ENERGY TECHNOLOGY INNOVATION POLICY RESEARCH GROUP

The Next Frontier in United States Shale Gas and Tight Oil Extraction:
Strategic Reduction of Environmental Impacts

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VANESSA R. PALMER
YIQIAO TANG
A. PATRICK BEHRER

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Energy Technology Innovation Policy (ETIP) Research Group
Belfer Center for Science and International Affairs
John F. Kennedy School of Government
Harvard University
79 JFK Street
Cambridge, MA 02138
Fax: (617) 495-8963
Email: bcsia_ksg@harvard.edu
Website: http://belfercenter.org

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ABSTRACT

The unconventional fossil fuel extraction industry—in the U.S., primarily shale gas and tight oil—is expected to continue expanding dramatically in coming decades as conventionally recoverable reserves wane. At the global scale, a long-term domestic supply of natural gas is expected to yield environmental benefits over alternative sources of fossil energy. At the local level, however, the environmental impacts of shale gas and tight oil development may be significant. The development of technology, management practices, and regulatory policies that mitigate the associated environmental impacts of shale gas development is quickly becoming the next frontier in U.S. unconventional fossil resource extraction.

In this report, we argue that strategic planning by both companies and regulatory agencies to minimize the environmental impacts of unconventional extraction requires a contextualized understanding of regional issues and the available technical, management, and policy interventions to mitigate them. Following an introduction to the topic of impact mitigation in hydraulic fracturing, we present a brief discussion of the history of the U.S. unconventional oil and gas extraction industry and its associated environmental challenges. Next, we characterize the environmental concerns in three key U.S. unconventional plays, differentiating between concerns common between plays and those specific to the Barnett, the Marcellus, or the Bakken. We follow this section by reviewing opportunities for environmental impact mitigation and the policy incentives that might drive their adoption in tight oil and shale gas operations.

Finally, we present cost-benefit analyses for three technologies—reduced emissions completions, model-assisted optimized hydraulic fracturing, and reduced-impact well site foundations—contextualized in the specific environments of the focus plays. These technologies offer a comparative perspective on the scale of technology benefit (global, regional, local), the range of forces driving adoption (regulation, cost-minimization, lease holder demands), and the degree of current adoption (widely adopted to very limited adoption). We find that two of the three technologies are currently cost neutral or cost-saving without additional regulatory intervention, while the third is expected to become cost-neutral before 2014.

The laggard adoption of environmental mitigation technologies in the unconventional shale gas and tight oil extraction industries, however, suggests that cost effectiveness is a necessary but insufficient condition for technology implementation. Lease-holder education and empowerment, incentives for technology implementation, and regulatory interventions will be critical in stimulating widespread adoption of these technologies. Finally, effective policy instruments will be based upon a systemic understanding of the regional impacts associated with unconventional oil and gas extraction and will adapt as drilling activity expands to new plays.

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I. THE CALL FOR REGIONAL ENVIRONMENTAL IMPACT ANALYSIS AND ASSOCIATED MITIGATION EFFORTS IN UNCONVENTIONAL EXTRACTION

Unconventional fossil fuel extraction from shale formations has already transformed the U.S. energy portfolio. An anticipated 100-year domestic supply of relatively inexpensive natural gas is spawning vast change in the electricity sector, with nearly half of electricity production coming from natural gas fired power plants in 2012 (US EIA 2012c). The substantial increase observed in domestic oil production over the past five years has the U.S. on track to become the world's leading oil producer by 2017. And the growth of both oil and gas production is expected to make the U.S. a net gas and oil exporter by 2030 (IEA WEO 2012a).

These projections for U.S. extraction gloss over the innovation that preceded them and the challenges that this magnitude of extraction activity will pose for regions endowed with shale resources. The pairing of horizontal drilling and hydraulic fracturing capabilities has enabled shale gas and tight oil extraction from low-porosity shale beds previously considered inaccessible, but the complex and intensive extraction process comes with a broader suite of risks and environmental impacts. These significant advances in extraction capability have also precipitated a transition in the spatial extent of drilling activity. The diffuse nature of unconventional extraction translates into intensive drilling operations over frequent intervals, further elevating the regional impacts of the extraction process.

Another unique attribute of U.S. unconventional resources is the geographic distribution of shale gas and tight oil resources. The expansion of drilling operations outside of the past decade's largest U.S. basins, mostly concentrated in Gulf Coast states, have re-introduced large scale oil and gas extraction operations to regions and populations unaccustomed to intense drilling activity. The social and environmental implications of this expansion must be considered in light of regional and global benefits, but they cannot be justified by these factors. Instead, the pressing challenge for policy makers, oil and gas companies, and innovators is to develop regulations, management strategies, and technologies to reduce regional impacts.

The relative novelty of combined horizontal drilling and hydraulic fracturing technologies, combined with the intensity of drilling operations and the distribution over populated areas, necessitates a comprehensive evaluation of environmental impacts from shale gas and tight oil extraction. It also motivates an honest evaluation of impacts and risks intrinsic to the process itself, and those impacts or risks that can be mitigated through environmental technologies or better management practices.

This report aims to characterize the regional environmental impacts of unconventional extraction by focusing on the unique environmental sensitivities of three major unconventional plays: the Barnett in Texas, the Marcellus in Pennsylvania, and the Bakken in North Dakota. After reviewing the projections for well development in these plays, this work evaluates regional environmental risks, and identifies potential mitigation efforts. A range of well-level technologies, company management practices, and regional policies are detailed, with three strategies highlighted in cost-benefit evaluations. We find that cost effectiveness is a necessary but insufficient condition for the voluntary adoption of environmental mitigation technologies in unconventional oil and gas extraction, and we suggest that lease-holder empowerment, incentives for technology implementation, and regulatory interventions will be critical to stimulating regionally appropriate technological adoption.

II. OVERVIEW OF UNCONVENTIONAL EXTRACTION IN THE UNITED STATES

ROLE OF NEW TECHNOLOGIES IN ENABLING UNCONVENTIONAL EXTRACTION

The synergistic pairing of two established techniques has been a key driver in the rapid development of unconventional oil and gas plays over the past five years. The first, horizontal drilling, involves creating a wellbore that runs roughly parallel to the surface after reaching a desired vertical depth. Rather than drawing only from the point at which a vertical bore reaches the targeted stratum, a horizontal wellbore makes contact with a long lateral section of source rock. This would boost production in many formations, but is an especially advantageous approach under two conditions often found in shales: (1) the presence of hydrocarbons in disjointed pockets rather than as a continuous reservoir, and (2) a hydrocarbon-bearing formation that is extensive but thin. Horizontal drilling increases the subsurface space that is accessible via one well, reducing the number of wells needed to develop the area of a lease holding. These wells present a greater technical challenge in drilling than their vertical counterparts, and first became economically practicable in the 1980s (US EIA 1993).

The second practice critical to modern unconventional extraction from shale plays, hydraulic fracturing, occurs following drilling during the completion phase of a well. Large volumes of fluid are pumped down the wellbore at high pressures to create a network of cracks in the source rock, which are held open by a proppant—typically sand—carried by additional injected fluid. Fracturing fluid consists of primarily of water and proppant (≈99% by volume), but it also contains acids, biocides, and polymerizing gels to prevent scaling, facilitate large fractures, and deter biochemical oxidation of the hydrocarbons (ALL 2009). Following the fracture process, the well is depressurized and hydrocarbons begin to flow out of the cracks through the porous matrix of the proppant. The net effect of the process is to increase the effective surface area of the reservoir, which in turn makes a greater amount of oil or gas recoverable from a given volume of rock. Though it can add significant costs to a well, hydraulic fracturing has been widely used in conventional vertical operations since the 1950s (Montgomery and Smith 2010). Thus, by combining horizontal drilling with hydraulic fracturing, producers can induce economic flow rates across a large, diffuse subsurface area, then extract from it at volume—all through a single well.

Though hydraulically fractured horizontal wells were something of a novelty ten years ago, the technology has since advanced considerably. Two industry-wide trends have become apparent. First, the horizontal sections of these wells ("laterals") have become longer over time. The length of a lateral is governed by geology and economic considerations, as longer laterals are more costly to drill and may not contribute to increased production in all reservoirs. For shale gas wells, lateral length now clusters around 1,500 m (IHS CERA 2010). In tight oil[1] plays[2] such as the Bakken, lateral length shows a wider range—from hundreds of meters to more than 6,000 m—but generally exceeds the average for shale gas wells (Zargari 2010). Second, like the reach of a lateral, the number of locations at which it is fractured along its length has also trended upward in the industry.[3] Fracture geometry is determined by many factors, but virtually all unconventional wells in the U.S. undergo several 'frac stages,' each of which contains multiple clusters of fractures. Laterals now most commonly undergo between 10 and 20 frac stages, though completions with as many as 40 stages have been reported (Montgomery and Smith 2010, Snyder and Seale 2011, personal communications with operators). Wells with several laterals radiating from a single central vertical borehole are not uncommon, and multiple wells are increasingly clustered on one drilling site (Ladlee and Jacquet 2011). As fractures grow in number and complexity on further-reaching lateral networks, producers continue to move toward higher efficiencies in exploiting unconventional reservoirs.

ROLE IN THE DOMESTIC ENERGY MIX

The pairing of horizontal drilling and hydraulic fracturing technologies has opened formally unattractive reserves to economical oil and gas extraction. Domestic production of dry gas has risen by 20% between 2007 and 2012, driven almost exclusively by increases in shale gas production (Figure 1). Unconventional plays have also altered the landscape of U.S. petroleum. After a long period of decline starting in the 1970s, domestic oil production has seen a recent increase beginning in 2008 (US EIA 2012e). Analogous to the uptick in gas production due to shale development, much of this oil increase can be attributed to withdrawals from diffuse, low-porosity crude reservoirs that were previously infeasible to access (IEA 2011).

Underlying recent production increases is the promise of long-term withdrawals. The U.S. Energy Information Administration's estimate of the nation's shale gas reserves recoverable with existing technology more than tripled from 2005 to 2010—from 126 to 482 trillion cubic feet (US EIA 2012b[4]).

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[1] Tight oil is not to be confused with other types of unconventional crude including oil shale, oil sands, and heavy oil. A global survey of these resources can be found in World Energy Council 2010. For analyses of the environmental impacts of oil sands and oil shale, see Jordaan 2012 and Gavrilova et al. 2010, respectively.

[2] The larger contiguous area in which a geologically similar collection of hydrocarbon reservoirs is situated is referred to as a play.

[3] Paradoxically, more is not always more—a larger number of fractures may actually translate to reduced flow rates and a lower ultimately recovery (see Cheng 2012).

[4] Table 13, p. 57. This is the most recent estimate by the US EIA. A 2009 estimate, published in 2011, was much higher at 827 trillion cubic feet and has since been characterized by EIA as an overestimate.

The same estimate for tight oil increased by nearly an order of magnitude over this period, from 3.7 to 33.2 billion barrels (US EIA 2012b[5]). Though technically recoverable reserve estimates do not consider the economic feasibility of recovery, continued innovation in drilling practices suggests that economical means to tap these unconventional fossil fuel resources will be developed.[6] Under a range of scenarios, both the U.S. government's Energy Information Administration (EIA) and the autonomous International Energy Agency project steady production growth for shale gas (Figure 1) and tight oil (US EIA 2012b, IEA 2011, IEA 2012).

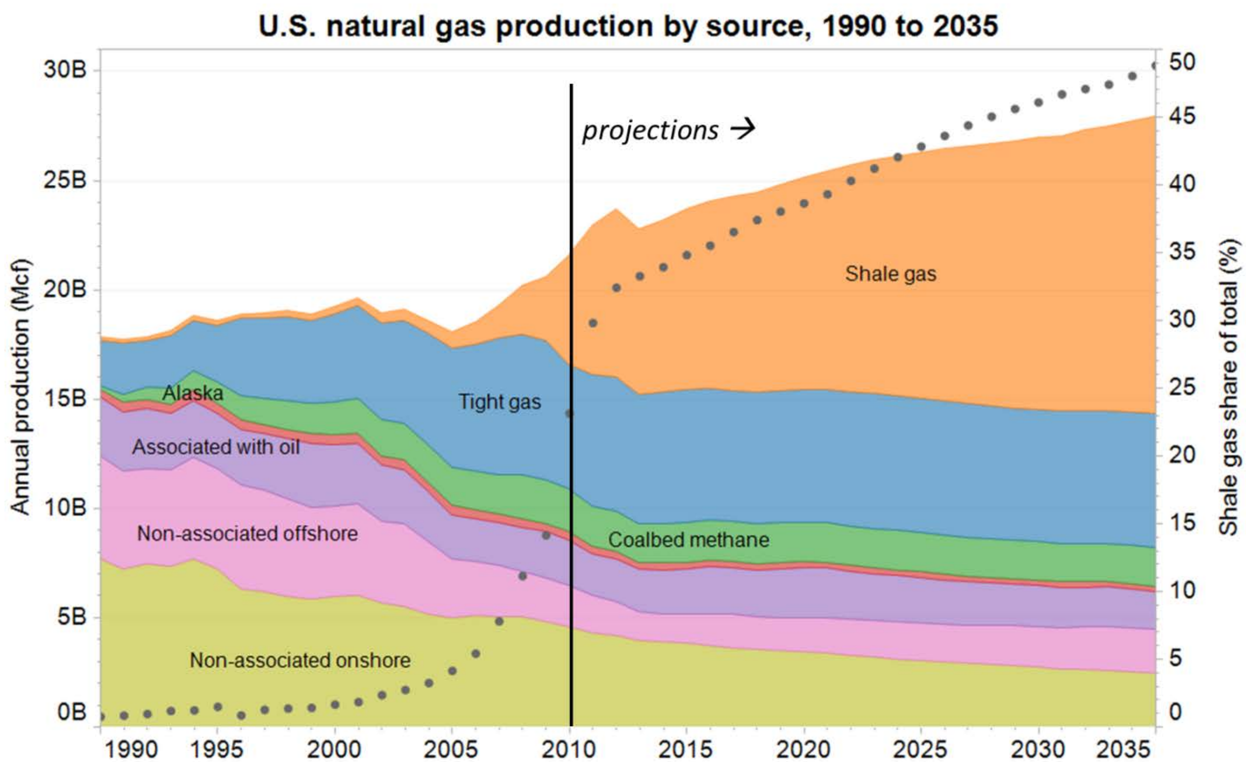

Figure 1. Domestic production of natural gas, with historical data from 1990-2010 and projections to 2035. The percentage of total production from shale gas is plotted with the dotted line, which maps to the right-hand vertical axis. Data source: US EIA 2012b, via p.93 (publicly available).

April 2012 marked an important point on the opposite end of the supply chain: for the first time since data collection began, natural gas was used to generate as much American electricity as coal (US EIA 2012c). Relative to one year before, gas-fired generation in the second quarter of 2012 rose by

[5] Table 14, p. 57

[6] To put these numbers into perspective: using the most recent estimates, technically recoverable domestic shale gas and tight oil reserves could satisfy 20 and six years of all national gas and oil demand, respectively, at 2010 levels of consumption (EIA 2012b: Table 18, p. 60; Table 19, p. 62).

nearly half—from 22% to 31% of the national net total (US EIA 2012c). By some forecasts, natural gas could permanently overtake coal in U.S. electricity generation in the next quarter-century, with one- to two-thirds of domestic production coming from shale (IEA 2012[7], US EIA 2012b[8], Paltsev et al. 2011). Low prices at the Henry Hub (Figure 3), along with tightening regulations on the air pollutants associated with coal-fired power plants, such as the promulgation of the Mercury and Air Toxics Standards (MATS) by the U.S. Environmental Protection Agency in late 2011, will facilitate increasing reliance on natural gas.

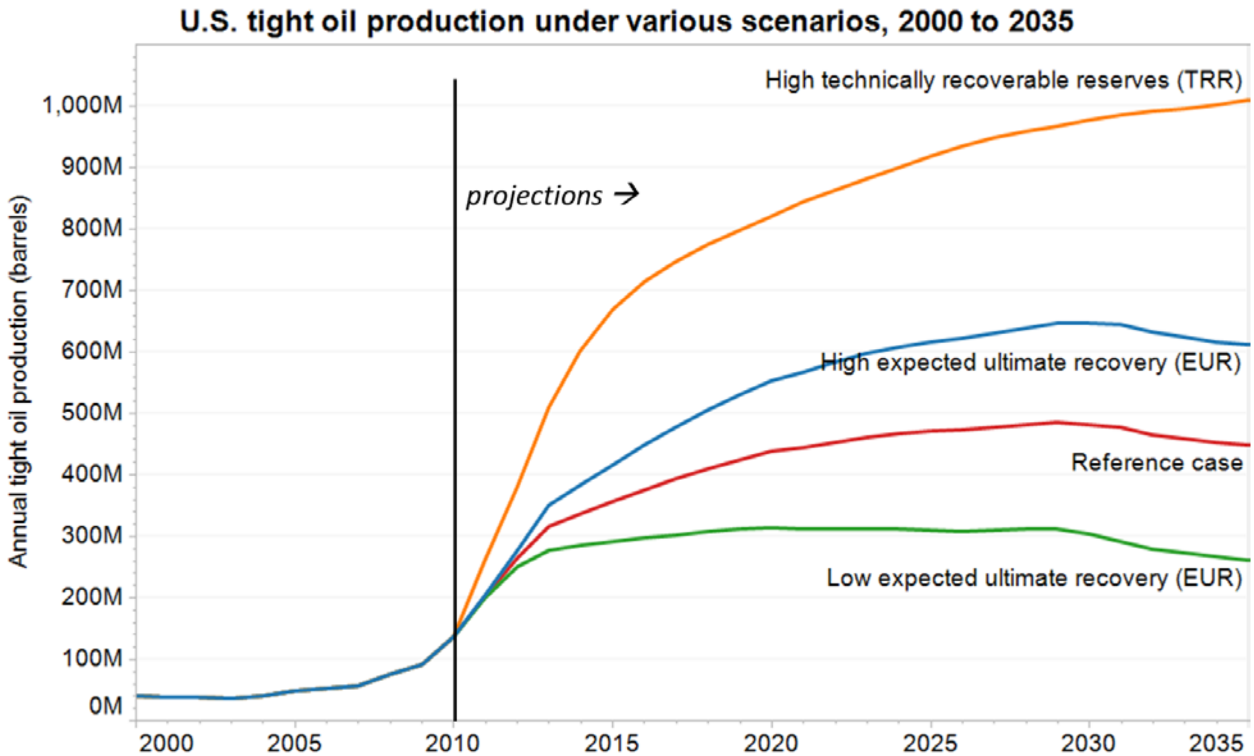

Figure 2. Domestic production of tight oil, with historical data from 2000-2010 and projections under four scenarios to 2035. Technically recoverable reserves (TRR) refers to the total amount of petroleum that can be extracted from tight oil reservoirs using currently available technologies. Expected ultimate recovery (EUR) is the total production volume that is actually extracted given costs and market conditions. As a fairly new energy source, ultimate recovery from tight oil reserves is subject to large uncertainties. Data source: US EIA 2012b, via p.61 (publicly available).

In tight oil, even the most pessimistic EIA models predict a near-doubling of U.S. production by 2035 (Figure 2) as crude production from other sources remains static or diminishes (US EIA 2012b[9]). Prices remain strong, further encouraging tight oil development as technology and operator experience

7 Table 2.6, p. 81; Figure 2.5, p. 83
8 Table 19, p. 62

9 Table 18, p. 60

mature (Figure 3). Though the broader-scope implications of these trends are only beginning to be characterized,[10] unconventional oil and gas are poised to dominate the U.S. market in the coming decades.

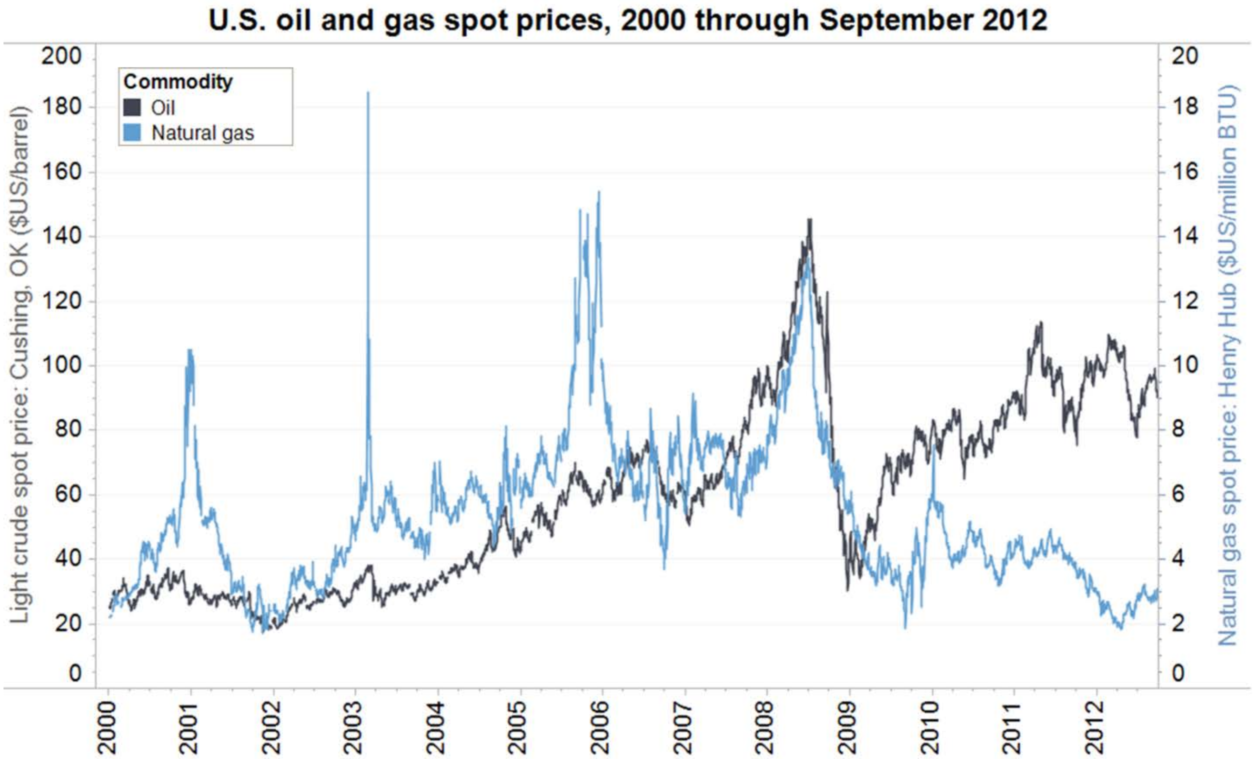

Figure 3. Oil and natural gas spot prices, 2000 through July 2012. April 2012 marked an historic low for natural gas, while oil prices have remained high. This strongly incentivizes exploration for oil and condensate (the market price for the latter is linked to oil's). Data sources: US EIA 2012h-i (publicly available).

