GHG Emissions Associated with Two Proposed Natural Gas Transmission Lines in Virginia[i]

Summary of GHG Emission Estimates

The primary purpose of this white paper is to estimate possible greenhouse gas (GHG) emissions associated with several proposed new interstate natural gas transmission lines that would run through parts of Virginia. By "associated" emissions we mean the major GHG emissions that are estimated to occur (a) from operation of the transmission pipelines, (b) from the upstream stages of production and processing of the natural gas that is intended to go into to those transmission pipelines, and (c) from combustion of the transported natural gas. (The analysis excludes leaks from local distribution lines, which we assume would be avoided if the gas will be combusted in large plants connected closely to the transmission lines; however, local distribution lines are a major source of methane emissions and would need to be accounted for—in addition to combustion emissions—if deliveries are first made to local gas distributors.)

The four major interstate natural gas transmission lines and their daily throughputs of gas proposed in Virginia are the Atlantic Coast (ACP, 1.5 bcf/day), the Mountain Valley (MVP, 2.0 bcf/day), the WB Xpress Project to expand the capacity of the Columbia Gas Transmission pipeline by 1.3 bcf/day), and the Appalachian Connector (up to 2 bcf/day), for a total of 6.8 bcf/day.

Our emission estimates for the Atlantic Coast (ACP) and Mountain Valley (MVP) pipelines are summarized in Figures 1 and 2, respectively. The base case (in the first column of the Figures) is from a published analysis: that of Laurenzi and Jersey (2013), referred to here as the "ExxonMobil" analysis since the authors are employees of that Corporation and used data from drilling sites owned by it. In addition we developed three alternative cases based on different assumptions than used in the ExxonMobil results, although one of those cases is derived directly from the ExxonMobil results. In general, the four cases fall into two pairs (labeled ExxonMobil and"EX") that amount to a low and a higher estimate of upstream emissions of methane (CH_4), while estimated carbon dioxide (CO_2) remain the same for all cases. Within each pair the difference in carbon dioxide-equivalent (CO_{2eq}) total emissions is due to two different assumptions about how methane is weighted—known as the Global Warming Potential (GWP) of methane. (More detail on the quantitative contributions of CO_2 and CH_4 in the four cases is given in Tables 1 and 2 in the next section.) For comparison to those pipeline-associated GHG emissions, a seventh column in the Figures shows the total reported emissions of GHGs in Virginia in 2014 from EPA's Greenhouse Gas Reporting Program.

