Risk Analysis, Vol. 32, No. 8, 2012 DOI: 10.1111/j.1539-6924.2011.01757.x

Water Pollution Risk Associated with Natural Gas Extraction from the Marcellus Shale

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In recent years, shale gas formations have become economically viable through the use of horizontal drilling and hydraulic fracturing. These techniques carry potential environmental risk due to their high water use and substantial risk for water pollution. Using probability bounds analysis, we assessed the likelihood of water contamination from natural gas extraction in the Marcellus Shale. Probability bounds analysis is well suited when data are sparse and parameters highly uncertain. The study model identified five pathways of water contamination: transportation spills, well casing leaks, leaks through fractured rock, drilling site discharge, and wastewater disposal. Probability boxes were generated for each pathway. The potential contamination risk and epistemic uncertainty associated with hydraulic fracturing wastewater disposal was several orders of magnitude larger than the other pathways. Even in a best-case scenario, it was very likely that an individual well would release at least 200 m^3 of contaminated fluids. Because the total number of wells in the Marcellus Shale region could range into the tens of thousands, this substantial potential risk suggested that additional steps be taken to reduce the potential for contaminated fluid leaks. To reduce the considerable epistemic uncertainty, more data should be collected on the ability of industrial and municipal wastewater treatment facilities to remove contaminants from used hydraulic fracturing fluid.

KEY WORDS: Marcellus; probability bounds analysis; water

1. INTRODUCTION

Natural gas has become a preferred fossil fuel from an environmental and political perspective.[1] Compared to coal or oil, natural gas generates less air pollution and greenhouse gases (although natural gas production potentially can generate excessive methane emissions that could offset the beneficial effects of reduced CO_2 emissions[2,3]). In the United States, natural gas is a primarily domestically produced fuel that creates jobs and does not increase international trade deficits. Finding new supplies of natural gas to keep up with demand is a challenge. Shale formations are a very promising source of natural gas.[4] Shale is a sedimentary rock formed from clay-rich mud in slow moving waters. The mud is a precursor to natural gas and oil deposits owing to its high organic material content. By 2030, it is expected that half of all natural gas produced in the United States will come from unconventional sources, primarily shale formations.[5] The Marcellus Shale is the largest of the newly developing shale gas deposits in the United States.

The Marcellus Shale is a thin, black formation that covers approximately 124,000 km^2[6] from New York to West Virginia at depths ranging from ground level to over 2,500 m (Fig. 1). As recently as 2002, the entire formation was estimated to hold 53 billion m^3 of natural gas.[7] However, more recent estimates of recoverable natural gas are as large as 13.8 trillion m^3.[8,9] By using the advanced techniques

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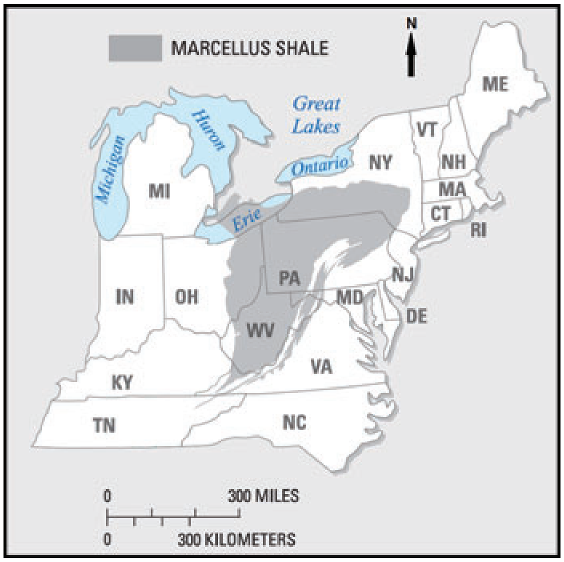

Fig. 1. The Marcellus Shale formation in northeastern United States (modified from Milici and Swezey[71]).

of horizontal drilling and hydraulic fracturing, it now seems to be economically feasible to extract natural gas from the Marcellus Shale. Although these techniques are well established, they are not without potential risk.

Hydraulic fracturing uses high-pressure solutions to create and prop open fractures in rock to enhance the flow of oil, gas, or water. More than 750 distinct chemicals, ranging from benign to toxic, have been used in hydraulic fracturing solutions.[10,11] Although these additives are less than 2% by volume of the total fracturing fluid, hydraulic fracturing is a water-intensive process and at least 50 m^3 of chemicals would be used for a typical 10,000 m^3 hydraulic fracturing project.[12] Given the extensive use of hydraulic fracturing in recovering gas from the Marcellus Shale, large quantities of wastewater are expected to be generated. In 2010, the U.S. Environmental Protection Agency started an investigation, scheduled for completion in 2012, of the potential impact of hydraulic fracturing on drinking water.[13] Currently, hydraulic fracturing is exempt from regulation under the Safe Drinking Water Act due to an exemption written in the Energy Policy Act of 2005.[14,15,16]

The public policy decision to pursue natural gas extraction from the Marcellus Shale involves several potential risks and benefits. The crucial unknown is the potential risk of water contamination from hydraulic fracturing. This study generates bounded probability ranges of water contamination risk for a typical natural gas well in the Marcellus Shale region that is being developed using high-volume hydraulic fracturing and horizontal drilling. The probability bounds constitute the best case (smallest possible contamination) and worst case (largest possible contamination) for a single well. The distance between these bounds represents the amount of epistemic uncertainty (lack of knowledge) regarding the process. The analysis is intended to inform the contentious public debate over shale gas extraction in the region. Stakeholders and the public generally can decide if they are willing to accept potential water contamination risks within the probability bounds and policymakers can decide if additional research is needed to decrease the epistemic uncertainty before a policy decision can be made.