ENVIRONMENTAL IMPACTS ASSOCIATED WITH HYDRAULICALLY FRACTURED HORIZONTAL WELLS

Environmental impacts of unconventional shale gas and tight oil extraction can be broken down along three axes. The first axis reflects the stage in the fuel lifecycle generating the impact, in this case the upstream extraction process, the midstream processing activity, or the downstream combustion method. The second axis denotes the scale of the impact—local, regional, or global—and the third axis

[10] Treatment of unconventional drilling's life cycle-scale ecological tradeoffs and its opportunity cost to renewable energy development is beyond the scope of this paper. See Weber and Clavin 2012 for a survey of greenhouse gas assessments for shale gas drilling, and Lior 2012 and Helm 2011 for discussions of shale gas and tight oil's role in energy policy and economics.

describes the impacted environmental media, including air, water, land use, and other environmental impact categories. While this report does not seek to provide a comprehensive analysis of the existing literature highlighting potential environmental impacts along these three axes, we provide a brief introduction to prominent environmental impacts as a means of contextualizing subsequent discussion on regionally specific impacts and the technologies that exist to mitigate them.

Much of the discussion around the environmental implications of the U.S.'s shale gas resources has focused on the global carbon emission benefits of downstream natural gas combustion as a substitute for coal. Natural gas has the lowest carbon dioxide emission factor at combustion of any fossil fuel and, on a per-heating unit basis, releases lower amounts than coal of all air quality criteria pollutants (US EIA 2011a, 2012a[11]). Domestic production of shale gas and tight oil would also reduce energy losses and environmental impacts of long-distance midstream transport associated with importing fuels (Engelder 2011). When the global environmental impacts of shale gas are assessed on the life-cycle scale—that is, when the associated extraction and transport processes are taken into account—the *prima facie* reductions in greenhouse gas emissions of unconventional fuels become less pronounced. The climate impacts of drilling, completions, and natural gas transport to climate change has been widely discussed in the literature (Jiang et al. 2011, Howarth et al. 2012), with particular emphasis placed on the need for accurate estimates of methane leakage from natural gas pipelines (Weber and Clavin 2012).[12] Also highlighted in recent literature is the potential for low gas prices to undermine the cost-competitiveness of renewable energy technologies in certain regions (Lee et al. 2012).

Regional air quality impacts from upstream extraction and midstream processing are also a growing environmental concern (Colborn et al. 2011, McKenzie et al. 2012). Pad construction, water and material transport, drilling and fracturing, and gas delivery activities are associated with increased emissions of particulates, ozone precursors, air toxics, and other criteria pollutants (Kemball-Cook et al. 2010, Schmidt 2011). Trucking and transport activity stemming from the hundreds to thousands of truck trips over a well pad's life-cycle (NY DEC 2011) has clear regional impacts, but so too does the release of volatile organics, such as those dissolved in flowback and produced water, and NOx from on-site generators that can effect downwind ozone concentrations many miles from the well pad (Kemball-Cook et al. 2010). These well-pad emissions also create local hot-spots for air toxics that, depending on

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[11] Table A-1, p. 173; Table A-4, p. 176

[12] By the most widely-accepted calculations, methane has 25 times the climate forcing potential of carbon dioxide over a hundred-year time horizon, and 72 times that of carbon dioxide over a twenty-year period (Forster et al. 2007).

background concentration levels and other environmental conditions, may exceed the EPA's acceptable cancer risk range (CO Dept. of Public Health 2010). To realize potential climate and health benefits of transitioning from coal to natural gas, the upstream and midstream activities associated with bringing shale gas and tight oil to market must be performed in an environmentally responsible and regionally appropriate manner.

In addition to air quality impacts at the global, regional, and local scales, there is a growing focus on the land use implications of shale gas extraction (Cucura, 2012). Individual and collective land use impacts of well pads, including increased erosion, habitat fragmentation, and disruption of ecosystem processes, are evident at the local and regional scales (Johnson et al. 2010).

The most prominent environmental issues surrounding shale gas and tight oil development, however, are the potential impacts of unconventional extraction on water resource availability, subsurface water quality, and waste water disposal. The large volumes and chemical content of hydraulic fracturing wastewater (ALL 2009)—along with high-profile reported instances of methane migration into water wells (Smith et al. 2010, Osborne et al. 2011)—have stoked public fears of water contamination. Water-related impacts of unconventional extraction fall into three general categories:

1. **Sourcing:** Freshwater withdrawals of several million gallons per unconventional well can impinge on local ecosystems and compete with regional water demands. While water consumption by hydraulic fracturing activity is generally a small fraction of a state's total water consumption (<1% for TX), local impacts will vary with water availability (Nicot 2012, Entrekin et al. 2011, Rahm and Riha 2012).
2. **Groundwater contamination:** Near the surface where groundwater may be present, several concentric layers of metal piping ("casing") and cement are intended to isolate the contents of the wellbore from the surrounding environment.[13] Aging processes or poor well construction can precipitate cracks in the casing and cement, compromising the integrity of this isolation and opening the possibility for aquifer contamination (Gresh 2011). Although hydraulic fracturing processes generally occur more than a thousand feet below the surface, at least one documented instance of aquifer contamination by hydraulic fracturing fluids occurred in a poorly-planned vertical well fractured at shallow depths (US EPA 2011a). Contamination events (such as

[13] The industry group American Petroleum Institute recommends that the drilling of this near-surface portion of the wellbore itself be performed using fresh water, air, or freshwater-based fluids to minimize the risk of groundwater contamination prior to casing and cementing (API 2009a). This practice is required by law in some states.

methane migration) involving rural residential water supplies are more likely if these water wells are poorly encased (Gold 2012).

3. **Waste water disposal:** A sizable fraction of the water injected—roughly 10% to 40%—flows back up the well following the completion (Stepan et al. 2010, Galusky 2011). This water is high in dissolved minerals, including trace amounts of naturally occurring radioactive metals (NORM), and contains detectible levels of residual fracturing chemicals and dissolved hydrocarbons. The hundreds of thousands to millions of gallons of wastewater produced per well are temporarily stored on site and subsequently reused in future fracture operations, transported off-site for treatment, or injected into Class II wells. The risk of accidental discharge through leaks in detention units or spills during waste transfer creates logistical challenges for its reuse or disposal. One method of wastewater disposal, deep-well underground injection, was recently linked to a series of small earthquakes in Ohio (OH DMR 2012).[14] Though opponents point to risks across several categories in invocations of the precautionary principle, the water-related impacts of unconventional extraction have loomed large (Finkel and Law 2011).

The true magnitude of the environmental risks posed by unconventional extraction continues to be the subject of passionate scientific and popular debate. A number of life-cycle assessments, greenhouse gas emissions inventories, and local environmental assessments are currently under development by academics, industrial players, and non-government organizations to clarify the extent of impacts at the local, regional, and global levels. A national taskforce, coordinated by the U.S. Environmental Protection Agency, has also been formed to evaluate the potential impacts of hydraulic fracturing on drinking water resources (US EPA, 2012c). In the meantime, a regulatory vacuum on the federal level[15] has placed states with poor oil and gas regulatory infrastructure in the challenging position of ascertaining environmental impacts of unconventional drilling, drafting environmental regulations, and enforcing these new requirements. This absence of federal regulatory oversight, paired with residual

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[14] In addition to the Ohio seismic events associated with injection wastewater disposal, a report by the Oklahoma Geological Survey found a possibility that hydraulic fracturing itself was the cause of several 2011 earthquakes in that state (Holland 2011). See Section II for discussion of related findings in Texas.

[15] Until April 2012, emissions associated with hydraulic fracturing were not specifically addressed in the Clean Air Act (Weinhold 2012). Per the 2005 Energy Policy Act, hydraulic fracturing injection activities are currently excluded from regulation under the Safe Drinking Water Act with the exception of those injecting diesel (US EPA 2012a). This is because a 2002 EPA study of hydraulic fracturing practices (as used in the extraction of coalbed methane, typically shallower and at smaller scales than current processes for shale gas or tight oil) found that diesel used in fracturing fluid constituted the only appreciable threat to drinking water supplies (US EPA 2002). However, the use of diesel as a fracturing fluid additive was phased out from 2003 (US EPA 2004).

uncertainty over the magnitude of human and environmental impacts, the reluctance of some unconventional extraction firms to disclose information about their drilling practices, and perceptions of regulatory incompetence or corruption at the state level, have precipitated public distrust of hydraulic fracturing in a significant portion of the population. Unfortunately, the polemics of the hydraulic fracturing debate have often limited discussion about the technical, managerial, and policy interventions that might mitigate impacts associated with unconventional resource extraction, as well as the effects that these interventions would have on the relative costs and benefits of unconventional oil and gas extraction compared to conventional and renewable energy sources.

Even the most efficient, soundly managed, and optimally cited operations generate human and environmental impacts. Contextualizing these consequences in relation to the impacts of other energy production methods, as well as evaluating them in a holistic regional context, may inform impact minimization and mitigation efforts. The following section will evaluate the regional environmental challenges specific to three major U.S. unconventional plays: the Barnett, the Marcellus, and the Bakken, while Section IV will evaluate technologies, management strategies, and policies to minimize regional human and environmental impacts.

III. COMPARATIVE ANALYSIS: ENVIRONMENTAL CONTEXT OF THREE U.S. UNCONVENTIONAL PLAYS

From a global perspective, a hydraulically fractured horizontal well in one state may appear environmentally equivalent to a similar well located elsewhere around the country. Similar processes beget similar carbon emissions, land area demands, and water usage. The leap from environmental inventories to environmental impact analysis, however, requires that these impacts be contextualized within the regions' existing human and environmental stressors. Detailing the specific environmental attributes of major plays is therefore essential to relating the degree of environmental impact to cost-effective interventions for mitigation.

In this section, we evaluate the regional characteristics of three major U.S. unconventional plays. All of them—the Barnett Shale in Texas, the Marcellus Shale in Pennsylvania, and the Bakken Oil Shale in North Dakota—host extensions of the booming U.S. unconventional extraction industry, but each exists within a unique set of ecological, economic, and demographic parameters. The Barnett is the most mature play, with ready access to an extensive physical infrastructure. Its predominant environmental concerns are water scarcity and air pollution in a development area with a large population base. The Marcellus has developed more recently than the Barnett, but it possesses a well-developed pipeline network stemming from past conventional drilling activity and its proximity to gas demand centers in the Northeast. Its primary environmental challenge is wastewater disposal and materials distribution across a spatially diffuse development area. The Bakken is the most recently established unconventional play discussed here and is growing at a pace that threatens to overwhelm the region's resources. Greenhouse gas emissions due to venting/flaring and minimizing wastewater-related risks are among its most prominent environmental concerns.

A characterization of the environmental context is presented for each play, followed by the local developmental arc of oil and gas from years 2000 to 2012. Each section concludes with discussion of the environmental impacts of unconventional extraction specific to that play. Plays are introduced in chronological order of development, and attributes are presented comparatively at the end of this section in Tables 1-3.

TEXAS' BARNETT SHALE

Located in the north-central portion of Texas near the Oklahoma border, the Barnett Shale is a moderate-sized play that is characterized by ecological heterogeneity and mixed population density. The core zone of the play is centered in a four-county area of 3,300 mi^2 (8,700 km^2), but Barnett wells have been drilled in 19 additional counties, collectively affecting a surface area of approximately 18,000 mi^2 (47,000 km^2) (TX RRC 2012f, US CB 2012a). The counties in which Barnett drilling has taken place account for only 7.0% of the state's total area, but their 5.8 million residents comprise almost a quarter (22.7%) of Texas' population. The positioning of the play poses a unique challenge: while most of the surface area above the formation is rural, the eastern portion is located beneath the heart of the Dallas-Fort Worth metroplex, the fourth most populous metropolitan area in the United States. For this reason, the population density in Barnett-affected counties ranges from 3.7 to 2,718.0 (median 40.3) persons per square mile (1.4 to 1049.4, median 15.5 km^{-2}).

Precipitation varies widely across the Barnett, with annual rainfall over the past decade averaging from 20 to 35 inches (51-89 cm) in the semiarid western section to between 25 and 45 inches (64-114 cm) in the east. The entire region is also prone to cyclical droughts, sometimes severe enough to cause acute water shortages; precipitation in 2011 was half of normal levels in some locations. The topography of the Barnett Shale surface area is characterized by flat or gently rolling plains, and ground cover in non-cultivated rural areas is primarily grasses (USGS 2012). These climatological and geographic features translate to Bailey ecosystem classifications of dry subtropical steppe in the west and humid temperate prairie in the east (USDI 2012). In addition to its ecological characteristics, the significant human presence in the area also comes to bear on impact considerations in energy development.

Fossil fuel extraction has long been a cornerstone of the Texas economy. In all but one of the past thirty years, Texas has surpassed every other state in oil and gas production, generally accounting for one-fifth to one-quarter of national totals for oil and approximately one-third of those for gas (US EIA 2012f-g). Since 2000, the state has collected between $2.0 and $4.1 billion dollars annually in severance taxes[16] (US CB 2012b). Though the Barnett was first proved in the early 1980s, production did not begin in earnest until the early 2000s, when the coupling of hydraulic fracturing and horizontal drilling was pioneered there. Between 2001 and 2011, natural gas production climbed from 135 billion cubic feet to 2.0 trillion cubic feet (Figure 5)—increasing the Barnett's contribution to Texas gas production from 2.4% to 27% (TX RRC 2012a-b). In 2001, there were 1,400 producing wells in the Barnett, representing half a percent of the oil and gas wells in the state; ten years later, there were nearly 16,000, comprising 5.6% of the state total (TX RRC 2012d-e). The Barnett's wells have chiefly been drilled to exploit its dry natural gas: while condensate and oil production does add value to wells (2011 production:

[16] Severance taxes are paid according to a set schedule—determined by individual states—on the extraction of non-renewable resources.

2.4 million and 5.8 million barrels, respectively), it does not occur at volumes that are presently attractive in the context of production elsewhere in Texas (Figure 6; TX RRC 2012a-b). Successes in this new play contributed to a pronounced statewide shift toward horizontal drilling during this time (Figure 4), and spurred exploration and development in shale gas plays around the country.

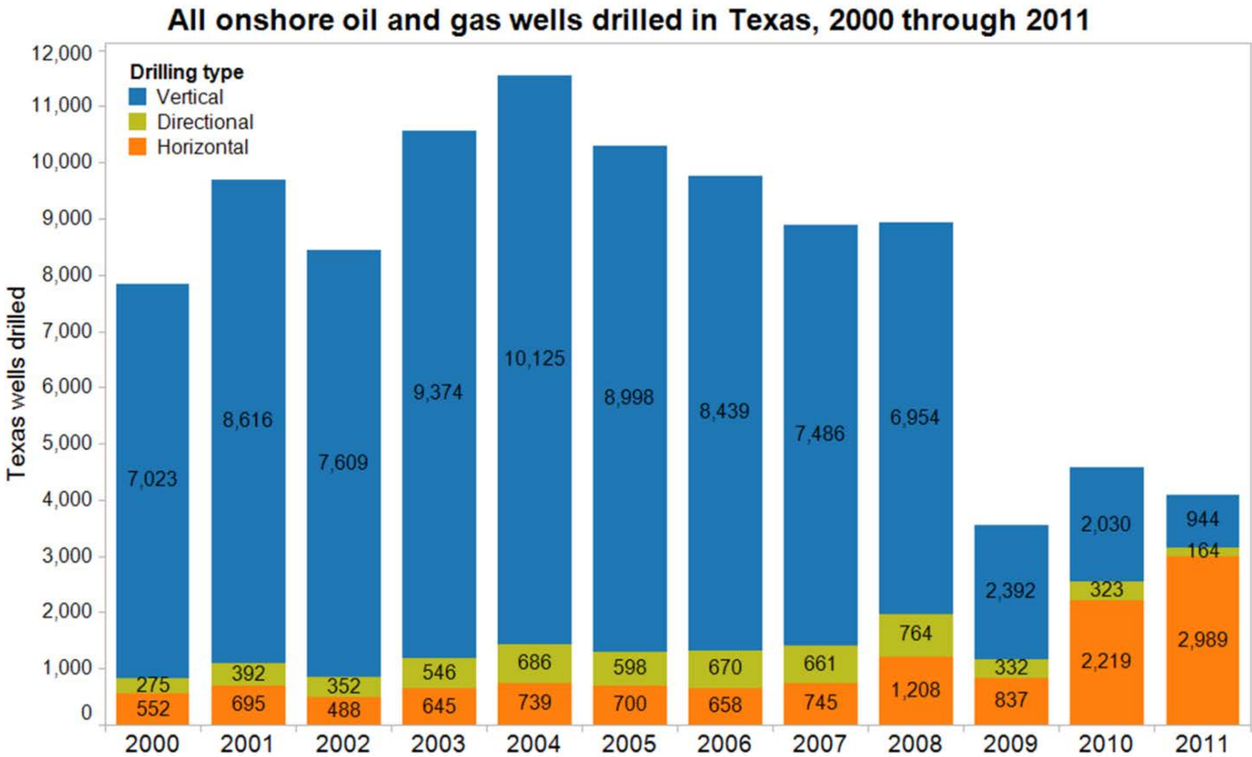

Figure 4. New wells drilled in Texas annually, 2000 through 2011. Offshore sites in the Gulf of Mexico are excluded, as technology and logistics are not directly comparable. Note the clear shift toward horizontal wells. The greater cost of horizontal as opposed to vertical drilling is reflected in the decrease in absolute number of new wells. Data source: HPDI data search of TX RRC data, April 2012 a-c.

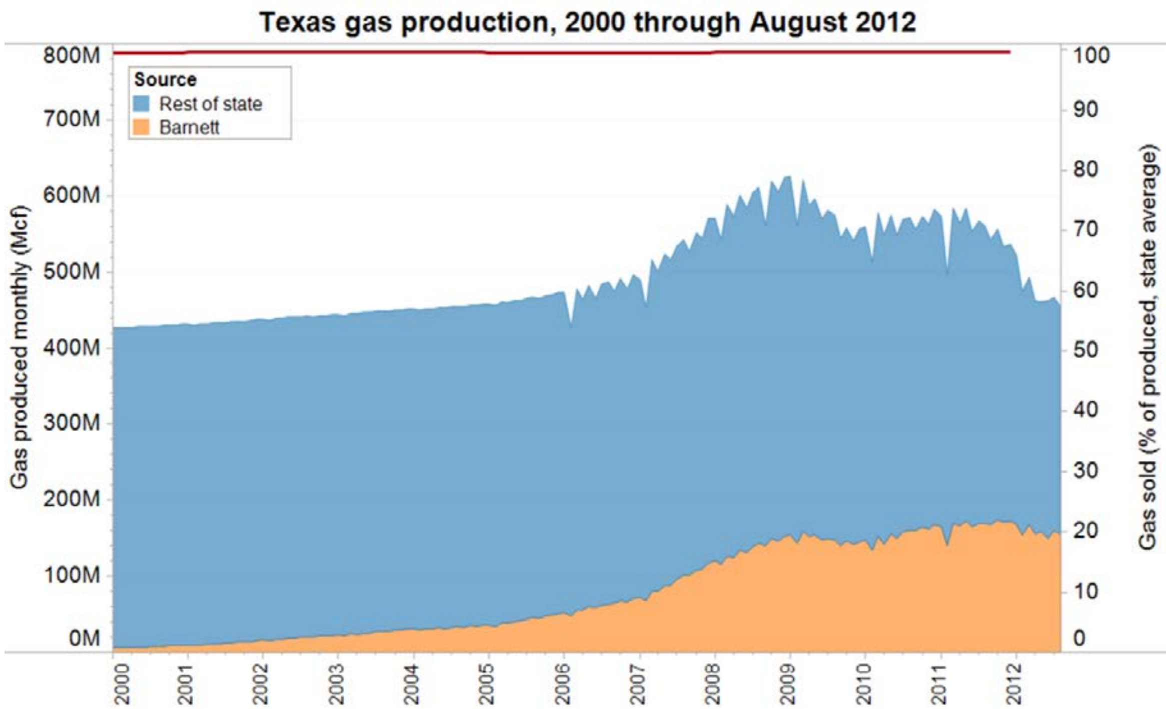

Figure 5. Monthly gas production in Texas from 2000 to the most recent date available at the time of writing. The red line, which maps to the right-hand vertical axis, represents the proportion of produced gas that is gathered. Note that virtually all Texas gas production is marketed. Prior to 2006, state-level data is publicly available only on an annual basis; monthly totals displayed for this time therefore reflect averages across twelve-month periods. Data sources: TX RRC 2012a-c (publicly available).

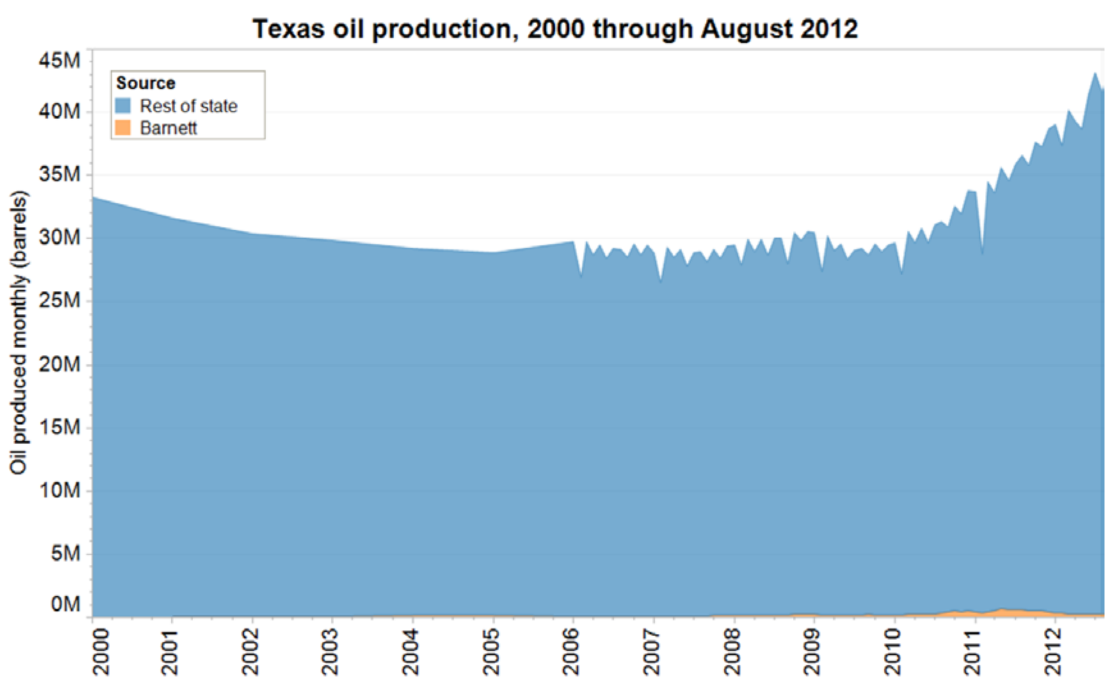

Figure 6. Monthly Texas oil production from 2000 to the most recent date available at the time of writing. Note the miniscule contribution of the Barnett Shale, which is chiefly a gas play. Prior to 2006, state-level data are publicly available only on an annual basis; monthly totals displayed for this time therefore reflect averages across twelve-month periods. Data sources: TX RRC 2012a-c (publicly available).

The most prominent environmental impacts of drilling in the Barnett, competition for water quantity and the air emissions from drilling operations, are exacerbated by the population density in the region. The economy of rural areas overlying the Barnett is dominated by ranging and irrigated agriculture and their demands for fresh water are in direct competition with a rapidly growing urban population (Sun et al. 2008). Periodic droughts magnify the water scarcity problem and attract scrutiny to the large volumes of freshwater (median: 3.3 million gallons per well; Nicot and Scanlon 2012) sourced from declining aquifers (Bené et al. 2007) and used for hydraulic fracturing operations.