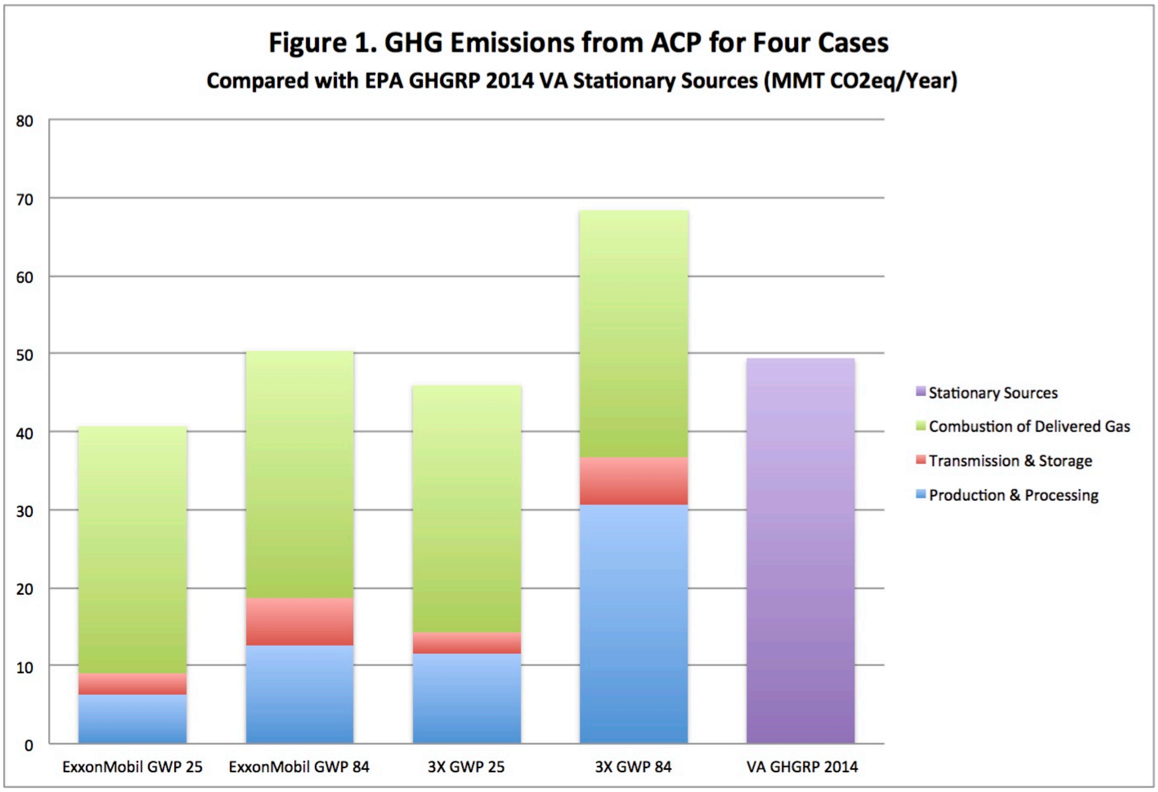


Figure 1. GHG Emissions from ACP for Four Cases
Compared with EPA GHGRP 2014 VA Stationary Sources (MMT CO2eq/Year)
80
70
60
50
40
30
20
10
0
ExxonMobil GWP 25
ExxonMobil GWP 84
3X GWP 25
3X GWP 84
VA GHGRP 2014
Stationary Sources
Combustion of Delivered Gas
Transmission & Storage
Production & Processing

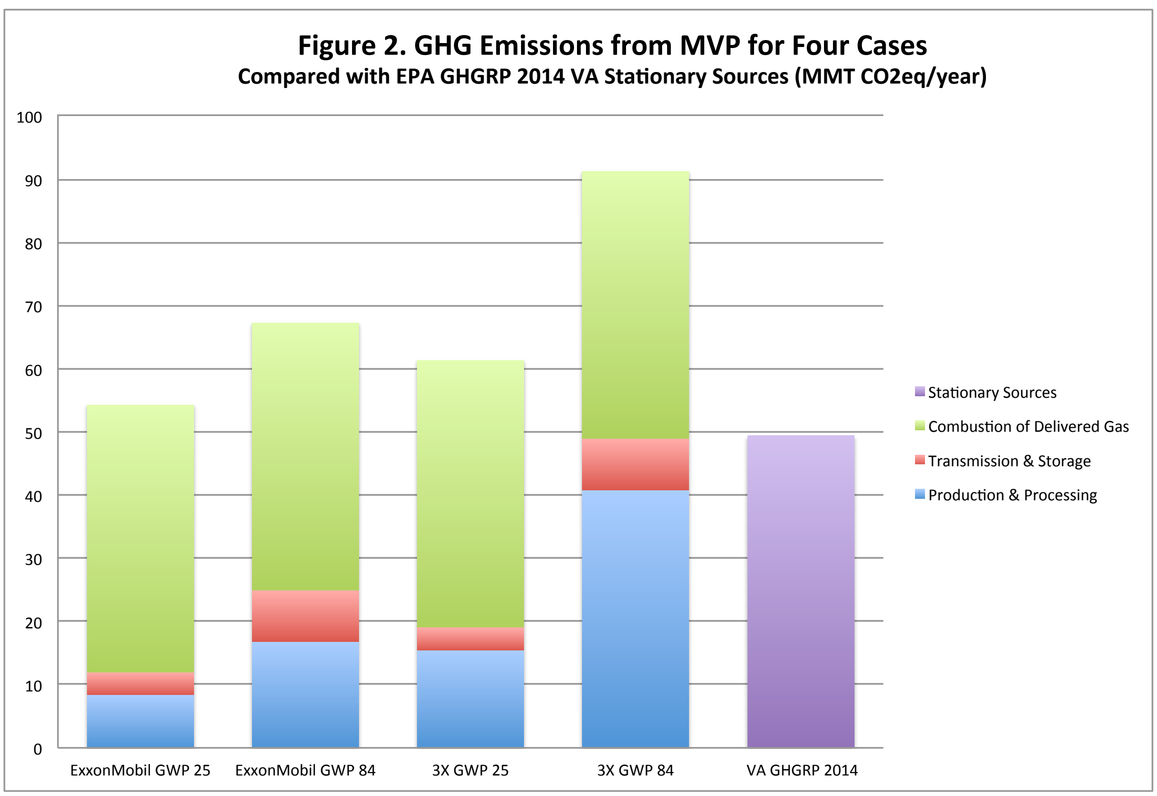
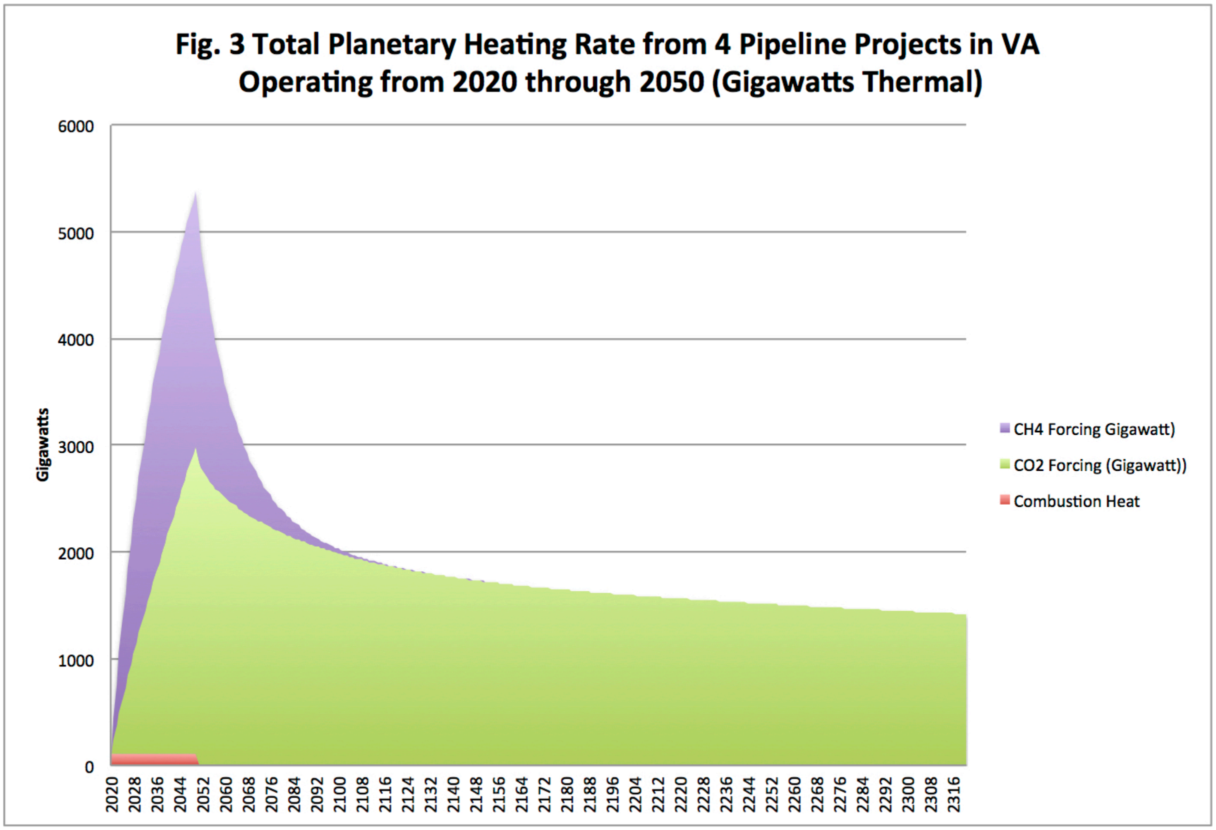