2. DATA AND METHODS

2.1. Analysis Method

The risk analysis was performed using probability bounds analysis (PBA) as developed by Yager,[17] Frank *et al.*,[18] Williamson and Downs,[19] Ferson and Ginzburg,[20] and Ferson.[21] PBA is used to create probability boxes (p-boxes) that combine probability distributions to represent aleatory uncertainty (natural variation) and interval arithmetic to represent epistemic uncertainty (lack of knowledge). Karanki *et al*.[22] provides a more complete overview of interval analysis and PBA calculations with examples. Because p-boxes emphasize the bounded range of a class of possible distributions that might be generated by techniques such as second-order Monte Carlo or Bayesian sensitivity analysis, p-boxes are particularly well suited to analyses where distribution parameters are highly uncertain and correlations are unknown. The computationally simple and mathematically rigorous bounds generated by PBA are useful for analyses where tail risks and best-case/worst-case scenarios are of special interest.[23] For these reasons, PBA has been recently used in a variety of environmental risk assessments.[24–27] The method has been critiqued as a simple worst-case technique,[28] but risk managers can use PBA to determine if a desirable or undesirable outcome resulting from a decision is even possible, whether the current state of knowledge is appropriate for making a decision, or as a complement to other risk analysis methods. For this study, the software Risk Calc 4.0[21] was used for all calculations.

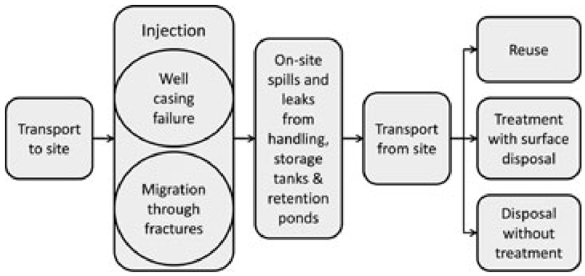

Fig. 2. Model of water contamination pathways.

2.2. Model

There are many types of water contamination that can result from the shale gas extraction process, including: gases (e.g., methane and radon), liquids (e.g., hydraulic fracturing fluids), and solids (e.g., drill cuttings). Because the hydraulic fracturing process generates primarily liquid waste products, this risk assessment only considers water contamination from drilling and hydraulic fracturing fluids. For the purpose of the assessment, the model defines contamination as anything that could potentially exceed the limits of the U.S. Clean Water Act or Safe Drinking Water Act. Given recent public attention to the potential environmental risks of hydraulic fracturing, drillers have been making the transition to hydraulic fracturing components that are considered largely benign.(29) However, even a benign hydraulic fracturing fluid is contaminated once it comes in contact with the Marcellus Shale. Recovered hydraulic fracturing fluid contains numerous materials from the Marcellus Shale formation in excess of drinking water standards, including: sodium, chloride, bromide, arsenic, barium, and naturally occurring radioactive materials such as uranium, radium, and radon.(30) Thus, any drilling or fracturing fluid is suspect for the purposes of this study.

The proposed potential water contamination pathways are shown in Fig. 2 for a hypothetical shale gas well drilled in the Marcellus Shale using high-volume hydraulic fracturing. The pathways followed the life-cycle of the water used and were modeled as described below.

2.2.1. Transportation

Potential water contamination due to tanker truck spills to and from the well site was modeled as:

$$CV_T = \frac{F(1 + P_R) \times N_C \times P_S \times P_L}{N_S}, \quad (1)$$

where CV_T is the contaminant volume spilled from transportation in m^3 per well, F is the drilling and fracturing fluid on site in m^3, P_R is the portion of drilling and fracturing fluid returned from the well, N_C is the number of hazmat truck crashes in the United States each year, N_S is the total number of hazmat shipments in the United States each year, P_S is the portion of hazmat tankers that spill in crashes, and P_L is the portion of a tanker truck load that would spill in a crash.

2.2.2. Well Casing Failure

A failure in a well casing that would cause a leak of fluids to the surrounding groundwater was modeled as:

$$CV_W = P_{WFail} \times P_{WLeak} \times F, \quad (2)$$

where CV_W is the contaminant volume leaked from the well casing in m^3 per well, P_{WFail} is the probability that a Marcellus Shale gas well fails, P_{WLeak} is portion of the injected fluids that leak from the well, and F is the drilling and fracturing fluid on site in m^3.