Disposal of fracture flowback has also created tension in the region. A typical Barnett well generates approximately 1.7 million gallons of wastewater (Galusky 2011), conservatively representing a collective annual volume on the order of 10^8 gallons as development continues. The conventional method of wastewater disposal in the Barnett is deep underground injection at a Class II disposal facility, and there are several dozen of these facilities in the region (Prozzi et al. 2011). Seismic activity stemming from the large volumes of injected waste, however, has elicited public concern (Frohlich 2012).

A third major environmental issue in the Barnett is air quality. The Dallas-Fort Worth metroplex has struggled for years with high ozone levels, and has failed since 1997 to reach attainment status under eight-hour national ambient air quality standards.[17] Because drilling in the Barnett sometimes occurs in close proximity to communities, public concern has been raised over its potential to exacerbate poor air quality. This has prompted several rounds of well pad-level measurements by the state environmental agency (TCEQ 2010).[18] Despite the long history of the oil and gas industry in Texas—and its importance to the greater Dallas-Fort Worth economy—the air and water impacts of Barnett shale gas extraction have drawn harsh criticism from some among the area's many residents.

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[17] Ozone is produced when mono-nitrogen oxides (NO_x) react with volatile organic compounds (VOCs) in the presence of sunlight. Its acute effects range from mild respiratory dysfunction (including wheezing or shortness of breath) to acute symptoms such as asthma attacks. Ozone can also contribute to increased mortality among susceptible subpopulations. Both NO_x and VOCs are generated by combustion engines, but VOCs such as benzene may also be released during well site operations—particularly if joints and valves on transfer equipment are not tightly sealed.

[18] While these studies did document the presence of a variety of VOCs—including several locations at which benzene levels exceeded the state's long-term air quality standards—no sites exceeded short-term thresholds. However, monitors were installed in four Barnett-are communities that now post real-time air quality data online for public download.

PENNSYLVANIA'S MARCELLUS SHALE

Unconventional extraction activity in the Marcellus Shale is primarily focused in Pennsylvania, though the play extends through a large swath of the eastern United States. Though larger than the Barnett in terms of absolute affected surface area, the Marcellus is not yet as densely developed with wells. The approximately 4,000 Marcellus wells drilled in Pennsylvania have been spread over a 38-county area, spanning some 29,000 mi^2 (74,000 km^2) (PA DEP 2012b-c; US CB 2012a). Operations are concentrated in the north-central portion of the state and its southwestern corner, but nearly two-thirds (66%) of the land area of Pennsylvania has been annexed into the broader Marcellus development (PA DEP 2012b-c). Much of the region is rural, though significant urban centers are also affected. The total population of the counties in which active Marcellus wells have been reported is 4.8 million (38% of the state), over half of whom reside in the greater Pittsburgh metropolitan area (US CB 2012a). As in the Barnett, population density in the Marcellus therefore shows a wide range: 12.8 to 1675.6 persons per square mile, with a median of 72.6 (4.9 to 647.0, median 28.0 km^{-2}; US CB 2012a).

The landscape of the Marcellus is primarily forested and the topography is hilly to mountainous (USGS 2012). The fractured geology underlying these features precludes high-volume underground injection of fluids as a means of disposal in some places (McCurdy 2011). The region enjoys favorable hydrology, with 35 to 55 inches (89 to 140 cm) of precipitation per year (OSU PRISM 2012) and many rivers and streams. Though surface water is generally plentiful, winter freezing can complicate access and transport. With its trees, abundant rainfall, and distinct seasons, the large and diffusely-developed area overlying the Pennsylvania Marcellus is classified as a humid temperate continental ecoregion with mixed forests.

Unconventional gas extraction precipitated important economic changes in Pennsylvania. Though the state was home to the first commercial oil well in the United States, by the 1990s its oil and gas production had plateaued, dwarfed by that of other states (US EIA 2012 g-h). The success of hydraulic fracturing in the Barnett shale spurred technology transfer to Pennsylvania, rapidly reigniting the gas industry in the region. The Marcellus functionally did not exist as a play in 2007, but in 2011 produced nearly 1.1 trillion cubic feet of natural gas—81% of the state total, and already nearly half of the Barnett's output despite having a quarter of the wells (Figure 8; PA DEP 2012b). Over the same time period, the percentage of new wells in Pennsylvania that were drilled horizontally rose from less than one percent to 63% (Figure 7; PA DEP 2012a). In the midst of a national recession, the number of extraction-sector jobs in the state increased by half (US BLS 2012).[19] While initial development was characterized by hectic exploration for dry gas, a glut in supply and warm winters have suppressed prices (Figure 3) and put pressure on the industry to diversify. Increasingly, operators have turned to petroleum liquids to augment returns: Marcellus oil and condensate production was over 500,000 barrels in the second half of 2011, up 40% from the year before (Figure 9; PA DEP 2012b). Within half a decade, unconventional extraction became a fundamental part of the physical and economic landscape throughout western Pennsylvania, and the industry continues to evolve.

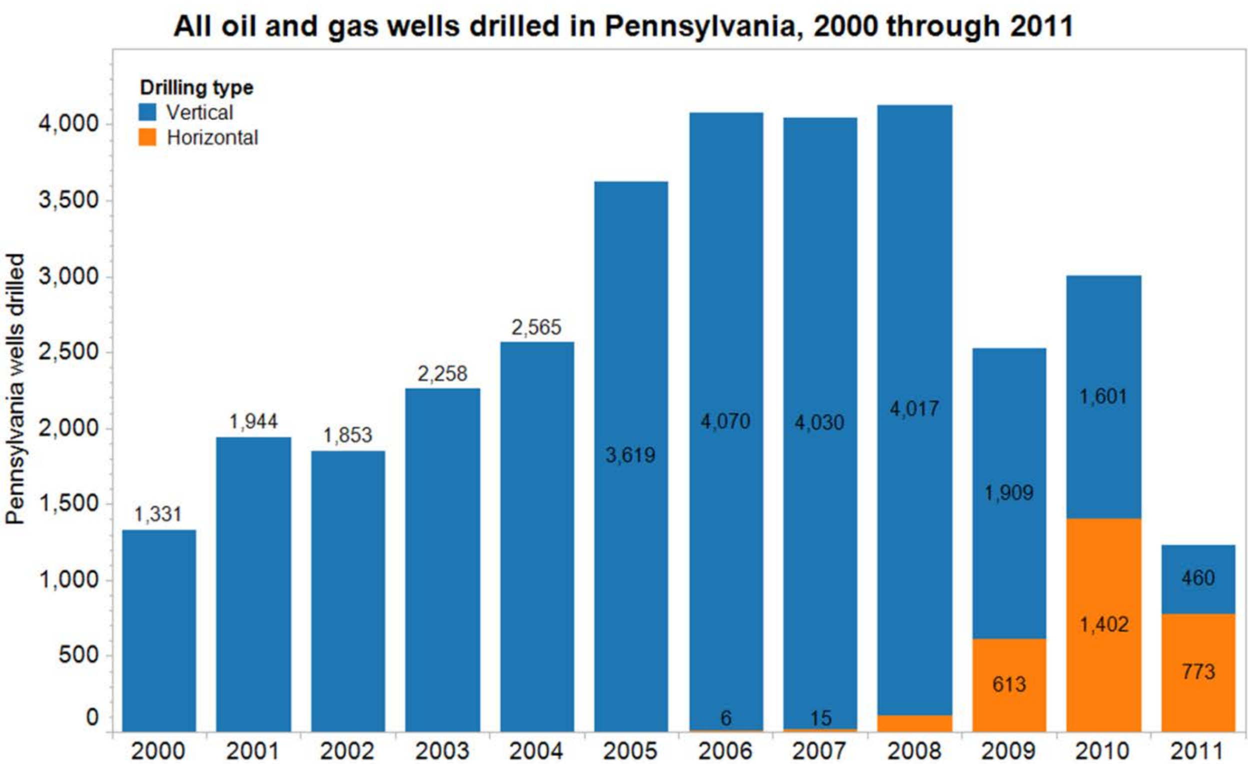

Figure 7. New wells drilled annually in Pennsylvania from 2000 through 2011. As in the Barnett, note the clear shift toward horizontal wells in recent years. Data source: PA DEP 2012a (publicly available).

[19]The shale gas industry has provided substantial economic benefit to Pennsylvania, but it has not contributed direct income to the state in the form of a severance tax; Pennsylvania does not have one, making it unique among the top fifteen gas producing states in the U.S. However, as of February 2012, individual counties may now assess an annual impact fees for shale gas operations (59 Pa.C.S. 2012).

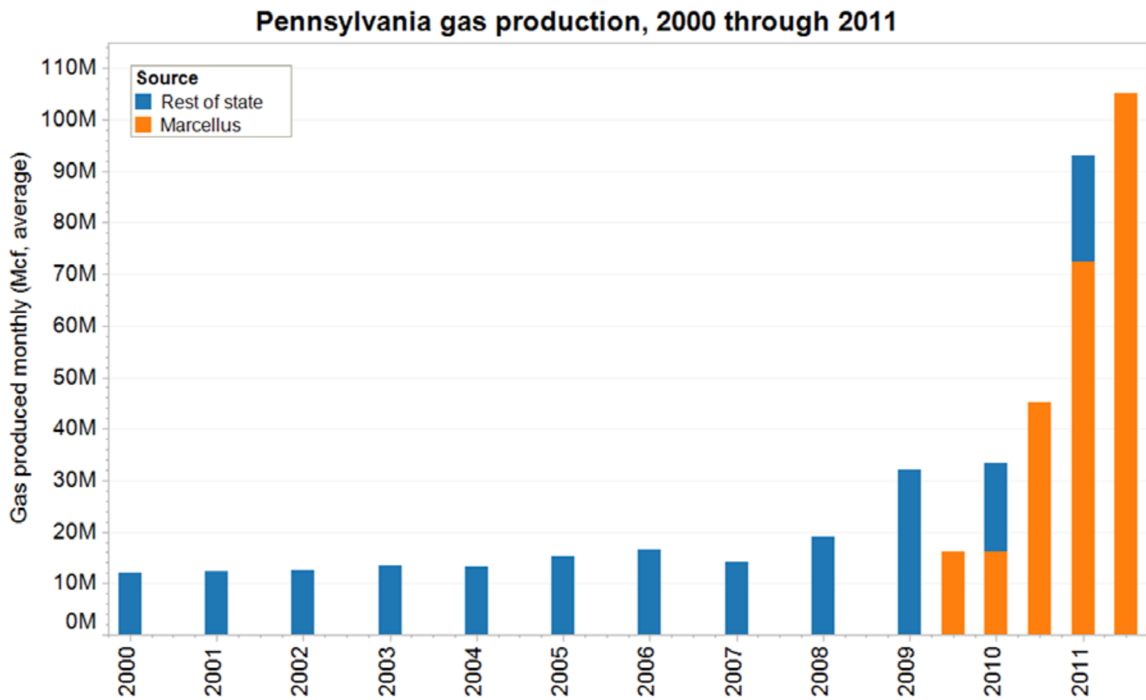

Figure 8. Monthly Pennsylvania gas production, 2000 through 2011. The state of Pennsylvania did not begin tabulating Marcellus production separately until mid-year in 2009, and reporting period start dates did not coincide with the rest of the state until 2011. Thus, Marcellus totals from mid-2009 through 2011 are averaged in six-month intervals, and statewide totals are averaged across twelve months to enable comparison. Beginning in 2012, Pennsylvania began tracking data by well type (conventional versus unconventional) rather than by formation; as they are not directly comparable, these data were not included. Data source: PA DEP 2012b (publicly available).

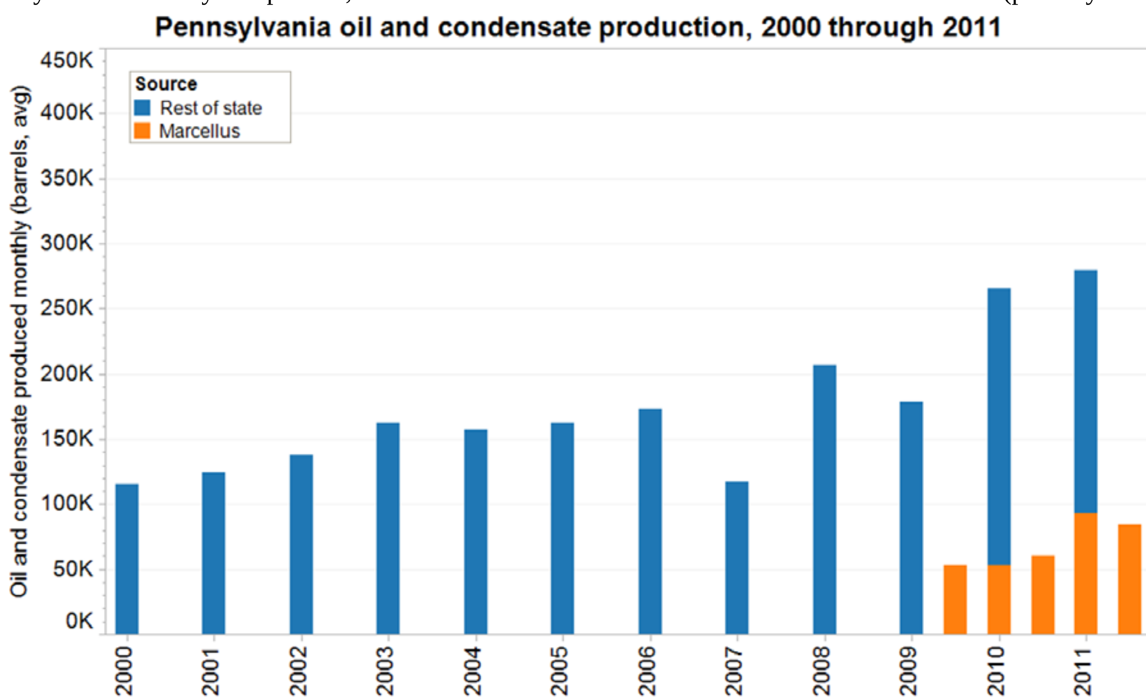

Figure 9. Monthly Pennsylvania oil and condensate production, 2000 through 2011. The same reporting period peculiarities described for Figure 8 are present here. Note that the Marcellus accounts for a sizeable proportion of total liquids production, but that levels overall are two orders of magnitude smaller than Texas'. Data source: PA DEP 2012b (publicly available).

The similarities between extractive operations in the Barnett and the Marcellus belie the substantive differences in environmental impacts. Wells in the Marcellus require the same 3.0 to 5.0 million gallons of fresh water (Cawley et al. 2012, Gaudlip and Paugh 2008), but water scarcity is not a significant regional concern in Pennsylvania. Instead, large-volume sourcing from numerous small surface waters may reduce in-stream flow rates and degrade local environmental quality. The greater challenge in the Marcellus lies in the management and disposal of fracture flowback and brines. There are fewer than 10 Class II injection wells for oil and gas wastewater in the state of Pennsylvania (US EPAR3 2012), compared to several dozen in the Barnett.

The scarcity of conventional disposal options has forced operators and service providers to seek alternative methods of disposal, such as brine recycling or thermal desalination, or transport the waste further afield. Evidence of this challenge is manifest in the lengthy average waste transport distances for Marcellus flowback: while the average waste transport distance in the Marcellus in 2011 was greater than 100 miles (Mauter 2012, in preparation), the average in the Barnett was approximately 10 miles (Prozzi et al. 2011). These long transport distances raise concern of large carbon footprints associated with waste transit, as well and the risk of accidental wastewater release. Until a 2011 law effectively banned the practice, one of the most economical disposal alternatives was discharge into surface waters via municipal water treatment facilities, which were unequipped to treat the high salinity levels and large volumes of wastewater produced by hydraulic fracturing operations. Today, the dominant waste management approach is to reuse the flowback water in future fracture operations, but risks associated with storage and transport between fracture operations remains a concern. Finally, groundwater impacts from hydraulic fracturing activity are also a concern in a state where a large percentage of rural communities source their drinking water from wells. The PA Department of Environmental Protection has linked drilling activity to elevated methane concentrations in residential wells,[20] but, to date, there has been no documented linkage between groundwater contamination and injected flowback waste.[21]

Collective land-use impacts of unconventional drilling present another distinct difficulty. The disperse drilling patterns in the Marcellus have established oil and gas operations as a pervasive part of the landscape, rather than a confined feature of a localized development zone, and has resulted in the habitat fragmentation of previously undisturbed forests (Johnson 2010). Soil disruption and the associated erosion and stream sedimentation have been a particular concern in the hilly terrain of the Marcellus, and

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[20] See e.g. Smith 2010, Gresh 2011

[21] See e.g. White 2012 for EPA's final findings in a collection of high-profile well contamination cases in Susquehanna County, Pennsylvania.

these issues have prompted recent changes to Pennsylvania's oil and gas permitting regime (59 Pa.C.S. 2012). Technological interventions to further minimize soil disruption will be addressed in Section IV. The rapid pace of unconventional extraction development in Pennsylvania—where an aging energy industry lacked the widespread public familiarity, regulatory experience, and strategic resources found in Texas—have made it something of a policy laboratory for environmental impact management strategies. Its profound ecological differences relative to the Barnett have also stymied attempts for direct adoption of regulatory and management practices from earlier shale plays.

NORTH DAKOTA'S BAKKEN OIL SHALE

The drilling technologies used in the Bakken are akin to those used in the Marcellus and the Barnett, but the Bakken's distinct set of environmental concerns hinge on the high density of agricultural and rangeland in the play. Current Bakken development has been focused in western North Dakota, though the formation spans several states and the boarder with Canada.[22] Bakken wells have been drilled in twelve North Dakota counties, affecting 27% of the state's land area—some 18,000 mi^2 (49,000 km^2), and only slightly smaller than the Barnett (ND DMR 2012c; US CB 2012a). Drilling density in the Bakken is more similar to the Marcellus, with approximately 3,400 wells spread across this area (ND DMR 2012b). While the Bakken development area encompasses a fifth (21%) of ND's rural population, the absolute number of people, 140,000, is thirty- and forty- fold less than its counterparts in Pennsylvania and Texas, respectively (US CB 2012a). Population density is quite homogenous, ranging from 0.7 to 30.6 persons per square mile with a median of 2.0 (0.23 to 11.8 km^{-2}, median 0.77; US CB 2012a). Unique among the three plays, a small part of the Bakken surface area (<10%) is located on the Fort Berthold Indian Reservation.

The rolling prairie that comprises most of the Bakken is topographically similar to the western Barnett, though the southwestern portion of the area is characterized by the rugged badlands of Theodore Roosevelt National Park. Annual precipitation in the last decade has averaged between 10 and 25 inches (25-64 cm), making the Bakken the driest of the three plays (OSU PRISM 2012). The limited rainfall and harsh winters result in few continuously-accessible surface waters, with the exception of a large man-made reservoir roughly centrally within the play. Thus, the ecological environment overlying the Bakken can best be described as dry temperate steppe.

[22] Two additional pools, atop which the Bakken is superimposed to varying degrees, have been discovered as industry has developed in western North Dakota. Monthly extractions from the Bakken, Sanish, Three Forks, and Bakken/Three Forks pools are reported by the state as production from the Bakken, and this convention is followed within this report.

The oil and gas industry also has historical precedent in the Bakken, but the recent arrival of unconventional extraction—focused here not on gas, but on oil—has brought dramatic changes. In 2006, just prior to the appearance of horizontal drilling and hydraulic fracturing in the Marcellus, 2.3 million barrels of oil were extracted from the Bakken's 313 wells, representing 5.8% of North Dakota production. In 2011, over 3,000 additional Bakken wells collectively produced 129 million barrels, or 84% of the state total (Figure 12; ND DMR 2012a-b) and 6.2% of national crude oil production (US EIA 2012f). The rapid expansion of oil extraction has also precipitated statewide economic changes, with collections of severance tax increasing from $347 million in 2006 to $1.8 billion in 2011. This shift represents an increase from 21% of all state tax revenue to 49% (US CB 2012b), and raises internal debate about allocation of rents from state resources. As the national unemployment rate peaked at 10.0% in 2009, North Dakota's reached a maximum of 4.2% (US BLS 2012). With the advent of technologies making tight oil profitable, this sparsely populated state is experiencing an extraordinary influx of equipment, capital, and personnel as production skyrockets.

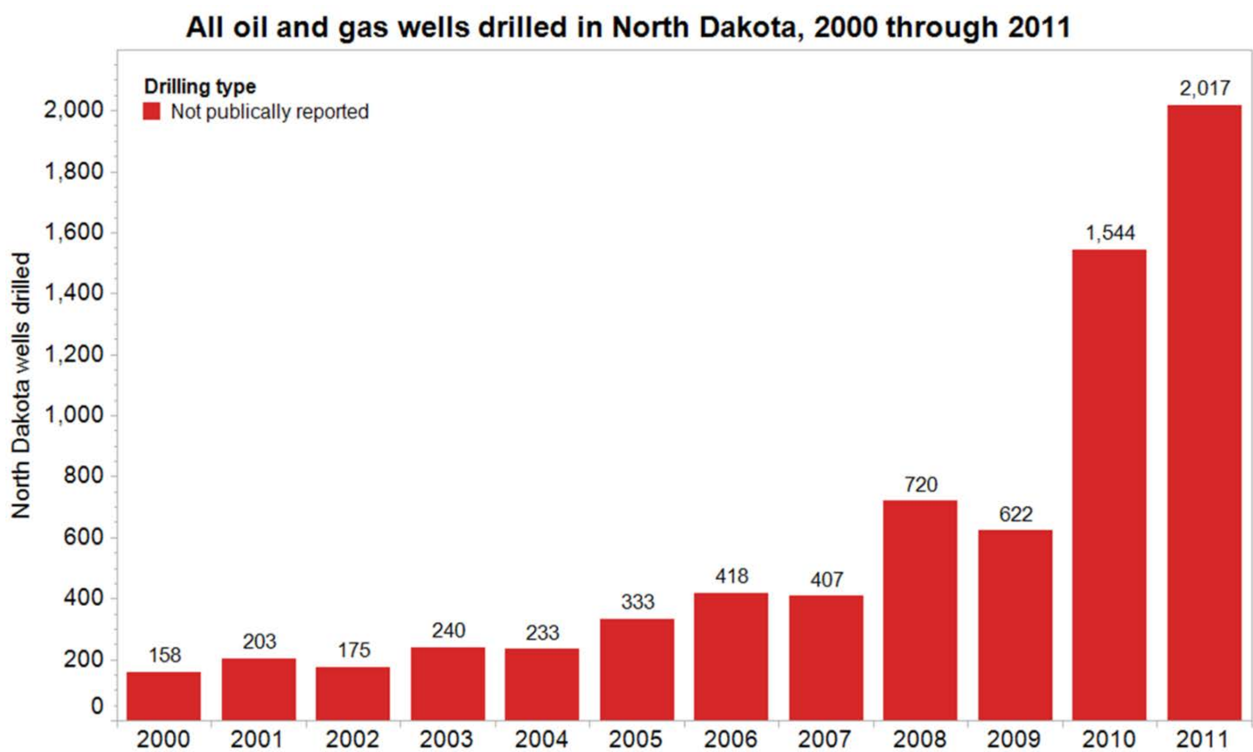

Figure 10. Wells drilled in North Dakota annually, 2000 through 2011. While the number of horizontal versus vertical wells is not publicly reported, what is important to note is the remarkable increase in drilling beginning in 2008. This uptick coincides with the transfer of hydraulically fractured horizontal wells from the Barnett to other unconventional plays (compare with the same pattern in the Marcellus as displayed in Figure 7), so it is likely that horizontal drilling accounts for most, if not all, of the increase in North Dakota drilling. Data sources: ND DMR 2012a-b (publicly available).