Figure 2. GHG Emissions from MVP for Four Cases
Compared with EPA GHGRP 2014 VA Stationary Sources (MMT CO2eq/year)
100
90
80
70
60
50
40
30
20
10
0
ExxonMobil GWP 25
ExxonMobil GWP 84
3X GWP 25
3X GWP 84
VA GHGRP 2014
Stationary Sources
Combustion of Delivered Gas
Transmission & Storage
Production & Processing

The issue of which GWP to choose can be bypassed by computing the time-dependent radiative forcing due separately to CO_2 and CH_4. Figure 3 shows the results of calculations of radiative forcing computed by a simple model. However, instead of showing radiative forcing in conventional units of watts/meter^2 we show the total thermal heating effect on the planet of GHG emissions from all four pipeline projects, consisting of the radiative forcing multiplied by the total surface area of the Earth plus, for comparison, the much smaller generation of heat generated by combustion of the natural gas delivered by the pipelines. Note that the thermal effect of CO2 persists long after operations cease (we show it for 300 years), and will last for centuries after that. The basis for this graph is explained in more detail in the Discussion section below.



A more detailed explanation of the results is given in the next section. A subsequent section, Discussion of Assumptions and Results, describes the underlying basis and compares our results to other studies from the recent literature. Following that section we present some recommendations based on the results and lessons learned in analyzing the literature on emissions from the natural gas fuel cycle.

Detailed Description of Results

The ExxonMobil analysis produced results based on emission values per unit output of a hypothetical natural gas electric power plant (Kg CO_{2eq}/MWh), and we scaled their GHG emissions values to correspond to the potential maximum natural gas throughput of the respective pipelines (1.5 Bcf/day for ACP and 2.0 Bcf/day for the MVP). We chose this study because it was a partial LCA analysis (of the production at the well head stage), provided detailed results for process steps separately for carbon dioxide (CO_2), methane (CH_4) and nitrous oxide (N_2O) emissions, and pertained to conditions specific to natural gas from hydraulic fracturing production in the Marcellus shale region, which is identified as the source for the two pipelines in question, including some measurements made on the Corporation's own well operations.