2.2.3. Contaminant Migration Through Fractures

The potential for hydraulic fracturing fluid to travel through fractures into overlying aquifers was modeled as:

$$CV_F = P_{FL} \times P_{Fluid} \times F(1 - P_R), \quad (3)$$

where CV_F is the contaminant volume leaked through fractures in m^3 per well, P_{FL} is the probability that well fractures will leak to an overlying aquifer, P_{Fluid} is the portion of fluids leaked through fractures, F is the drilling and fracturing fluid on site in m^3, and P_R is the portion of the fracturing fluid returned from the well.

2.2.4. Drilling Site Surface Contamination

The potential for water contamination from drilling site spills due to improper handling or leaks from storage tanks and retention ponds was modeled as:

$$CV_{DS} = P_D \times P_{FD} \times F \times P_R, \quad (4)$$

where CV_{DS} is the contaminant volume discharged at the drilling site in m^3 per well, P_D is the probability that the drilling site will experience some discharge, P_{FD} is the portion of drilling site fluids discharged, F is the drilling and fracturing fluid on site in m^3, and

Table I. Data Used for the Model Variables

Variable	Description	P-Box Used	Source
F	Drilling and fracturing fluid on site	MinMaxMean (9e3, 3e4, 1.7e4)	10, 33
P_R	Portion of drilling and fracturing fluid returned from the well	MinMaxMean (0.1, 1, 0.3)	10, 33, 35
N_C	Number of hazmat truck crashes in the U.S. each year	MinMaxMean (5,000, 7,800, 5,200)	32
N_S	Total number of hazmat shipments in U.S. each year	MinMax(2.9e8, 3.3e8)	32
P_S	Portion of hazmat tankers that spill in crashes	MinMaxMean (0.1, 0.4, 0.36)	32
P_L	Portion of a tanker truck load that would spill in a crash	MinMax (0.01, 0.99)	Estimate
$\mathrm{P_{WFail}}$	Probability that gas well fails	MinMaxMean (2e-8, 2e-2, 1.5e-3)	37, 39–42
P_{WLeak}	Portion of the injected fluids that leak from the well	MinMax (1e-6, 0.1)	Estimate
P_{FL}	Probability that well fractures will leak to aquifer	MinMax (1e-6, 0.1)	Estimate
P_{Fluid}	Portion of fluids leaked through fractures	MinMax (1e-6, 0.1)	Estimate
P_D	Probability that site has some discharge	MinMaxMean (0.1, 0.5, 0.3)	53
P_{FD}	Portion of on-site fluids discharged	MinMaxMean (1e-6, 1, 1e-4)	42, 53
P_T	Portion of wastewater treated and released	MinMax (0.75, 0.85)	42, 53
P_{CR}	Portion of contaminants released after treatment	MinMax (0.3, 1)	10, 58
P_{NT}	Portion of wastewater not treated	MinMax (0, 0.05)	42, 53

P_R is the portion of the fracturing fluid returned from the well.

2.2.5. *Contamination from Disposal of Used Hydraulic Fracturing Fluids*

The potential for water contamination from disposal of the used drilling and hydraulic fracturing fluids depends on the method of disposal. If the fluid is reused, it was assumed there are no disposal losses for the well and any further losses are accrued by the next well. Deep well injection, to be discussed later, was not considered. The disposal contamination was modeled as:

$$CV_{WD} = (F \times P_R - CV_{DS})(P_T \times P_{CR} + P_{NT}). \tag{5}$$

Substituting in Equation (4) for CV_{DS} yields:

$$CV_{WD} = (F \times P_R(1 - P_D \times P_{FD})) \times (P_T \times P_{CR} + P_{NT}), \tag{6}$$

where CV_{WD} is the contaminant volume from wastewater disposal in m^3 per well, F is the drilling and fracturing fluid on site in m^3, P_R is the portion of the fracturing fluid returned from the well, P_D is the probability that the drilling site will experience some discharge, P_{FD} is the portion of drilling site fluids discharged, P_T is the portion of the wastewater treated and released to surface waters, P_{CR} is the portion of contaminants that are released to surface waters after treatment, and P_{NT} is the portion of wastewater not treated and released to surface waters.

2.2.6. *Correlations*

For each of the pathways described above, the individual variables may or may not be independent. Some relations are most likely independent. For example, there is no reasonable mechanistic relation between the number of hazmat truck crashes, N_C, and the portion of the fracturing fluids returned from a gas well, P_R. Other variables may be theoretically correlated. For example, the portion of the fracturing fluids returned from a gas well, P_R, the probability that well fractures will leak to an overlying aquifer, P_{FL}, and the portion of fluids leaked through fractures, P_{Fluid}, are all at least partially dependent on the hydrogeological conditions in the local shale. Similarly, there could be some positive correlation between the total fluid used, F, and various spill and treatment rates due to the difference in difficulty of managing the operations of a small versus a large hydraulic fracturing project. There is also a likely correlation among the possible pathways. An assumption of independence suggests that each step of the drilling process is separately managed and operated. A more likely scenario is that all of the contaminant pathways are positively correlated because they are managed by a single company that is consistently conscientious or careless during each step of the process. To find the most conservative bounds, all calculations used the Fréchet[31] method, which does not assume a specific dependence.

