Monterey Shale, will require further evaluation and likely new approaches to deal with play-specific geologic issues.

R&D Challenges and Opportunities

Current UOG development can benefit significantly from advanced scientific understanding of the thermodynamic, petrophysical, chemical, and geomechanical nature of UOG reservoirs and the interaction between such reservoirs and stimulation practice. Given the current unconstrained scale of both UOG resources and UOG development activity, the benefits of advanced science and technology that allow greater resource recovery from fewer wells could be substantial. For example, any increase in national recovery efficiency would considerably expand the nation's resource base, with significant economic benefits. At present resource estimates, every 1% increase in recovery efficiency adds 50 to 100 tcf to the nation's recoverable resource base. Significant reductions to freshwater usage are also possible with more efficient development.

Therefore, the primary R&D challenges include, but are not limited to: (1) understanding the nanoscale structure of UOG reservoirs and the nature of hydrocarbon storage, release, and flow; (2) improving extraction efficiency from current low levels to reduce the incidence of stranded/unproduced resources and the related lost economic and energy security benefits; (3) understanding the continued likely growth in recoverable resource volumes with technology advance and accurately assessing the potential nature, scale, and rate (intensity) of future development in various areas of the country to guide assessment of region-specific and cumulative impacts; and (4) mitigation of future development intensity, in terms of significant reduction in the number of wells required to drain a given area, via more effective creation and control of stimulated rock volume.

Science and Technology Assessment - Water Quality

UOG development can impact water resources at many stages throughout the UOG life cycle, including site construction, drilling, completion, production, and wastewater management.[66] The science of assessing impacts includes identification and measurement of changes in water quality (including basic parameters such as flow rates, temperature, turbidity, etc., as well as occurrence of chemical, microbial, or biological contaminants) and various experimental and modeling activities designed to understand geochemical reactions between rocks and injected fluids, to the potential release and migration of pollutants through surface water and groundwater, and ultimately, to attribute contaminants to specific sources. The R&D opportunities to address the issue of water quality are described via four topics: (1) assessment and analysis,[67] which focuses on measurement and modeling studies to identify and characterize changes in water quality and attribute them to potential sources; (2) enhanced wellbore integrity, which focuses on effective wellbore design, diagnosis, and intervention to ensure that wells provide effective, long-term separation of stimulation and production fluids from shallow water resources and the atmosphere; (3) effective produced water treatment and management, which seeks to find more effective means for enabling produced water beneficial use; and (4) reduced risk of groundwater contamination, which focuses on studies to assess the potential for unintended subsurface migration of fluids, the mobilization of methane and other contaminants in shallow potable water aquifers during or in association with drilling, and the identification and characterization of potential contaminant pathways (e.g., improperly abandoned legacy wells).

Current State of the Art and R&D Drivers

Assessment and Analysis: To date, substantial effort has been made to measure water quality in areas of ongoing UOG development and assess spatial correlation between water quality changes and UOG activities.[68] For example, Entrekin et al.[69] report impacts associated with site construction activities. Osborn et al.[70] reported a correlation between methane contamination in 68 water wells in New York and Pennsylvania and proximity to UOG well sites. Molofsky et al.[71] determined that methane occurrence in water wells was most strongly associated with geographic location (valleys - and therefore perhaps more closely coupled to natural methane sources by virtue of being in areas with greater natural fracturing). Such studies are likely to be very location-specific and highly sensitive to a range of parameters, such as seasonality, sampling protocols and frequency, and local geology and climate.[72,73] As a result, reaching broad conclusions as to the generic risks of UOG development from observational studies will continue to be difficult to develop.

Substantial effort has been expended to determine natural tracers that can differentiate shallow fluids from those that occur with depth;[74] with identification of strontium (Sr) as a particularly valuable species.[75] Darrah et al.[76] utilize hydrocarbon geochemistry and noble gas isotopes to enable attribution of observed hydrocarbon occurrences in water wells to shallow sources, intermediate-depth sources (suggesting loss in annular cement integrity), and deeper producing reservoirs.

The EPA is currently completing a comprehensive study of the potential effects, nature, and causes of impacts to drinking water quality associated with the full life cycle of UOG development.[77] The effort includes data review, case studies, laboratory studies, and numerical simulation of subsurface processes. While methane contamination and surface spills related to handling and disposal of wastewater[78] appear to be the primary risks to water quality, elevated radium and salinity in groundwater in areas of UOG development are also subjects of ongoing study.[79] The varied geochemistry of produced water, as well as the interactions between injected fluids and native fluids and minerals under subsurface pressure and temperature conditions, are also areas of active study.[80]

Enhanced Wellbore Integrity: Designing a casing and cementing program that will ensure that these materials serve as effective barriers between the rock formation and the wellbore during a well's lifetime is one of the more important elements of any drilling and completion program.[81] Loss of well integrity is a complex issue with multiple manifestations and causes.[82,83] The primary issue is the nature and quality of the well completion and cementing[84] and any deterioration in cement bond quality that may occur during well stimulation or via long-term degradation. Well integrity loss can include phenomena that lead to gas and fluid communication between various casings within the completion string (and leading to observations such as "sustained casing pressure" pointing to integrity issues within the well), as well as larger breaches that can introduce fluids to shallow formations outside the well. Given the potential scale of UOG development, much attention is paid to assessing the frequency of well integrity issues,[85,86,87] with rates ranging from 0.3% to 9.1% of wells reporting well integrity issues. However, the data often used to assess wellbore integrity, such as reports of violations, are often inconclusive and difficult to assess with respect to cause, severity, or potential impact. This data is also difficult to evaluate because of the inclusion of different and occasionally unclear populations of wells, and varying criteria as to what constitutes a loss of well integrity. Finally, due in part to the relative newness of UOG development, data tends to focus on incidents early in well life, with little data currently available on the occurrence of well integrity issues over longer time frames.

Effective Produced Water Treatment and Management: Shale gas and shale oil wells are stimulated with large volumes of water pumped in multiple stages along the horizontal laterals of each wellbore. The total volume of water required can range from 2 to 10 million gallons per well depending on the play and well configuration.[88]

The vast majority of the injected fluid remains in the formation [Hansen et al.[89] report this value as 92% for Marcellus wells in West Virginia between 2010 and 2012]. Therefore, unlike many industrial usages, as much as 90% of all water injected during UOG well development remains permanently removed from the active hydrologic cycle. Over the well's lifetime, additional water is produced, depending on the reservoir. Generally, this produced water is high in dissolved solids, metals, and sometimes also naturally occurring radioactive materials[90] that are often found concentrated in shales. At present, increasing volumes of this water are treated, mixed with additional freshwater, and reused in subsequent well stimulations. Ultimately, when the water becomes too impaired, or local options for its economic reuse are not or are no longer available, the water is disposed of. Increasingly, this disposal is via deep injection wells.[91] Currently, industry (particularly in the East) no longer disposes of water via municipal water treatment facilities, which was a common practice early in UOG development and one that was often linked with degradation of regional surface water quality.[92]

Depending on the nature and concentrations of the constituents, produced water can be effectively mixed with freshwater to enable its reuse as fracturing fluid makeup water in subsequent wells. To a lesser degree, the water may be cleaned to a point where it is suitable for other beneficial uses. Water that cannot be economically treated is typically trucked to a disposal well and pumped into a deep formation. While this consumption of water resources, when properly managed, may not be a critical issue in shale development areas with high annual rainfall (e.g., Pennsylvania, Ohio, West Virginia), in some areas (e.g., Texas, Oklahoma, southern California) experiencing drought conditions and significant competition for water supplies, it is an issue of concern.

Treatment options range from simple filtering combined with the addition of chemicals to render the dissolved constituents less reactive, to much more energy-intensive (and thus more expensive) thermal, electrochemical, osmotic, or other water desalination processes that can result in a pure or nearly pure water stream. In many cases, the costs of cleaning up the produced water stream exceed those of transport, disposal, and replacement from natural sources of freshwater. But in cases where the wastewater is relatively clean and freshwater is scarce, treatment and reuse can be an economic choice.

Reduced Risk of Groundwater Contamination: A potential source of contamination of shallow potable water aquifers related to drilling, completion, and stimulation of UOG wells is associated with the mobilization of stray gas during drilling of the surface section of the wellbore. Depending on the fluid pressure regime in place, drilling fluids may migrate into these aquifers or cause naturally occurring methane from shallow sources to be mobilized and driven toward nearby water wells.

Much attention has been paid to the potential migration of fluids from the production zone into overlying aquifers. Little evidence exists that such migration occurs, given the large physical separation between reservoirs and aquifers[93] and the extremely low permeability of the intervening formations.[94,95] Field studies to test this finding are complex and scarce but suggest limited vertical flux of fluids from the production zone through overlying strata.[96] However, other enabling pathways may be present, including faulty annular cement within the primary production wells[97] and orphaned "legacy" wells (older vertical wells, of which a significant portion are likely to be very poorly cemented, if cemented at all), that may provide a more rapid conduit through the overburden in rare circumstances.[98]

R&D Challenges and Opportunities

Enhanced Wellbore Integrity: Opportunities for research to reduce the risks of poor wellbore integrity focus primarily on gaining a common understanding of the various manifestations of well integrity loss and the causes of each. Such insight can be gained only from detailed case studies and extensive data availability. The primary phenomena can then be further investigated via experimental efforts and numerical modeling to determine the development of well integrity loss and the most promising procedural and technological solutions. Such work needs to assess not only the causes for improper well completion, but also the long-term degradation of cement and pipe that have been successfully installed in full accordance with established protocols.