However, while these ExxonMobil estimates are useful as a starting point, they may not be representative of all fracking operations in the Marcellus or other shale regions. In fact, other estimates of overall emissions from that region suggest much higher fugitive emissions of methane, and it is clear that some operators are responsible for much more emissions per unit of production than others. For that reason we also present an alternative set of estimates for methane emissions from the overall production and processing stage, as discussed below. Note that neither of these estimates appears to consider the problem of post-production leaks, which, as documented by Schlumberger, may emerge many years after a well has been capped and taken out of operations.

Figure 1 and Table 1 show results applicable to the ACP pipeline, while Figure 2 and Table 2 show similar results for the MVP pipeline. For simplicity, we aggregated the original authors' more detailed process level results into three major fuel cycle stages:[1] Production and Processing (i.e., operations upstream of the transmission line), Transmission and Storage, and Combustion of the delivered pipeline gas (assuming no local distribution). (CO_{2eq} emissions of N_2O are neglected in Tables 1 & 2 as relatively small compared to the GHG impacts of methane and CO_2 emissions.) We believe that assessing GHG emissions from all three major fuel cycle stages, not just the transmission pipeline stage, is important because these new pipelines are intended to collect the produced gases and transport them to new or expanded markets in Virginia and North Carolina, and possibly even to foreign export terminals. Hence, the pipelines will tend to generate or at least support additional uses of natural gas that arguably will result in greater gas production and combustion and their associated emissions. Some of the uses may include new industrial plants owned by foreign companies that are attracted to the region by the availability of cheaper natural gas supplies than available abroad. Pipeline proponents have been touting such economic development as a benefit of their pipelines.

The two principle issues in making methane leakage estimates are: 1) what is the actual leakage rate of methane from various stages of the natural gas fuel cycle? and 2) what is the appropriate choice of *global warming potential* (GWP) (or other method) to apply when comparing emissions of CO_2 to other GHGs, especially to methane? The reason

[1] The f*uel cycle* approach means analysis of operational impacts of all relevant stages from extraction through use and disposition of wastes; a *life cycle analysis* (LCA) approach extends the analysis to consideration of the indirect impacts of manufacturing and transporting the equipment and the raw materials that go into the stages and is evaluated over the estimated lifetime of the capital facilities.

there are four columns in the two tables and first two figures is because we made alternative choices for both of those issues. In Tables 1 and 2 the first column is from the generic estimates given by Laurenzi and Jersey (except for the scaling up to each pipeline). Note that the scale-up assumes the pipelines operate at full capacity 24/7/365 because we have no estimates from the proponents about their planned operating schedule. The second column adjusts the methane CO_{2eq} emission values (the first column was based on EPA's 100-year GWP assumption of 25) to the 20-year GWP of 84 from IPCC AR5 when summing to obtain total CO_{2eq} emissions from each stage. The third and fourth columns (3X) increase the methane emissions from Production and Processing (but not the transmission or combustion stage emissions) by multiplying Columns 1 and 2, respectively, by a factor of three to reflect results typical of *top-down* higher methane emission measurements in the Marcellus and other shale basins. The reason for this choice is explained below in the Discussion section. Those two adjustments increase the upstream production and processing emissions in Column 4 by a factor of 4.9 and the total system emission by a factor of 1.7 relative to column 1. (Note that the CH_4 emission values shown in the Tables are in million metric tonnes (MMT) of methane, not CO_{2eq}.) The CO_{2eq} values from the four columns in the tales are also shown graphically in the bar charts of Figures 1 and 2.

For comparison, Virginia's two largest sources of CO_{2eq} GHG emissions in 2014 were the Chesterfield (7.22 MMT) and Clover (5.67 MMT) coal-fired power plants. The Column 1 total in Table 1 from the ACP pipeline (40.7) is comparable to the total contribution from the 177 GHG sources in Virginia (49.4 MMT CO_{2eq}) from EPA's Greenhouse Gas Reporting Program (GHGRP) in 2014, while the total in Table 2 from the MVP pipeline considerably exceeds it.[2] (However, only part of the emissions in Tables 1 and 2 would occur in Virginia.) These Virginia GHGRP values also are compared against the pipeline values in Figures 1 and 2. Obviously the comparable totals for the higher methane emissions assumed in Columns 3 and 4 of the two tables would be even higher, but only Columns 1 and 3 should be compared with EPA's GHG values since the latter also assume a GWP of 25. Emissions from the other two proposed pipelines would nearly double the total emissions from the ACP and MVP for a total of 185 MMT CO_{2eq} at a GWP of 25 in the base case, the ExxonMobil rates, or 3.7 times the EPA GHGRP total for Virginia.

