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A Technical Report from the Agriculture, Energy, & Environment Program at Cornell University

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Citation: Santoro, R.L.; R.W. Howarth; A.R. Ingraffea. 2011. Indirect Emissions of Carbon Dioxide from Marcellus Shale Gas Development. A Technical Report from the Agriculture, Energy, & Environment Program at Cornell University. June 30, 2011

Report is available electronically at: http://www.eeb.cornell.edu/howarth/Marcellus.htm

Design and layout: R.L. Santoro

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ACKNOWLEDGEMENTS

Preparation of this report was supported by a grant from the Park Foundation, an endowment fund of the David R. Atkinson Professorship in Ecology & Environmental Biology at Cornell University, and the Dwight C. Baum Professorship in Civil and Environmental Engineering at Cornell University. We thank D. Hughes and C. Costello for their review of the manuscript, and B. Sell for useful comments on an earlier version of the report. We further wish to thank G.R. Smith, R. Marino, M. Carcella, D. Swaney for information, encouragement, advice, and feedback.

Summary

Shale gas is often characterized as a bridge fuel to renewable energy in part because a perception that natural gas has a lower greenhouse gas footprint than other fossil fuels; however, the actual magnitude of greenhouse gas emissions from shale gas has received very little study and the Council of Scientific Society Presidents (2010) cautioned that relying on shale gas might actually aggravate global warming.

The Marcellus shale is cited as being one of the world's largest on-shore unconventional natural gas resources (Fig 1). The northern portions of the play have recently experienced a rush of development due to spikes in the market value of natural gas and advanced drilling and stimulation technology previously developed in the Barnett shale formation.

In this report, we estimate the emissions of carbon dioxide associated with all fuel combustion associated with the shale gas life-cycle focusing on the Marcellus shale as a case study. We calculate all GHG emissions from land clearing, resource consumption, and diesel consumed in internal-combustion engines (mobile and stationary) during well development. Energy consumed once the gas well is brought into production (i.e. that consumed in production, processing, and transmission/distribution streams) are assumed to be similar to previously published estimates; therefore, we use emission intensities from the literature for these sources. Additionally, we do not address fugitive and vent emissions here. Rather, the reader is directed to our companion paper (Howarth et al., 2011), which emphasizes the importance of methane venting and leakage, concluding that in fact shale gas has a larger greenhouse gas footprint compared to other fossil fuels.

We estimate total indirect CO_2 emissions as between 1.17 and 1.69 g C MJ^{-1} (LHV), depending upon whether or not the raw gas requires processing. Compared to the direct (i.e. end-use combustion) CO_2 emissions: 15 g C MJ^{-1} (LHV), the indirect emissions are small, but not trivial. Our estimated indirect CO_2 emissions from shale gas are 0.04 to 0.45 g C MJ^{-1} greater than that reported for conventional gas (Woods et al., 2011). Still, a far greater part of the greenhouse gas footprint of shale gas comes from methane venting and leakage (Howarth et al., 2011).

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1. Introduction

Conventional gas reserves[a] are being depleted in both the U.S. and globally, and many view natural gas from shale formations as a replacement over coming decades (DOE/EIA 2010; Woods et al. 2011), although Hughes (2011) cautions that the resource may not be as large as is sometimes promoted. This shale gas is often characterized as a bridge fuel, allowing society to continue to use fossil fuels over the coming few decades while slowly building towards a path of renewable energy, in part because a perception that natural gas has a lower greenhouse gas footprint than other fossil fuels. However, the actual magnitude of greenhouse gas emissions from shale gas has received very little study, and the Council of Scientific Society Presidents (2010) cautioned that relying on shale gas might actually aggravate global warming. In Howarth et al. (2011), we estimated the greenhouse gas footprint of shale gas, emphasizing the importance of methane venting and leakage, and concluding that in fact shale gas has a large greenhouse gas footprint compared to other fossil fuels. In this report, we estimate the indirect emissions of carbon dioxide[b] associated with shale gas development, focusing on the Marcellus shale as a case study.