Technological solutions are likely to include new cement formulations that maximize the chances of good isolation across a range of pressure, temperature, and wellbore fluid conditions, as well as advancing the technology of cement bond evaluation (at installation and monitoring over time) so it can be more widely and effectively applied. Advanced materials for casing and cements for long-term durability in a range of geologic environments are likely needed as well.

Effective Produced Water Treatment and Management: Given the increasing scale of development, perhaps the best solutions to the issue of environmental impacts associated with produced water handling are those approaches that reduce produced water volumes. Further opportunities include the broad collection and dissemination of chemical data on flowback and produced water characteristics by play and subplay to facilitate broad development and application of new technologies, or novel combinations of existing technologies, for the rapid, mobile, and large-volume treatment of produced water.

Reduced Risk of Groundwater Contamination: Opportunities for research to further reduce the potential for groundwater contamination related to UOG development include: (1) gathering information to more accurately characterize shallow potable water aquifers in UOG play areas (e.g., depth, thickness, pressure, salinity); (2) determining play-specific best practices for surface hole drilling operations; (3) conducting field experiments that characterize and quantify the risk of unintended subsurface migration of drilling and completion fluids under a variety of scenarios; and (4) developing, testing, and demonstrating novel, cost-effective techniques for locating legacy wells.

Science and Technology Assessment - Water Availability Impacts

From the 1920s to the 1950s, roughly 90% of shale wells in the United States were stimulated with explosive (gelled nitroglycerin) fracs. Beginning in the 1950s, hydraulic fracturing jobs were small. From the mid-1970s on, development of the Antrim, Huron, and New Albany shales was primarily enabled through nitrogen-foam fracs[99] to mitigate reservoir damage related to water injection into clay-rich formations. In the 1990s, the use of high-volume water plus select chemicals (such as biocides, scale inhibitor, friction reducer, gelling agent, acids) (slickwater) HF showed positive results in the early development of the emerging deeper, high-pressure Barnett[100,101] and Fayetteville shales. Today, UOG development in the United States is focused largely on those formations that respond well to HF and is primarily enabled by the widespread availability of freshwater and the high effectiveness and low cost of water as a fracturing fluid within most (brittle and clay-poor) shales. Science and technology related to assessing and mitigating the burden on water resources posed by water withdrawals in association with UOG development include four primary efforts. The first, is focused on understanding the characteristics of water supply, the variability of supply geographically and seasonally, and the environmental implications of various scenarios of water withdrawal under a range of local hydrologic conditions. Three additional research areas focus on means to mitigate demands on freshwater sources, including: (1) alternative water sources - addressing opportunities to use non-fresh or otherwise compromised water sources (brines, brackish water, acid mine drainage water) to offset freshwater usage in hydraulic stimulation; (2) efficient (less water-intensive) hydraulic fracturing, which addresses opportunities to decrease the ratio of water injected to gas produced by developing information and technologies that allow the optimal, well-specific, selection of fracture stage location and design; and (3) waterless stimulation, which targets the development and expanded use of promising alternative (waterless) stimulation technologies, including the use of CO_2-foams, hydrocarbon-based fracturing fluids, and other potential means.

Current State of the Art and R&D Drivers

Water Resource Characterization: A national review conducted by Freyman[102] indicated that nearly half of all wells hydraulically fractured in the United States since 2011 were in regions of high or extremely high water stress, with the most significant issues present in Texas and Colorado. Per-well water use varies greatly by play, with the average horizontal gas well using 4.8 million gallons of water (3.2 million per horizontal shale oil well.[103] While these values are typically less than that associated with other uses and industries, the vast majority (estimated at greater than 90% in West Virginia and Pennsylvania[104]) of the water withdrawal for UOG development is ultimately removed from the local hydrologic cycle. Numerous surface and groundwater monitoring networks exist to assess the nature and changes in water quantities, but these networks have not been located with the goal of assessing the impacts of UOG withdrawals. As a result, only a limited number of studies have been conducted to describe the profile of water utilization in UOG development (Appalachian basin,[105] Texas:[106]) and its impact on surface water[107] and groundwater. Further, as the range of water sources used to support UOG development continues to expand to include various nonpotable and brackish sources, very little is known regarding the baseline conditions of these resources.

Alternative Water Sources: The demand for freshwater for HF in UOG shale plays has led to the consideration of non-freshwater alternatives. These include acid mine drainage (AMD) found in abandoned coal mines and associated holding areas in Appalachia or hard-rock mines in the Rocky Mountain states, as well as brackish water found in either surface water bodies or subsurface formations in arid areas (e.g., Texas[108]). While brackish or saline water must be desalinated before it is usable as a public water supply, it may be usable for HF after less intensive treatment. However, current desalination processes require significant amounts of energy. AMD has a low pH (acidic) attributable to the oxidation of sulfide minerals associated with the materials being mined. Some mine drainage also contains high quantities of metals. These constituents must be neutralized or removed for the water to be useful as hydraulic fracturing makeup water, as the acidity or metal ions would interfere with other additives. AMD utilization for UGO development also faces a range of regulatory impediments.

Efficient (Less-Water-Intensive) Hydraulic Fracturing: Recent estimates suggest that more than half of all fracture stages pumped contribute only minimally to well production.[109] The causes of this inefficiency are complex and result from the interplay between variations in application of the fracture stimulation along the wellbore and variable formation geology. At present, industry continues to seek means to improve stimulation effectiveness while maintaining the cost and operational efficiency benefits that come with standardized stimulation designs.[110] Such new approaches may result in either decreases or increases in total volumes of water used, but show promise of enabling improved ratios of water used per gas produced with attendant reduction in need for subsequent restimulation. Continued reduction of ineffective water use will likely depend on further advances in formation characterization and evaluation along horizontal well bores,[111] improved fundamental understanding of how those variations might impact optimal stimulation, and focused field trials to identify the most effective approaches. Additional potential for reduction in water utilization will come from optimized well placement and field-scale development management (as discussed prior). Various advanced concepts to better control the initiation, placement, and/or orientation of hydraulic fractures through mechanical or other means have been investigated. Such approaches would enable the more prudent and effective use of water during stimulation. The use of cryogenic fluids such as liquid nitrogen,[112] which fracture rock through imposition of strong thermal shocks, has shown intriguing results, but the literature is sparse and the concept will face significant logistical and technical (proppant-carrying capacity) challenges.

Additional opportunities for reduction in water usage in hydraulic fracture employ a substantial non-water component as a large share of the fluid make-up.[113] According to data contained in the FracFocus database,[114] 609 "energized fracs" were performed using compressed gases in the 2011–2012 time frame, representing less than 2%–3% of the fracturing jobs in the United States and 20%–30% of the fracturing jobs performed in Canada. In addition to the benefits of reduced water use, such alternative fracture fluids can improve well productivity by avoiding water blockages and other impacts associated with excess water emplacement. Nitrogen-based foam fracturing has been commercially performed and available since 1975, and operators continue to use this type of treatment in selected areas, particularly in shallow and intensively naturally fractured shales (Huron, Antrim, New Albany) that require less energy to effectively fracture stimulate. Nitrogen-energized fracking uses roughly 50% nitrogen and 50% water and can facilitate the return of injected fluids. Likewise, CO_2-based foam fracturing enables a similar reduction in water use; in one application reported from the Utica Shale of Ohio, two wells were stimulated using less than 500,000 gallons of water each.[115] It is important to recognize that a large share of the CO_2 injected into a well for stimulation purposes would not remain underground; once the CO_2 is captured on flowback, it would still need to be stored, reused, or sequestered.

Waterless Stimulation: The greatest potential to significantly mitigate water utilization in UOG development is to develop an effective alternative to water as the working fluid for stimulation. Even though pure nitrogen- and CO_2-based fracturing methods have been available since the 1970s, they still represent a very small share of the market primarily because of the availability, low cost, and demonstrated effectiveness of water, even in areas where water resources are strained. Pure nitrogen fracs are currently common in the low-pressure, Huron shale in West Virginia and Kentucky, which is widely interpreted to experience formation damage when water is used as a hydraulic fracturing fluid.[116] CO_2/sand fracturing, which uses no water and pumps the CO_2 as a supercritical liquid rather than as a gas, was originally developed by Canadian FracMaster in the 1980s and was unsuccessfully introduced by American FracMaster in the 1980s to the U.S. marketplace.[117] The CO_2/sand fracturing process—using a closed system blender—has been successfully performed on more than 1,000 wells in Canada and portions of the United States. Once an affordable supply of CO_2 is available, the process is likely to expand in commercial use.

The use of various hydrocarbons in place of water has promise and certain advantages over CO_2 and nitrogen, including greater potential availability and stimulation effectiveness. Liquefied Natural Gas (LNG) fracturing is a recent development that has had limited applications in the United States. Gelled LPG fracturing is a process introduced in 2006 that uses liquefied petroleum gas (LPG) and sand in a closed system blender.[118] However, this process introduces additional safety risk, and limited incidents in Canada have occurred related to ignition and burns to on-site personnel.[119] The application has had limited trials in the United States.