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[2] This is based on EPA's "Flight database" from their Greenhouse Gas Reporting system, but that database excludes GHG emissions from onshore oil and gas production at the state level, hence it does not include the emissions from coal bed methane extraction operations in Virginia, for example. Also, the list of 177 large sources includes some that reported zero emissions in 2014 compared with substantial emissions in prior years and EPA generally assumes the GHGRP reported emissions underestimate actual totals somewhat. Only large sources are required to report, and the database does not include transportation and many small sources

TABLE 1. Generic GHG Emission Estimates for the ACP Pipeline

GHG Emissions by gas and fuel cycle stage	ExxonMobil* (w/CH_4 GWP=25 over 100 years)	Adjusted ExxonMobil* (w/CH_4 GWP=84 over 20 years)	Top-Down Higher CH4 Leakage Estimate** (w/CH_4 GWP=25)	Top-Down Higher CH4 Leakage Estimate** (w/CH_4 GWP=84)
Production & Processing				
CO_2 (MMT CO_2/year)	3.60	3.60	3.60	3.60
CH_4 Losses (MMT CH_4/year)	0.107	0.107	0.321	0.321
Total CO_{2eq} Emissions (MMT/year)	6.3	12.6	11.6	30.6
Transmission & Storage				
CO_2 (MMT CO_2/year)	1.27	1.27	1.27	1.27
CH_4 Losses (MMT CH_4/year)	0.058	0.058	0.058	0.058
Total CO_{2eq} Emissions (MMT/year)	2.7	6.1	2.7	6.1
Combustion of Delivered Gas				
CO_2 (MMT/year)	31.7	31.7	31.7	31.7
Grand Total GHG Emissions (MMT CO_{2eq} /year)	40.7	50.4	46.0	68.4

* ExxonMobil means the ANALYSIS analysis of Laurenzi & Jersey (2013); note that this was a generic analysis, not specific to the ACP pipeline. The values here represent a conversion from their numbers in terms of emissions/MWh into emissions/SCF, which are multiplied times the ACP capacity of 1.5 Bcf/day to get the MMT/year values shown here. These values assume full-time operation 24/7/365.

** Assumes 3 X ExxonMobil CH_4 Production & Processing emissions (see discussion)

TABLE 2. Generic GHG Emission Estimates for the MVP Pipeline

GHG Emissions by gas and fuel cycle stage	Exxon-Mobil* (w/CH_4 GWP=25 over 100 years)	Adjusted Exxon-Mobil* (w/CH_4 GWP=84 over years)	Top-Down Higher CH4 Leakage Estimate** (w/CH_4 GWP=25)	Top-Down Higher CH4 Leakage Estimate** (w/CH_4 GWP=84)
Production & Processing				
CO_2 (MMT CO_2/year)	4.8	4.8	4.8	4.8
CH_4 Losses (MMT CH_4/year)	0.143	0.143	0.428	0.428
Total CO_{2eq} Emissions (MMT/year)	8.4	16.8	15.5	40.8
Transmission & Storage				
CO_2 (MMT CO_2/year)	1.7	1.7	1.7	1.7
CH_4 Losses (MMT CH_4/year)	0.077	0.077	0.077	0.077
Total CO_{2eq} Emissions (MMT/year)	3.6	8.1	3.6	8.1
Combustion of Delivered Gas CO_2 (MMT/year)	42.3	42.3	42.3	42.3
Grand Total GHG Emissions (MMT CO_{2eq} /year)	54.3	67.2	61.3	91.2

* ExxonMobil means the ANALYSIS analysis of Laurenzi & Jersey (2013); note that this was a generic analysis, not specific to the MVP pipeline. The values here represent a conversion from their numbers in terms of emissions/MWh into emissions/SCF, which are multiplied times the MVP capacity of 2.0 Bcf/day to get the MMT/year values shown here. These values assume full-time operation 24/7/365.
** Assumes 3 X ExxonMobil CH_4 Production & Processing emissions (see discussion)

Discussion of Assumptions and Results

The two principle issues in making these estimates are: 1) what is the actual leakage rate of methane from various stages of the natural gas fuel cycle, and 2) what is the appropriate choice of *global warming potential* (GWP) (or other method) to apply when comparing emissions of CO_2 to other GHGs, especially to methane? Both of those questions have been issues for several decades. Neither is completely settled today. We have approached it in our estimates by choosing a lower and higher value for each factor, and also produced a separate analysis that obviates the GWP issue.

The issue of leakage rates remains unresolved and a very controversial topic. The way chosen here to represent a range of opinion on leakage rates from the upstream production and processing stages is to show a lower estimate (the so-called ExxonMobil values, which are similar to EPA's emission factors) vs. a higher estimate (the "3 X" or "Top-Down Higher" values in Columns 3 &4) as explained further below.