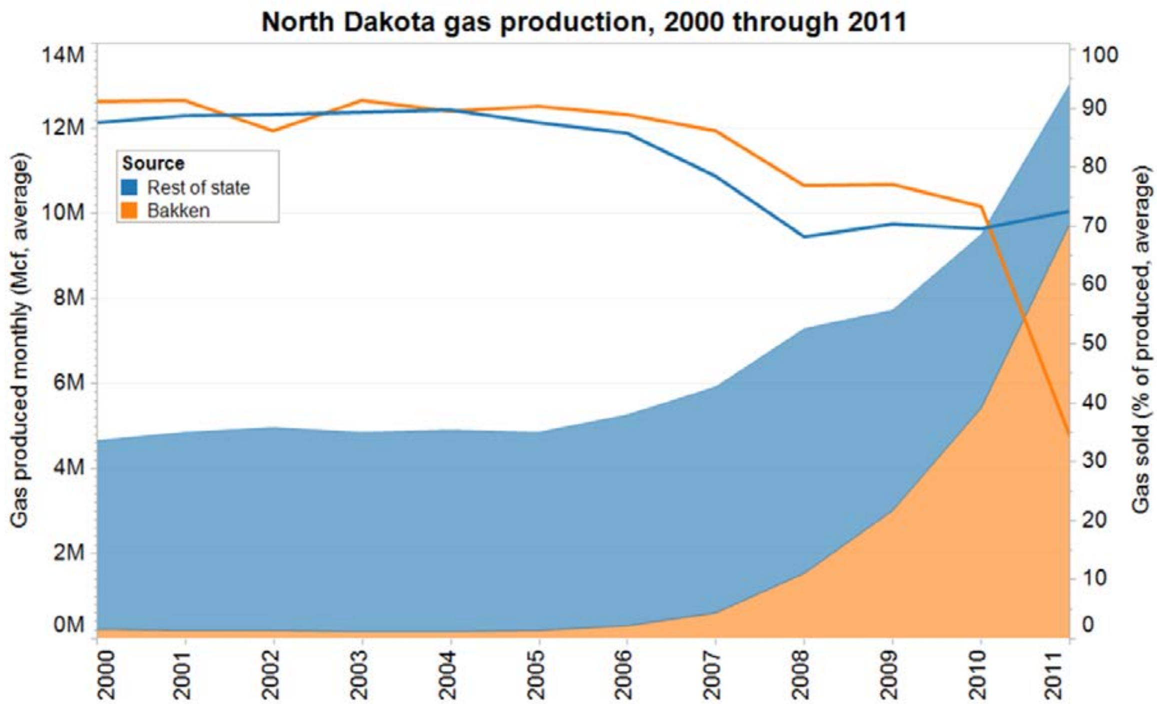

Figure 11. Monthly North Dakota gas production from 2000 through 2011, averaged from annual totals across twelve-month periods for comparison with other plays. Percentage of gas sold (as opposed to being flared) is shown by lines corresponding to the right-hand vertical axis. Less than 40% of the gas produced in the Bakken in 2011 was marketed, chiefly due to lack of infrastructure capacity. Compare this to near-100% marketing of gas production in Texas, as seen in Figure 5. Data sources: ND DMR 2012a-b (publicly available).

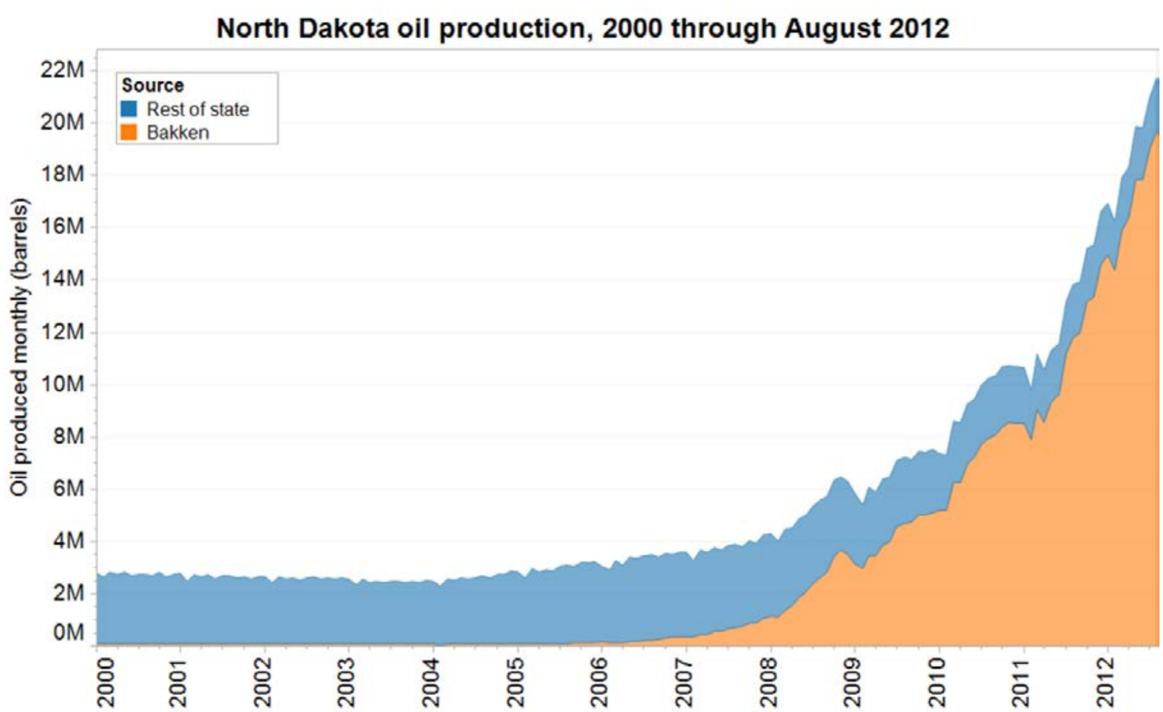

Figure 12. Monthly oil production in North Dakota, 2000 through the most recent date available at the time of writing at the time of writing. In the first half of 2012, the Bakken accounted for 89.1% of total state production. Data sources: ND DMR 2012a-c (publicly available).

As in the Marcellus and the Barnett, unconventional extraction in the Bakken is associated with context-specific environmental impacts. The extraction industry faces land use conflicts with the area's farms and ranches,[23] and hunters have been critical of ecological disruption on rangelands. Analogous to the other plays, water sourcing is another concern. Although the absolute quantity of water required for hydraulic fracturing activity represents a fraction of the 18 billion gallons per year utilized for irrigation in Bakken-area counties (USGS 2005), surface water is often locally limited and new water demands have the potential to generate conflict with agricultural users in the state. The frackwater is generally sourced from groundwater stores or are trucked long distances from the area's few large reservoirs (Stepan 2010). Groundwater often requires treatment to remove dissolved minerals, representing additional costs and energy input, while the carbon cost of trucking surface water grows as development expands farther afield from a small number of readily-accessible sources.

Third, waste disposal in the Bakken presents unique difficulties associated with the high development rate of the play. Class II injection facilities for oil and gas wastewater are distributed throughout the region, though trucking large volumes of wastewater to these sites carries the same risk of accidental release as in other plays. The enforcement of waste handling regulations essential to reducing this risk has proved challenging in a thinly-populated state with few field inspection staff.[24]

The final major environmental challenge in the Bakken is a consequence of its geographic isolation and absence of ready markets for natural gas. Unlike oil, gas must be piped to refining facilities via gathering lines. Historical natural gas extraction in Pennsylvania and Texas has left ready networks of lines crisscrossing the Marcellus and the Barnett, but no such legacy exists in North Dakota. In the Bakken, gas production is predominantly an indirect consequence of oil development, and the infrastructure presently in place in western North Dakota simply lacks the capacity to accommodate the fourteen-fold increase in produced volumes between 2006 and 2011 (ND DMR 2012a-b). Of the 116 billion cubic feet produced in the Bakken in 2011, less than 60% was marketed (ND DMR 2012b).

The challenges of transporting natural gas to market have made methane byproducts from oil extraction a waste product rather than a commodity. State law prevents direct venting of natural gas into

[23] In North Dakota (as in Texas and Pennsylvania), mineral rights and surface rights are severable, with the former dominant. That is, the rights to a given parcel of land and the oil and gas beneath it may belong to different entities, with the party owning the subsurface rights retaining the right of access via the overlying land—with or without the consent of the surface rights holder.

[24] As of July 2012, there are thirteen field inspectors employed by the state (ND DMR 2012d). See Dalrymple 2012 for an example of recent compliance challenges.

the ambient environment, so gas not piped for sale must be burned nonproductively (“flared”) at the well site. These flares represent a significant source of carbon dioxide emissions: in 2011, 47 billion cubic feet of natural gas—equivalent to 4.5% of production in the Marcellus—was flared from the Bakken (ND DMR 2012b), illuminating the region in photographs taken by satellites in space. Though a smaller human population is affected than in the Marcellus or the Barnett, managing the global carbon impacts of unconventional extraction in the Bakken nonetheless represents a new challenge for North Dakota.

	Barnett	Marcellus	Bakken
Gas production,			
thousand cubic feet			
(Mcf)	134,657,164	*Not reported*	2,228,038
2001	720,195,169	*Not reported*	3,313,204
2006	2,049,068,028	1,066,013,143	116,738,887
2011			
Play percentage of state	2.4%	*n/a*	3.8%
2001	11.3%	*n/a*	5.3%
2006	27.0%	81.2%	74.7%
2011			
State percentage of national	25.7%	0.64%	0.27%
2001	28.6%	0.91%	0.29%
2006	30.0%	2.6%	0.37%
2010*			
	TX RRC 2012a-c	PA DEP 2012b	ND DMR 2012a-b
	US EIA 2012g	US EIA 2012g	US EIA 2012g
Data sources:			
Oil production, barrels			
2001	4,524	*Not reported*	663,028
2006	323,515	*Not reported*	2,310,756
2011	5,764,445	384,867	128,747,885
Play percentage of state			
2001	0.0012%	*n/a*	2.1%
2006	0.093%	*n/a*	5.8%
2011	1.4%	14.8%	84.2%
State percentage of national			
2001	20.0%	0.076%	1.5%
2006	21.3%	0.19%	2.1%
2011	26.2%	0.17%	7.4%
Data sources:	TX RRC 2012a-c	PA DEP 2012b	ND DMR 2012a
	US EIA 2012f	US EIA 2012f	US EIA 2012f
Producing wells			
2001	1,390	*Not reported*	215
2006	5,720	*Not reported*	313
2011	15,870	3,902	3,399
Fraction of state O&G wells			
2001	0.55%	*n/a*	6.2%
2006	2.3%	*n/a*	8.4%
2011	5.6%	5.7%	51.0%
Data sources:	TX RRC 2012d-f	PA DEP 2012b	ND DMR 2012a-b

Table 1. Comparative production statistics for the three focus plays. *Most recent year for which data from all states was reported.

	Barnett	Marcellus	Bakken
Condensate production, barrels			
2001	402,197	*Not reported*	
2006	1,674,359	*Not reported*	*Not reported*
2011	2,420,994	684,334	
Data sources:	TX RRC 2012a-c	PA DEP 2012b	
National context, 2011	**8.5% of U.S. natural gas**	**4.4% of U.S. natural gas**	**6.2% of U.S. oil**
Data sources:	TX RRC 2012a US EIA 2012g	PA DEP 2012b US EIA 2012g	ND DMR 2012a US EIA 2012f

Table 2 continued. Comparative production statistics for the three focus plays. *Most recent year for which data from all states was reported.

	Barnett	Marcellus	Bakken
Approximate production area, mi^2	20,100	29,421	18,881
Percentage of state land area	7.7%	65.8%	27.3%
Data sources:	TX RRC 2012f: counties with Barnett wells US CB 2012a	PA DEP 2012b: counties with Marcellus production US CB 2012a	ND DMR 2012c: counties with Bakken wells US CB 2012a
Approximated well spacing, mi *i.e., as uniformly averaged over production area*	1.1	2.7	2.4
Annual precipitation, production area (2000-2010) Data source: OSU PRISM 2012	20-35 (west), 25-45 (east) *2011 drought: 15-20 (west), 20-25 (east)*	35-55	10-25
Bailey ecoregion domain and division	Humid temperate prairie; dry subtropical steppe	Humid temperate continental (mixed forests)	Dry temperate steppe
USDA Major Land Use Area Data sources: USDI 2012, USDA 2012	Southwestern prairies cotton and forage, Central Great Plains winter wheat and range	Northeastern forage and forest, East/Central farming and forest	Northern Great Plains spring wheat
Frac water use per horizontal well, Mgal	0.75 to 5.5 (median: 2.8)	3-5	0.5 to 3.0
Data source:	Nicot and Scanlon 2012	Cawley 2012 Gaudlip and Paugh 2008	Stepan 2010

Table 3. Selected comparative geographic and ecological characteristics of the three focus plays.

	Barnett	Marcellus	Bakken
Severance taxes collected by state			
2001	$2,044,795,000	$0	$164,624,000
2006	$3,216,387,000	$0	$346,672,000
2011	$2,677,604,000	$0	$1,883,816,000
As percentage of state tax revenue			
2001	6.9%	*n/a*	14.1%
2006	8.8%	*n/a*	21.4%
2011	6.2%	*n/a*	49.3%
Data source: US CB 2012b			
Population, production area*	5,824,733	4,820,003	142,418
Percentage of state	22.7%	37.8%	20.8%
Data source: US CB 2012a			
Population density, production area, persons/mi^2*	3.7 to 2718.0 median: 40.2	12.8 to 1675.6 median: 72.6	0.7 to 30.6 median: 2.0
Data source: US CB 2012a			

Table 4. Selected comparative tax and demographic statistics for the three focus plays. **For production areas as defined in Table 1.*

IV. OPPORTUNITIES FOR ENVIRONMENTAL IMPACT REDUCTION IN SHALE GAS AND TIGHT OIL OPERATIONS

POTENTIAL OPPORTUNITIES

The regional environmental impacts stemming from unconventional extraction in the Barnett, Marcellus, and Bakken plays are both intrinsic to the technology and exacerbated by the failure to implement available control technologies, to adopt responsible environmental management practices, and improve regulatory oversight. Fortunately, these failures at the well and regional levels are beginning to garner attention across the extraction, oil and gas services, and policy sectors as opportunities for risk reduction and profit maximization. Technological, management, and policy interventions to mitigate or reduce the environmental impacts of shale extraction are catalogued in Table 4. This table highlights mitigation opportunities in four dimensions: (1) the scale of technology implementation, from the single-well level to the development scale (i.e., all the sites owned in an area by a particular operator); (2) the scale of technology benefits, from the local level to the regional level to the global level; (3) the present degree of adoption, from an emerging technology embraced by early adopters, to widespread implementation, to regulations mandating adoption; and (4) the type of mitigation measure (discrete technology, shift in management practices, or feasible regulatory intervention).

While the list represents promising technologies, management strategies, and policies for reducing or mitigating environmental impacts, it is not an exhaustive compilation. We exclude technologies in the development and testing stage, instead choosing to focus on technologies that are available for deployment in 2013. The list is also not intended to endorse any individual product or vendor, but to identify viable and commercially available technical interventions to reduce impacts intrinsic to the extraction process. Also omitted are practices designed to reduce impacts not directly related to environmental quality, an example of which would be noise control measures.[25] It should be noted that many operators already make use of one or more of these strategies, and that some interventions are legally required in certain jurisdictions. The costs and benefits of three of these impact reduction measures, representing a range of implementation scales, benefit categories, and degrees of adoption, are presented as case studies in Section IV.

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[25] Other serious non-environmental impacts of unconventional extraction operations include social changes and strain on local infrastructure in affected communities. The potential feedback impacts of these phenomena on the industry's "social license to operate" were featured prominently in a recent report from the International Energy Agency—see IEA 2012.

	Scale of implementation	Scale of benefits	Degree of adoption	Potential environmental benefits	Type
Laying impermeable liner over well pad site	Well	Loc	Wide	- *Reduces risk of soil and surface water contamination*	T R
Laying reusable mats over well pad site and planned access routes, rather than laying gravel**	Well	Loc Reg	Emg	- *Reduces risk of soil and surface water contamination* - *Speeds reclamation process once well is put on production* - *Reduces risk of erosion damage*	T R
Installing containment walls or dikes around all equipment used to store hydrocarbons	Well	Loc	Wide Law	- *Contains potential spills and fires, reducing risk*	T R
Setting surface casing at greater depths *(API recommendation is 100 ft below deepest aquifer)*	Well	Loc	Wide Law	- *Provides additional separation of groundwater from drilling activities*	M R
Cementing intermediate casing, if present, to surface	Well	Loc	Emg Wide	- *Provides additional layer of pipe and cement between borehole and aquifers it passes through* **May not be appropriate for all wells*	M R
Extending cementing on production casing farther above fracturing zone—to surface if practicable *(API recommendation is 500 ft above highest formation to be fractured)*	Well	Loc	Wide	- *Reduces risk of interzone migration of subsurface hydrocarbons*	M R

Table 5. Candidate technologies and practices for environmental impact reduction of hydraulically fractured horizontal wells. Scale of implementation: single well pad versus development area as scale of technology implementation; scale of benefit: scale(s) at which environmental benefits of technology are most applicable (local, regional, or global); adoption: prevalence of technology (legally required in some places, widely used, and/or emerging); type: discrete technologies (T), shifts in management decisions (M), and/or feasible regulatory intervention points (R). **Included in case study in Section IV.

	Scale of implementation	Scale of benefits	Degree of adoption	Potential environmental benefits	Type
Collection and analysis of surface and subsurface data, used to inform planning and real-time management of hydraulic fracturing jobs**	Well	Loc Reg	Emg	- *Optimizes fracturing program, reducing water use and wastewater associated with non-productive fractures—thereby also decreasing truck trips required per well* - *Reduces risk of fracturing beyond desired zone* - *Enables detection of wellbore instability induced by high pressures, reducing risk of rupture and leakage of fluids*	T M R
Transitioning to (more) environmentally benign hydraulic fracturing fluids	Well	Loc Reg	Emg Wide	- *Reduces chemical hazard of wastewater* **May conflict with water reuse strategies, as not all fracturing fluid blends are compatible with water high in dissolved minerals*	T R
Including non-radioactive tracers in injected proppant	Well	Loc	Emg	- *Facilitates monitoring of fractures' locations and fluid flow within them, detection of communication with aquifers*	T R
Conducting small-scale test run ('mini-frac') before commencing full hydraulic fracturing job	Well	Loc	Emg Wide	- *Reduces risk of casing and cement failure under fracturing pressures*	T M R
High-density selective batch fracturing (open-hole completions only)	Well	Glbl	Emg	- *Increases efficacy of fracturing job when paired with optimized completion design, thereby increasing production tradeoff for drilling operation* **May be most compatible with non-cased ('open hole') completion designs*	T M
Installing remotely-controlled downhole system of permanent monitors, packers, and sealing elements, used to optimize flow rates of hydrocarbons and wastewater ('intelligent completion')	Well	Glbl	Emg	- *Allows dynamic adjustment of in-hole equipment throughout life of well, increasing production tradeoff for drilling operation*	T M
Air and water quality sampling throughout life of well (including baseline), used to inform operations	Well Area	Loc Reg	Wide Law	- *Enables immediate detection and mitigation of spills or leaks*	T M R

Table 6 continued. Candidate technologies and practices for environmental impact reduction of hydraulically fractured horizontal wells. **Included in case study in Section IV.

	Scale of implementation	Scale of benefits	Degree of adoption	Potential environmental benefits	Type
Wastewater recycling and reuse, through blending and/or treatment	Well Area	Loc Reg	Emg Wide	- *Reduces volumes of freshwater input and wastewater output of each well* **Requires coordinated completions schedule across development area to make use of large volumes of recycled wastewater* **May require alteration of fracturing fluid composition to accommodate higher concentrations of dissolved minerals*	T M R
Reuse of drilling fluids and muds ('closed-loop drilling')	Well Area	Loc Reg	Emg	- *Reduces solid waste* - *For 100% recycling, requires coordinated drilling schedule and/or large-volume storage capacity across development area to make use of fluids*	T M R
Using 'double-ditching' (preserving topsoil layering) when burying equipment in undisturbed areas	Well Area	Loc Reg	Emg Law	- *Reduces land use impact by preserving soil integrity, native plant root structures and seedstock, and existing microfauna* **Required on some federal lands*	M R
Capturing fugitive methane by implementing reduced-emission completions ("green completions"), replacing high-bleed valves, installing vapor-recovery units on tanks, etc.**	Well Area	Loc Reg Glbl	Emg Wide Law	- *Reduces carbon footprint of individual wells and of development area* - *Reduces emissions of ozone precursor compounds, such as VOCs and* NO_x*, from wells, flares, and equipment*	T M R
Implementing an inspection plan on a set schedule for all pipes and equipment	Well Area	Loc Reg	Emg Wide	- *Enables immediate detection and mitigation of spills or leaks*	M R
Clustering wells around a centralized water supply of sufficient volume	Area	Loc Reg	Emg	- *Reduces freshwater transport distances* - *With planning, reduces flow reduction impact of water sourcing on small surface waters by allowing small withdrawals over time, rather than large ones at time of use*	M

Table 7 continued. Candidate technologies and practices for environmental impact reduction of hydraulically fractured horizontal wells. **Included in case study in Section IV.

	Scale of implementation	Scale of benefits	Degree of adoption	Potential environmental benefits	Type
Centralized pumps and impoundments with pipes, used to hydraulically fracture multiple surrounding sites ('centralized fracturing')	Area	Loc Reg	Emg	- *Reduces truck trips needed to move fluids and equipment to individual sites*	T M
Installing temporary pipes to transport large volumes of water for short-term needs (e.g, hydraulic fracturing)	Area	Loc Reg	Wide	- *Reduces truck trips required for fresh water*	T M R
Burying corrosion-resistant lines and pipes for longer-term operations	Area	Loc Reg	Emg Wide Law	- *Reduces truck trips, where used as an alternative* - *Reduces collective surface impacts of infrastructure within greater development area* - *May reduce risk of rupture, relative to aboveground lines* **Required on some federally-managed lands*	T M R
Planning multiple wells per pad	Area	Loc Reg Glbl	Wide	- *Reduces collective land use footprint of operation* - *Reduces trucking distances (equipment centralized)* - *Maximizes production tradeoff for well pad*	M R
Surveying and data collection to choose the least environmentally sensitive site from which the target formation may be effectively accessed	Area	Loc Reg	Emg Law	- *Reduces land use conflicts and/or absolute magnitude of ecological impact*	T M R

Table 8 continued. Candidate technologies and practices for environmental impact reduction of hydraulically fractured horizontal wells. **Included in case study in Section IV.