Before the advent of hydraulic stimulation, explosive fracturing (often using gelled nitroglycerin) was the prevailing technology for shale development (within the Huron shale of Appalachian basin). The approach was again investigated in the 1970s, and in general, the process appears to be highly effective in creating permeability in the near wellbore environment but with very limited reach into the formation, although very little recent literature exists.

All of the alternative fracturing techniques listed above can reduce and/or alleviate a range of water-related issues associated with UOG development. Whether these stimulation processes can consistently maintain or improve production compared to 100% water-based hydraulic fracturing remains to be determined through field testing. Most of the alternatives to hydraulic fracturing described above have most commonly been used in small to medium volumes in vertical wells, and substantial challenges will be posed if they are to duplicate the large stimulated reservoir volumes produced by hydraulic fracturing as currently being practiced in horizontal wells. The industry has large capital investments in water pumping equipment that must be amortized. A major shift to the use of CO_2 or LNG could be difficult to justify from a service company business model standpoint.

R&D Challenges and Opportunities

Alternative Water Sources: Primary needs in enabling the accelerated use of AMD and/or brackish water as an alternative for freshwater in HF operations will require the comprehensive development, testing, and demonstration of technologies that reduce the treatment cost and demonstrate a broad applicability in a range of geologic and operational settings. Information related to the characteristics and availability of such sources in various UOG basins will also be required.

Less-Water-Intensive Hydraulic Fracturing: Opportunities for research to reduce the volume of water required to effectively produce a given volume of hydrocarbon include the following: (1) the collection, analysis, and dissemination of data sets that relate completion design to production performance; (2) new technologies and analytical approaches that support the optimal placement of hydraulic fracturing treatments based on advanced characterization of the variation in reservoir condition (lithology, saturation, natural fracturing, etc.) along horizontal wellbores; (3) new technologies that enable greater control of placement, nature, and extent of induced fractures; (4) improved imaging of the distribution of and nature of induced fractures; (5) the collection, analysis, and dissemination of data sets that enable the performance of alternative fracture fluids to be assessed; and (6) new formulations for CO_2-based and other foams that improve technical performance.

Waterless Stimulation: The establishment of effective, waterless stimulation could have a major transformational impact on the environmental profile of UOG development, particularly in areas where water resources are already stretched thin. To be most effective, such technologies would not only need to provide well performance that is similar to, or improved from, what is currently achievable, but would also need to do so without requiring a vastly larger number of wells. To date, information on the limited field trials of waterless fracturing (LNG or LPG) is lacking or proprietary. The most promising approaches will need to be identified and comprehensive evaluation and well performance monitoring conducted to quantify the nature and effectiveness of the resulting stimulation. With such data, the benefits and challenges (technical, logistical, and economic) that limit the use of alternative fracture fluids can be assessed through focused experimental and numerical simulation studies and the most promising technologies further refined. In the case of CO_2 specifically, additional challenges, such as the availability of a long-term, secure supply of reasonably priced

CO_2, and infrastructure/logistical concerns (on-site storage, blending and other equipment, affordable and portable post-frac cleanup and separation/capture of CO_2 from natural gas, etc.) will all need to be addressed through iterative field testing and demonstration.

Proper evaluation of waterless stimulation technologies will require long-term production testing of a suite of wells completed with waterless or reduced water HF techniques and scientific comparisons of their performance with geologically similar wells completed via large volume slickwater treatments. In addition to demonstration of technical effectiveness, the development, field testing, and demonstration of modified pumping and mixing equipment layouts required to pump waterless or reduced water HF treatments roughly comparable to large-volume slickwater treatments will be needed. In the case of CO_2, additional capabilities, such as the portable, economic, well-site-deployable technologies for separating CO_2 from flowback fluids and capturing for reuse will need to be developed and demonstrated.

Science and Technology Assessment - Air Quality

The expanded utilization of natural gas is often considered to have strong net positive impacts on air quality, particularly where it serves as a replacement fuel for other, less-clear sources, although the issues are complex.[120] UOG development, from proppant mining through gas gathering and distribution, has the potential to release an array of pollutants with implications for greenhouse gas/climate issues.[121,122,123] In addition to fugitive and intentional releases of methane, UOG development also produces emissions of CO_2 (through increased traffic and other engines), as well as a range of volatile organic compounds (VOCs), hazardous air pollutants (HAPs), particulate matter (PM), and radioactive substances such as radon. These air pollutants, their emission rates, and the technologies associated with the development of unconventional reservoirs remain insufficiently characterized at this time to allow a complete, scientifically based evaluation of their effects. The environmental benefits of natural gas, particularly with respect to emissions of GHGs and related negative implications for climate change, are strongly sensitive to the associated fugitive methane emissions, although the matter is neither simple nor well understood.[124,125] It is widely agreed that total leakage of more than approximately 3% to 4% of incremental produced methane would negate any potential GHG reduction benefits associated with gas use.[126] Air quality benefits are also strongly tied to whether gas truly displaces other fuels, as opposed to generally enabling expanded energy use.[127] The effort to understand and mitigate the impact of UOG development on air quality consists of two primary elements: (1) measurement and attribution includes efforts to accurately measure emissions of various pollutants, differentiate them from other natural or non-UOG sources, and reliably attribute them to specific aspects of the UOG life cycle; and (2) mitigation seeks to provide technological approaches to reduce air quality impacts.

Current State of the Art and R&D Drivers

Measurement and Attribution of Air Quality: Technology is available for accurate measurement of methane and other pollutants both in the atmosphere and at point sources. Nonetheless, there remains significant uncertainty with the rate of pollutant emissions from UOG development and any impacts that recent trends in the industry, including ongoing implementation of “green completions” in accordance with New Source Performance Standards,[128] may have on emissions.[129,130] Recent interest has been highly focused on reconciling emissions estimates for methane associated with the production, gathering, processing, transmission, and distribution of natural gas from shale reservoirs.[131]

A primary source of data for greenhouse gas emissions is the EPA’s Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990–2012.[132] According to the latest inventory, natural gas systems were responsible for 23% of the total U.S. methane emissions in 2012. Methane emissions account for more than 10% of the net greenhouse gas emissions for all sources within the United States when using the common approach of calculating global warming potential over 100 years. Because methane is short-lived in the atmosphere, its global warming potential is much more significant in the short term. While a gram of methane is 21 times more effective at global warming than a gram of CO_2 over a 100-year time period, it is about 86 times more effective over a 20-year time period.[133] The primary basis for the inventory is a study by the Gas Research Institute and EPA completed in 1996, prior to the widespread adoption of UOG development data that is currently being supplemented by new studies and data obtained under the Greenhouse Gas Reporting Program (GHGRP), a congressionally mandated EPA program requiring large emitters of GHGs from many sectors to estimate and report their emissions to EPA.

The EPA greenhouse gas inventory projects a gas leakage rate of slightly more than 1% of the total natural gas produced. This estimate is at the low end of a range of published estimates in recent years, some of which extend to ~10%. Given that values greater than 3%–4% suggest that gas utilization poses a potentially greater GHG impact than the coal or oil it may displace, there is great interest in refining these estimates. The major discrepancy is that the studies reporting the highest estimates[134,135,136] tend to be based on atmospheric methane concentration measurements (known as “top-down” methods) from which non-UOG sources must be subtracted. The accuracy of these approaches rests in the representativeness of the area surveyed, the reliability with which natural and anthropogenic (non-UOG) emissions are known in that area, and the analytical procedures used to convert atmospheric measurements to emission rates. Similarly, the estimates at the low end[137] typically attempt to measure emissions from different segments of the UOG lifecycle and sum them up (“bottom-up”). Bottom-up estimates likewise rely on the accuracy of the measurements and the representativeness of the devices and processes investigated. For example, certain point sources for methane emissions may be characterized by a small number of very large emitters, complicating the measurement and scaling-up of results. Top-down methods require that non-natural gas system sources of methane emissions are identified and accurately estimated. A recent study[138] used the top-down study results to determine that the current emissions from all sources were roughly 1.5x the current EPA methane emissions inventory. Miller et al.[139] concluded that the major cause of ongoing discrepancies in emissions estimates is most likely to be missing and/or improperly characterized sources of methane emissions in current bottom-up inventories (a compilation of industry activity data, engineering estimates of emissions, and equipment/process methane measurement data).

Mitigation of Air Quality Impacts: Well stimulation requires large arrays of fluid-pumping engines that are most commonly diesel powered. These engines generate emissions during operations, and efforts to mitigate those emissions include the increasing (but as yet minor) use of natural-gas engines in place of diesel power. The benefits of gas-powered engines on emission reduction can be important, particularly if fugitive methane emissions associated with the activity are minimized. In addition, the transport of equipment and (primarily) water to and from well sites by heavy-duty trucks (estimated at <1,500 truck trips per well[140]) generates an array of air quality and other impacts, and operators are currently seeking means to reduce truck traffic via more careful planning and alternative water transportation methods.

Numerous nonfugitive sources of VOC and methane emissions related to UOG development have been identified by researchers and operators. Examples of nonfugitive emission sources are venting during well completions, venting of stranded gas, venting as a result of liquids unloading from gas wells, venting from pneumatic control devices and pumps, and others. Several methods have been devised to mitigate these emissions associated with well completion. There are reduced emissions completions (RECs), also known as “green completions,” that capture and treat gas from known emission points so it can be directed to the sales line.