Choice of GWP. The GWP issue is now quite well understood scientifically but remains controversial in the policy and political arenas. The issue with a GWP selection is that the UN adopted a 100-year GWP as part of the Kyoto Protocol. EPA also adopted it because of the need to have a specific way to weight various GHGs and value emission tradeoffs and to be consistent with International reporting requirements. However, for other purposes such as evaluating mitigation strategies and longer-term tradeoffs, many climate scientists and policy analysts, including the latest IPCC reports, now understand its limitations. For strategic purposes there are alternative solutions for characterizing the relative impacts available in the literature (e.g., Alvarez et al. 2012) that render that choice irrelevant. However, for simplicity here we simply compute methane effects for two widely different values of the GWP to illustrate the range: EPA's value of 25 (that was based on the IPCC AR4 2007 report for a 100-year time frame) and was used by Laurenzi and Jersey, and the IPPC AR5 2013 value of 84 for a 20-year time frame. We believe that the latest scientific estimates should be applied and that there is no scientific justification for preferring a 100-year over a 20-year values, especially since many of the GHG mitigation goals of the U.S. (for example, the U.S. pledge to the UNFCCC process for 2025) will occur over much shorter periods of time, closer to a 20-year period.

We also show in Figure 3 the results of a simple model that shows the temporal evolution of planetary heating due to the emissions of CO_2 and CH_4 (separately) plus heating from combustion of the delivered gases from all four pipeline projects. For this chart we used the higher methane emission rates (columns 3 and 4 in the tables). Planetary heating from the GHG emissions means the incremental radiative forcing at the top of the atmosphere due to the emitted gases. Our simple model is similar to that described by Alvarez et al. 2012, although we use updated parameters based on the latest estimates of total greenhouse gas concentrations in the atmosphere and display our results in absolute terms as planetary heating. Our model will be described in more detail in a subsequent paper. This approach eliminates the need for using GWPs and provides more information.

Production and Processing Stages. Estimates of GHG emissions from natural gas production, processing and gathering pipeline transport operations differ widely and currently are very controversial. Briefly, there is an unresolved disconnect between two general approaches to estimating emissions: so-called *bottom-up* methods that sum up measurements and/or generic emission factor-based estimates for individual operations and equipment in the overall process, versus *top-down* methods based on measuring concentrations of methane in the atmosphere for some region in which there are natural gas and/or oil producing operations, then translating those measurements into estimates of emissions associated with natural gas and oil production, processing and other stages (depending on what operations are occurring in the study region). Those two approaches lead to estimated emissions that can differ by as much as an order of magnitude. Figure 4 below shows some examples of top-down compared with EPA bottom-up estimates. Note that several top-down estimates shown in Figure 4 have a median value of about 10% leakage, compared with the EPA estimate between 1 and 2%.

Tables 1 and 2 begin with one estimate (Columns 1 & 2) of a bottom-up approach, the Exxon-Mobil study, which is near the lower end of the range of such estimates, (although there are even lower ones). It amounts to about 1.12 % leakage of methane from the upstream production and processing stages of Marcellus shale fracking, in particular in the Southwestern Pennsylvania part of that region. We also give hypothetical (3X) estimates (Columns 3 & 4) (based on multiplying the Exxon Mobil results by a factor of 3) that we believe are representative of the middle of the top-down estimates and also are comparable to the higher end of bottom up estimates), which is equivalent to upstream methane emissions of about 3.4%. The ExxonMobil results for methane emission appear to be roughly in the same range as some other bottom-up estimates near the low end, including values based on EPA's Greenhouse Gas Emission Inventory. There are a number of general issues with most bottom-up studies, including the difficulty of assuring that individual measurements made to determine emission factors are representative of the broader industry operations, and that most measurements have been made by or in close association with the producing industry that has a vested industry in showing low emissions. (It is difficult to make detailed measurements at a site without the operator's cooperation, and there always is a question about whether the operator may do things differently when he knows researchers or government inspectors are present.)

The particular high-end estimate for methane leakage we use here (3.4%) is comparable to the top-down results reported in the study by Petron *et al.* (2014), *viz.* 4.1±1.5%. However, that pertained to natural gas production from a combination of oil and gas wells and supporting infrastructure. That study involved atmospheric studies using various combinations of ground-based air monitors, aircraft measurements, and other measurements of methane and VOC concentrations. There have been relatively large uncertainty bounds on top-down methods. (See bounds shown in Figure 4 below, but also the newer Zavala-Araiza *et al.,* 2015 study discussed below.) The advantage of top-down estimates is that they tend to capture all the methane emissions in a region, including natural gas industry sources that may have much higher emissions than represented by emission factors (and there is much evidence that a few large leakage sources account for a disproportionate contribution to totals). Their result was nowhere near the worst-case leakage example among top down studies, some of which found values of methane leakage on the order of 10% or more, as shown in Figure 4. A leakage rate of 3.4% is also consistent with higher estimates using bottom-up methods from the literature [for example, see Brandt et al. (2014)]. Atmospheric measurements do not measure CO_2 emissions, so we use the same CO_2 estimates from Laurenzi and Jersey in this column in Table 1. Also note that atmospheric measurements do not necessarily capture all the indirect LCA values since some of those may apply to operations outside the producing areas, but those tend to be the smaller part of the total emissions.