2.3. Data

Table I lists the model variables and the data used to create the p-boxes. Because the published data are sparse for Marcellus Shale gas extraction and the drilling process is inherently uncertain, there is considerable uncertainty regarding appropriate variable values and distributions. This analysis used nonparametric p-boxes, a capability of PBA with minimal data distribution assumptions that generates conservative bounds. It can be useful in PBA to select boundaries that are more conservative than available data to account for uncertainty and to ensure that the final p-box encloses the true probability. However, the selected level of conservatism can be contentious. This study used publicly available data and estimates where available without inflating the bounds. Generally, the best-case boundary (left side of p-box) showed a contamination probability resulting from the estimates of hydraulic fracturing proponents (e.g., the natural gas drilling industry). Similarly, the worst-case boundary (right side of p-box) showed a contamination probability resulting from the estimates of hydraulic fracturing opponents (e.g., environmental organizations). Details of the variables are described later.

2.3.1. Transportation

Because there are no specific statistics available for hydraulic fracturing fluid transportation spills, the spill rates for liquid hazardous materials (hazmat) transport in the United States are used as a proxy. Hazmat spill rates were chosen because they are tracked more reliably than non-hazmat. According to the U.S. Department of Transportation, there are over 800,000 shipments of hazmat by truck each day and about 5,200 hazmat truck accidents annually in the United States. However, the accident statistics are underreported because an estimated one-quarter of hazmat truck accidents involve intrastate carriers and the federal statistics are only collected on interstate carriers; similarly, the data are on the basis of self-reporting by carriers.(32) When accidents involve fatalities, the spill rate for hazmat tankers is approximately 36%.(32)

For this assessment, the total number of hazmat shipments in the United States each year, N_S, was set as an interval between 2.9×10^8 and 3.3×10^8, which equates to between 800,000 and 900,000 daily shipments. The number of hazmat truck crashes in the United States each year, N_C, was set as a nonparametric distribution with a mean of 5,200, a minimum of 5,000, and a maximum of 7,800 based on the assumption that hazmat truck accidents could be as much as 50% underreported. The portion of hazmat tankers that spill in crashes, P_S, was set to a mean of 0.36, a minimum of 0.1 based on the assumption that nonfatal and unreported accidents have lower spill rates, and a maximum of 0.4. The portion of a tanker truck load that would spill in a crash was set as a wide interval between 0.01 and 0.99. That is, a tanker truck spill can range between very little and almost the entire load.

2.3.2 Drilling and Fracturing

Although the fluids used in the drilling mud do not have the same characteristics or recovery rate as the hydraulic fracturing fluids, the two are not treated separately in this analysis because the drilling fluid is only about 1% of the total combined volume.(33) Average estimated water usage for drilling and hydraulic fracturing a well in the Marcellus Shale ranges from 13,000 m^3(10) to 21,000 m^3(33) with limits of 9,000 m^3 to 30,000 m^3 for a typical 1,200 m horizontal well.(10) For this analysis, the drilling and fracturing fluid used, F, was set as a nonparametric distribution with a mean of 17,000 m^3, a minimum of 9,000 m^3, and a maximum of 30,000 m^3. The rate of return of hydraulic fracturing fluid for shale gas wells has been stated to range from: 9% to 35%,(10) 30% to 60%,(34) 15% to 60%,(35) 15% to 80%,(36) or even 10% to 100%.(33) For this analysis, the portion of drilling and fracturing fluid returned from the well, P_R, was set as a mean of 0.3 with minimum and maximum bounds of 0.1 and 1, respectively.

Regarding the likelihood of a well casing failure, a commonly cited statistic(10) originated with an American Petroleum Institute (API) report(37) that estimates the absolute risk of contaminating an underground source of drinking water from a Class II (oil & gas) injection well as between 2×10^{-5}(1 in 50,000) and 2×10^{-8}(1 in 50 million) well-years. The report uses historical well failure rate data and is based on the simultaneous failure of multiple well casings and fluids moving between the deep injection reservoir and surface aquifer.(38) It has been argued(10) that the API study serves as an upper bounds for well failure risk because wastewater injection wells continuously operate at higher than the geologic formation pressure whereas hydraulically fractured wells only operate above the formation pressure for a few days during construction. However, this assumption does not consider the much higher pressures involved in hydraulic fracturing and the specific intent to generate additional fracturing in the formation. Other studies have not supported the

API low failure rates. For example, Browning and Smith[39] find an average 10% failure rate for mechanical integrity tests of oil and gas injection wells. Presumably, the actual leakage rate is much lower. Although the sample size was only 43 wells, a subsequent report by the Underground Injection Practices Council (UIPC)[40] finds a 2% leak rate into underground sources of drinking water for Class I wastewater injection wells. The Pennsylvania Department of Environmental Protection (PA-DEP) found 52 separate cases of methane migration in a five-year period ending in 2009.[41] There are approximately 71,000 active gas wells in Pennsylvania.[42] This corresponds to a 1.5×10^{-4} (1 in 7,000) chance of a well leaking each year. Assuming a short 10-year well lifespan, the lifetime well leak risk is 1 in 700. For this analysis, the probability that a gas well fails, P_{WFail}, was set as a mean of 1.5×10^{-3} (1 in 700) with a minimum bound of 2×10^{-8}, based on the API study,[37] and a maximum bound of 2×10^{-2}, based on the UIPC study.[40] Lacking reliable data, the portion of the injected fluids that leak from the well, P_{WLeak}, was conservatively set as an interval ranging from 1×10^{-6} to 0.1.