Where gas is coproduced with oil, there are locations where separate gas gathering lines are not economical to put in place. As a result, the gas is frequently sent to combustion devices (e.g., flares) or vented directly into the atmosphere. The same process is repeated in cases where wells are recompleted at a later time in order to maintain or increase production. In lieu of flaring or venting, R&D is investigating a range of alternative gas use technologies, including the liquefaction of natural gas, natural gas liquids (NGL) recovery, gas reinjection or cycling, and electricity generation for use on-site.

While newly completed wells generally have sufficient pressure to lift water and hydrocarbon liquids to the surface, ongoing pressure decline results in the accumulation of liquids in the well that must be intermittently "unloaded" to allow gas production. Emissions occur during this process, which often is done by opening the well to the atmosphere. Primary techniques for unloading liquids from gas wells include use of plunger lifts, artificial lift systems such as rod pumps and pumping units, installation of velocity tubing, and the use of foaming agents.

Compressors have been identified as an emissions source during oil and gas production, gathering, processing, transmission, and storage. These emissions typically increase over time as the compressor components degrade. Emissions from compressors can be readily managed when they are detected, and new approaches for monitoring, detection, and notification are being developed. Another major emission source is pneumatic controllers and pump systems. Pneumatic controllers counter hazardous pressure buildup via the direct release of gas to safe levels. Pneumatic pumps are typically used at oil and natural gas production sites where electricity is not readily available and often use natural gas directly from the production stream. Emissions from pneumatic pumps may be mitigated by replacing gas-assisted pumps with instrument air pumps, solar-charged direct current pumps, or electric pumps (both DC and AC powered).

A wide array of methane and VOC emissions fall under the category of fugitive (not a part of the proper and intended functioning of the equipment) emissions. Fugitive emissions occur at connections (e.g., flanges, seals, and threaded fittings) and moving parts of valves, pumps, and other types of process equipment. Leaks may be caused by improperly operated equipment and normal wear and tear. Leaks are currently managed through leak detection via periodic inspection with portable analyzers or continuous monitoring using optical gas imaging (OGI), acoustic leak detection, and other monitoring systems. New technologies for leak detection are the focus of the MONITOR program currently managed by DOE ARPA-E.

R&D Challenges and Opportunities

A high priority will continue to be placed on accurately characterizing the national and regional emissions footprint of UOG development as it is currently being conducted. Resolution of the discrepancies between top-down and bottom-up methodologies will be critical to achieving a consensus on this issue. Since top-down studies cannot readily identify what might be missing from the existing bottom-up inventories, additional and long-term point-source monitoring and measurements are required along the UOG life cycle where potentially significant emissions are possible. To be effective, such systems need to be broadly deployed, inexpensive, and autonomous. Additional top-down studies will be needed to validate bottom-up estimates using measured values and to identify emissions "hot spots" for closer measurement. Comprehensive, colocated joint bottom-up and top-down efforts, such as that currently underway in northeastern Pennsylvania, may yield significant insights encouraging related studies in other areas of the country.

UOG operations involve the transport of equipment, fluids, and other materials, usually by trucks. Water hauling, both to well sites and from well sites to disposal locations, is a primary contributor. Truck traffic results in increased hazards, noise, dust, road damage, and air emissions from the trucks. Technologies that minimize water use or well count, or provide alternative methods of transporting water, will reduce truck traffic and related impacts.

Technological solutions to address both fugitive and nonfugitive emissions associated with UOG include more durable components related to gas handling and compression, nonventing pneumatic controllers and alternative procedures for lifting fluid in mature gas wells without venting, and effective distributed technologies and procedures to improve leak detection and repair. Finally, solutions that provide commercially viable, beneficial uses for associated gas in areas lacking gas gathering infrastructure are needed to eliminate venting and flaring.

Technology Assessment - Induced Seismicity

Any injection or withdrawal of fluids from the subsurface has the potential to alter local stress conditions. Therefore, three aspects of the UOG development—(1) well stimulation via hydraulic fracturing (injection), (2) hydrocarbon and formation water production (withdrawal), and (3) waste water disposal via deep wells (injection)—have the potential to induce seismic events.[141] Well stimulation occurs in the context of short-duration, high-energy injection into reservoirs of low permeability with the express intent of inducing local rock failure. Roughly 1 million HF stimulations have been conducted in the United States,[142] and the consensus view at present is that the resultant seismic events, while numerous, are characteristically of very low magnitude, well below the thresholds to cause surface damage or even to be felt by humans at the surface.[143] Of greatest concern are deep injection wells that are used to dispose of large volumes of produced and flowback water from UOG and other conventional oil and gas development. EPA reports that approximately 144,000 Class II wells operate in the United States, injecting over 2 billion gallons of brine every day. Such operations generally target deep, highly permeable water-bearing reservoirs and as such, are not expected to create seismic events. However, given the large volumes of water, long time frames for injection, and wide lateral reach of injected fluids, these injected wastewaters may impinge on preexisting faults and induce seismic events.[144]

R&D on the topic of induced seismicity is described with reference to: (1) analysis and attribution, which includes case studies of regions of apparent induced seismicity associated with UOG operations, with the aim of developing technologies for establishing cause and related seismicity to specific UOG activities; and (2) prediction and mitigation, which evaluates the potential for developing tools to support the design of geologic characterization and wastewater injection protocols that avoid or mitigate seismicity.

Current State of the Art and R&D Drivers

Analysis and Attribution: Over the past decade, a marked increase in earthquakes with a Richter magnitude (M) equal to or greater than 3.0 (earthquakes with potential to be felt at the surface) has been observed throughout the continental United States, including Arkansas, Colorado, Ohio, Oklahoma, and Texas. Many of these seismic events have been suggested to be associated with energy extraction activities, and in some cases events were observed in areas that are not historically tectonically active. In Oklahoma, for example, the rate of seismic events of M=3.0 or higher has increased by more than an order of magnitude since 2010.[145] Seismicity is also being increasingly observed in areas that have historically been seismically quiet such as eastern Ohio.[146] A broad consensus exists that the increased frequency of seismic events is related directly to disposal of wastewaters associated with oil and gas activities,[147] and while all oil and gas production generates produced water that is disposed in injection wells, the recent acceleration of UOG development and the high water volumes it generates suggests that UOG development is central to the observation of induced seismicity.

Wastewater injection is considered most prone to generating seismicity due to the nature, volumes, and duration of injection. These factors, when combined with the high permeability of the reservoirs, allow increased fluid pressure to be felt over a much larger volume of the subsurface. If this pressure perturbation reaches faults that are very close to the critical sliding stress (and most faults are considered to be in this state constantly), a slip event may occur.[148] If the volume of fluid injected is such that it changes the hydrostatic loading in the subsurface, it can also cause effective stress changes in faults below the injection location and induce slip events. In contrast to wastewater injection, hydraulic fracture stimulation is much less prone to significantly alter the subsurface pore pressure far away from the stimulated well because of the low permeability of UOG reservoirs and the short duration and relatively low volumes of injected fluid. Furthermore, as production begins to remove fluid (both injected and in situ formation fluids) from the reservoir, the pressure and stress implications of the stimulation are mitigated. Nonetheless, as the intensity of development continues to accelerate, concerns continue to be expressed about the seismic risks inherent in HF operations, and events linked to well stimulation have been documented in the United States[149] and in UOG development in Canada and the United Kingdom.[150] The removal of fluids from UOG reservoirs via production is not considered to be a significant cause of induced seismicity.

Not all areas that are experiencing intensive UOG development are experiencing increased seismicity, however, e.g., the Williston basin,[151] indicating that the factors controlling seismicity are complex and local. In addition to the numerous unfelt earthquakes, some relatively large earthquakes (magnitude 4.0), including one of M 5.7, have been attributed—through careful analyses—to Class II oil and gas fluid disposal wells.[152] Earthquakes are commonly linked to injection procedures, especially when they occur more than one year after the start of injection, when they occur within 2-3 km of injection wells and along unknown faults, where high volumes of water are injected (>100,000 barrels per month), and where epicenter depths are at/below injection depth. However, the exact attribution of any event to any specific activity, particularly in areas of preexisting seismicity, is extremely difficult.[153] Ongoing work in multiple basins is currently attempting to collect and correlate seismic events with known geologic structures and UOG activities to determine how confidently attribution of causes for the seismicity can be made and what conditions predispose certain regions to induced seismicity.