The Marcellus shale is cited as being one of the world's largest on-shore unconventional natural gas resources (Ubinger et al. 2010). The Marcellus shale is a Devonian sedimentary rock formation extending from West Virginia to south-central New York and from eastern Ohio to large parts of Pennsylvania and small portions of Maryland and Virginia. It is estimated to contain at least 4.64 trillion m^3 (164 tcf; NYDEC 2009) of natural gas with some estimates of in-place resource as high as 13.8 trillion m^3 (489 tcf; Englender and Lash 2008). Typical developable depths of the shale are 1,524 m near the New York- Pennsylvania border and increase southward, with thickness ranging from 30 – 60 m. Until recently, the gas in-place had not previously been exploited due to high development costs, a low price for natural gas, and technological challenges (National Academy of Sciences, 2001); however, increased market value of natural gas between 2005 and 2008 (DOE/EIA 2011a) combined with advances in drilling and stimulation technology proven in the Barnett shale formation - directional drilling combined with high volume hydraulic fracturing (HVHF) – made the Marcellus more economic, at least for a while, thus starting a rush of development in 2007 in some states in the region. More than 3,000 Marcellus-only wells have been drilled within the past 4 years. In 2009, 768 wells, 70% of them horizontal, were drilled in Pennsylvania alone (PA DEP, 2010; NETL, 2010) with an additional 1,386 Marcellus wells drilled there in 2010. Note that since 2009, the price of natural gas has fallen (DOE/EIA 2011a), and the economics of shale gas are being increasingly questioned (Urbina 2011; Hughes 2011).

The natural gas life-cycle consists of three "streams" or segments: upstream, which consists of exploration, extraction, and gathering of gas; midstream, or the off-site processing of raw gas to meet pipeline specifications; and downstream, or transportation/storage and distribution to consumers. Both conventional and unconventional gas development follow the same general path from extraction to end-use consumption; however, energy and material inputs in unconventional gas extraction will be shown here to be higher.

Early shale gas development depended on high densities of vertical, hydraulically-fractured wells to help maximize production (NPC, 2007). Early hydraulic fracturing experiments in shale used gel-fluids, which made the process less water intensive (NPC, 2007). However, the cost and problems associated with clean up - and the inability to pump high volumes of gel-based fluid at high pressure - proved inhibitory, leading to experimentation with high-volume, slick water fracturing (NPC, 2007). Modern shale gas recovery relies on directional drilling and multi-stage, slick-water, HVHF technology. Directional drilling maximizes areal exposure to the formation, and, thus, production rates of the well, by drilling laterally along the formation rather than at a cross-section as with traditional vertical drilling. Horizontal wells decrease land impacts by decreasing the number of wells required to maximize recovery within a given land area, but further increase total drilling depth (i.e. vertical depth plus lateral length) and, therefore, energy inputs and the associated CO_2 emissions. Still more energy and materials are required in the HVHF process, as numerous pumps of 1000 hhp or more are required to force frac fluids down the borehole and into the formation at a high enough pressure to optimally fracture or re-fracture the rock.

Energy consumed upstream depends largely on the total drilling depth, as well as physical characteristics (e.g. permeability) of the formation. The permeability of discrete, conventional gas deposits is several orders of magnitude higher than that of shale, where gas is locked in a complex system of microfractures and existing joint sets over a much larger spatial scale. Thus shale gas development requires either high-density well spacing, and/or long laterals to maximize the area of extraction, and thereby the volume of gas produced from a given spatial extent of the matrix. Modern conventional gas wells, while typically vertically drilled, may also employ directional drilling; however, lateral lengths are substantially shorter than that required to economically develop a shale gas well. Typical Marcellus vertical depths in Pennsylvania are ~ 2 km (ICF, 2009b) with the average lateral extending 1.4 km (NYDEC, 2009).

Well stimulation is another critical difference between conventional and unconventional gas wells. While modern conventional wells do rely on hydraulic fracturing to stimulate production, the volume of frac fluid consumed is significantly less than that required for a shale gas well. For one, longer laterals require higher frac fluid volumes and multiple frac stages (typically 1 stage for about every 100 m of lateral), in which sections of the lateral are sequentially plugged, perforated, and fraced. Conventional and vertical wells are generally completed in a single or a few stages due to lack of, or minimal extent of, the lateral. New York state regulations limit the volume of frac fluid used in conventional wells to 300 thousand liters (80,000 gal; NYDEC, 2009); shale gas wells consume on average 20 million liters (2.4 – 7.8 million gallons; NYDEC, 2009), or a volume 2 orders of magnitude greater.

A full life-cycle accounting of GHG emissions (CO_2, CH_4, N_2O) associated with the natural gas industry must include those emissions associated with direct (i.e. end-use) combustion of the natural gas, as well as all indirect emissions associated with the fossil fuels consumed and fugitive losses incurred throughout the streams of the lifecycle, including stationary (e.g. rigs) and mobile (e.g. truck transport of equipment and wastes) diesel engines, land-use change, and resource (e.g. steel, cement, organic chemicals, etc.) consumption.