The risk of hydraulic fracturing fluid migrating through fractures to an overlying aquifer is a point of considerable debate.[43] Proponents of hydraulic fracturing posit that there is no known mechanism by which fractures and fluid can propagate through over 1,000 m of sedimentary strata; some recent data even suggest that Marcellus Shale wells should be more closely spaced due to shorter effective fracture lengths than originally estimated.[44] In reply, critics say that several potential mechanisms cannot be ruled out:[10,45] unexpected vertical fracturing through overlying strata,[46,47] and fracturing fluid preferentially traveling through naturally occurring fractures and faults.[44,48] Besides, critics argue, current conventional fracturing models are not appropriate for shale gas reservoirs,[49] and the interpretation of microseismic data used to monitor hydraulic fracturing is still controversial.[50] Bredehoeft[51] discusses the substantial portion of conceptual groundwater models that are found to be invalid once further data are available. As an initial assessment, Myers[52] simulated a Marcellus Shale well that had 19,000 m^3 of fracturing fluid injected over five days. Given the uncertainty in hydrogeological parameters (particularly conductivity, local flow gradients, and depth of shale), it was determined that fracturing fluids could flow into overlying aquifers in timescales ranging from years to millennia. Given the considerable incertitude on the subject, the assessment assumes an interval probability of fracture contamination, P_{FL}, as somewhere between extremely rare (1 in 1 million) and relatively common (1 in 10).

2.3.3. *Drilling Site Leaks and Spills*

According to PA-DEP records[53] from July 2009 to June 2010, there were about 4,000 permitted Marcellus wells in PA. Of these wells, about 850 wells were producing gas, 400 wells were not producing, and 2,800 wells were planned or in process. During this same time, 630 environmental, health, and safety violations were issued for Marcellus wells in PA, of which approximately half were for discharges up to 60 m^3 or for potential to cause discharge. These data are acknowledged by public officials to be underreported.[42] For this analysis, the probability that a site has some discharge, P_D, was set as a mean of 0.3, based on the number of discharge violations divided by the number of active wells, a minimum of 0.1, based on the number of discharge violations divided by the number of total permitted wells, and a maximum of 0.5 under the assumption of substantial underreporting. The portion of drilling site fluids discharged, P_{FD}, was set as a mean of 1×10^{-4}, based on the mean violation discharge divided by the mean total fluid used, a minimum of 1×10^{-6}, which represents the smallest spill volume of interest, and a maximum of 1, which assumes a catastrophic retention pond failure where the entire contents are spilled.

2.3.4. *Wastewater Treatment*

Although some well operators recycle and reuse hydraulic fracturing fluids for multiple wells, most operators do not due to the cost of separation and filtration.[54] Instead, the used hydraulic fracturing fluid is transported to a wastewater treatment facility and discharged to streams. From July 2009 to June 2010, 729,000 m^3 of Marcellus Shale hydraulic fracturing wastewater was reported in PA.[53] Of the total, 77.5% was sent to approved industrial wastewater treatment facilities, 16% was reused in other wells, 5% was sent to municipal wastewater treatment facilities, 1% had unknown disposal, 0.5% was injected into deep wells, and 0.007% was spread on roads. Although deep well injection is a common disposal method in other shale gas areas of the United States, the Marcellus Shale region has relatively few suitable deep injection sites[42] and the permitting process for these wells is protracted.[55] Therefore,

Table II. Comparison of Contaminant Concentrations Before and After Industrial Wastewater Treatment

Contaminant	Typical Untreated Wastewater Concentrations (Min, Median, Max) in ppm[10]	Mean Effluent Concentration in ppm[58]	Portion of Contaminant Not Removed as Interval Range[a]
Barium (Ba)	(0.5, 1450, 15700)	27	[0.001, 1]
Bromide (Br)	(11.3, 607, 3070)	1,069	[0.35, 1]
Strontium (Sr)	(0.5, 1115, 5841)	2,983	[0.51, 1]
Chloride (Cl)	(287, 56900, 228000)	117,625	[0.51, 1]
Magnesium (Mg)	(9, 177, 3190)	1,248	[0.39, 1]
Total Dissolved Solids (TDS)	(1530, 63800, 337000)	186,625	[0.55, 1]

[a] Assumes that the effluent had not been substantially diluted when measured in the stream and that upstream sources were not substantially adding to the effluent concentrations.

deep well disposal is considered negligible in this analysis.