A very recent report by Zavala-Araiza *et al.* (2015) reconciles bottom-up and top-down estimates in the Barnett shale oil and gas-production region of Texas. It augments conventional bottom-up inventories, accounts for high emitters, and compares them to top-down aircraft studies in which ethane measurements are used to correct for biogenic sources. Their bottom-up inventory is 1.9 times estimated emissions based on the EPA GHGI program, and represents a methane leakage rate of 1.5% (1.2—1.9%). The Aircraft top-down measurements of fossil methane averaged about 10% higher than the bottom-up estimates, but still within the top-down uncertainty bounds. Those results for the Barnett region indicate a significantly smaller leakage rate than the Petron et al. (2014) results obtained in the Denver-Julesburg gas and oil production region.

The Zavala-Araiza results (a methane leakage rate of 1.5% for upstream production and processing stages) suggest a medium leakage case in between our base Exxon Mobil value and the "Higher 3X" leakage estimate of 3.4% in columns three and four. Of course, neither of those estimates from other basins necessarily pertains to the Marcellus shale gas production region, so we cannot say whether our assumed medium and high values in the Tables and Figures are consistent. We do not claim that the value of 3.4% used here is a valid upper estimate for the Marcellus region, but only that it illustrates the potential impact of a higher estimate that is slightly smaller than a top-down result from another region that involved particularly comprehensive measurements.

A report by Marchese *et al.* (2015) gives estimates of emissions from the gas processing and gathering pipeline stages (which stages are included in our estimates of Production and Processing). Generally they found that their measurements of 16 gas processing plants were even lower than EPA's emission factors, but measurements of 114 gathering pipeline facilities were often much higher than EPA emission factors. A few of the smaller gathering facilities appear to have leakage rates exceeding 10% of gas throughput, but most were much less than that. Marchese et al. did conclude that:

> "While there is uncertainty in determining gathering facility emissions from the EPA GHGI, the results of this study suggest that the GHGI substantially underestimates emissions from gathering facilities.

The Marchese study indicates that emissions from gathering lines may be considerably larger than estimated in the ExxonMobil analysis. However, such increased methane emissions presumably would already be accounted for in broad region top-down studies that are the basis for our medium and higher methane estimates, so there does not appear to be a need to factor that into our results in columns three through six.

A recent report, Concerned Health Professionals of New York Report (2015), found that (p. 52-57):

"Leakage from faulty wells is an issue that the industry has identified and for which it has no solution. According to Schlumberger, one of the world's largest companies specializing in fracking, about five percent of wells leak immediately, 50 percent leak after 15 years, and 60 percent leak after 30 years. Data from Pennsylvania's Department of Environmental Protection (DEP) for 2000-2012 show over nine percent of shale gas wells drilled in the state's northeastern counties leaking within the first five years. Leaks pose serious risks including potential loss of life or property from explosions and the migration of gas or other chemicals into drinking water supplies.

"Leaks also allow methane to escape into the atmosphere, where it acts as a more powerful greenhouse gas than carbon dioxide. Indeed, over a 20-year time frame, methane is 86 times more potent a heat accumulator than carbon dioxide. There is no evidence to suggest that the problem of cement and well casing impairment is abating. Indeed, a 2014 analysis of more than 75,000 compliance reports for more than 41,000 wells in Pennsylvania found that newer wells have higher leakage rates and that unconventional shale gas wells leak more than conventional wells drilled within the same time period. Industry has no solution for rectifying the chronic problem of well casing/cement leakage."

Combustion Stage. CO_2 emissions from the natural gas-fired combustion (e.g., power plant) stage depend mainly on the amount of gas consumed, which in this case is simply the throughput of the pipeline, and slightly on the composition of natural gas (which changes the CO_2 per cubic foot). Effectively we used the latter factor from Laurenzi and Jersey since they based it on typical pipeline natural gas produced in the Marcellus shale region (rather than EPA's nominal emission factor). Any combustion use of the transmission line natural gas throughput would give the same result. However, natural gas delivered further for use through local distribution lines would have higher overall CO_{2eq} emissions because of the substantial extra leakage of methane in many distribution systems. GHG emissions published by Laurenzi and Jersey from this stage are just from combustion, are not based on a life cycle analysis, and do not account for any leakage of methane or unburned methane in the power plant exhaust or pre-combustion handling. While we could not find a definitive emission factor from EPA for methane specific to NGCC power plants, NETL (2010) gives the factor 8.56 E-06 kg/MWh for NGCC plants[3]. That would be negligible compared with the CO_2 emissions.