Emissions may be calculated by various methods depending on the data available, although uncertainty increases inversely with data requirements. Direct, long-term measurement is potentially the most robust[c], but requires location-specific fuel consumption and activity data, which are often not publicly available and make the method impractical over spatial scales larger than a single plant/operation. Alternatively, published emission factors (EF) may be used. These generally represent an average rate of emission for a specific source or activity, but the associated uncertainty of non-CO_2, non-combustion EFs are generally high[d] (±25% to more than 200%; Shires et al., 2009), as they depend on the representativeness and accuracy of the input data used to derive them. Additional uncertainty may result from the choice of activity factors (AF) or assumptions about fuel characteristics in the emissions calculation. In the absence of available EFs, engineering calculations, though sensitive to simplifying assumptions and sometimes data intensive, are recommended (Shires et al., 2009).

Most of the carbon dioxide emissions associated with natural gas development are related to combustion of fossil fuels, either the end product (burned by market consumers) or other fuels used to run drilling engines, compressors, generators, etc. Thus, fuel properties are important parameters in the emissions inventory. Heating value, the energy released in full combustion, can vary by fuel type and specific fuel composition, i.e. the proportions of individual carbon-containing components. Published heating values reflect typical compositions of fuel types and are reported in both high (HHV) and low (LHV) heating values. HHV accounts for condensation of water during combustion; water is considered in the vapor phase in LHV reported values. U.S. data are commonly reported in HHV, while the IPCC (2007) and international sources report using LHV. We used LHV in Howarth et al. (2011). Use of either HHV or LHV is a matter of convention and the choice of either does not impact the emissions inventory, provided that both energy values and emission factors reflect the same convention (Shires et al., 2009). We report HHV and LHV emissions for all sources.

2. Assumptions & Detailed Methodology

We calculate the upstream GHG emissions associated with developing and producing gas from a representative Marcellus well[e]. Specifications for well and casing design (Table 2.1) are taken from a permit application representative of the industry requests received to date by Broome County, NY (L. Collart, NYSDEC Reg 7, *personal comm.*). The inventory uses EFs and default engine efficiencies as reported in the API Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Natural Gas Industry (Shires et al., 2009) for all upstream internal combustion (IC) engine sources. Indirect emissions are calculated using specific EFs for the industry of interest. Table 2.2 lists the emission factors used in this inventory.

Gas recovered in the northeastern portion of the Marcellus play is expected to be low in sulfur compounds (i.e. sweet), with high methane content, and dry (i.e. "pipeline ready") and will not require processing. However, wet gas production has been reported in the southwestern portion of the play. We therefore provide both no-processing and processing scenarios.

Table 2.1 Well Specifications for a representative Marcellus shale gas well, Broome County, NY (Source: Chesapeake 2009).

Total Drilling Depth	8785	ft	2678	m
Lateral Length	3938	ft	1200	m
BHP	5000	psi	340.2	atm
BHT	250	F	121	C
	Casing Detail			
	d (in)	L (ft)	Wt (lb)	Grade
Conductor	16	60		
Surface	9.625	1000	40	J-55
Production	5.5	8785	40	P-110
	Cement Detail			
	Grade	ID (in)	OD (in)	% excess
Cond-Surface	Class A inhibited	16	9.625	100
Surface-Prod		9.625	5.5	15

Post drill/completion activities for Marcellus gas will not differ from that of conventional natural gas aside from the need to construct new gathering lines and drilling and stimulation of new or increased capacity underground storage facilities. Emission estimates related to pipeline construction are detailed below. At this time, we do not have adequate information with which to calculate emissions related to activities to increase regional storage capacity[f]. Indirect emissions from production, processing and transmission /distribution stages are calculated based on literature values (ARI/ICF, 2008; Armendariz, 2009).

Well drilling, stimulation, and completion of the well are not continuous emission sources over the lifetime of the well and need to be allocated over the time between drilling and any re-working of the well. Here, we assume a 10-year life of the well (NYDEC, 2009) during which time the original well completion is assumed to be the only time that the well undergoes hydraulic fracturing. After 10 years, well production is expected to drop below that which is marginally economic and the well will

Table 2.2. Emission Factors (EF). Combustion EFs are taken from Shires et al (2009). Sources for land use change and resource consumption are as noted in the table.