Scale of Implementation

Technologies, policies, and management interventions to mitigate the environmental impacts of hydraulic fracturing may occur at the well level or at the development (area) scale. Historically, interventions have emphasized well-level mitigation strategies that are primarily technological in nature. Examples listed above include improved site protection (e.g. impermeable liners to contain spills), reductions in hazardous materials (e.g. transitioning to environmentally benign hydraulic fracturing fluids), or pollution control technologies (e.g. vapor separation systems to capture fugitive methane emissions during the completion process).

These technology-focused well-level interventions present simple, often cost-effective opportunities for companies or regulators to reduce the environmental impacts of hydraulic fracturing. Exclusive emphasis on well-side technologies, however, obscures the more meaningful development scale interventions. These development scale interventions address systemic inefficiencies that arise from treating each well as an individual entity, rather than part of a larger extraction network. Opportunities highlighted in Table 4 include technologies that leverage efficiency of scale (e.g. centralized pumps and impoundments that serve multiple well sites), well drilling strategies to maximize recovery while minimizing environmental impact (e.g. planning multiple wells per pad), and coordination of operations to improve opportunities for synergistic activity (e.g. spatial temporal clustering of drilling operations to maximize wastewater reuse). These development scale technology and management interventions are often low or no cost modifications that result in significant reductions in environmental impact.

Scale of Benefits

Incentivizing adoption of pollution control technologies or risk mitigation practices will largely fall to land owners and regulators on the local, state, or national levels. Table 4 categorizes the scale of benefit accrual from impact mitigation practices to offer perspective on the appropriate scale of policy intervention.

Interventions with highly localized benefits include landscape preservation techniques, technologies to minimize of hazardous releases, and management practices to reduce the probability of accidents. While locally proposed legislation at the city or county level may face legal challenges, land-owners have significant leverage during the lease signing process to mandate the use of specific mitigation technologies. Regional scale benefits are more closely associated with management interventions that minimize oil and gas trucking activity, control technologies that reduce criteria pollutants, and water conservation and treatment strategies to maintain adequate health of regional watersheds. Global benefits are primarily liked to greenhouse gas mitigation technologies, but these same mitigation technologies often have trickle down effects at the regional and local scales. Indeed, the vertical translation of benefits across scales is apparent in many technologies listed.

DEGREE OF ADOPTION

Each technology, management strategy, or regulatory intervention presented in Table 4 has shown demonstrable impact reduction in field applications. The degree of technology adoption (emerging, widespread, or legally mandated) is therefore a function of factors other than technology readiness. Cost, magnitude of benefits, regional availability of a product, or demand from the community may be influencing the extent of technology adoption.

Evaluating the adoption of impact mitigation technologies at the company level may reveal additional insights obscured by aggregate data presented in Table 4. Technology diffusion in a play can occur within a firm or across a region, though few studies have evaluated the primary mode of technology transfer in the hydraulic fracturing industry. Another question of potential interest is the competitive advantage associated with early adoption. Devon Energy in Texas, for instance, leveraged their early adoption of water reuse and green completions technology to launch a public relations campaign. Similarly, Range Resources employed spokesmen to communicate their water recycling efforts in the Marcellus far before other firms began addressing these public concerns on a regional level. Anecdotal evidence suggests that firms are not allocating resources to promote environmental impact mitigation efforts in North Dakota, though it is not clear whether this is attributable to poor environmental performance in the state or lower public concern surrounding the environmental impacts of tight oil extraction. Other advantages of early adoption from a productivity or risk mitigation perspective are more difficult to ascertain with available data, but represent an interesting opportunity for future research.

BARRIERS TO IMPLEMENTATION

Despite the low to moderate cost of many interventions, time, capital, and environmental trade-offs have been cited as barriers to adoption. The extended timeframes associated with many of the surveying and testing technologies may limit the agility and competitiveness of firms. For instance, careful well siting requires lengthy pre-drilling testing and analysis, though collectivization of this analysis for a set of spatially clustered wells combined with improvements in the technology itself, may soon reduce this barrier. Once a site is selected, optimizing its design can both reduce the number of additional pads needed and increase recovery efficiency; however, it too takes time and technical expertise. Practices that promote centralization and multi-site coordination may require sequential, rather than simultaneous, drilling, with a net effect of longer times to production. The cumulative effects of this lag time will weigh on companies with expiring leases, limited numbers of rigs, or seasonal constraints. Efforts by firms to develop longer leasing contracts may reduce barriers to spatial temporal clustering of drilling operations and promote environmentally sensitive development scale planning and drilling coordination.

In addition to time constraints, the large capital costs associated with centralized drilling operations pose a significant barrier to entry. For instance, large operators with long payback periods on their investments have been the early adopters of permanent physical infrastructure for water transport, while small operators or operators seeking to aggregate and sell leases have little incentive to pursue these costly strategies beyond statutory mandates. Business and regulatory schemes to promote shared water infrastructure systems may offer a compromise that preserves the competitiveness of small firms without accepting the systemic inefficiencies that small scale operators impose.

Finally, the resistance to pricing environmental externalities including pollution, habitat fragmentation, or low-probability, high impact events limits the incentives that companies have to implement environmental safety and impact mitigation technologies. While this problem is not unique to hydraulic fracturing, regulatory action to internalize energy externalities would offer a technology- and management strategy- agnostic means of driving down many of the environmental impacts of unconventional extraction. On a risk front, the incentive to adopt risk reduction measures will depend largely on the legal and financial consequences of an event. While the fines levied for violations vary by state, a recent analysis found that fines on federal lands were inconsistently applied, incongruous with the extent of damages, and insufficient to deter future violations (Markey and Holf, 2012).

WHERE ARE THE LOW-HANGING FRUIT?

Comparing the scale of implementation, the distribution of benefits, and the degree of adoption across available technologies highlights characteristics of successful environmental mitigation strategies in an industry with an historically slow rate of technology adoption. Technologies and practices with low barriers to entry tend to be economically favorable, applicable on the individual well scale, and require very little additional lead time. Capital intensive technologies, such as intelligent completions technologies that add $100K to $1M per well, have been slow to catch on in unconventional plays despite their frequent deployment in deep-sea offshore wells (Gao 2007). Similarly, technologies requiring extensive development scale coordination have seen low adoption rates among unconventional drillers. This may be influenced by the large number of companies operating less than 10 wells, the constraints that expiring leases place on development scale coordination, or the capital costs of some of the infrastructure systems. Finally, lead times appear to be a critical barrier to technology adoption. The rush to develop lease holdings in areas with time requirements may disincentivize measures like planning multiple wells per pad because operators must drill on each site to maintain lease.

Variation in the landscape of technology adoption across large and small companies is not yet established in the literature. Aside from anecdotal evidence that larger operators concerned about maintaining a social license to operate may be more inclined to adopt environmental technologies that are inherently unprofitable, or that smaller operators are reluctant to adopt environmental technologies unless regulation obligates them to do so, there is surprisingly little empirical evidence to support claims around environmental innovation in the unconventional extraction industry. There is some evidence that large firms with greater access to capital may be lobbying for tighter environmental regulation of the unconventional extraction industry. This raises the concern of regulatory capture through a process of establishing regulation that prices-out or discriminates against the economic interests of smaller competitors with less access to the capital necessary for the adoption of some mitigation approaches.

There is similarly scant data available on the diffusion of technologies between operators. One might posit that the diffusion of environmental impact reduction practices will be accelerated in plays dominated by large operators with uniformity between wells, though this too remains unexplored in this specific body of literature. Further characterization of formal and informal data exchange would benefit research in this area. Finally, research to probe the relationship between the experience of operators in a play and their commitment to environmental mitigation would shed light on the long term prospects for impact reduction in unconventional extraction operations.

V. IMPACT MITIGATION CASE STUDIES AND CONTEXTUALIZED BENEFITS IN FOCUS PLAYS

Despite a range of technological, management, and regulatory strategies for impact reduction, unconventional extraction generates significant climate, health, and environmental impacts. Companies or regulatory agencies seeking to mitigate these impacts would benefit from a cost-based ranking of abatement measures. To assist on that front, as well as to highlight common synergies between field-based efficiency measures and impact reduction practices, we present cost-benefit analyses for three mitigation interventions. The case studies presented below were chosen from among those discussed in Section IV. because (1) all are well pad-level practices, and (2) data on their costs and benefits were either available or directly estimable. The region-specific impacts of each on the environmental issues of concern in the Barnett, the Marcellus, and the Bakken are discussed. The first case study, reduced-emissions completions, is also relevant to interpreting the Final Air Rules for the Oil and Natural Gas Industry issued by the U.S. EPA in 2012 (US EPA 2012b).

CASE STUDY: PROBABILISTIC ECONOMIC CONSEQUENCES OF REDUCED-EMISSIONS COMPLETIONS (RECS)

In this section, we consider technologies to reduce pollutant emissions and capture natural gas during the initial period of production, when mixtures of gases and/or petroleum liquids flow out of the well along with large volumes of water from the hydraulic fracturing process. So-called “green completions”—also known as reduced - emissions completions (RECs)— implement a closed-loop system that pairs temporary processing equipment with permanent infrastructure to separate and capture hydrocarbons for processing and future sale. In the absence of REC technology, volatiles are directly released to the atmosphere or flared on-site until hydrocarbon flow has stabilized and the well can be permanently connected to separation and gathering infrastructure.

By reducing flaring and venting, RECs provide two important benefits. First, RECs abate the release of volatilized organic compounds (VOCs) and nitrous oxides (NO_x), thereby moderating ozone levels in the surrounding area. Second, RECs reduce greenhouse gas emissions by preventing both the methane release of direct venting and the carbon dioxide release associated with flaring. The U.S. Energy Information Administration has estimated that 2-3% of natural gas production is leaked on-site (US EIA2012j). Of this, approximately 30% is attributable to the completion stage and can, in principle, be recovered during RECs to generate revenue (NRDC 2012). The combined benefits of reduced air toxics and greenhouse gas emissions coupled with the potential for increased recovery have made RECs the cornerstone of regulatory policy in at the national level.

The economic and environmental returns expected from REC technologies precipitated the U.S. Environmental Protection Agency's April, 2012 mandate requiring RECs on new unconventional gas wells effective in 2015 (US EPA 2012b). EPA and others (EPA 2011b; NRDC 2012) have modeled payback periods of less than a year, but different scenarios swing between sizable economic gain and loss (US EPA 2011b, ARI 2012, NRDC 2012). Industry critics maintain that low gas prices coupled with the present scarcity of separation equipment will present an economic burden that slows well development (ARI 2012). The politically charged nature of the issue—along with volatile gas prices and wildly differing estimates of costs and capacity—have complicated analyses of the economic consequences of REC adoption.

The present analysis clarifies this uncertainty by estimating the likelihood of profit or loss using iterative Monte Carlo simulations to sample within a broad parameter space (Dunn and Shultis 2011), rather than employing a traditional upper- and lower-bounded modeling approach. As shown in Equation 1, inputs for the simulations included gas price, methane volume to be captured per well, and REC cost per well.

$$\Pi_{well} = p_{gas,\ wellhead} \times V_{gas} - C_{well} = (p_{gas,\ HH} \times 0.95) \times V_{gas} - C_{well}$$

Equation 1. Profit of REC-completed well, where Π_{well} is profit; $p_{gas,\ wellhead}$ is the wellhead price of natural gas; V_{gas} is the volume of gas captured during the completion; C_{well} is the cost of the completion; and $p_{gas,HH}$ is the Henry Hub price of natural gas. See Table A-1 for parameter values and data sources.

The model output is Π_{well}, or the projected profit per well. Assigned parameter values and data sources are detailed in Table A-1. Briefly, where strongly conflicting values for a parameter have been reported by industry or regulators, we took these values as the upper and lower bounds of a 95% confidence interval. For each of these input parameters, we assumed a Gaussian distribution. We included a 5% annual reduction in REC cost per well due to learning, in-line with learning rates in other energy technologies (Qiu 2011). A separate set of runs was conducted under the assumption of a 30USD tCO_2^{-1} carbon tax after Greenstone et al. 2011. In these carbon tax scenarios, we separately modeled added revenue from REC carbon savings as compared to direct venting (Equation 2) and to flaring (Equation 3).

$$S_{tax,\ venting} = T_{carbon} \times V_{gas} \times GWP_{CH_4} \times \rho_{CH_4}$$

Equation 2. Revenue added per well due to carbon tax savings for reduced emissions completion, as compared to direct venting. T_{carbon} is the scenario carbon tax of 30 USD tCO_2^{-1}, V_{gas} is the volume of gas captured during the completion, GWP_{CH4} is the 100-year global warming potential of methane (25), and ρ_{CH4} is the mass density of methane. Note that all captured gas was assumed to be methane for conversion purposes.

$$S_{tax,\ flaring} = T_{carbon} \times M_{CO_2} = T_{carbon} \times V_{gas} \times \rho_{CH_4} \times \left(\frac{44 \text{ g mol}^{-1} \text{ CO}_2}{16 \text{ g mol}^{-1} \text{ CH}_4} \right)$$

Equation 3. Revenue added per well due to carbon tax savings for reduced emissions completion, as compared to flaring. T_{carbon} is the scenario carbon tax of 30 USD tCO_2^{-1}, M_{CO2} is the mass of carbon dioxide emitted as a result of flaring, V_{gas} is the volume of gas captured during the completion, ρ_{CH4} is the mass density of methane, and 44/16 is the molar mass ratio of carbon dioxide and methane. Note that all captured gas was assumed to be methane for conversion purposes. Combustion efficiency was assumed to be 100%.

To estimate the critical parameter of future wellhead gas price, we used the upper and lower 95% confidence limits for projected NYMEX Henry Hub futures prices, multiplied on a monthly basis by a constant factor of 0.95 (US EIA 2012j). This multiplier was derived from historical correlations between Henry Hub and wellhead values. Random sampling was conducted n = 5,000 times for each of three future gas price points. As the costs associated with an REC will differ both within and between plays based on geology and job requirements, we present one set of generalized results for all plays.

In general, the results of our simulation of REC adoption's economic consequences fall between the extremes of EPA and industry estimates. From the histograms in Figure 13, it can be seen that in the near future (October 2012), RECs will most likely lead to a statistical profit loss. With greater uncertainty, the practice shifts closer to the break-even point in the longer term (August 2013), and eventually tips towards a positive economic outcome, as seen in the plots for December 2013. A carbon tax[26] provides significant incentive for adoption of RECs by operators. Further, with a carbon tax in place, our simple calculations in Equations 2-3 suggest flaring as an economically favorable option to venting. This is in addition to the sizable net reduction of methane emissions: 3.7 to 12.2 tons CO_2e per well (7,000 to 23,000 cubic feet; see Table A-2 for conversion units).

[26] We also considered the effects of a trade-and-cap program on air toxins, such as NO_x, and found the economic consequences to be insignificant.

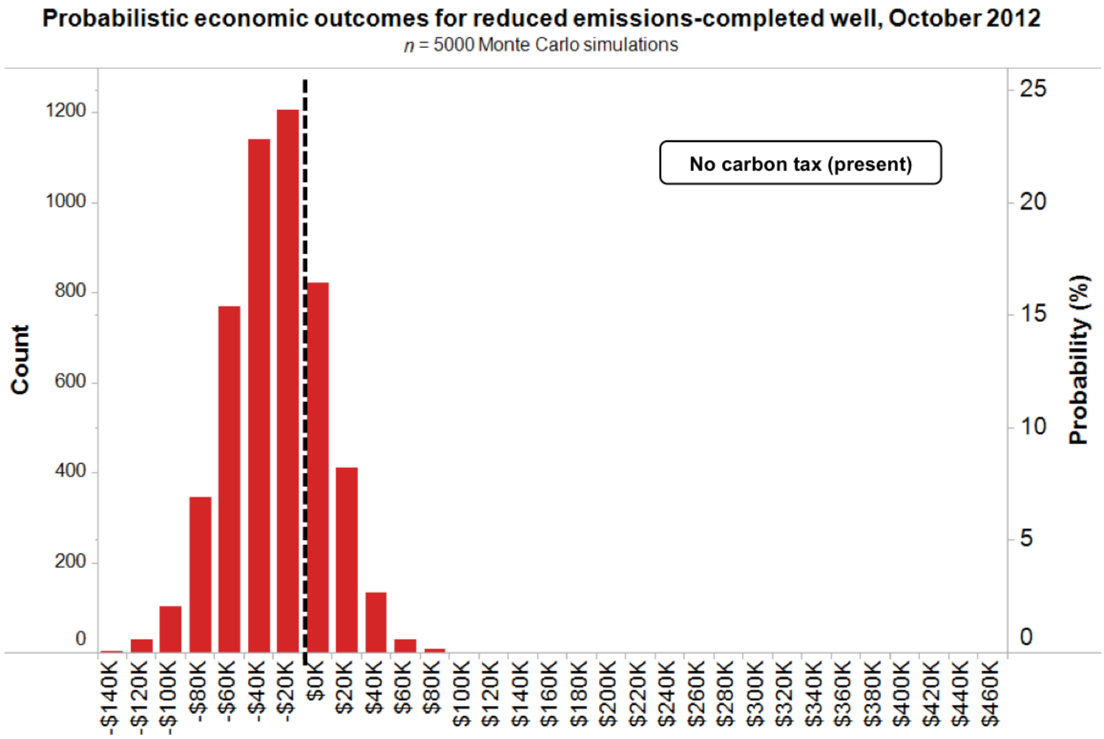


Figure 13a. Probabilistic economic outcomes for RECs in Oct 2012, not including revenues from liquid generation;

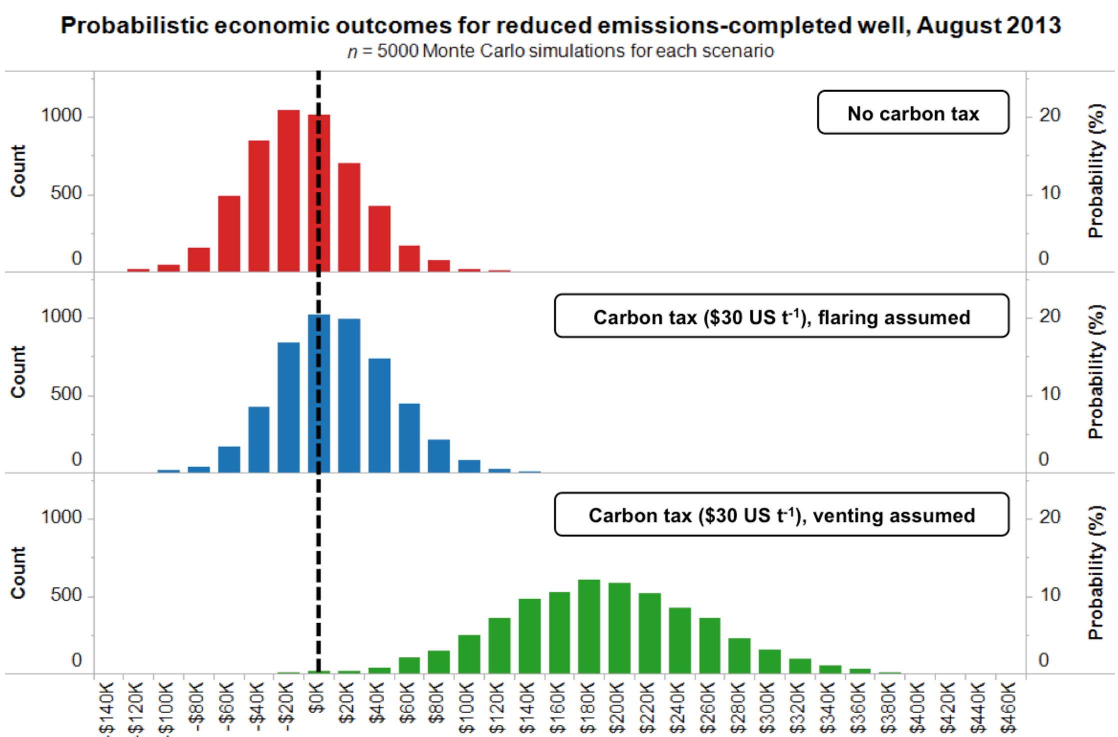


Figure 14b. Probabilistic economic outcomes for RECs in Aug. 2013, not including revenues from liquid generation. Three scenarios, no carbon tax, carbon tax with reference to flaring, and carbon tax with reference to venting are considered;

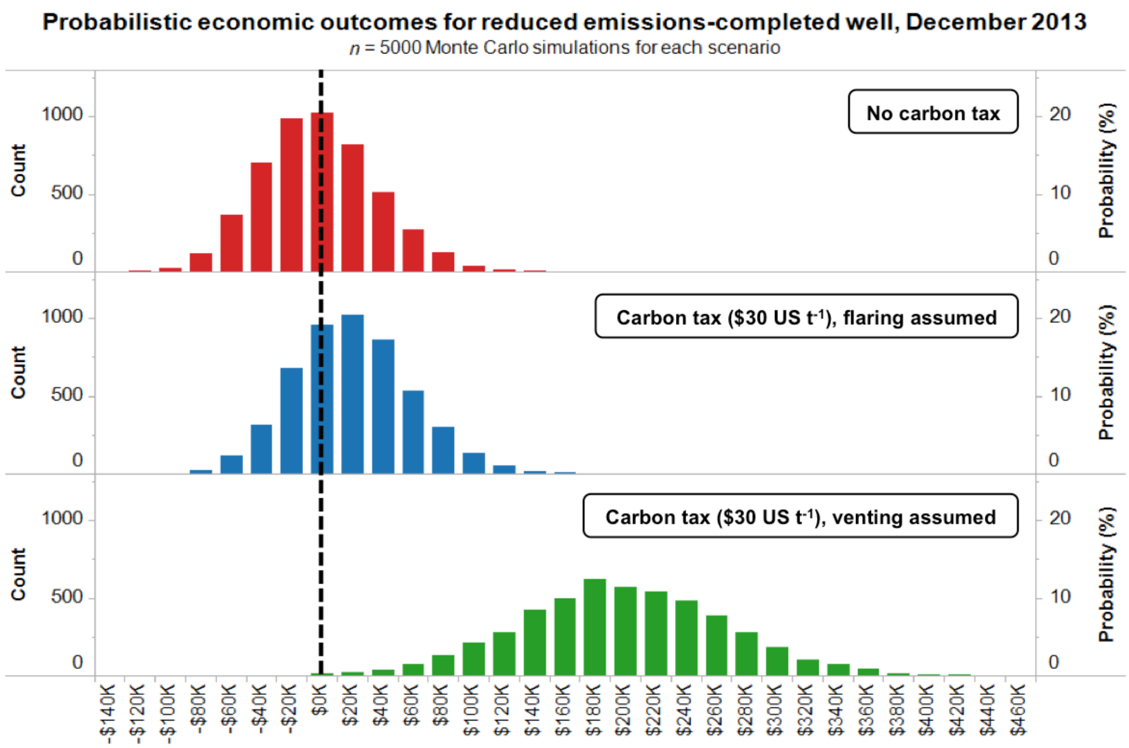


Figure 15c. Probabilistic economic outcomes for RECs in Dec. 2013. The three scenarios are the same as in 13b.