Prediction and Mitigation: Presently, induced seismicity prediction/mitigation focuses primarily on careful monitoring and reaction to local seismicity. Upon recognition that seismicity has exceeded some pre-set threshold determined through statistical evaluation of observed events, injection activities can be altered in response. In 1976, McGarr[154] proposed a relationship between injection volume and size of associated seismic events based on empirical data. Increased seismic reaction to the passing of stress pulses from remote earthquakes has been shown as a potential indicator that a region has been brought to a critical stress state.[155]

Physics-based predictive models and geomechanical models for induced seismicity are as yet poorly developed. Detailed hydrologic models that predict changes in fluid pressures throughout a reservoir due to injection activities have been around for a long time, from industry, laboratory, and academic sources. In general, they have been well tested for predicting the migration of fluids and pressure changes, although there are always significant uncertainties involved. Models that couple mechanical and hydrologic predictive capabilities are much rarer and not as well tested compared to hydrologic models, although the individual pieces have been tested, as demonstrated with TOUGH2 and FLAC3D.[156,157] Such models would attempt to accurately simulate the subsurface environment and then impose perturbations consistent with those induced by HF or wastewater injection. The quality of the simulation depends on the quality of data available to construct (constrain) the subsurface environment, particularly with respect to stress state, rock geomechanical properties, fracture and fault networks and other heterogeneities, and the delineation and characterization of faults. Unfortunately, this information is not readily determined from available data, and many deep faults in sedimentary basins are not resolvable with existing seismic data. Site characterization is also problematic in wastewater injection scenarios as those reservoirs, not being the targets for development, are generally very poorly characterized. Analysis would also necessarily include accurate information on fluid injection volumes and rates. Theoretically, given accurate information, numerical analyses can predict what rates of injection would equate to increased risk of induced seismicity and what the general maximum magnitudes of events might be. They also could determine how much fluid can be injected, at what rate, and at what depth, before stress conditions are reached that would match those where seismicity would be expected. However, while numerical models may be able to assess bulk behavior of the geologic system, they would likely never be capable of predicting the occurrence or nature of specific events.

R&D Challenges and Opportunities

Analysis and Attribution: Although induced seismic events due to anthropogenic activities have been known and studied for decades, and the link between observed seismicity and UOG activities is becoming clearer, a number of questions in the field remain unanswered. Protocols for distinguishing injection-induced events from natural events are unclear and may be highly variable from location to location. What features most predispose an area to induced seismicity, and how can those features best be understood? Additional studies that collect comprehensive data to enable correlations between causes and effects will be required within each basin where UOG activities are ongoing, and more will be needed. Further, while induced seismicity linked to hydraulic fracturing is rare and clearly of much lower priority than that associated with wastewater injection, it has occurred and likely will occur increasingly as development intensifies. This risk is not clearly understood.

Prediction and Mitigation: Seismicity monitoring will continue to guide the management of wastewater injection, and improved protocols for the evaluation of local conditions and the setting of thresholds will continue to be developed, based on improved statistics-based attribution and analysis capability. At present, there is very little in the literature for modeling of changes in stress from wastewater injection, likely due to the difficulty in getting an accurate description of the model environments. Research is needed to determine the viability of developing reliable and actionable, physics-based prediction capabilities. For example, attributes of useful predictions would include indications as to whether the seismic response in a specific area will occur as individual large events or as a series of smaller events over time. The first step in realizing the promise of physics-based models is to determine what constitutes sufficiently detailed descriptions of the subsurface environment and the best means to collect that data. It is likely that new tools and sensors may be required for data collection on key stress-state-related properties. Improved means of fault detection are also required. Models informed with such data can then be history matched to determine ability to hind-cast observed phenomena.

Appendix

UOG R&D at DOE

DOE's Office of Fossil Energy (FE) has a long history of supporting and conducting R&D related to UOG. The oil and gas industry is a mature, worldwide commercial entity. The federal role in this enterprise is necessarily focused on ensuring the public good and manifests itself in activities that protect the environment, improve safety, and contribute to the nation's security. FE's UOG R&D aims to develop technology in the public domain that can reduce the activity's footprint through the drilling of fewer wells, protect and improve water and air quality, and address induced seismicity associated with unconventional oil and gas development. This research and development is needed to inform the process of setting and advancing regulations. From 1977 to 1992, FE programs were focused on specific resource elements (such as the Eastern Gas Shales Program, the Western Tight Gas Sands Program, and the Coal-bed Methane Program) that were deemed to be abundant but greatly underutilized due to technological limitations (NETL, 2007). From 1993 to 2007, DOE/FE's "Exploration and Production" program focused on a wide range of specific technological issues, such as deep drilling, advanced imaging, reservoir life extension, and others, that commonly targeted UOG among other resource elements and contributed to the development of many highly impactful technologies, including mud telemetry, fracture mapping via microseismic imaging, and others. In addition, the "(Effective) Environmental Protection" (EEP) program was intermittently funded from 1984 to 2012 and, most recently, focused on the development of technologies related to management and treatment of produced formation water. From 2005 to 2013, the EPACT 2005 Sec 999 Program allocated ~$12M/y to the development of a UOG research portfolio managed by the Research Partnership to Secure Energy for America (RPSEA). EPACT Sec 999 also allocated ~$6M/y for complementary unconventional resources R&D conducted by NETL's Office of Research and Development (ORD). Congress has also periodically appropriated funds to the "Unconventional FE" program, which has supported a range of upstream oil and gas issues, including onshore unconventional R&D in 2012, 2013, and 2014 (see table 7.G.2). Congressionally directed project (CDP) funding has also been provided to the Ground Water Protection Council (GWPC) in recent years to develop improved options for the streamlined collection of regulatory data by individual states as well as other data provided voluntarily by industry, including the chemical constituents of hydraulic-fracturing additives via the "FracFocus" web portal.

In 2011, a subcommittee of the Secretary of Energy Advisory Board[158] released a report highlighting public interest issues related to UOG development. In 2012, the President's Executive Order "Supporting Safe and Responsible Development of Unconventional Domestic Natural Gas Resources" directed Federal agencies to pursue multidisciplinary, coordinated research on the safety and environmental sustainability of UOG development.[159] This order resulted in the development and ultimate release of a "Federal Multiagency Collaboration on Unconventional Oil and Gas Research"[160] plan that describes collaboration between DOE, DOI, and EPA in pursuing research needs on near-term, high-priority science and technology development. In conjunction with this initiative, the EEP program was ended and the "Environmentally Prudent Development" (EPD) program was initiated in 2014 with the intent of enabling FE R&D activities that would be closely aligned with emerging R&D priorities identified in the Multiagency Plan.[161]

The Current DOE/FE Program Structure

The DOE/FE program in UOG R&D includes three primary components: assessment and analysis,[162] modeling and analysis, and technology development. Assessment and analysis activities are those that are focused on documenting, quantifying, and modeling the environmental implications of UOG development. Through the Multiagency R&D Framework, this work is closely coordinated with other similar scientific observation and analysis activities that occur with the collaborating federal agencies. This work focuses on documenting baseline environmental conditions where possible, measuring environmental conditions in areas of UOG development, and advancing the understanding of fundamental physical and chemical processes that occur during UOG development activities. Modeling and analysis activities include efforts to isolate and attribute observed environmental changes to specific causes within the UOG development life cycle from among a wide variety of other potential natural and non-UOG anthropogenic causes. Modeling and analysis also includes efforts to improve the ability to predict various subsurface phenomena and to determine the potential scale and nature of UOG development. Efforts in assessment/analysis and modeling/analysis are designed to identify and close those information gaps that are most relevant to the identification and development of technology with promise to avoid and/or mitigate the environmental impacts of UOG development. Among all the agencies within the Multiagency effort, DOE is unique in its focus and capability for impact reduction through technology

Table 7.G.2 Funding to DOE/FE Programs in Unconventional Oil and Gas R&D (2008–2014) $k

Program	FY 2008	FY 2009	FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015
Effective Env. Protection	-	-	$2,833	0	$2,874	$7,917	-	-
Env-Prudent Development	-	-	-	-	-	-	$10,400	$7,021
Unconventional FE	-	-	-	-	$500	$2,446	$15,000	$4,000
Congressionally Directed	-	-	-	0	$2,123	$1,600	$2,200	$3,600
RPSEA Consortium	$12,000	$12,000	$12,000	$12,000	$12,000	$12,000	-	-
NETL Sec 999 Comp (UCR)	$6,000	$6,000	$6,000	$6,000	$6,000	$6,000	-	-
TOTAL	**$18,000**	**$18,000**	**$20,833**	**$18,000**	**$23,497**	**$29,963**	**$27,600**	**$14,621**

development. Without technology, impact reduction can be achieved only through regulation, which may often lead to reductions in the economic and energy security benefits of production.

Scale and Nature of Resource Development – Current R&D Portfolio

DOE/FE currently has 10 active projects assigned to this R&D subtopic. Several of these projects are focusing on improved understanding of the physical and mechanical nature of hydraulic stimulation. Three projects are addressing improved means to image the effectively stimulated rock volume so that the impact on the reservoir of existing and variable stimulation approaches can be assessed. Such insights are expected to lead to further opportunities to modify stimulation designs such that more extensive, predictable, and consistent stimulations occur, which will lead to more effectively spaced wells.

In FY2014, NETL awarded six projects to four national laboratories to address fundamental issues related to UOG development. These projects are designed to utilize the unique capabilities and equipment housed in the DOE National Laboratories to investigate basic physical, chemical, geomechanical, and thermodynamic issues related to hydrocarbon production via hydraulic fracturing in nanoporous media. These initial studies are expected to reveal new insights that will inform the next generation of numerical simulators that can serve as a foundation for analyzing well performance, designing optimal development scenarios using existing technologies, and identifying promising new technology that will mitigate both resource waste/degradation and cumulative environmental impact. In addition, DOE has recently launched an initiative to establish regional field laboratories that will provide integrated field sites for: (1) the comprehensive study of UOG reservoirs and production processes and associated environmental impacts; (2) the demonstration of alternative advanced technologies; and (3) effective outreach and education on all issues related to UOG.

Water Quality – Current R&D Portfolio

The current program consists of 23 projects (6 recently completed; 17 ongoing). Following are two examples of key projects currently in the portfolio.