Source category	Original Units			G C basis	
	Reference	CO2 EF	Units	CO2 EF	Units
Diesel fuel	IPCC, 2007 table 1.3	20.2	Kg C GJ-1 (LHV)	1.92E-05	g C J-1 (HHV)
Natural gas (pipeline-ready)	EPA, 2008	14.47	Kg C MMBtu-1	1.37E-05	g C J-1 (HHV)
Cement	Hanle, 2004	0.97	tCO2 t-1	2.65E+05	g C tonne-1
Steel	US Steel, 2009	1.14	tCO2 t-1	3.25E+05	g C tonne-1
Gravel	EPA, 2003	0.0025	MTCE t-1	1.26E+03	g C tonne-1
US Org chem.	Ozalp & Hyman, 2002	1.43	tonnes CO2 tonne-1	3.91E+05	g C tonne-1
Asphalt	Chehovits& Galehouse, 2010	8.5 - 13.1	Kg m2-1	2.32E+03 - 3.58E+03	g C tonne-1
Land clearing	Tyner et al., 2010	167.5	tonne CO2 ha-1	4.57E+07	g C ha-1
Foregone C seqestration.	Tyner et al., 2010	12.38	Tonne CO2 ha-1	9.38E+03	g C ha-1 mth-1

require additional fracturing to boost production. Emission intensities for upstream activities are therefore calculated using the predicted 10-yr production of the well. We note, however, that the Barnett experience indicates that wells may require earlier re-stimulation (ICF, 2009a); in this case the emission intensities would be expected to be greater than those reported here.

Predicting production rates for a play so early in development is difficult, as data particular to the northeastern Pennsylvania Marcellus play, where our representative well is located, is limited and recoverable resources vary widely across shale formations and even within a particular formation. We start with wellhead production estimates taken from industry reports (Engelder 2009) on projected 5-year cumulative production per well for the Marcellus play (8.8 million m^3 yr^{-1}). Berman (2009) concludes that industry has over-estimated potential production for many of the U.S. plays citing the differences between initial Barnett shale[g] predictions and reported well production over time. See also Hughes (2011). We have therefore compared the industry-reported Marcellus production estimates to reported 2009 and 2010 production for wells in Susquehanna County, PA (PADEP, 2010), assuming exponential decline curves. Given (limited) data currently available, we find the industry prediction is reasonable and base our well production on it. To adjust the 5-yr cumulative production to our 10-yr life of the well, we assume an additional reduction of 1/3 based on the decline curve, yielding 58.5 million m^3 cumulative production over 10 yrs.

Table 2.3 Wellhead Production and Life-Cycle Losses for a representative Marcellus shale gas well.

GROSS (casinghd)		cf	m^3	MJ
	5 yr cumm[a]	1.55E+09	4.39E+07	1.67E+09
	5 yr annual avg	3.10E+08	8.78E+06	3.34E+08
	10 yr annual avg[b]	2.07E+08	5.85E+06	2.22E+08
	10 yr cumm	2.07E+09	5.85E+07	2.22E+09
LOSSES				
1.9%	completion[c]	3.93E+07	1.11E+06	4.23E+07
1.1%	production[c]	2.27E+07	6.44E+05	2.45E+07
0.19%	processing[c]	3.93E+06	1.11E+05	4.23E+06
2.5%	Trans/dist[c]	5.17E+07	1.46E+06	5.56E+07
	Lease + pipe fuel[d]	3.37E+07	9.54E+05	3.63E+07
	Plant fuel[d]	8.93E+06	2.53E+05	9.61E+06
Sum losses NO PROC		1.47E+08	4.17E+06	1.59E+08
Sum losses PROC		1.60E+08	4.54E+06	1.72E+08
10 yr NET (no proc)		1.92E+09	5.43E+07	2.07E+09
10 yr NET (proc)		1.91E+09	5.40E+07	2.05E+09

[a] Engelder 2009
[b] 5 y production is extended to the assumed 10 y life of the well by reducing cumulative production by a third.
[c] median reported values from Howarth et al 2011
[d] long-term average for US domestic gas as reported by EIA 2011

However, cumulative wellhead production does not represent the energy available to end-users, as losses are incurred throughout the lifecycle; net production, or the balance between wellhead production and the total volume lost to fugitive/vent emissions and gas consumed as fuel enroute to consumers, is more appropriate. We therefore adjust wellhead production by subtracting the median fugitive methane losses reported in Howarth et al (2011) and lease, plant and pipeline gas consumed (average of US data 2000-2010 as reported by EIA, 2011). Table 2.3 provides a detailed accounting of the gross and net energy per well.

All gas conversions from volumetric to mass basis assume API standard conditions (1 atm and 288.75 K; Shires et al., 2009). Gas density is assumed to be 42.2 moles m^{-3} at these conditions. All combustion emissions assume 100% oxidation.