A number of issues affecting cost are worth discussing here. First, in revenue calculations, we did not consider co-generated hydrocarbon liquids; for the majority of gas wells, the volume of condensate that can be expected as a by-product constitutes an insignificant revenue stream relative to captured natural gas, and wells drilled with the intention of exploiting liquid reserves would be exempt from the ruling (US EPA 2012b). Second, real costs will differ dramatically in the short term between wells with ready access to REC equipment and high-capacity gathering lines and wells for which this infrastructure is still emerging. Third, as RECs become widespread across unconventional gas plays, we expect that progression of technology and economies of scale will produce universally lower costs over time. Industry estimates have predicted that 900 new REC units will be required in addition to the 200 extant to fulfill the EPA mandate, and assume a linear increase in available units over time in analyses that conclude that the 32-month transition period is too brief (ARI 2012). In contrast, we hold that it is unlikely that equipment growth will follow a linear track given the strong demand for REC units to meet the EPA mandate and suggest that a logistic function may be more appropriate for use in econometric analyses (see Figure A-1).

The implications of the reduced emissions completions mandate are substantively different between plays. As the most mature U.S. shale gas field, in the Barnett RECs have been standard practice on a voluntary basis among some operators for years. They are required for completions within the city of Fort Worth under certain conditions (US EPA 2012b). Nonetheless, universal adoption of green completions across the Barnett's many wells will further reduce gas well-associated VOC and NO_x emissions in this densely populated area, hopefully providing some degree of improvement in its long-standing air quality issues. Turning to RECs' impact on the greenhouse gas footprint of shale gas, both the Marcellus and the Barnett are highly productive plays for which the absolute magnitude of methane emissions reduction is likely to be large. This reduction will strengthen the arguments of proponents of natural gas as a more environmentally responsible fossil fuel.

Finally, the introduction of reduced emissions completions presents a unique challenge in the Bakken. As noted in Section II, the primary reason behind the flaring of such significant volumes of gas (47 billion cubic feet in 2011 alone) is lack of infrastructure to transport it to market. Importantly, unconventional gas wells demonstrated to lie outside of areas with established gas gathering lines of sufficient capacity—termed "wildcat" or "delineation" wells—are exempt from the REC mandate, as are wells drilled primarily for oil.[27] Thus, due both to the Bakken's primary purpose as a tight oil play and the dearth of gas lines, the promulgation will functionally not apply there. Absent EPA compulsion, economic incentives for rapid construction of pipelines in the Bakken are relatively weak given (1) its remote location (2) recent low gas and high oil prices, (3) a national gas surplus, and (4) the play's plentiful oil reserves. While VOC and NO_x emissions are unlikely to have a large absolute human impact locally due to the sparse population, flaring in the Bakken is a considerable source of greenhouse gas emissions without the forthcoming regulatory and market-based solutions applicable in other plays.

Reduced emissions completions (RECs) are effective in mitigating some of shale gas extraction's air-related impacts, as they substantially cut the release of both air pollutants and greenhouse gases—including methane, which is also the desired end product of normal well operations and therefore provides some economic incentive for RECs. Given volatility in gas price, controversial estimation on RECs' costs, and recoverable methane volume, we applied Monte Carlo methods to examine the economic consequence of REC implementation. We conclude that RECs performed today may lead to profit loss in the near term. As expected gas price rise over time, however, RECs economics tip toward profitability within one to two years, before the mandated implementation in 2015. For states or regions seeking to evaluate their own potential policies, we suggest performing region-specific econometric study in

[27] However, wildcat and delineation gas wells will be required to flare methane emissions as opposed to venting them (EPA 2012b). Some states—including North Dakota—already prohibit venting, but the practice will now be required nation-wide.

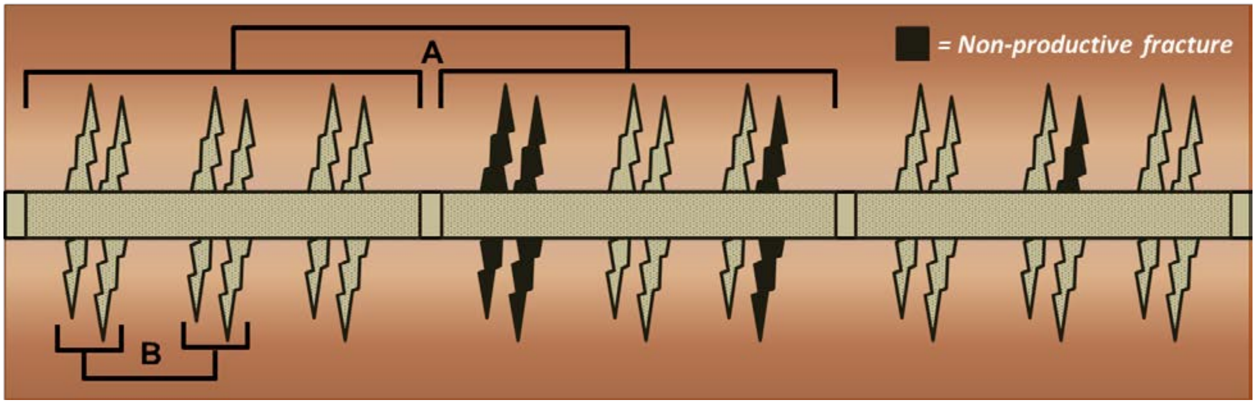
particular unconventional plays, given the vast heterogeneity in production, field practice, and infrastructure availability.

Case study: Hydraulic Fracturing Program Optimization to Reduce Water-Related Impacts and Costs

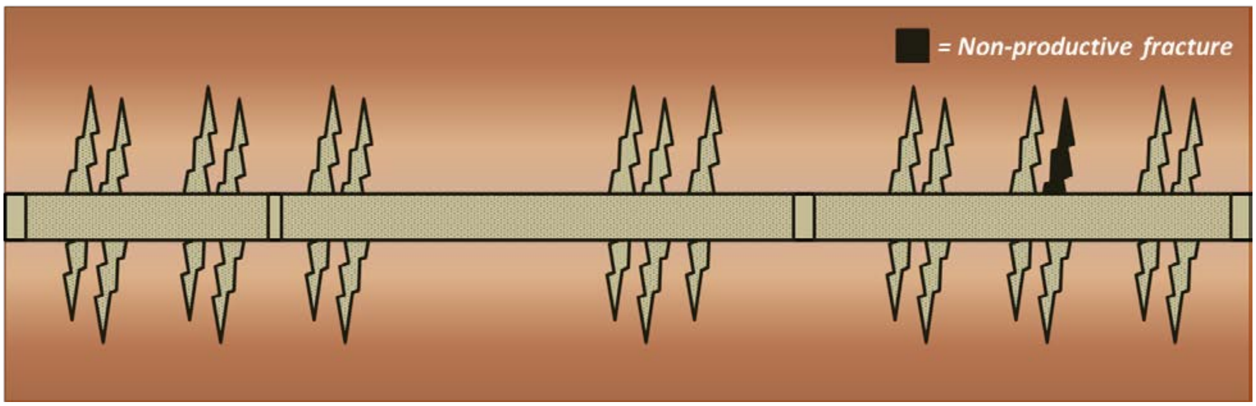
The second case study considers software technology to be used during the completions phase of a well. During hydraulic fracturing, each stage targets a predetermined length of lateral and contains several clusters of perforations ("perf clusters") from which fractures into the surrounding rock will originate (Figure 14). Stage and perforation density is determined by the geological properties of the formation, but the actual spacing between perforations is generally uniform along the wellbore. This so-called "geometric" completion design does not optimize drilling to account for naturally-occurring fractures or reservoir heterogeneity. As a result, an estimated 30% to 40% of fractures placed along a geometrically-completed lateral do not contribute to production (IEA WED 2012), though they still require the same equipment, time, and large volumes of water to complete. In theory, optimized completions can reduce the water and fracturing chemicals required to complete a well without negatively affecting its production, thereby reducing input costs for operators.

During the early years of unconventional extraction, the performance of predictive computer models in optimizing completions in shale reservoirs was mixed. These software packages have generally utilized some combination of surface data, subsurface measurements acquired via downhole instruments, and past performance data from analogous wells to suggest the most promising fracture placements along a wellbore. Without a consistent record of added value with model-assisted planning, however, uniform spacing has largely remained the standard design (King 2010). Recent developments in modeling capabilities for unconventional plays have advanced significantly, and a variety of modular combinations of software, down-hole sensors, and surface monitoring arrays are now commercially available. As the technology becomes more reliable, these software-assisted improvements to well design may represent an economically attractive opportunity to lesson environmental impacts by reducing the intensity of drilling operations.

Schematic of a geometric completion



Schematic of an optimized completion



Figures 16a-b. Top panel: schematic of a horizontal wellbore with a geometric completion design, with uniform spacing of (A) fracturing stages and (B) perforation clusters. (A) is typically on the order of 10^2 m and (B) on the order of 10^1 m (Beard 2011). Dark shading indicates non-productive fractures (30-40% of total). Bottom panel: schematic of the same hypothetical horizontal wellbore with an optimized completion design. Most of the nonproductive fractures have been eliminated, theoretically reducing water use without affecting production. Figures not to scale.

Region-specific environmental cost-benefit analyses were performed to examine the economic and environmental impacts of optimized completions in the Barnett, the Marcellus, and the Bakken. In each of the focus plays, both a low scenario and high scenario were modeled. In the low scenario, a modest reduction of 10% of total water volume was assumed to result from the use of model-assisted optimization; in the high scenario, a 20% reduction was modeled. Parameter values were assigned based on academic literature, government documents, and consultant publications relevant to each play (Appendix, Tables A1-3). For parameters for which a range was found, upper and lower bounds were used for high and low scenarios, respectively, with the exception of highly skewed data. In these cases, a median value +/- 50% was used instead. Rates of intra-operator wastewater recycling, which are highly variable between plays, were modeled at 56% for the Marcellus, 10% for the Barnett, and 0% for the Bakken based on the available literature and state-reported data (Mauter 2013 in preparation, Nicot and

Scanlon 2012). Recycling rates were factored in to metrics for both water acquisition and wastewater disposal. Based on interviews with operators, we assumed that intra-operator recycling processes would occur at or very near well sites, and conservatively modeled the transport distance for recycled water as zero. We account for the carbon costs of water-related transportation only, and do not consider the carbon costs of recycling technologies themselves. Results are discussed in the following two subsections.

Estimated reduction in water use and wastewater production using optimized completions

The amount of fresh water used in hydraulic fracturing jobs varies both between and within plays, but even a modest 10% reduction with an optimized completion would translate to substantial volumes saved. Based on play-specific injection volumes, intra-operator recycling rates, and the 10-20% savings from optimized completions, we estimate optimized completions would reduce consumptive use of fresh water by 149,000 to 891,000 gallons per well in the Barnett; 132,000 to 440,000 gallons in the Marcellus; and 50,000 to 600,000 gallons in the Bakken (Figure 15). With respect to absolute water availability, this reduction is likely most significant in the Barnett as competition from urban and agricultural water users grows. However, it is also meaningful in the Bakken due to the regional logistical challenge of longer-distance water sourcing, and in the Marcellus because of the ecological impacts of flow reductions among small surface waters.

The majority of wastewater exits a hydraulically fractured horizontal well in the first thirty days after completion. The percentage of water recovered during this ‘flowback period’ depends on the geological properties of the formation, but the volumes of wastewater that must be disposed of are invariably large. Per well, optimized completions could reduce wastewater production by an estimated 27,000 to 490,000 gallons in the Barnett; 30,000 to 200,000 gallons in the Marcellus; and 11,000 to 400,000 gallons in the Bakken (Figure 15). Smaller volumes of wastewater represent a reduction in risk of surface contamination events—and operator liability—across all plays. This liability reduction holds particularly true in the Marcellus, where few near-field options for disposal exist and average waste transport distance exceeds 100 miles (Mauter 2013 in preparation). Further, while numerous deep injection facilities are present in the Barnett, the recent links between these sites and induced seismic activity in the Dallas-Fort Worth area may make them a less feasible disposal choice in the future.

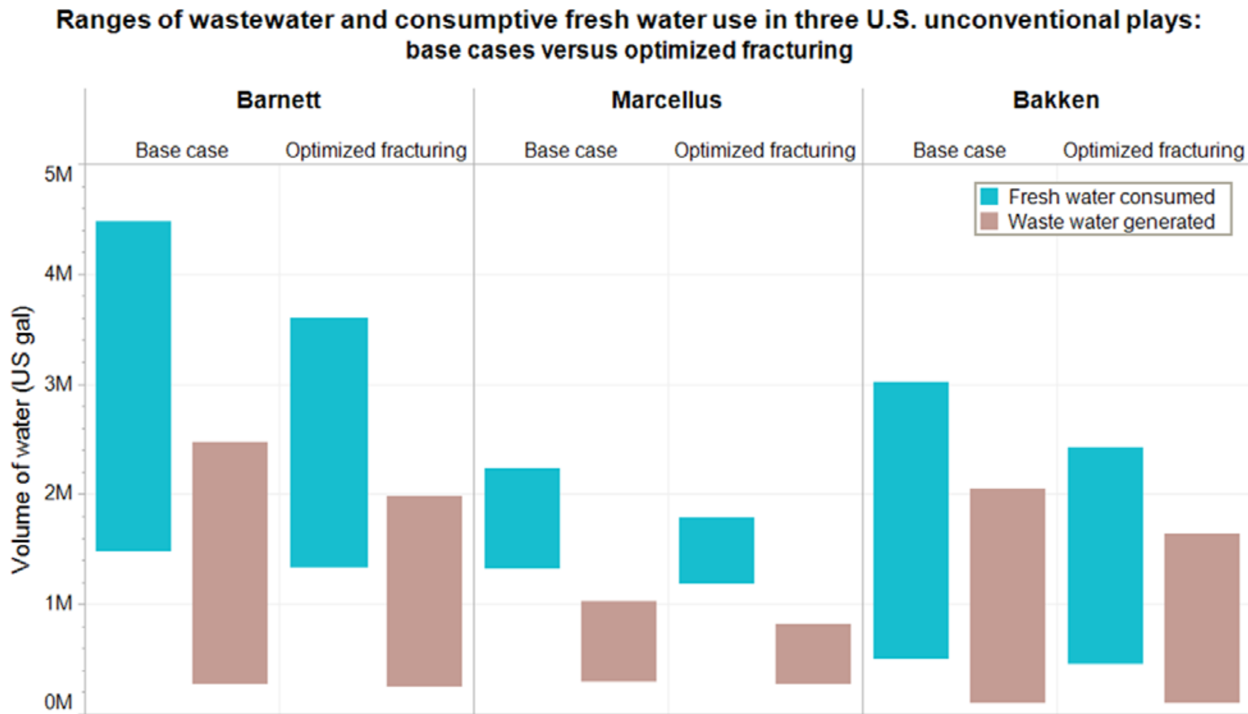


Figure 17. Estimated reductions in fresh water consumption and wastewater production using optimized completions for a typical well in each of the three focus plays. Bars are bounded by low case and high case estimates. In each of the low cases, an injection volume reduction of 10% is assumed; in the high cases, 20%. Note that the indicated fresh water consumption values account for average regional intra-operator rates of recycling; that is, water that is sourced from operators' recycled stores is not included.

Estimated reduction in water transport-related carbon dioxide emissions using optimized completions

The industrial-scale operations on a hydraulically fractured horizontal well site require several hundred truck trips for water-related supplies and equipment alone (NY DEC 2011, Prozzi 2011). A reduction in water volume via an optimized completion would be accompanied by a proportionate reduction in truck trips and associated carbon dioxide emissions. To model emissions reductions stemming from reduced water usage, we assumed that all water transport is via truck rather than pipeline, as this is the dominant practice in all three plays.[28] All truck trips are modeled as two-way; trips both to and from the well site are included. Fuel economy is assigned as the average across all commercial-weight truck classes from 2000-2010 (US DOE 2012); differences in miles per gallon based on freight are ignored. It was assumed that completions additives, such as fracturing chemicals and sand, vary proportionally with injected water volume, but that completions equipment (e.g., trucks and tanks) does

[28] Relative to trucking, piping would almost certainly reduce the carbon cost of all water transportation, though this would depend on site topography and transport distance. In addition, spill risk concerns exist for the piping of wastewater.

not.[29] Because robust estimates were not available, the models further do not consider the carbon costs of the injection process itself. See Tables A1-3 for parameter values and data sources.

The carbon cost of water-related transportation is sensitive to transport distance. Thus, absolute values are highest in the Marcellus due to the relative scarcity of disposal and treatment facilities across the large development area. Reductions in the number of truck trips resulting from downscaled water use would reduce water transportation-related carbon dioxide emissions by an estimated 1.2 to 10.1 tons (2.8-12.6%) per well in the Barnett; by 1.8 to 13.9 tons (2.3-10.7%) per well in the Marcellus; and by 0.65 to 10.6 tons (0.98-9.4%) per well in the Bakken. Concomitant decreases in other vehicular emissions, such as ozone-precursor VOCs and NO_X, resulting from fewer truck trips would likely provide additional air quality improvements. These unquantified benefits are particularly relevant in the Barnett, a densely-populated area with recurrent air quality issues.

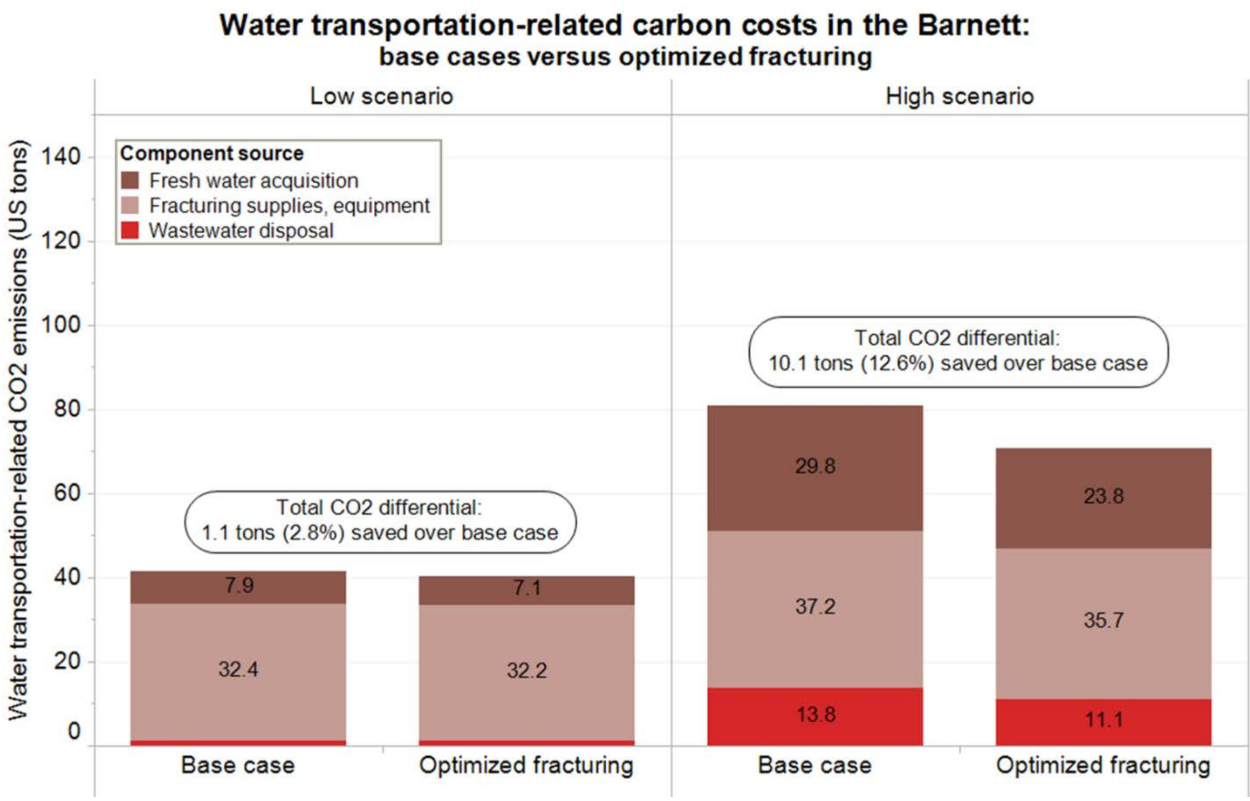
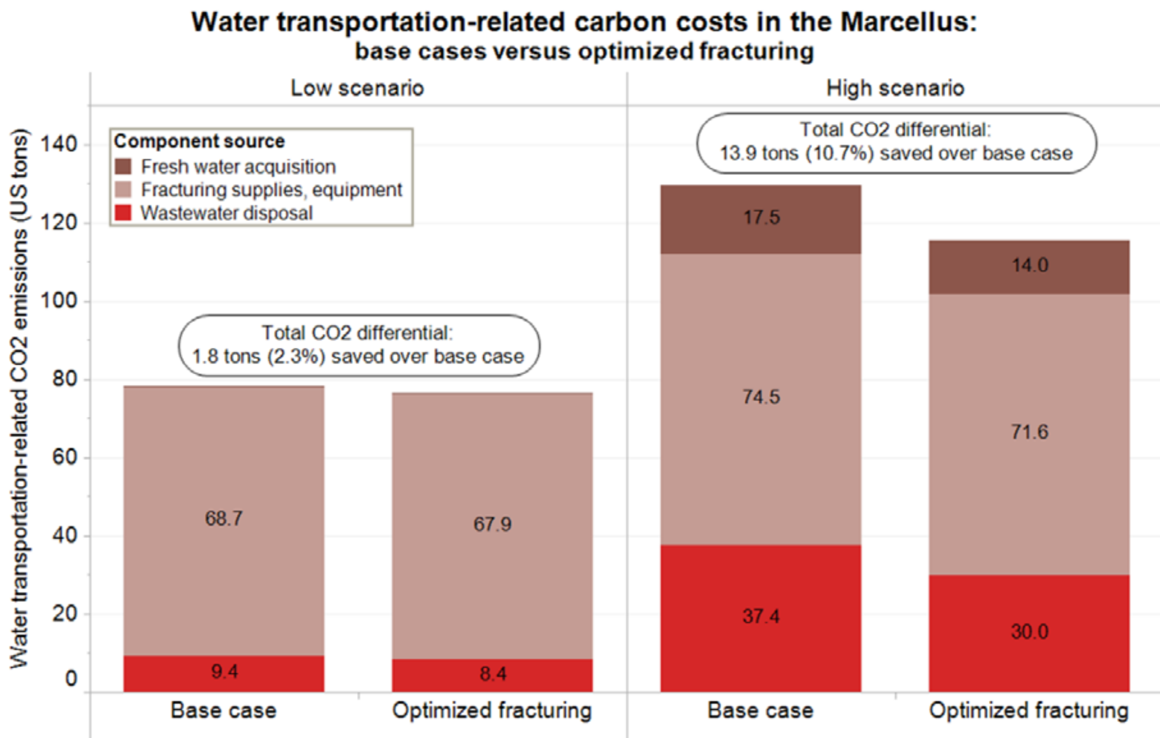


Figure 18a. Modeled reductions in CO_2 emissions related to water transport using optimized completions for a typical well in each of the three focus plays. Completions additives—but not completions equipment—are assumed to vary proportionally with injected water volume.

[29] If equipment could be scaled back, then reduced volumes would translate to additional CO_2 reductions.