Municipal wastewater treatment facilities are not designed to handle hydraulic fracturing wastewater containing high concentrations of salts or radioactivity two or three orders of magnitude in excess of federal drinking water standards.[42,56] As a result, high salinity and dissolved solids in Appalachian rivers have been associated with the disposal of Marcellus Shale hydraulic fracturing wastewater after standard wastewater treatment.[57] The amount of wastewater treated in public sewage facilities seems to be underreported and actual levels may be as high as 50%.[42] Volz has presented data[58] that industrial wastewater treatment facilities may also release effluent in excess of drinking water standards (Table II). For this analysis, the portion of wastewater treated and released to surface waters, P_{T}, was set as an interval with a minimum of 0.75 and a maximum of 0.85 based on data reported to the PA-DEP and whether treatment at a municipal wastewater treatment facility counted as treatment. The portion of contaminants released after treatment, P_{CR}, was set as an interval with a minimum of 0.3 and a maximum of 1 based on data in Table II. The portion of wastewater not treated, P_{NT}, was set as an interval with a minimum of 0 and a maximum of 0.05 using the assumption that treatment at a municipal wastewater treatment facility could be categorized as nontreatment because it is not designed to treat Marcellus Shale brines.

3. RESULTS

The p-boxes generated for each fluid loss pathway given the assumptions stated above are shown in Figs. 3–7. In each p-box, the left side of the p-box represents the cumulative distribution function (CDF) of the smallest potential water contamination (best-case scenario). Similarly, the right side of the p-box represents the CDF of the largest potential water contamination (worst-case scenario). The horizontal distance between the right and left side of the p-box represents the epistemic uncertainty or lack of knowledge of the risk. Comparing the p-boxes in Table III, the risks of water contamination are listed in increasing order with transportation (Fig. 3) risks and epistemic uncertainty being negligible compared to the other pathways. The contamination risks and epistemic uncertainties associated with well casing failure (Fig. 4) and migration of fluids through fractures (Fig. 5) were potentially substantial, but minor compared to the contamination risk and epistemic uncertainty associated with disposal of used hydraulic fracturing fluids (Fig. 7). Although both the best- and worst-case 50th percentile risk of drilling

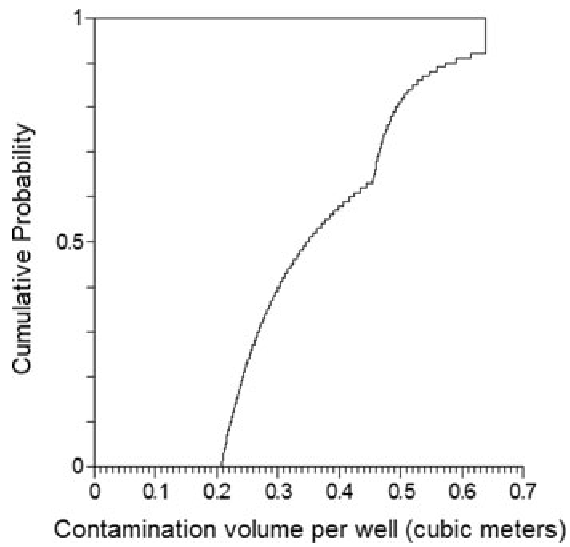

Fig. 3. P-box generated for transportation spill risk.

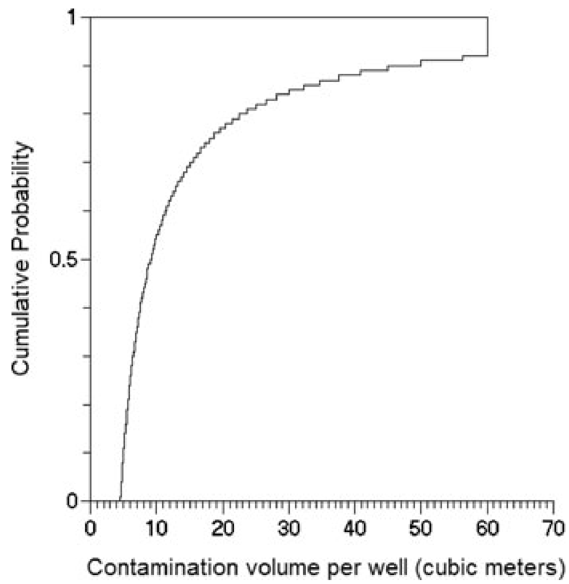

Fig. 4. P-box generated for well casing failure risk.

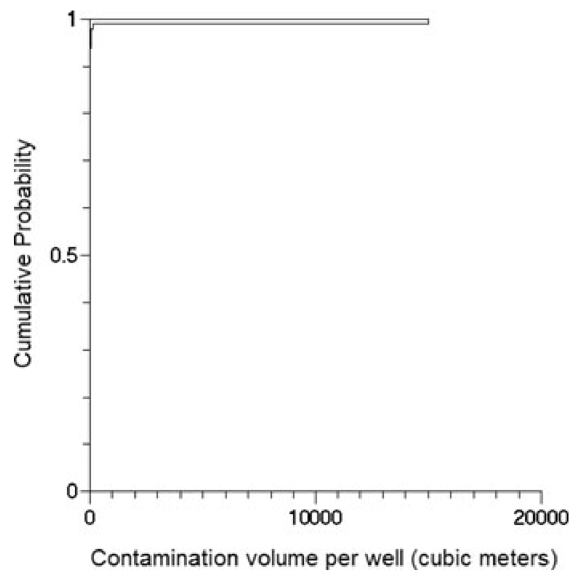

Fig. 6. P-box generated for drilling site discharge risk.

site surface contamination (Fig. 6) were modest, at the 99.9th percentile, a rare, but serious retention pond failure could generate a very large contaminated water discharge to local waters. An important feature of Fig. 7, the left side, or best-case boundary, is expanded in Fig. 8 which more clearly shows that it was very likely that an individual well would generate at least 200 m^3 of contaminated fluids (by comparison, an Olympic-size swimming pool has a volume of 2500 m^3).