Development of Methods to Prohibit and Remediate Loss of Annular Isolation in Shale Gas Wells: *Prevention and Remediation of Sustained Casing Pressure and Other Isolation Breaches*: The objectives of this project are to develop techniques to mitigate risk to groundwater resources associated with shale gas development, to remediate a failed annular seal to stop communication in an existing well, to improve techniques that enhance lifelong wellbore annular isolation during the wellbore construction process, and to prevent potential annular seal failure, which can cause sustained casing pressure (SCP) later in a well's life.

Advancing a Web-Based Tool for Unconventional Natural Gas Development with Focus on Flowback and Produced Water Characterization, Treatment, and Beneficial Use: The objective of this effort is to create a set of web-based tools that will enable producers and others to characterize, treat, beneficially use, and manage produced water and fracturing flowback water from unconventional gas production. The goal is to sustain natural gas production while minimizing potential impacts on natural water resources, public health, and the environment.

Water Availability – Current R&D Portfolio

The current program consists of six projects, all ongoing, five of which are listed below.

Development and Validation of an Acid Mine Drainage Water Treatment Process: The goal of this project is to research and optimize a floatation liquid-liquid extraction (FLLX) water treatment system to process and repurpose AMD for use in HF operations, assess the feasibility of using the system byproducts in flowback water treatment processes, and determine the environmental, regulatory, and commercial implications of using treated AMD as source water during HF.

Water Treatment System for Effective Acid Mine Drainage: The objective of this project is to develop and field test a new water treatment system that economically processes sulfate-rich acid mine drainage water to make it suitable for use in hydraulic fracturing. The project will develop: (1) a novel ion exchange membrane and water treatment process capable of reducing sulfates to no more than 500 ppm at bench-scale influent flow rates of 1–5 gal/min; and (2) filter cartridges, skids, and system maintenance processes for the new system that generates water with sulfate concentrations of no more than 500 ppm as tested against API standard RP 45 for oil field waters, at intermediate scale influent flow rates of 10–50 gal/min. The field tests will be conducted at influent flow rates of 400–500 gal/min.

A Geomechanical Analysis of Gas Shale Fracturing and Its Containment: This project will conduct an integrated experimental and numerical study to accomplish the following objectives: (1) understand the role of rock texture, fabric, and deformation regime on induced fractures; (2) develop rock strength/elasticity heterogeneity models that can be used for gas shale; and (3) integrate experimental findings into improved 3D numerical fracture simulation models for assessment of containment and estimation of the stimulated volume.

Development of Non-Contaminating Cryogenic Fracturing Technology for Shale and Tight Gas Reservoirs: The objective of this project is to study, test, and develop a novel cryogenic fracturing technology that can significantly reduce near-wellbore flow and increase mobile gas volumes in unconventional gas reservoirs.

Development of Nanoparticle-Stabilized Foams to Improve Performance of Water-less Hydraulic Fracturing: The overall objective of this project is to develop a new method for using stabilizing foams with fracturing fluids, namely, the addition of surface-treated nanoparticles to the liquid phase. The research will be conducted using fluids already employed in hydraulic fracturing (carbon dioxide, nitrogen, water, liquefied petroleum gas) and commercially available nanoparticles.

Air Quality – Current R&D Portfolio

The current DOE/FE R&D portfolio consists of six projects, as follows:

Assessing Fugitive Methane Emissions Using Natural Gas Engines in Unconventional Resource Development (West Virginia University): The goal of this project is to create an inventory of diesel engines, their use, and emissions incurred during unconventional well development. The first objective is to analyze the benefits of operating these or similar engines on dual fuel or dedicated natural gas to determine regulated and nonregulated emissions and fuel cost reductions. The next objective is to determine the effects of operating these or similar engines and fugitive methane emissions based on the operation of current technologies using a variety of natural gas compositions. The final objective will be to examine new catalyst formulations that can be used in conjunction with these developing technologies to minimize these new sources of fugitive methane emissions associated with unconventional well development.

Continuous, Regional Methane Emissions Estimates in Northern Pennsylvania Gas Fields Using Atmospheric Inversions (Pennsylvania State University, NOAA, University of Colorado, Picarro): The goal of this project is to quantify fugitive and total emissions of methane from the Marcellus gas production region of north-central Pennsylvania with an emphasis on detecting changes in emissions over time caused by changing gas production activity.

Measurements and Modeling to Quantify Emissions of Methane and VOCs from Shale Gas Operations (Carnegie Mellon University): The goals of this project are to determine the leakage rates of methane and ozone-forming volatile organic carbons (VOCs) and the emission rates of air toxics from Marcellus shale gas activities at a process level. Methane emissions in the Marcellus Shale region shall be differentiated between "newer" sources associated with shale gas development and "older" sources associated with coal or conventional natural gas exploration.

Reconciling top-down and bottom-up greenhouse gas and air pollutant emission estimates from unconventional gas development in the Denver-Julesburg Basin (Colorado School of Mines): The objective of the project is to provide the scientific and industrial communities with a tested, standardized research protocol for estimating methane emissions from onshore oil and gas systems in a given natural gas production basin anywhere in the continental United States. This protocol shall include advancements in both bottom-up and top-down components, aiming to reconcile potential differences between results from the two approaches. Reconciliation is defined as reducing the gap observed in prior studies between inventories and measurements with the goal of achieving the closest agreement possible considering relevant uncertainty analysis for each approach.

Measurement of Hydrocarbon and Greenhouse Gas Emissions from Uncharacterized Area Sources (Utah State University): This project will quantify emissions from uncharacterized area sources, including produced water evaporation ponds, farm land, areas with natural (and human-enhanced) geological seepage, and soils near wells in Utah's Uintah Basin. These sources have never been quantified but likely contribute significantly to overall ozone-forming hydrocarbon and greenhouse gas emissions. Quantification will improve the accuracy and efficacy of air quality decisions made by operators while expanding the pool of characterized emission sources that can be used in emissions reductions schemes required by air quality regulators in the Uintah Basin and other areas. Emissions from facilities that employ different solid and liquid waste management strategies will be tested to determine the air emissions impact of each strategy.

NETL ORD and SEAP: NETL-ORD has conducted on-site measurements of emissions from oil and gas production activities using a trailer-based autonomous air monitoring laboratory[163] as well as airborne surveys in connection with the evaluation of emissions potentially associated with legacy wells. Ongoing work includes efforts to collect methane and other air pollutant emissions measurements from Marcellus Shale development sites for application within NETL-SEAPs life cycle assessment framework[164] to further the evaluation of the air quality effects of unconventional resource development.

Induced Seismicity – Current R&D Portfolio

Analysis and Attribution: Existing projects are designed to evaluate the region- and event-specific triggers for induced seismicity, to relate these phenomena to baseline geologic conditions, and to develop improved analytical and predictive models.

The University of Texas at Austin is compiling geospatial information on injection locations, histories, and volumes, and conducting spatial and temporal correlation analyses of injection and earthquake activity around a variety of shale plays (Barnett, Eagle Ford, Bakken, and Haynesville shales.[165]) Battelle is reviewing deep wastewater injection from more than 300 Class II injection wells in the Appalachian basin.

NETL-ORD is using publically available data to generate catalogs of seismic events around injection locations in eastern and central United States. Events specific to HF-related wastewater injection (such as in Johnson County, Texas) are the focus of induced seismicity research efforts in progress through the Energy Policy Act of 2005 Complementary Program (EPAct).

The University of Oklahoma is conducting a comprehensive review of industry operations and reservoir geology and geomechanics in central Oklahoma to refine techniques for induced seismicity diagnosis and mitigation.

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Acronyms

AC	Alternating Current
AMD	Acid Mine Drainage
ARPA-E	Advanced Research Project Agency-Energy
CDC	Centers for Disease Control and Prevention
CDP	Congressionally-Directed Project
CIMMM	Multi-scale Measurements and Modeling Consortium
CO2	Carbon Dioxide
DC	Direct Current
DOE	United States Department of Energy
DOI	United States Department of Interior
EDF	Environmental Defense Fund
EEP	Effective Environmental Protection
EERC	Energy and Environmental Research Center
EIA	Energy Information Administration
EPA	United States Environmental Protection Agency
EPAct	Energy Policy Act
EPD	Environmentally Prudent Development
EUR	Estimated Ultimate Recovery
FE	Fossil Energy
FLLX	Flotation Liquid-Liquid Extraction
FRAC	Fracture Research and Application Consortium
FVF	Formation Volume Factor
FY	Fiscal Year
gal	Gallon(s)
gal/min	Gallons Per Minute
GHG	Greenhouse Gas
GRI	Gas Research Institute
GHGRP	Greenhouse Gas Reporting Program
GWPC	Groundwater Protection Council
HAPs	Hazardous Air Pollutants