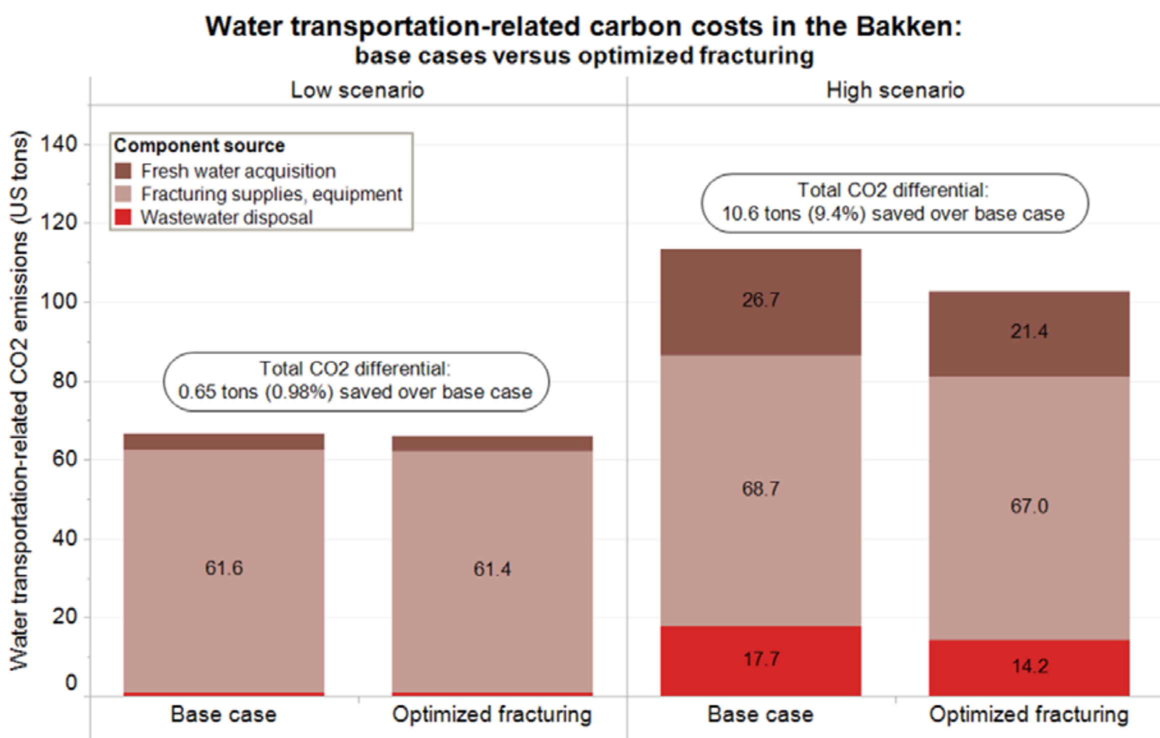


Figure 19b and 16c. Modeled reductions in CO_2 emissions related to water transport using optimized completions for a typical well in each of the three focus plays. Completions additives—but not completions equipment—are assumed to vary proportionally with injected water volume.

Estimated changes in water-associated costs using optimized completions

One economic dimension of optimized completions is the potential for operational cost reduction, which we present here for water-associated expenses. Importantly, however, we assume that optimized completions facilitate no improvement in production—that is, the profit potential of a well was held constant and only changes in costs associated with reduced water use were examined. Further, we do not account for reductions in cost attributable to lower consumption of completion additives (e.g., fracturing chemicals and sand) in the optimized wells. Overall, we find that optimized completions technology would be cost-effective at prices between $2,700 and $41,000 in the Barnett; $4,300 and $71,000 in the Marcellus; and $1,400 and $190,000 in the Bakken. Disposal was the dominant downward driver of total cost in all plays, and was greatest in the Marcellus and the Bakken—though reported values in the latter spanned a wide range due to constrained availability of disposal facilities in both space and time. As one recent estimate predicts a cost of approximately $200,000 per horizontal well for downhole data collection and interpretation (IEA 2012), water-associated savings alone do not economically justify optimized completions. However, when considered along with the co-occurring environmental benefits; reduction in environmental liability, simplification of logistics, and potential for enhanced production, optimized completions may represent a sound investment.

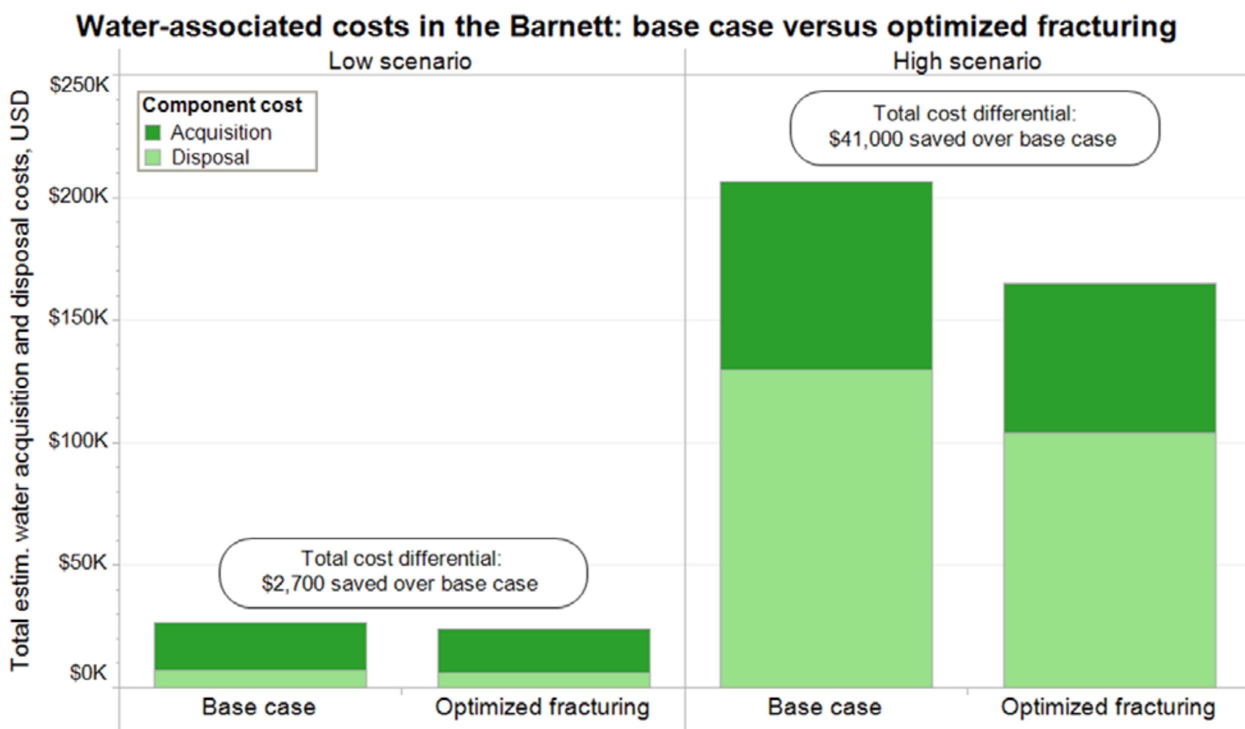
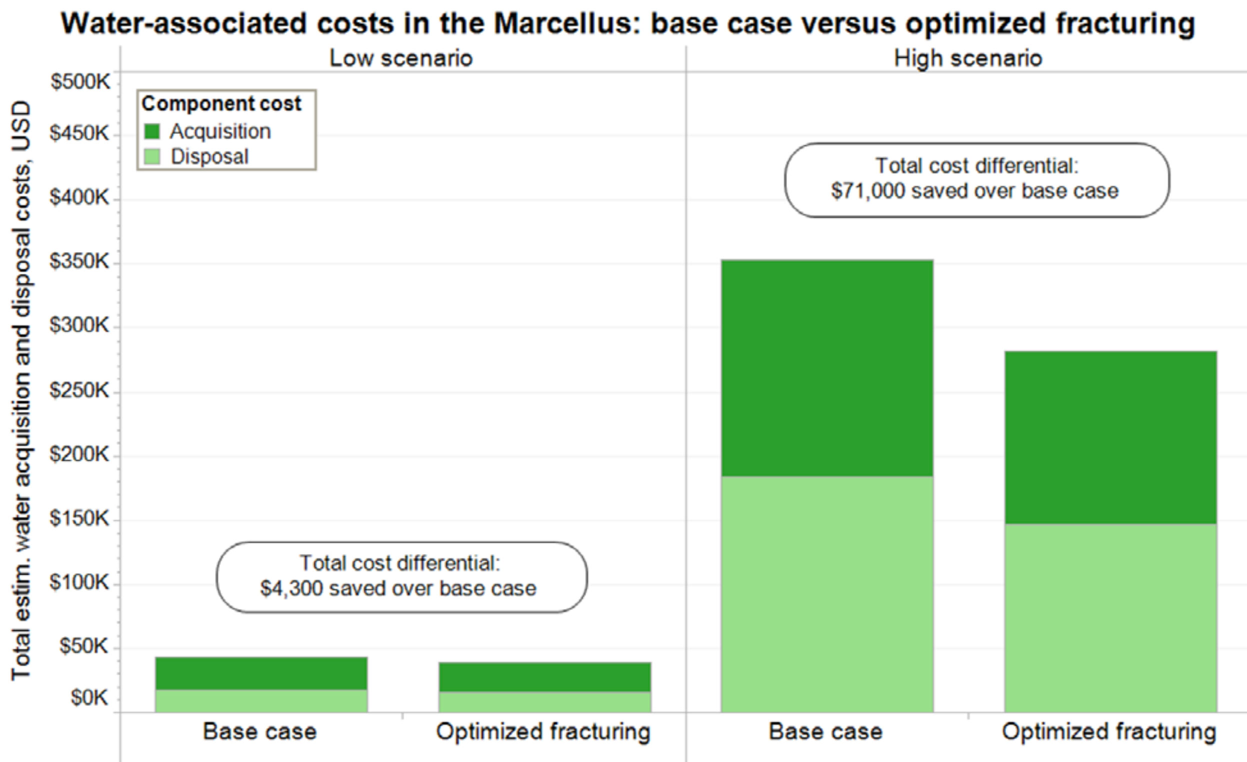


Figure 20a. Modeled changes in water-associated costs using optimized completions for a typical well in each of the three focus plays. Note that we do not account for reductions in cost attributable to lower consumption of completion additives (e.g., fracturing chemicals and sand) in the optimized wells.



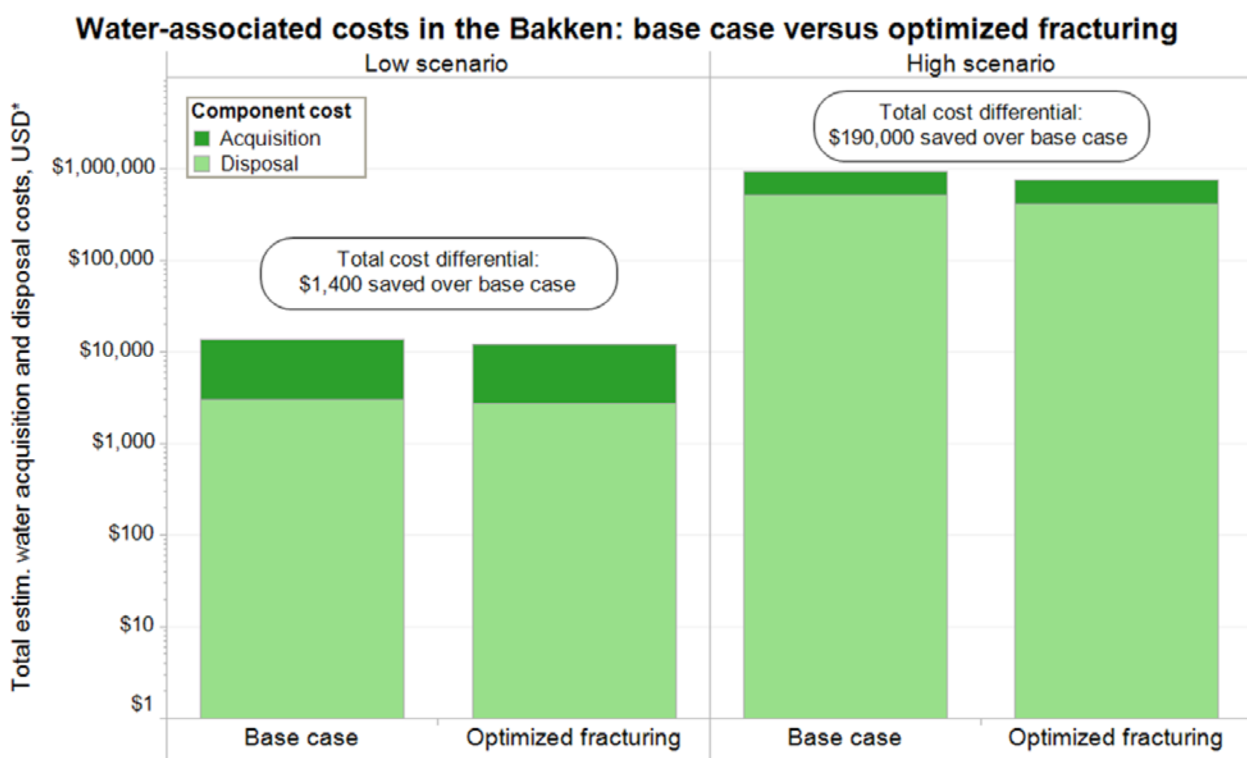


Figure 21b and 17c. Modeled changes in water-associated costs using optimized completions for a typical well in each of the three focus plays. Note that we do not account for reductions in cost attributable to lower consumption of completion additives (e.g., fracturing chemicals and sand) in the optimized wells.

Case Study: Reduced-Impact Well Site Foundations

As discussed in Section I, the land use impacts of unconventional extraction include erosive damage, sedimentation of nearby streams, and incompatibility with previous and surrounding patterns of use. Sites have become smaller over time but are still sizable, with a typical Marcellus well at the peak of its development occupying some two to six acres of land (Hefley et al. 2011). While some degree of well site reclamation is required by state law in each of the focus plays, time to return to baseline conditions can be protracted given the disturbance to soil and plant root structures. Land use impacts are most effectively mitigated by thoughtful siting and become more defensible with maximized production tradeoff for a site (e.g., by drilling multiple wells per pad). Even with optimal siting and efficiency, however, the construction of well pads and access roads unavoidably affects the local environment.

One opportunity to minimize the risks and environmental impacts of siting is to replace the use of gravel ground cover with reusable, prefabricated access pads. From an ecological perspective, pads offer improvements in biodiversity preservation, erosion control, and spill control. From a carbon perspective, prefabricated pads offer potential improvements over gravel by reducing the number of truck trips required to prepare the site, reducing the amount of time that heavy machinery operates in site-preparation, reducing the soil disturbance, and increasing the reusability of site materials. And from a risk perspective, the presence of an impermeable barrier will significantly reduce the risk that small spills pose to human and environmental health—and therefore the risk that violation or litigation costs pose to a company's bottom line. The absence of strong regulatory or economic incentives for ecological preservation or carbon abatement makes it difficult to compute the full scale of economic benefits derived from of this intervention. Nevertheless, we find that the operational cost savings obtained by substituting mats for gravel justifies the adoption of this technology even without internalizing these other benefits.

A well pad and access road is typically constructed by clearing and leveling the site, constructing or installing erosion controls, and spreading several layers of gravel approximately a foot thick across the site (Hefley et al. 2011). Once the well is producing at a stable rate, the site is reclaimed up to the active production area; this includes gravel removal, re-grading, and re-spreading of topsoil. In both cases modeled here, the well pad is assumed to have been leveled and constructed to meet erosion control standards. However, in the mat case, prefabricated mats linked together with steel pins replace the gravel layers. Construction of the access road is simplified in the mat case because eliminating the gravel removes the need to grade to sub-soil depths, allowing the topsoil and root structures to remain relatively undisturbed. We assume one layer of mats is required to line the well site, and that the initial distance that the gravel and mats are transported is equal at 45 miles round-trip. Reused materials are assumed to be transported a shorter round-trip distance of 20 miles. Further, we assume that topsoil is stored on site and respread during reclamation, rather than being trucked in at the reclamation stage. The amount of time required to clear land and prepare the foundation (gravel or mats) is assumed to be proportional to the area treated, and equal in both cases. In order to account for the effects of reuse over the pads' expected lifetime, a ten-year timeframe was chosen for the model. We include the carbon costs of the foundation materials themselves, and assume a 70% recycling rate for gravel. "High" and "low" scenarios vary only in the land area associated with the well site. See Table A-6 for a full list of parameter values and data sources derived from the Marcellus play. We assume comparable well site construction practices across plays and present one generalized, ten-year cost model. It should be noted that robustness checks indicate that the general results discussed below are robust to positive and negative changes in all of our critical assumptions.

The results from our model run with the standard assumptions reveal that reusable mats are associated with a net reduction of 88.3 tons (22.0%) and 967.6 tons (56.5%) of CO_2 in the low and high scenarios, respectively, over the use of gravel. The present values of costs associated with the pad cases is 22.3% (66.9%) lower than the costs associated with gravel. Notably, the improved performance vis-a-vis costs occurs beginning in year 1; there is no upfront increase in costs with pads that is offset by lower operating costs over the lifetime of the pads. Rather, the pads are less expensive in every year utilized. This result is driven primarily by the higher cost of transporting gravel from well to well. A more detailed examination of the results indicates that for each of the three categories of site preparation identified—land clearing, materials, and site reclamation—the mats offer low scenario (high scenario) reductions in carbon emissions of 11.2% (61.37%), 44.8% (44.2%), and 43.3% (46.2%).

While our results are robust to the assumptions made, they are not independent of them. It is clear that a significant part of the improvement in emissions stems from the reusable nature of the mats as opposed to the need to purchase at least some new gravel for each well. This allows the carbon cost associated with the manufacture of the mats, which on a CO_2 per kilogram of product basis is much higher than that of gravel, to be amortized over the full ten-year life of the mat. So while gravel has a much lower carbon factor than the mats, there are additional emissions for every well site over the ten-year period. The amount of additional emissions per mat associated with the production of new gravel depends on the amount of gravel that is assumed to be recycled from well to well.

The second major driver of the lower emissions associated with the mat is due to the variations in transport requirements. While we assume that the mats and the gravel travel the same distance to reach the well and, in the case of recycled gravel, the same distance between well sites, gravel requires substantially more truck trips in both cases than the mats. In the low scenario, the mileage associated with the initial delivery of gravel is more than double the mileage associated with the delivery of the mats. Additionally, gravel incurs a second emissions penalty in the transport category due to its low reusability as compared to mats. Except in the case where 100% of the gravel is assumed to be reused, at least some gravel at each well site is new gravel. Because we assume that the initial distance traveled for each material is greater than the distance between well locations, using some new gravel at each well-site, as opposed to re-using the mats, results in significantly higher total mileages required for gravel over the ten-year period than for the mats. In the low scenario, both the initial (the emissions associated with the delivery of new material to a well-site) and subsequent (defined as the emissions associated with moving materials from one well-site to the next) are more than double those emissions in the same categories for the mats. The importance of this aspect of gravel is reinforced by the results in the extreme case where it is assumed that 100% of the gravel can be reused. In that situation, gravel's carbon performance is nearly the same as that of mats in the low scenario (small well pad size) with standard assumptions.

The final driver of the difference in carbon performance between gravel and the mats is differences in the vegetative emissions associated with each. Because we assume that in the mat scenario the vegetation underneath the access road remains substantially undisturbed, this area does not count towards emissions from vegetation change. In the low scenario this is a very minor difference (less than 5% of the area) but for the high case it means that the devegetated area in the mat cases is 34% smaller than in the gravel scenario. The difference here explains why in the high case the mats significantly outperform gravel. As a robustness check the model was run assuming the same area was devegetated in both cases and we find no difference in the overall conclusions of the model.

Aside from the overall results demonstrating the improvement of the reusable mats over gravel in terms of emissions and costs, the most important result from our model is the indication that the percent of recycled material utilized in the manufacture of the mat is crucially important for the emissions profile of that option. While the cost results do not change - an artifact of the small percentage of overall costs associated with a price on carbon, regardless of that price - the emissions benefits are very sensitive to the percentage of recycled material. Interviews with representatives of one mat manufacturer indicated that current mats are made almost exclusively from recycled material. The standard model, therefore, assumes a 100% recycling in the production of the mats (McDowell 2012). Based on the EPA's WARM model (EPA 2012) using the 100% figure results in a reduction in the emissions factor associated with the manufacture of the mats by 80.6%. Clearly, assuming a lower percentage of recycled material in the production of the mats will have a substantial impact on its emissions performance relative to gravel.

Figure 19 indicates just how sensitive the emissions performance of the mat technology is to the amount of recycled material used. As is obvious from the graph, for our standard set of assumptions, in the low scenario there exists a critical threshold at 15% recycled material, below which the mats actually have a lower performance from an emissions standpoint than gravel. Robustness checks reveal that while the precise location of this threshold is sensitive to our assumptions, its existence in every case but one is not. In other words, regardless of the other assumptions in the model, this threshold exists. In our robustness checks the threshold value ranged between 15% and 95%.

Overall, shifting from gravel to reusable access mats improves the carbon emissions performance of hydraulically fractured horizontal wells at a lower cost than utilizing gravel. From a carbon emissions perspective the mats offer clear improvements over gravel as long as a crucial assumption is met: the percentage of recycled material used in the production of the mats must exceed the threshold value. While that threshold value will depend on a number of firm and site specific criteria, the maximum carbon benefits are realized when the percentage of recycled material is as close to 100% as possible. Our ten year cost model shows that these carbon improvements more than pay for themselves in lower operating costs, regardless of whether there is a price on carbon.

Ultimately, the improvement in both environmental and cost performance is measurable and significant even when including only one dimension of environmental performance. Consideration of environmental categories in addition to carbon emissions—erosion control, biodiversity preservation, spill control, etc.—will likely add to the performance benefits of reusable mats relative to gravel. Finding ways to quantify both the improvements offered by mat technology in these areas and the economic benefit of the improvements is an important area of future research.