Stationary Engines

Upstream energy inputs for stationary combustion are estimated from the energy output (hp-hr/yr) of the various engines onsite. The largest of these engines are the prime-mover - the drilling rig's main power source - and the frac pumps. Estimated power required to run the drawworks is a function of total borehole depth with 10 hp required for every 30.5 m (Nguyen 1996), or a minimum power requirement of 880 hp for our Marcellus well. Industry sources report that the ideal and most commonly used rig in Marcellus drilling is a 1000 hp unit (NYDEC,2009; Rigzone, 2010), though completion rigs maybe significantly smaller. We assume a 1000 hp rig running at 50% for both drilling and completion. Frac pump hydraulic horse power (hhp) is a function of the injection rate (bpm) and surface treating pressure (psi). Typical Marcellus injection rates range from 30-71 bpm and with expected pressure ranges of 5,000 - 10,000 psi (NYDEC, 2009). Taking the average of each range, the minimum required hhp is 9283 hhp ((bpm x psi)/40.8), which we have rounded up to 9300 hhp. Smaller auxiliary engines are also needed to run mud and cement pumps, air supply, and generators that supply electricity to the doghouse and other onsite buildings. A detailed list of drilling, completion, and mobile engines is provided in Table 2.5.

Emissions for stationary drilling and completion engines are calculated from equation 1. For our well, all drilling-process engines are assumed to run at 50% load, 24 hrs/d, for 4 weeks, the low end estimate reported by NYDEC (2009). Frac pumps are assumed to run for an average of 70 hr (NYDEC, 2009) at 100% load (to meet calculated hhp requirements). All engines are assumed to run on diesel fuel and power output is converted to power input using a default thermal efficiency factor of 3179 J_{in}/J_{out} for diesel IC engines (Shires et al., 2009).

Eq 1. $$E_i = (ER * LF * OT * ETT) * EF$$

where:

E_i = g C emissions of species i

ER = equipment rating in hp

LF = fractional load factor

OT = operating time in hr well life^{-1}

ETT = Equipment thermal efficiency in J $_{input}$ hp-hr $_{output}$ $^{-1}$

Combustion emissions associated with other streams (i.e. production, processing, and transmission/distribution) in the life-cycle are difficult to estimate without details of site equipment and/or fuel usage data. We therefore rely on emission rates from the literature. ARI/ICF (2008) assessed the life-cycle GHG inventory of US domestic natural gas and LNG imports and indicate combustion emissions of 0.58, 0.49, and 0.15 g C MJ^{-1} (assuming 2006 US

Table 2.4 Internal Combustion Engines at Well Site, Activity Data [a]

Stationary Combustion	*no.*		*hp*	*load*	*hr/year*[b]
Drilling	1	Prime mover/drawworks (1000 hp)	1000	0.50	672
	2	Mud pumps (750 hp each)	1500	0.5	673
	1	Generators (1200hp)	1200	1.5	674
	2	Air package (30hp)	60	2.5	675
	1	Cement pump (750hp, 9.5 bpm max cap @ 2650 psi)	750	3.5	676
Stimulation	n/a	Pumps (50.5bpm, 7500 psi: min hhp = 9283.1)	9300	1.00	70
	1	Generators (1200hp)	1200	5.5	70
Mobile Combustion			*truc*	*load*	*# trips*
Equipment trucks		**TOTAL**	**280**	**0.5**	**2**
		Drill pad & road construction	45	1.5	3
		Drilling rig	30	2.5	4
		Drilling equip	50	3.5	5
		Completion equip	5	4.5	6
		Fracture stimulation equip	150	5.5	7
Fluids trucks		**TOTAL**	**650**	**6.5**	**8**
		Water trucks	440	7.5	9
		Chemical trucks	5	8.5	10
		Flowback trucks	190	9.5	11
		Production water trucks	15	10.5	12
Site clearing mobile combustion[c]			Joules per ha		
		Bulldozers (grading purpose; 335 net hp)	1.24E+12		
		large excavator (mid-level: 159 net hp)	9.77E+10		

[a] All engines are assumed to run on diesel fuel.
[b] Drilling activity is expected to last 4 weeks with engines running 24 hr d^{-1}; Fracturing time is expected to last from 40 to 100 hours per well depending on well and geologic characteristics (NYDEC, 2009); we use the average of 70 hours as a conservative estimate of pump engine time.
[c] Earth moving equipment input is estimated assuming 6 grading dozers and 1 large excavator employed in clearing the well site over 3 days at 12 hr d^{-1}. Energy input is then divided by the number of hectares cleared to convert energy input to a per hectare basis. Earth moving emissions are estimated separately for each category (pad, access road, or pipeline) assuming the area cleared and machinery used in clearing (see text).