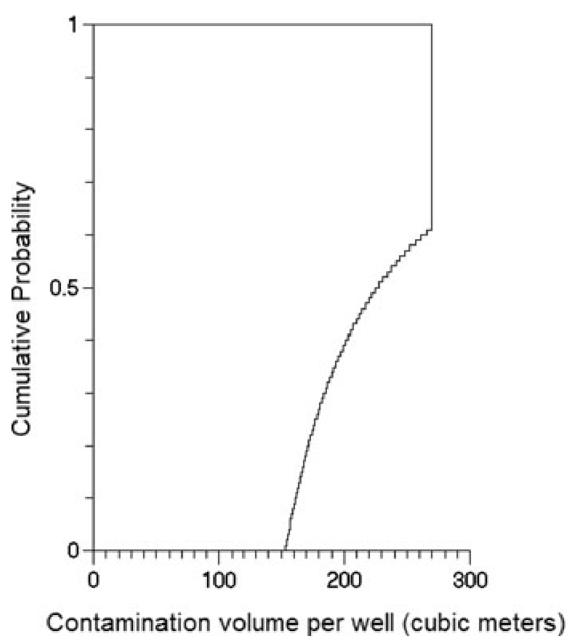

Fig. 5. P-box generated for fracture leaks to aquifer risk.

4. DISCUSSION

Estimating the risks of contamination scenarios is subject to more general underlying methodological and conceptual dilemmas than can be addressed

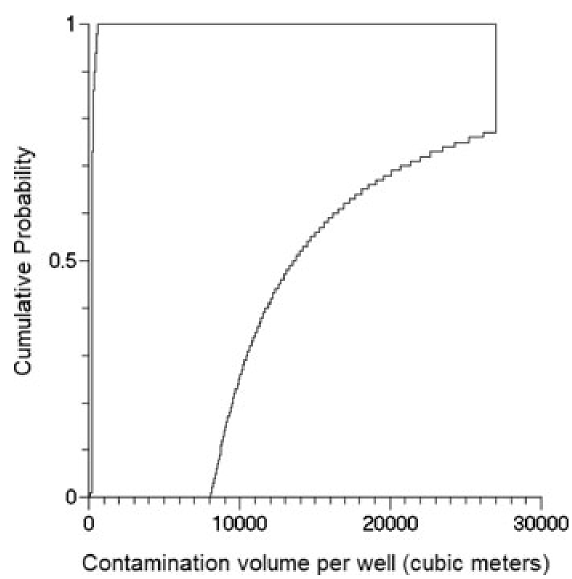

Fig. 7. P-box generated for wastewater discharge risk.

Table III. Comparison of Water Contamination Pathway Risks from Hydraulic Fracturing in a Typical Macellus Shale Gas Well

Pathway	Best-Case 50th Percentile Contamination Volume (m^3)	Worst-Case 50th Percentile Contamination Volume (m^3)	Maximum Epistemic Uncertainty Between Best and Worst Case (m^3)
Transportation	< 0.01	0.3	0.6
Well casing failure	< 0.01	9	60
Fracture migration	< 0.01	225	270
Dilling site spills	< 0.01	3	15,000
Wastewater disposal	202	13,500	26,900

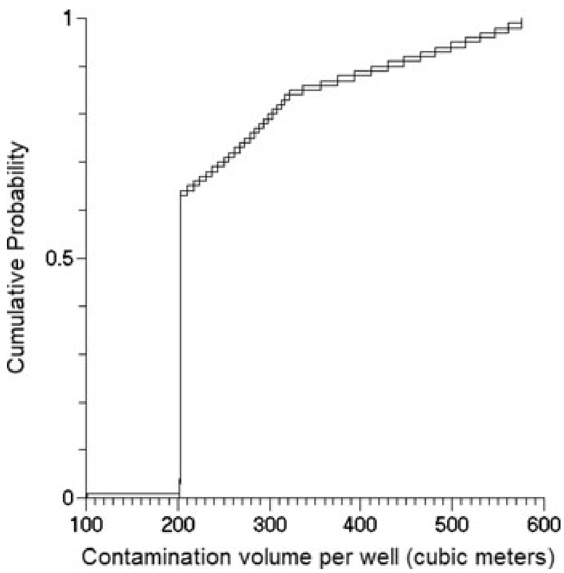

Fig. 8. Left bound (best-case) for wastewater disposal per well p-box.

here—in assigning probabilities or probability distributions to the pertinent scientific theories and mathematical models of groundwater contamination themselves, in ensuring that all major contamination scenarios have been considered, in characterizing the varieties of uncertainty within Bayesian and non-Bayesian frameworks, and in designing "how clean is clean enough?" policy. These dilemmas are diagnosed by Reaven.(59–61)

No time variable was included in the present analysis to minimize the number of variables. As such, only the total contamination potential at some future steady state was calculated. However, it is not expected that the contamination from shale gas would be experienced all at once or evenly over some predefined time period. Instead, each contamination pathway has a unique timeframe. First, the spills from transportation, drilling site handling and storage, and disposal would be experienced during or shortly after the well construction phase. Second, any well casing failure would impact the surrounding areas during or after construction depending on distance to the well. Finally, the time for fluid to migrate through fractures is poorly understood, but would likely affect drinking water sources years or decades after the well was constructed.