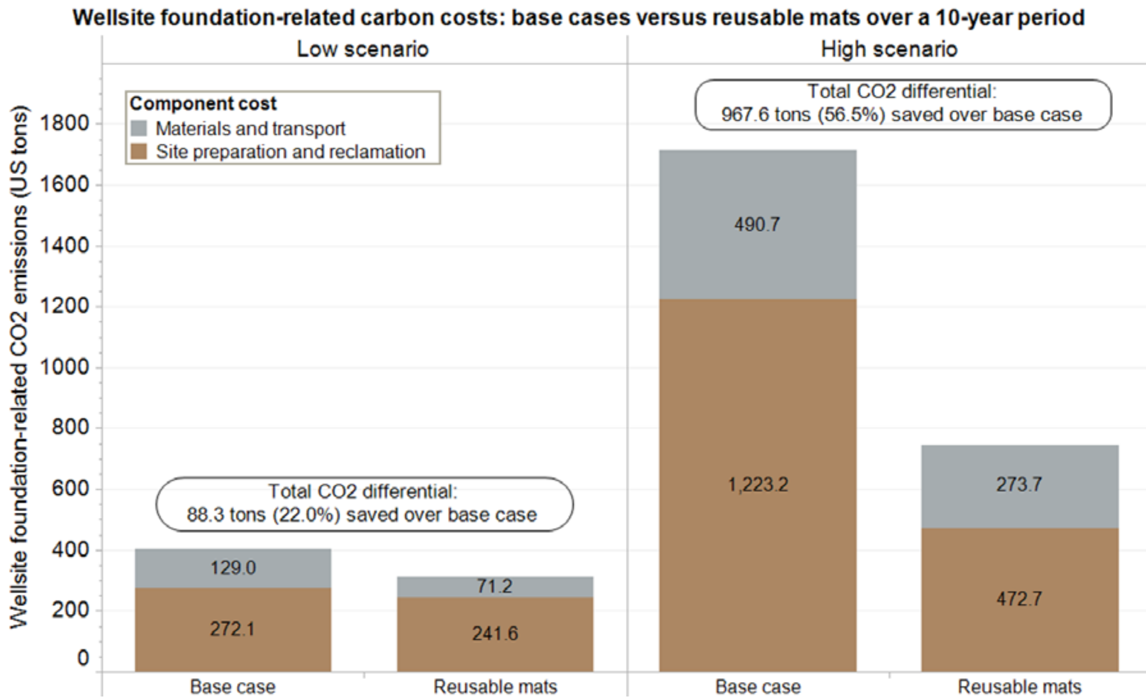


Figure 22. Modeled reductions in CO_2 emissions related to well site foundation preparation, construction, and reclamation at a typical unconventional well site, amortized over a ten-year development period. Site preparation includes leveling of site, carbon tradeoff of vegetation loss, and spreading of gravel; site reclamation includes removal of gravel and re-spreading of stockpiled topsoil. Transportation includes truck trips to and from the well site. Carbon costs of base materials themselves are included, with the assumptions of 70% recycling of gravel and mat composition of 100% recycled plastics. This model is assumed to be generalizable across all plays. See **Table A-6** for all parameters, data sources, and assumptions.

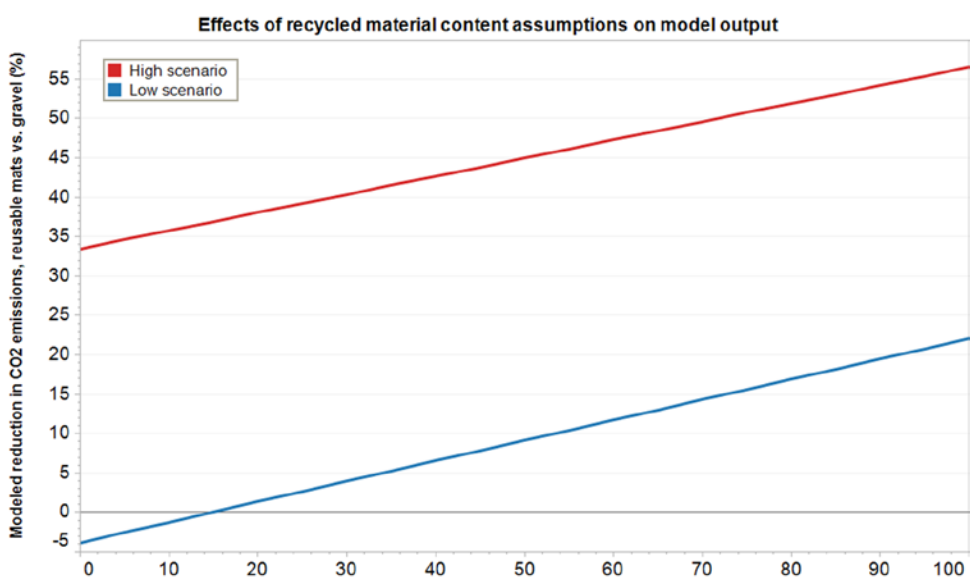


Figure 23. The assumed recycled material content of the reusable mats has appreciable impacts on model results. In the low scenario, reusable mats are estimated to result in higher CO_2 emissions as compared to gravel if they contain less than 15% recycled plastics. In models shown in **Figure 18**, mats were assumed to be composed of 100% recycled plastics based on industry interviews.

VI. POLICY IMPLICATIONS

Domestic unconventional extraction will play an increasingly important role in meeting future U.S. energy demand, but the environmental impacts of these operations can be considerable. The unique ecological, demographic, and geological characteristics of each unconventional play suggest that a multi-criterion approach that maximizes environmental returns is necessary to account for the heterogeneity of impacts at the local and regional levels. An exclusively regional approach to environmental impact mitigation, however, is unlikely to internalize externalities at the national or global scale. In addition, regional oversight of unconventional oil and gas extraction may elicit public mistrust of regional regulators with scant history in managing the oil and gas industry, or perceptions of corruption where regulatory oversight is not commensurate with public demands. Thus, a robust regulatory framework for managing unconventional oil and gas extraction in the U.S. should pair national regulation establishing thresholds for maximum local impacts based on protecting human health and the environment with state-level regulation and adaptive management practices that improve upon federal baselines and reduce long-term risk to state resources. States might set minimum depths for hydraulic fracturing to reduce risk of freshwater aquifer impairment, mandate emissions reductions in high population density areas, work with companies to develop water management plans that minimize vehicular water transport, or require the adoption of low-impact well site foundations.

Regulatory pressure to adopt technologies and management practices that reduce human and environmental impacts of hydraulic fracturing may also be complemented by social and economic drivers for reduced environmental impact. Many existing environmental interventions are net present value positive or neutral, allowing companies to adopt mitigation efforts without significant penalty to their bottom line. Despite historically conservative patterns of technology adoption in the oil and gas industry, a number of companies have embraced select environmental mitigation technologies in an effort to improve public relations. Sustained social and political pressure may be an important lever for encouraging the voluntary adoption of management practices, like waste water reuse or model-assisted hydraulic fracturing optimization, that would be unlikely to fall under regulatory oversight.

From an industry perspective, the nebulous nature of environmental benefits and the absence of defined prices for environmental damages have complicated cost-benefit analyses for technology adoption and have often resulted in environmental benefits being excluded as a decision making factor. The three case studies of environmental mitigation practices evaluated in this report highlight tools that companies may leverage to internalize the long term benefits of environmental mitigation technologies during a product or process cost-benefit evaluation. Each of the case studies—reduced emissions completions (RECs), model-assisted optimized hydraulic fracturing, and low-impact well site foundations—highlight technology that is both readily available and cost-neutral in at least one major play.

Adoption of RECs will be federally mandated by 2015, but many other technologies remain under utilized by the industry despite their economic viability. This suggests a potential regulatory role for facilitating or mandating the adoption of technologies and management practices when the environmental externalities of unconventional extraction are not covered by existing regulations. There has been scant federal action on this front for the past year, though the anticipated release of the congressionally mandated U.S. Environmental Protection Agency study of hydraulic fracturing and its potential impact on drinking water resources may yield additional federal mandates for the adoption of pollution control technologies and risk reduction interventions.

Unconventional extraction presents two categories of environmental impact: those impacts or risks intrinsic to the hydraulic fracturing process, and those that can be mitigated through environmental technologies or better management practices. Without dwelling extensively on this first class, we highlight policies, technologies, and management decisions that address this second class of impacts, in some cases without adding costs to the extraction process. Nevertheless, heterogeneity among plays, including population density, water resource availability, infrastructure access, ecological sensitivity, and subsurface geology, precludes a single set of solutions to cost-effectively mitigating the environmental impacts of unconventional extraction. Contextualizing impacts within the framework of a regional environment will help to prioritize mitigation efforts. As the ever-shifting U.S. unconventional extraction industry enters its second decade, it is of critical importance for those in business and policy to support development that is sensitive to regional environmental concerns.

VII. APPENDIX

Assigned value, Monte Carlo models			
Parameter	**Lower bound**	**Upper bound**	**Data source**
Methane captured per well (V_{gas}; Mcf)	7,000	23,000	ARI 2012 NRDC 2012 *Set as bounds for 95% confidence interval; normal distribution assumed*
Carbon tax (T_{carbon}; \$ tCO_2e^{-1})	30		*Assumed based on Greenstone et al. 2011*
Density of methane (ρ_{CH4}; kg m^{-3})	0.71		Calculated (ideal gas)
Global warming potential, methane (GWP; relative to CO_2)	25		Forster et al. 2007
Combustion efficiency of methane to CO_2 during flaring (%)	100		*Assumed*
Cost, reduced emission completion (C_{well}; \$/well)	8,700 *(assumes 9 d)*	125,000 *(assumes 25 d)*	ARI 2012 *Set as absolute bounds; normal distribution assumed*
Annual reduction in cost (%)	5		*Assumed effect of technology progression and scale economies*
Natural gas price, Henry Hub ($p_{gas, HH}$; \$ Mcf^{-1})	Upper and lower estimates, monthly		US EIA 2012j *Gaussian distribution assumed*
Natural gas price, wellhead ($p_{gas, wellhead}$; \$$Mcf^{-1}$)	Henry Hub prices ($p_{gas, HH}$) by 0.95 empirical multiplier		Projections from US EIA 2012j (see **Figure A-1**)
Samplings, Monte Carlo simulation	*n* = 5,000		Dunn and Shultis 2011

Table A-1. Parameters and data sources for reduced emissions completion (REC) case study.

Assigned value, CO_2e calculation			
Parameter	**Lower bound**	**Upper bound**	**Data source**
Methane captured per well (V_{gas}; Mcf)	7,000	23,000	ARI 2012 NRDC 2012
Heat content, if burned (Btu/ft^3)	1.024		US EIA 2011b, Table A4 (2010)
Emissions factor, if burned (lb CO_2MMBt^{-1})	117		US EIA 2011a
Density, methane (lb ft^{-3})	0.0425 (=0.66 kg/m^3)		US EPA 2008
Global warming potential, methane (GWP; relative to CO_2)	25		Forster et al. 2007

Table A- 2. Assigned values, conversion units, and data sources for parameter used for carbon benefits of RECs.

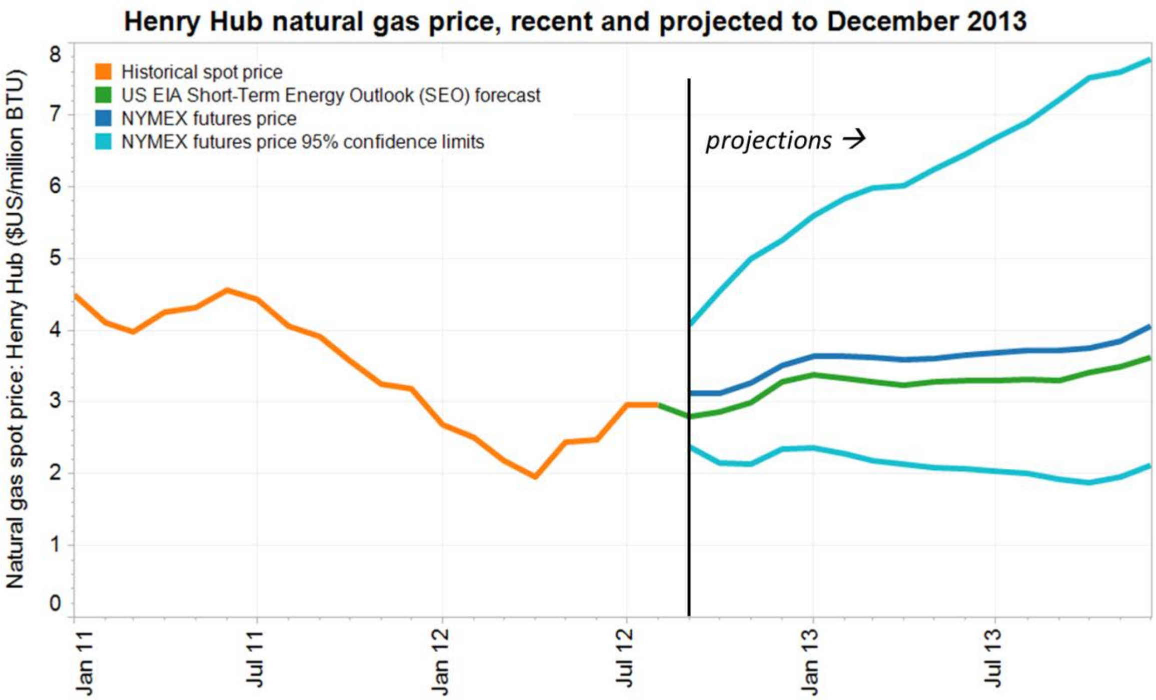


Figure A-1. Henry Hub natural gas price projections used in REC case study. The light blue lines represent the upper and lower 95% confidence limits used to develop model inputs. To obtain the estimates used in the model for wellhead prices, Henry Hub prices were multiplied by an empirically-derived factor of 0.95. Data source: US EIA 2012j (publicly available).

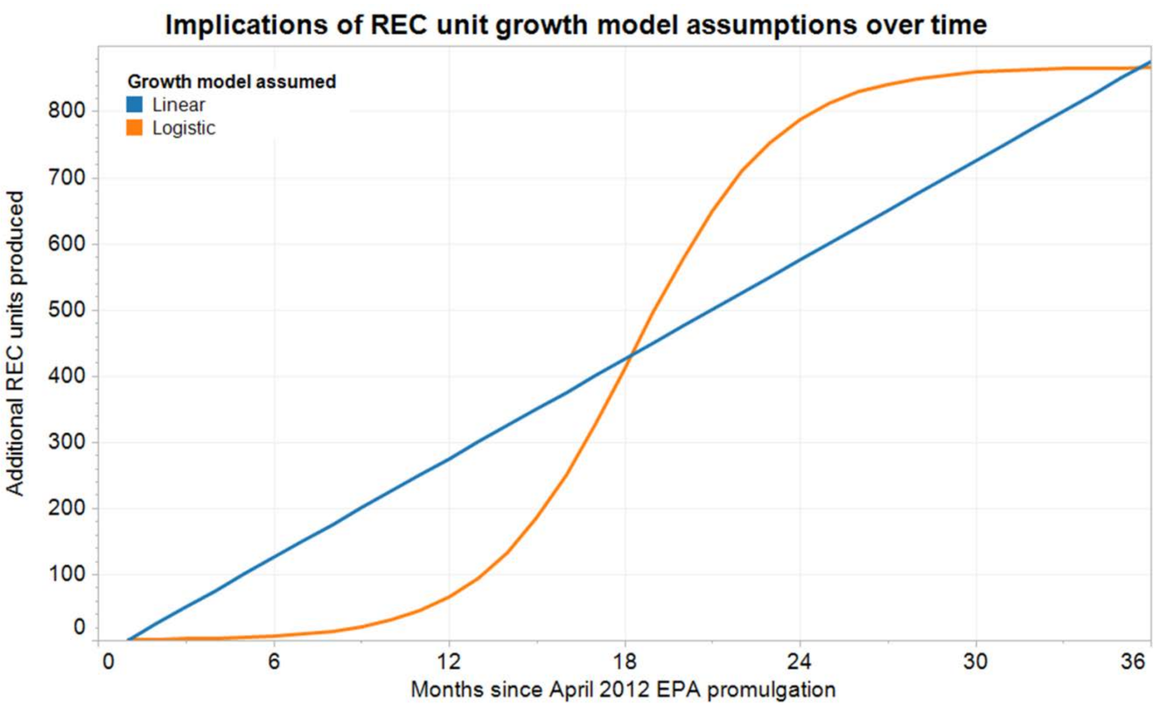


Figure A-2. The number of additional REC units expected to be available in projections is strongly dependent on the growth model assumed, particularly in the short term.

	Assigned value, base case		
Parameter	**Low scenario**	**High scenario**	**Data source**
Reduction in fracturing stages with model-assisted optimization	0.1	0.2	*Assumed*
Water tanker capacity (gal)	6,300	5,000	Prozzi 2011
Water volume, injected fresh (gal)	1,650,000	1,485,000	Nicot and Scanlon 2012 *(median +/- 50%)*
Proportion of water recycled internally by operator	0.10		*Assumed based on Nicot and Scanlon 2012*
Cost, acquisition, fresh water ($/gal)	0	0	*No data; no assumption made (error toward reduced savings)*
Cost, transport, fresh water ($/gal)	0.0119		McCurdy 2011 *(assumed same as for waste)*
Cost, total, recycled water ($/gal)	0.024	0.095	Personal interviews with Marcellus operators *(assumed same technology)* **Half of total cost of recycling water was assigned to acquisition, half to disposal*
Distance, water transport (mi)	10		*Estimated based on spatial analysis; surface water is dominant source (Nicot and Scanlon 2012)*
Distance, recycled water transport (mi)	0		*Assumed onsite recycling*
Wastewater returned, proportion of injected	0.165	0.495	Galusky 2011 *(0.33 +/- 50%)*
Cost, wastewater disposal ($/gal)	0.0155	0.0536	Kenter 2012 Whitworth 2009 McCurdy 2011
Cost, wastewater transport ($/gal)	0.0119		
Truck trips, completion chemicals*	13.2	39.6	NY DEC 2011 **Scaled linearly by fracturing volume from 5M-gallon fracturing operation modeled in NYDEC 2011 assessment*
Truck trips, completion equipment	10		
Truck trips, fracturing equipment (e.g., trucks and tanks)	350		
Truck trips, sand*	15.2	45.5	
Distance, completion materials trucking (mi)	50	50	*Assumed*
Distance, wastewater trucking for disposal (mi)	9.4		Prozzi 2011
Fuel economy (mi/gal)	6.7		US DOE 2012, Tables 5.1-5.2 *(average, 2000-2010)*
CO_2 emissions, diesel (lb/gal)	22.4		US EPA 2008, Table 5

Table A-3. Parameters and data sources for fracturing optimization case study in the Barnett Shale play.

Parameter	Assigned value, base case Low scenario	High scenario	Data source
Reduction in fracturing stages with model-assisted optimization	0.1	0.2	*Assumed*
Water tanker capacity (gal)	5,000	4,200	Personal interviews with operators
Water volume, injected fresh (gal)	3,000,000	5,000,000	Cawley 2012 Gaudlip and Paugh 2008
Proportion of water recycled internally by operator	0.56		Mauter 2012
Cost, acquisition, fresh water ($/gal)	0.003	0.015	Hefley 2011
Cost, transport, fresh water ($/gal)	0.0012		*Assumed from McCurdy 2011*
Cost, total, recycled water ($/gal)	0.024	0.095	Personal interviews with operators **Half of total cost of recycling water was assigned to acquisition, half to disposal*
Distance, fresh water transport (mi)	0	10	*Assumed after Jiang 2011*
Distance, recycled water transport (mi)	0		*Assumed onsite recycling*
Wastewater returned, proportion of injected	0.1	0.2	Hefley 2011 Personal interviews with operators
Cost, wastewater disposal ($/gal) Cost, wastewater transport ($/gal)	0.12	0.36	Personal interviews with operators
Truck trips, completion chemicals* Truck trips, completion equipment Truck trips, fracturing equipment (e.g., trucks and tanks) Truck trips, sand*	24 10 350 27.6	40 46	NYDEC 2011 **Scaled linearly by fracturing volume from 5M-gallon fracturing operation modeled in NYDEC 2011 assessment*
Distance, completion materials trucking (mi)	100	100	*Assumed*
Distance, wastewater trucking for treatment or disposal (mi)	107		Mauter 2012 **Average across all methods of disposal/treatment other than intra-operator recycling*
Fuel economy (mi/gal)	6.7		DOE 2012, Tables 5.1-5.2 *(average, 2000-2010)*
CO_2 emissions, diesel (lb/gal)	22.4		EPA 2008, Table 5

Table A-4. Parameters and data sources for fracturing optimization case study in the Marcellus Shale play.

	Assigned value, base case		
Parameter	**Low scenario**	**High scenario**	**Data source**
Reduction in fracturing stages with model-assisted optimization	0.1	0.2	*Assumed*
Water tanker capacity (gal)	8,000	7,500	Stepan 2011 *(ranges)*
Water volume, injected fresh (gal)	500,000	3,000,000	
Cost, water acquisition ($/gal)	0.0060	0.025	
Cost, water transport ($/gal)	0.015	0.12	
Distance, water transport (mi)	20		*Estimated based on spatial analysis of Bakken surface water sites*
Wastewater returned, proportion of injected	0.22	0.67	Stepan 2010 *(weighted average +/- 50%)*
Cost, wastewater disposal ($/gal)	0.012	0.042	Stepan 2010 *(ranges)*
Cost, wastewater transport ($/gal)	0.015	0.21	
Truck trips, completion chemicals*	4	24	NYDEC 2011
Truck trips, completion equipment	10		**Scaled linearly by fracturing volume from 5M-gallon fracturing operation modeled in NYDEC 2011 assessment*
Truck trips, fracturing equipment (e.g., trucks and tanks)	350		
Truck trips, sand*	4.6	27.6	
Distance, completion materials trucking (mi)	100		*Assumed*
Distance, wastewater trucking (mi)	19.7		ND DMR 2012c *Average of shortest five rank waste transport distances*
Fuel economy (mi/gal)	6.7		DOE 2012, Tables 5.1-5.2 *(average, 2000-2010)*
CO_2 emissions, diesel (lb/gal)	22.4		EPA 2008, Table 5

Table A-5. Parameters and data sources for fracturing optimization case study in the Bakken Shale play.

	Assigned value				
	Base scenario		Mats scenario		
Parameter	**Low**	**High**	**Low**	**High**	**Data source**
Fuel economy (mi gal^{-1})	6.7				DOE 2012, Tables 5.1-5.2 *(average, 2000-2010)*
CO_2 emissions, diesel (lb gal^{-1})	22.4				EPA 2008, Table 5
CO_2 emissions, vegetation loss (g ft^{-2} y^{-1})	27				Averaged from Jiang 2011
Site preparation phase					
Land cleared, access road (acres)	0.1	2.75	0.1	2.75	Jiang 2011 *(we assume equivalent across plays)*
Land cleared, well pad (acres)	2.2	6.0	2.2	6.0	
Total wells, 10-year period	30				*Assumed*
Pad rock, aggregate (depth, in)	10		n/a		Hefley 2011
Pad rock, crush (depth, in)	3.5		n/a		
Carbon content (kg CO_2e kg^{-1})	0.00339 (aggregate) 0.0102 (crush)		0.4079 (plastic)		EUJRC 2012 (aggregate) Börjesson 1998 (crush) EPA 2010, Table 15 (plastic)
Mat area (ft^2)	n/a		91		McDowell 2012 Rehm 2011 *(industry data)*
Mat lifetime (y)	n/a		10		
Proportion from recycled plastics, mats	n/a		1 (at baseline)		
Times per year reused, mats	n/a		3		*Assumed*
Proportion of gravel recycled	0.7		n/a		
Initial truck miles (two-way)	45				
Subsequent truck miles (i.e., recycling trips, two-way)	20				
Truck capacity	2500 ft^3		46 mats		*Volume assumed;* Rehm 2011 *(industry data)*
Time, bulldozer (h per acre prepped)	8				Rice 2012 *(personal communication)*
Time, skip loader (h per acre prepped)	16		6		
CO_2 emissions, equipment (lb h^{-1})	0.438				SCAQMD 2005, Table C-1
Site reclamation phase					
Topsoil spread depth (in)	4				Hefley 2011
Time, skip loader (h $acre^{-1}$)	12		8		Rice 2012 *(personal communication)*
Revegetation function	100% of well site devegetated for initial 1y, 25% of area devegetated to 10 y				*Assumed*
Access roads reclaimed over 10 y (%)	50		n/a (all pads simply removed)		*Assumed*

Table A-6. Parameters and data sources for land use impact reduction case study.

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