domestic supply; DOE/EIA, 2011b) for production, processing, and transmission/distribution streams, respectively. Armendariz (2009) combined all compressor emissions in the Barnett shale as a single emission term (compressors are considered the only significant combustion emission source in the production and transmission streams) indicating a combined emission intensity of 0.69 g C MJ^{-1} for production and transmission; assuming a similar distribution of emissions as reported in ARI/ICF (2008), 80% of this can be attributed to the production stream (0.54 g C MJ^{-1}) with the remainder (0.14 g C MJ^{-1}) attributed to transmission engines. Here, we use the average of the two studies for reporting production and transmission emissions (0.56 g C MJ^{-1} and 0.15 g C MJ^{-1}, respectively). Only ARI/ICF (2008) reported processing emissions from combustion of plant gas; we use their value of 0.49 g C MJ^{-1}.

Mobile Engines

The numerous trucks and tankers needed to transport drilling and frac equipment, resources and waste products to and from the well site make up the mobile source category. Moss (2008) estimates 280 truckloads are required to transport drilling and completion equipment. Assuming a maximum load of 7,000 gal per truckload, we estimate an additional 1,069 truckloads are required to transport fresh water, fracing chemicals, and wastes.

Emissions from mobile internal combustion engines are calculated from equation 2. Truckloads are doubled and a 50% load is assumed to account for roundtrips. Estimated mobile source combustion estimates assume a default fuel economy factor of 0.161 gallons/mile for articulated diesel trucks (Shires et al., 2009). We assume average distances of 200 miles/truckload for drilling and completion equipment and an average of 125 miles/truckload for water, chemicals, and wastes. PADEP data from 2010 show recycling at about 40% of water brought to a well industry wide. We have therefore reduced water and waste truckload by 40%.

Eq 2. $$E_i = (load * 2 \; * FE * diesel\ HHV) * EF$$

where:

Load=the number of trucks required to transport a given volume of resources or equipment

FE = default fuel economy

Fuel HHV is expressed as J gal^{-1} assuming standard fuel density

Resource Consumption

In addition to consumption of diesel fuel, on-shore gas extraction consumes various manufactures and other resources - i.e. steel, cement, and gravel, as well as land resources - each of which have additional GHG emissions associated with them. Marcellus shale gas development additionally consumes large quantities of organic chemicals for use in fracturing fluids and hot mix asphalt for upgrading local roads which were not designed for high volume, heavy truck and tanker traffic.

Emission intensities for material resources consumed in preparing and developing the well site are generally given on a per mass or volume basis. Emission factors for the consumables considered here are given as g C-CO_2 tonne^{-1}, thus total emissions from resource consumption is simply a product of the EF and tonnage of resource consumed. We provide the calculations for estimating resource tonnage below.

Steel production - Steel consumption per well accounts only for steel tubing used in surface and production casings (conductor casing is not included because it is such a small percentage of total casing volume) and the fraction of gathering pipeline attributed to an individual well. Steel resources used in drilling masts and other heavy equipment is not included, as these uses continue from well site to well site and are not considered 'consumed'.

Eq 3.

$$T = ppf * L * \frac{tonne}{lb}$$

Where:
T = tonnes of steel
ppf = pounds per foot
L = length of pipe

Eq 4.

$$ppf = F * 10.68 * T * (OD\text{-}T)$$

where
F = relative weight factor adjusted to MAOP[h]
(default U.S. Steel ~ 1)
T = nominal wall thickness in inches
OD = nominal outside diameter in inches

Steel tonnes required for well casings and gathering pipeline is calculated from the weight of steel (ppf) and total length of the pipe (Eq 3). Weight of casing tube steel is reported in the casing design (Table 2). The mass of steel consumed in construction of the recently proposed Laser gathering line is estimated using equation 4 and assuming 52.32 ppf and a total of 3.38 km of pipeline (Laser 2010). Steel tonnage consumed over the entire pipeline is then adjusted to a per well basis assuming the current number of wells connected.

If New York State lifts its moratorium on HVHF drilling, the number of wells connected to the gathering line will undoubtedly rise, although additional connections will also require additional piping. Emission intensity (tonnes CO_2 tonne $^{-1}$ steel) for steel manufacturing is taken from recent industry reported values (AISI, 2009).

Cement production – Cement consumed is limited to that used in sealing the conductor, surface and production casings. We calculate the mass of portland cement used in stabilizing well casings based on the annular volumes of the casings as suggested by the well specifications (Eq

5; Table 2.1). Emission intensity for U.S. cement manufacturing is taken from Hanle et al. (2004).