Similarly, the rate at which hydraulic fracturing fluids would leak from a failed well casing is not considered. Methane has a low molecular weight and viscosity and is expected to leak at a higher rate and travel farther than a heavier gas like radon and much more than many of the hydraulic fracturing components. However, it is likely that any gas leak large enough to be publicly noticeable is also leaking hydraulic fracturing fluids.

The estimate for transportation losses may be overestimated because some sites mix hydraulic fracturing fluids on site. For these sites, most fluid going to the site will consist of plain water. This overestimation decreases with the increasing reuse of hydraulic fracturing fluid. Regardless, the overall contribution of transportation to the total potential water contamination turns out to be negligible.

Although PBA generates mathematically rigorous bounds(62) (i.e., the bounds are mathematically guaranteed to enclose the true value), the bounds can be too narrow or broad based on the validity of the data and assumptions inherent in the selection of the input variables. In this analysis, input bounds were selected from currently available data and estimates. Any change in hydraulic fracturing practices in the Marcellus Shale would change the PBA. Similarly, as the Marcellus Shale is developed, additional information will become available and the epistemic uncertainty should decrease. From Table III, it is clear that the lack of knowledge associated with the disposal of used hydraulic fracturing fluid is the most important area for further research. Within the disposal pathway, the critical variables are: the drilling and fracturing fluid used, *F* (the primary variable that influences all pathways) and the portion of contaminants that are released after wastewater treatment, P_{CR}.

Regulators have recently moved to control the surface disposal of hydraulic fracturing wastewater more stringently.(63) The expected increased costs of disposal may cause drillers to increase fluid reuse or select alternative fracturing techniques. If not, regulators should explore the option of mandating alternative fracturing methods to reduce the water usage and contamination from shale gas extraction in the Marcellus Shale. Some extensively tested, widely used alternatives are: N_2 gas,(64) N_2-based foams,(65,66) CO_2,(67) and even liquefied petroleum gas (LPG).(68) Although water-based fracturing is the most commonly used for reasons of cost, familiarity, and effectiveness on low permeability, high pressure formations like the Marcellus,(69) nitrogen-based fracturing is the least expensive and most often used alternative due to its ability to improve low-pressure well production and reduce waste costs. Carbon dioxide is a more expensive and corrosive fracturing fluid, but it can preferentially displace methane, thereby sequestering carbon dioxide(70,71) and lowering the carbon footprint of shale gas extraction. Although it is counterintuitive, even LPG fracturing potentially could decrease the total water pollution generated from Marcellus Shale gas extraction. The PBA for Marcellus Shale hydraulic fracturing found that the main sources of potential water pollution were from drilling site spills and wastewater disposal. LPG fracturing would reduce drilling site spills because there would be no retention ponds, only storage tanks. Similarly, LPG vaporizes after fracturing so it has a very high recovery rate; moreover LPG is a saleable product that creates a strong incentive to minimize loss. Given the limited wastewater disposal options in the Marcellus Shale region, any of these fracturing fluid alternatives that substantially reduce wastewater generation could make Marcellus Shale gas development more environmentally benign and a less controversial source of future energy for the United States.

5. CONCLUSION

The study model identified five pathways of water contamination: transportation spills, well casing leaks, leaks through fractured rock, drilling site surface discharge, and wastewater disposal. Probability boxes were generated for each pathway. The epistemic uncertainty was largest for wastewater disposal and for the rare, but serious, retention pond breach that could cause a large drilling site discharge. The p-box for the contamination risk from fluid migrating through fractures to an overlying aquifer (Fig. 5) had substantial epistemic uncertainty. That is, the p-box was almost box-shaped—a representation of simple interval uncertainty. This was a result of the very large interval estimates used to represent the probability that well fractures would leak and the portion of fluid that would leak through the fractures. Normally, this would suggest that future research efforts be focused on the fluid fracture migration pathway. However, the total uncertainty of fracture leaks was very small compared to the wastewater disposal potential risk and epistemic uncertainty. Hence, future research efforts should be focused primarily on wastewater disposal and specifically on the efficacy of contaminant removal by industrial and municipal wastewater treatment facilities. Even in a best-case scenario, an individual well would potentially release at least 200 m^3 of contaminated fluids.

Given typical well spacing in the Marcellus Shale,(10) if only 10% of the region is developed, this would equate to 40,000 wells. Using the best-case median risk determined above, this volume of contaminated water would equate to several hours flow of the Hudson River or a few thousand Olympic-sized swimming pools. This potential substantial risk suggests that additional steps be taken to reduce the potential for contaminated fluid release from hydraulic fracturing of shale gas.

ACKNOWLEDGMENTS

We would like to thank Scott Ferson for his assistance and helpful suggestions regarding probability bounds analysis.

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