HC	Hydrocarbon
HEI	Health Effects Institute
HF	Hydraulic Fracturing
HHS	United States Department of Health and Human Services
km	Kilometer
LCA	Life Cycle Assessment
LNG	Liquefied Natural Gas
LPG	Liquefied Petroleum Gas
M	Richter Magnitude
M/y	Million Per Year
MCOR	Marcellus Center for Outreach and Research
N	Nitrogen
NETL	National Energy Technology Laboratory
NOAA	National Oceanic and Atmospheric Administration
NGO	Non-Governmental Organization
NGL	Natural Gas Liquids
NPDES	National Pollutant Discharge Elimination System
OGI	Optical Gas Imaging
ORD	Office of Research and Development
PM	Particulate Matter
ppm	Parts Per Million
QTR	Quadrennial Technical Review
R&D	Research and Development
RECs	Reduced Emissions Completions
RF	Recovery Factor
RFF	Resources for the Future
RPSEA	Research Partnership to Secure Energy for America
SCP	Sustained Casing Pressure
SEAB	Secretary of Energy Advisory Board
SEAP	Office of Strategic Energy Analysis and Planning
Sr	Strontium
SRV	Stimulated Rock Volume

SUTUR	Shell/UT Unconventional Resources
tcf	Trillion Cubic Feet
tcf/y	Trillion Cubic Feet Per Year
TRR	Technically Recoverable Resources
U.	University
UCR	Unconventional Resources Portfolio
UNGI	Unconventional Natural Gas and Oil Institute
UOG	Unconventional Oil and Gas
USGS	United States Geological Survey
VOC	Volatile Organic Compound
$k	Thousands of Dollars

Glossary

Anthropogenic	Made or generated by a human or caused by human activity. In the context of global climate change, the term refers to gaseous emissions that are the result of human activities, as well as other potentially climate-altering activities, such as deforestation.
Aquifer	A body of rock whose fluid saturation, porosity and permeability permit production of groundwater.
Basin	A depression in the crust of the Earth, caused by plate tectonic activity and subsidence, in which sediments accumulate. Sedimentary basins vary from bowl-shaped to elongated troughs. Basins can be bounded by faults. Rift basins are commonly symmetrical; basins along continental margins tend to be asymmetrical. If rich hydrocarbon source rocks occur in combination with appropriate depth and duration of burial, then a petroleum system can develop within the basin. Most basins contain some amount of shale, thus providing opportunities for shale gas exploration and production.
Biocides	A biocide is a chemical substance or microorganism which can deter, render harmless, or exert a controlling effect on any harmful organism by chemical or biological means. Biocides are commonly used in oil and natural gas production activities to prevent the growth of microorganisms in the reservoir, well tubulars, or surface producing equipment.

Class II Injection Wells	An injection well classification used by the US EPA for wells that are used for the injection of fluids associated with oil and gas production, including: water, steam, or CO_2 for enhanced oil recovery; salt water disposal; and underground storage of hydrocarbon liquids. There are about 144,000 Class II wells in the US, ~80% of which are for enhanced oil recovery (EOR) and ~20% for salt water disposal.
CO_2 and Nitrogen Injection	CO_2 Injection - An enhanced oil recovery method in which carbon dioxide (CO_2) is injected into a reservoir to increase production by reducing oil viscosity and providing miscible or partially miscible displacement of the oil. Nitrogen Injection-A process whereby nitrogen gas is injected into an oil reservoir to increase the oil recovery factor. Below the minimum miscibility pressure (MMP), this is an immiscible process in which recovery is increased by oil swelling, viscosity reduction and limited crude oil vaporization. Above the MMP, nitrogen injection is a miscible vaporizing drive that can be achieved only with light oils under high pressures and is therefore suitable only in deep reservoirs.
Coal bed Methane	Methane produced from coal seams. Coal bed methane is formed during coalification, which is the geologic process that transforms organic material into coal.
Conventional Oil and Gas	Crude oil and natural gas produced by wells drilled into a geologic formation where the reservoir and fluid characteristics permit the oil and natural gas to readily flow to the wellbore.
Cryogenic Fluids	Fluids that exist at very low temperatures (typically -150 degrees Centigrade or below). In oilfield applications typical examples include liquid carbon dioxide, liquid nitrogen, or liquefied natural gas.

Drilling	The act of boring a hole (1) to determine whether minerals are present in commercially recoverable quantities and (2) to accomplish production of the minerals (including drilling to inject fluids). • Exploratory drilling is done to locate probable mineral deposits or to establish the nature of geological structures; such wells may not be capable of production if minerals are discovered. • Developmental drilling is done to delineate the boundaries of a known mineral deposit to enhance the productive capacity of the producing mineral property. • Directional drilling involves the purposeful deviation of a wellbore from the vertical to reach a specific subsurface target or targets. Note: this definition is focused on minerals
Extended Reach	Refers to wells considered to have a high ratio of horizontal distance to depth. The exact ratio depends on the construction complexity and drilling conditions.
Floatation Liquid-Liquid Extraction Water Treatment System	Systems designed to separate two liquid components of a mixture, most commonly oil and water in an oilfield context. One example involves the injection of a gas into the mixture to allow the gas bubbles to attach to dispersed oil droplets and float them to the surface where they combine into a single phase.
Flowback Water	Water that is produced back from a well immediately after a hydraulic fracturing treatment. Such water can be salty after picking up ionic constituents from the reservoir rock and fluids, and will also contain additives pumped along with the fracturing treatment. As such, it must be captured, handled carefully, and treated or disposed of properly to prevent environmental impacts. The share of injected water that returns as immediately as flowback water can vary based on the size of the treatment and the character of the reservoir.

Fracture	A crack or surface of breakage within rock not related to foliation or cleavage in metamorphic rock along which there has been no movement. A fracture along which there has been displacement is a fault. When walls of a fracture have moved only normal to each other, the fracture is called a joint. Fractures can enhance permeability of rocks greatly by connecting pores together, and for that reason, fractures are induced mechanically in some reservoirs in order to boost hydrocarbon flow. Fractures may also be referred to as natural fractures to distinguish them from fractures induced as part of a reservoir stimulation or drilling operation. In some shale reservoirs, natural fractures improve production by enhancing effective permeability. In other cases, natural fractures can complicate reservoir stimulation.
Fugitive Emissions	Unintended leaks of natural gas or volatile organic compounds during the production, processing, transmission, and/or transportation of fossil fuels.
Gas Hydrates	Solid, crystalline, ice-like substances composed of water, methane, and usually a small amount of other gases, with the gases being trapped in the interstices of a water-ice lattice. They form beneath permafrost and within deep ocean sediments under conditions of moderately high pressure and at temperatures near the freezing point of water.
Geophysical Explorations	The application of geophysical techniques to explore for minerals in the subsurface. In the context of oil and natural gas this generally refers to the acquisition, processing and interpretation of seismic data to image the subsurface and identify potential accumulations of hydrocarbon resources. Such seismic exploration generally provides the basis for drilling an exploratory well or wells. The geophysical logging data acquired during or after drilling is also part of the exploration process.
Geomechanics	The geologic specialty that deals with understanding how rocks, stresses, pressures, and temperatures interact. This understanding is used to solve oilfield problems, such as optimizing hydraulic fracturing treatments of shale reservoirs. Geomechanics specialists typically work with experts in geophysics, geology, petrophysics, reservoir engineering, drilling engineering, and rock physics to solve geomechanical problems and address production challenges in shale reservoirs.

Green Completions	Well completion processes that minimize the potential for environmental impacts. These often relate to the hydraulic fracturing process in particular and generally involve the use of systems that contain the injected and flowback fluids within a closed system, preventing emissions of gases or liquids that might contaminate the air, groundwater or soil near a well location. Such systems may also include gas flaring equipment designed to minimize emissions. This can also refer to the use of non-toxic fluids in the completion process.
Greenhouse Gas	Those gases, such as water vapor, carbon dioxide, nitrous oxide, methane, hydrofluorocarbons (HFCs), perfluorocarbons (PFCs) and sulfur hexafluoride, that are transparent to solar (short-wave) radiation but opaque to long-wave (infrared) radiation, thus preventing long-wave radiant energy from leaving Earth's atmosphere. The net effect is a trapping of absorbed radiation and a tendency to warm the planet's surface.
Hazardous Air Pollutants (HAPs)	Toxic air pollutants known or suspected to cause cancer or other serious health effects or adverse environmental effects. EPA lists 187 specific HAPs which include benzene, perchloroethylene, dioxin, asbestos, toluene, and metals such as cadmium, mercury, chromium, and lead compounds.
Horizontal Well	A well that is purposefully deviated from the vertical to a horizontal or nearly horizontal trajectory upon reaching the target formation. Such wells are designed to maximize the length of wellbore exposed within a producing formation and are often hydraulically fractured at multiple locations along the horizontal lateral section.
Hydraulic Fracturing	Fracturing of rock at depth with fluid pressure. Hydraulic fracturing at depth may be accomplished by pumping water into a well at very high pressures. Under natural conditions, vapor pressure may rise high enough to cause fracturing in a process known as hydrothermal brecciation.
Hydrologic Cycle	The water cycle describes the continuous movement of water on, above, and below the surface of the Earth.
Infill Drilling	The addition of wells in a field that decreases average well spacing. This practice both accelerates expected recovery and increases estimated ultimate recovery in heterogeneous reservoirs by improving the continuity between injectors and producers. As well spacing is decreased, the shifting well patterns alter the formation-fluid flow paths and increase production from areas where greater hydrocarbon saturations exist.