Eq 5. $$T = \sum \left[\left(\frac{\frac{5.615\ cf}{bbl} * AC_i * L_1}{yield} \right) * E_i \right] * \frac{tonne}{lb}$$

where:

T = tonnes of portland cement
AC = annular capacity of casing string i expressed as bbl ft^{-1}
L = length of the casing string $_i$ in feet
E = percent excess for casing string i expressed as a fraction
yield = cf of cement per 94 lb sack

Chemical manufacturing – Fracing chemical tonnage is estimated based on the expected volume of water consumption and mass ratio of chemicals consumed in the frac fluid relative to water (Eq 6). The Marcellus wells are expected to consume a total water volume 19.3 x 10^6 L with 0.5% chemicals added to the fluid on a mass basis (NYDEC 2009). Thus, we assume 96 tonnes of chemicals are consumed per well. Emission intensity (tonne CO_2 tonne $^{-1}$ production) for the U.S. organic chemical industry is taken from Ozalp and Hyman (2009).

Eq 6. $$T = (H2O * F_c) / 2204.6$$

where

T = total tonnes of chemical
F_c = mass fraction of chemical compound in fluid
H2O = lbs of water consumed

Gravel mining - The well pad and access road to the pad require several thousand tonnes of gravel to provide substrate and help control dust. Tonnes gravel consumed is estimated from total area and density of the aggregate (Eq 7). For both the pad and road we assume a thickness of 0.305 m and a mass of 1.365 tonne per cubic yard (t cyd^{-1}). The well pad is assumed to have a land area of 2 ha (NYDEC, 2009). We use the NY DEC (2009) estimated land area for the access road (1609 x 9 meters). The calculated tonnage is then converted to a per well basis assuming 8 wells per pad. Emissions from gravel production are estimated at 1.26E3 g C-CO_2 tonne $^{-1}$ (EPA 2003).

Eq 7. $$T = L * W * D * \frac{cyd}{cf} * d$$

Where

T = tonnes gravel (virgin aggragate)
L = length of the plot in feet
W = width of the plot in feet
D = depth of gravel cover in feet
d = density of the aggregate expressed as tonnes

Asphalt production - Most of the roads in counties where shale gas development is expected to be greatest are not constructed to handle the increased loading and traffic counts that are expected, resulting in substantial road damage. Damage is expected to be exacerbated by seasonal freeze/thaw cycles which may lead to roads so damaged that they are not passable. To address these concerns, counties in the already developed areas of the play have bonded roads used by the gas industry. Under such contracts, gas development companies agree to upgrade the roads they use to withstand the heavy truck traffic or pay for any excess repairs over normal maintenance. Pennsylvania DOT (2010) reports 1360 km of bonded road throughout Lackawanna, Luzerne. Pike, Susquehanna, Wayne, and Wyoming counties. Total Marcellus well count for these counties in 2010 is 159 (PA DEP 2010), yielding an estimated road area of 8553 x 9 meter per well.

Emission factors range from 2,265 g C-CO_2 m^{-2} for repaving with hot in-place recycling (HIR) to 3,575 g C-CO_2 m^{-2} for new road construction (Chehovits and Galehouse, 2010). Our calculations assume the mid-level option of repaving using hot mixed asphalt (HMA) with an emission factor of 2,320 g C-CO_2 m^{-2} (Chehovits and Galehouse 2010).

Additional consumables - We do not account for a number of other consumables such as pad liners, waste pit liners, spill absorbing materials, etc.

Land clearing – Emissions related to land clearing for a well pad, access road, and gathering line construction include both initial carbon loss and forgone carbon sequestration. Not all of these land clearing activities, however, will stay cleared for the same length of time. For example, 2/3 of the well pad might be reseeded within 9 months (1 month per well at 8 wells per pad) of the start of drilling and allowed to return to a nearly original state. The area surrounding gathering lines will also be reseeded, but the land will need to remain treeless to protect the buried lines. Annual grassland carbon uptakes are low (< 0.002 g C ha^{-1}; Soussana et al., 2009); therefore, we have assumed no reclamation for pipeline land area. Access roads are expected to remain as roads (e.g. no restoration).

We assume 2 ha of disturbance per well pad (Moss, 2008), and 0.44 ha for the access road (477 x 9 meters). The area required for gathering line construction includes 1609 meters of pipe per well pad and adequate width to allow machinery access to the site during construction (15 meters), or 2.46 ha. Total disturbance is ~5 ha per site, or 0.62 ha per well. The NYDEC (2009) estimates total disturbance in the range of 1.66 - 3.3 ha per multi-well site not including gathering lines.

Direct carbon loss and forgone carbon sequestration are estimated from area (ha) per well (Eq 8) assuming 8 wells per pad and accounting for the varying time frames of land disturbance and regrowth.

Eq 8. $$E = (A * EF_{loss}) + (A * EF_{seq} * t)$$

where:

E = Emissions of CO_2 (g C /well)
A = Area of land per well (ha)
EF_{loss} = Emission Factor for terrestrial CO_2 emissions resulting from disturbance (g C/ha)
EF_{seq} = Forgone sequestration of CO_2 resulting from land disturbance (g C/ha/month)

We also account for combustion emissions associated with the machinery required to clear the land. We assume 1,235 GJ ha^{-1} required for grading bulldozers and 98 GJ ha^{-1} for excavators. Pad and access road is assumed to employ both excavator and dozers, while the pipeline is assumed to make use of excavators only.

Table 3. Emissions of carbon dioxide from developing shale gas, including both indirect emissions and end use combustion

	HHV	LHV
	g C-CO2 MJ^{-1}	
Land disturb. & resources consumed	**0.16**	**0.17**
disturbance	0.01	0.01
Land clearing	<0.01	<0.01
Resource consumption	0.15	0.15
Exploration & development	**0.24**	**0.25**
Drilling combustion - RIG + FRAC	0.18	0.19
Drilling combustion-MOBILE	0.06	0.07
Gas production	**0.56**	**0.59**
Processing	**0.49**	**0.52**
Transmission & distribution	**0.15**	**0.16**
End-use combustion	13.70	15.00
TOTAL (w/processing)	**15.29**	**16.69**
TOTAL (no processing	**14.81**	**16.17**

We estimate total indirect CO_2 emissions as between 1.17 and 1.69 g C MJ^{-1} per unit of energy available when the gas is finally combusted (LHV), depending upon whether or not the gas is processed to remove sulfur and other non-methane constituents (Table 3). Note that these estimates are slightly greater than those we reported in Howarth et al. (2011), a range of 1 to 1.5 g C MJ^{-1}, since those did not include the land disturbance effects. The largest component of indirect CO_2 emissions is production engines (0.59 g C MJ^{-1}). When gas needs to be processed, that is the next largest source of indirect emission (0.52 g C MJ^{-1}). The other indirect CO_2 emissions come during exploration and development (0.25 g C MJ^{-1}), land disturbances and resource use (0.17 CO_2), and transmission and distribution (0.16 CO_2). We did not explicitly estimate the indirect CO_2 emissions from conventional gas, but Woods et al. (2011) conclude that indirect CO_2 emissions from shale gas are 0.04 to 0.45 g C MJ^{-1} greater than for conventional gas.

The indirect CO_2 emissions from developing shale gas are not trivial, but they are small compared to the direct CO_2 emissions as the gas is burned: 15 g C MJ^{-1} (also LHV; Hayhoe et al. 2002; Howarth et al. 2011). A far greater part of the greenhouse gas footprint of shale gas comes from methane venting and leakage. Using a 20-year integrated time frame to compare the global warming consequences of methane with CO_2, we concluded in Howarth et al. (2011) that methane emissions from shale gas contribute 21.3 to 48.6 g C MJ^{-1} CO_2 equivalents. Methane dominates the greenhouse gas footprint of shale gas, at least when viewed over the 20-year time horizon.

Endnotes

a. The use of "unconventional" to describe a gas resource is open to interpretation; as technology advances and discrete reservoirs become limited, the reserves considered "unconventional" a few decades ago are more commonly viewed as conventional by modern standards. In this paper, "conventional " refers specifically to discrete reservoirs of associated or unassociated natural gas and "unconventional" refers to tight-gas formations.

b. Note that the definitions of direct and indirect emissions here are consistent with Howarth et al. (2011) but differ from the API definitions (Shires et al 2009).

c. Accuracy of direct measurement is dependent on the compatibility of monitoring frequency and timing of emission source activity (Shires et al., 2009)

d. CO_2 emission factors are constrained by fuel characteristics; therefore uncertainty in country-level EFs is generally below ±5% (IPCC 2007)

e. Unconventional gas pads in shales may include as many as 16 wells, though NYDEC (2009) reports 6-8 as more common. We assume 8 wells per pad when allocating well pad emissions to an individual well.

f. New multi-turn storage is expected to require HVHF of abandoned wells (as done in developing the Stage Coach storage facility in Owego, NY) if natural gas is to replace a significant portion of coal use in the electricity generation sector (Aspen Environmental Group, 2010).

g.The Barnett shale in the Fort Worth region of Texas is the oldest and most highly developed example of HVHF gas extraction in the U.S. and has the benefit of relatively long-term production and well data.

h. MAOP = maximum allowable operating pressure

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