In Situ	Latin for "in its original place." In the original location or position, such as a large outcrop that has not been disturbed by faults or landslides. Tests can be performed in situ in a reservoir to determine its pressure and temperature and fluid properties.
Isotopes	Forms of the same chemical element that differ only by the number of neutrons in their nucleus. Most elements have more than one naturally occurring isotope. Many isotopes have been produced in reactors and scientific laboratories.
Lithology	The macroscopic nature of the mineral content, grain size, texture and color of rocks.
LNG (Liquefied Natural Gas is not spelled out in Report)	Natural gas (primarily methane) that has been liquefied by reducing its temperature to -260 degrees Fahrenheit at atmospheric pressure.
Liquefied Petroleum Gas	A group of hydrocarbon gases, primarily propane, normal butane, and isobutane, derived from crude oil refining or natural gas processing. These gases may be marketed individually or mixed. They can be liquefied through pressurization (without requiring cryogenic refrigeration) for convenience of transportation or storage. Excludes ethane and olefins.
Microseismic Imaging	Technique to track the propagation of a hydraulic fracture as it advances through a formation. Microseisms are detected, located, and displayed in time for scientists and engineers to approximate the dimensions and orientation of the created fracture. Computer imagery is used to monitor and display the fracture in 3D space. The monitored activities can be animated to show progressive fracture growth and the subsurface response to pumping variations. When displayed in real time, the microseismic activity allows one to make changes to the stimulation design to ensure optimal reservoir contact. Also known as hydraulic fracture monitoring, this technique delivers information about the effectiveness of the stimulation and can be used to optimize reservoir development in shale gas or tight gas sand reservoirs.
Modeling	The use of mathematical representations of physical processes to simulate modifications to those processes to better understand how to achieve desired outcomes. Examples include reservoir production modeling to understand how to optimally develop an oil or gas reservoir, and hydraulic fracturing modeling to understand how to optimize the design of a hydraulic fracture stimulation. Modeling can include an economic analysis component that optimizes based on certain economic objectives.

Mud Telemetry A method of transmitting logging while drilling (LWD) and measurements while drilling (MWD) data acquired downhole to the surface, using pressure pulses in the mud system. The measurements are usually converted into an amplitude- or frequency-modulated pattern of mud pulses. The same telemetry system is used to transmit commands from the surface.

New Source Performance Standards Uniform national EPA air emission and water effluent standards which limit the amount of pollution allowed from new sources or from modified existing sources.

Organic Carbon Carbon bound in an organic compound. Total organic carbon (TOC) is often used as a non-specific indicator of water quality. TOC may also refer to the amount of organic carbon in a geological formation, particularly the source rock for a petroleum play.

Pad Drilling A process whereby multiple oil or gas wells are drilled directionally from a single drilling "pad" or flat area constructed to permit the set up and operation of drilling and well completion equipment during the drilling process, and surface production equipment during the producing phase. The pad may consist of compacted earth, gravel, plastic mats, or ice (in arctic locations). This process can serve to reduce the overall surface impact or "footprint" of field development in environmentally fragile ecosystems or in densely populated areas.

Petrophysical Two definitions:

(1) A process or procedure used to interpret petrophysical (usually wireline log or core) data. Usually representing a set of equations, algorithms or other mathematical processes, petrophysical models often have multiple routines. For example, a deterministic model might include routines that calculate the volume, total porosity, effective porosity, water saturation, and permeability. Often, the model is calibrated using core, production, test, and other data sets. Although many software packages contain ready-built petrophysical models or component routines that can be called upon, many log-analysis problems are unique and require that "built to purpose" models be constructed. Construction of new petrophysical models is normally driven by the data available and the nature of the problem to be solved.

	(2) Rock types that have been classified according to their petrophysical properties, especially properties that pertain to fluid behavior within the rock, such as porosity, capillary pressure, permeabilities, irreducible saturations or saturations. Petrophysical rock types are often calibrated from core and dynamic data, but are usually calculated from wireline logs, where possible, because the wireline logs are generally the only measurements that are available for all wells at all depths. Electrofacies approaches are often used to determine rock types from logs.
Play	A set of known or postulated oil and gas accumulations sharing similar geologic, geographic, and temporal properties, such as source rock, migration pathway, timing, trapping mechanism, and hydrocarbon type. A play differs from an assessment unit; an assessment unit can include one or more plays.
Point Source	Point source pollution, on the most basic level, is water or air pollution that comes from a single, discrete place, typically an opening at an immobile facility (e.g., a sewage outflow pipe, a power plant smokestack).
Proppant	Sized particles mixed with fracturing fluid to hold fractures open after a hydraulic fracturing treatment has been pumped. In addition to naturally occurring sand grains, man-made or specially engineered proppants, such as resin-coated sand or high-strength ceramic materials like sintered bauxite, may also be used. Proppant materials are carefully sorted for size and sphericity to provide an efficient conduit for production of fluid from the reservoir to the wellbore.
Prudent Development	Development of a natural resource by parties acting with or showing care and thought for the future. This care can relate to immediate and future safety, environmental impact, fiduciary responsibility to shareholders, or a combination of all three.
Reservoir	A porous and permeable underground formation containing an individual and separate natural accumulation of producible hydrocarbons (crude oil and/or natural gas) which is confined by impermeable rock or water barriers and is characterized by a single natural pressure system.

Seismic Data	Data relating to an earth vibration caused by an external source. Data from seismic surveys generally is obtained using surface receivers to record the reflection of vibrations from subsurface rock layers induced by explosions at the surface. Borehole seismic data is data measured with receivers, sources, or both in a well, such as a vertical seismic profile (VSP), cross-well seismic data, or single-well imaging. By directly measuring the acoustic velocity of each formation encountered in a well, the well logs and borehole seismic data can be correlated to surface seismic data more easily. Borehole seismic data, including both S- and P-waves, can be gathered in a cased or open hole.
Shale Gas	Natural gas produced from wells that are completed in shale formations. Shale is a fine-grained, sedimentary rock composed of mud from flakes of clay minerals and tiny fragments (silt-sized particles) of other materials. The shale acts as both the source and the reservoir for the natural gas.
Shale Oil	Shale oil is a subset of tight oil. (See definition of tight oil).
Slick-Water	A type of hydraulic fracturing that typically involves the pumping of large volumes of water at high rates with low amounts of viscosity increasing additives but with friction reducing additives (hence the term “slick”). Such treatments replaced the lower volume, higher viscosity treatments in unconventional reservoirs, enabling their economic development.
Stimulated Rock Volume	The total 3-dimensional amount of the reservoir rock that has been hydraulically fractured.
Tight Gas	Gas produced from a relatively impermeable reservoir rock. Hydrocarbon production from tight reservoirs can be difficult without stimulation operations. Stimulation of tight formations can result in increased production from formations that previously might have been abandoned or been produced uneconomically. The term is generally used for reservoirs other than shales.
Tight Oil	Oil produced from petroleum-bearing formations with low permeability such as the Eagle Ford, the Bakken, and other formations that must be hydraulically fractured to produce oil at commercial rates. Shale oil is a subset of tight oil.
Unconventional Oil and Gas	An umbrella term for oil and natural gas that is produced by means that do not meet the criteria for conventional production. See Conventional oil and natural gas production. Note: What has qualified as "unconventional" at any particular time is a complex interactive function of resource characteristics, the available exploration and production technologies, the current economic environment, and the scale, frequency, and duration of production from the resource. Perceptions of these factors inevitably change over time and they often differ among users of the term.

Upper Devonian	The Devonian is a geologic period and system of the Paleozoic Era spanning from the end of the Silurian Period, about 419.2 ± 3.2 Mya (million years ago), to the beginning of the Carboniferous Period, about 358.9 ± 0.4 Mya. It is named after Devon, England, where rocks from this period were first studied. The Upper Devonian relates to the latest (most recent) epoch of the Devonian period. Several of the shale plays in the United States consist of rock formations that were deposited during the Upper Devonian time period.
Upstream Unconventional Oil and Gas Development	”Upstream” refers to the exploration, production, and field processing phases of the oil and natural gas commercial exploitation process. In the case of natural gas, this phase is followed by gas gathering and centralized natural gas processing, gas transportation and storage, and natural gas distribution phases. In the case of crude oil, it is followed by gathering transportation, refining, and refined product distribution phases. The gathering and transportation phases are sometimes referred to as “midstream” and the distribution and refining portions referred to as “downstream.” When focused on unconventional resources, it would be “upstream unconventional oil and gas development.”
Viscosifier	An agent or chemical designed to increase the viscosity of a fluid. Viscosifying (gelling) agents commonly added to water used in hydraulic fracturing include: natural guar gum, hydroxypropyl guar (HPG), hydroxyethyl cellulose (HEC), and carboxymethyl hydroxyethyl cellulose (CMHEC).
Well Bore Integrity	The condition of a wellbore that relates to its ability to maintain its stability during drilling (i.e., not allow the hole walls to cave in) and after the well has been cased and cemented, its ability to prevent the flow of fluids between permeable formations behind the casing. This requires a competent sheath of the appropriate type of cement that has been properly placed into the annulus and allowed to set under the proper conditions.
Well Stimulation	A treatment performed to restore or enhance the productivity of a well. Stimulation treatments fall into two main groups, hydraulic fracturing treatments and matrix treatments. Fracturing treatments are performed above the fracture pressure of the reservoir formation and create a highly conductive flow path between the reservoir and the wellbore. Matrix treatments are performed below the reservoir fracture pressure and generally are designed to restore the natural permeability of the reservoir following damage to the near-wellbore area. Stimulation in shale gas reservoirs typically takes the form of hydraulic fracturing treatments.