Transmission and Storage (T&S) Stage. Our base estimate for this stage is based on a different treatment. The ExxonMobil analysis did not base their estimate on a life-cycle analysis or a detailed calculation of emissions from pipeline facilities. Rather, it takes

[3] Methane emission factors vary with the type of combustion process; methane and N_2O emissions from simple gas turbines and other engines used to power pipeline compressors are not as small; e.g., EPA's AP-42 GHG emission factors for natural gas-fired turbines are 0.003 lb/MMBtu for N_2O and 0.0086 for CH_4, which together amount to about 1.4% of the CO_2 emissions when the AR5 20-year GWPs for those gases are applied (268 for N_2O).

2009 EPA estimates of total T&S fugitive methane emissions and total CO2 from compressors to calculate the ratio to total natural gas withdrawals that year. That results in an average leakage rate of 0.45% of methane and an average amount of CO2 emissions of 82 Kg/MMScf of transported gas. We only have limited information about the two proposed pipelines, such as lengths, sizes, compressor horsepower, and maximum gas throughput per day. There do not appear to be any emission factors available to estimate pipeline emissions based only on those parameters. Given those limitations and the generic nature of information from the Laurenzi and Jersey (2013) paper about the assumptions and data for their emission estimates of the Transmission and Storage stage, it did not appear feasible to estimate how their generic estimates of methane should scale with various pipeline parameters, other than a direct scaling with pipeline throughput capacity. We also note that GHG emission estimates from the pipeline proponents do not yet appear to be available. That may especially be important for the direct emission values for pipeline operations. The analysis of Laurenzi and Jersey (2013) assumes a 0.45% CH_4 leak rate in transmission but they do not state specific assumptions about transmission miles, compressor HP and other factors. Rather, they assume a fraction of total EPA estimates for pipeline CH_4 leakage and compressor CO_2 emissions in 2009 based on the fraction of gross gas withdrawals. The ACP and MVP transmission pipelines, totaling 554.6 miles and 294 miles, respectively, may not be typical of the length and leakage rates implicit in the Laurenzi and Jersey analysis. It would be desirable to update those estimates when more specific information becomes available.

Subramanian *et al.* (2015) recently published an onsite study of compressor station emissions. It includes measurements of methane emissions from 47 transmission line compressor and storage sites. This is claimed to be the most comprehensive set of measurements since the 1996 joint EPA/Gas Research Institute study. However, the measured fugitive methane emission estimates vary by several orders of magnitude among stations and the study found no correlation between emissions and compressor horsepower. Those results, together with results of other studies, indicate that there are large variations in emissions among different technologies used in equipment, probably in the amount of effort companies spend on maintenance of things like seals on compressors, valves, and leaks, and perhaps also in the efforts spent on monitoring to detect leaks.[4] Because of the wide variance in these results and the lack of clear correlation to pipeline parameters such as total horsepower and size of pipeline, we were unable to use the results to replace or compare directly with those of the ExxonMobil study.

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[4] An EPA background study, EPA (2014), prepared for analysis of a proposed NSPS standard, estimated the following methane emissions achievable per compressor for each of the three types of transmission compressor: 27.1 metric tonne/year for reciprocating, 126 for centrifugal with wet seals, and 15.9 for centrifugal with dry seals, but those estimates apparently do not include all the other components at a compressor station, which in practice can contribute substantial emissions due to leakage, venting and exhaust emissions.

Zimmerle *et al.* (2015) published a recent study of the U.S. natural gas transmission line and storage system (T&S) methane emissions. This study's estimated overall US transmission and storage sector emissions for 2012 as 1503 Gg/yr, which were within their statistical uncertainty of EPA's GHGI estimated value of 2071 Gg/yr. They also found super emitter stations that appear to be due to equipment or control malfunctions. One can compare those leakage estimates with the U.S. total value that the ExxonMobil study used as the basis for their generic estimate of pipeline emissions, which was 2,115 Gg/yr for 2009, or 0.45% of total gas production. Since total gross withdrawals in 2012 were about 16.5% larger than in 2009, the Zimmerle study value of 1503 Gg/yr corresponds to a methane leakage rate of about 40% less than the ExxonMobil study, or about 0.27% of gross withdrawals (apparent range of 0.23 to 0.39%). However, both of those estimates refer to averages over a national mix of different pipelines of different sizes, ages and capacities, so it is questionable whether they can be applied directly to specific new transmission pipeline projects. The Zimmerle *et al*. study includes the results from Subramanian et al. (2015) at individual compressor station and storage sites, but apparently extends the analysis. They fit all their results to several different models in order to draw conclusions about the overall population of sites, including the U.S. total T&S emissions cited above. However, it again it is difficult for us to interpret those results in terms of specific estimates for the ACP and MVP pipelines.

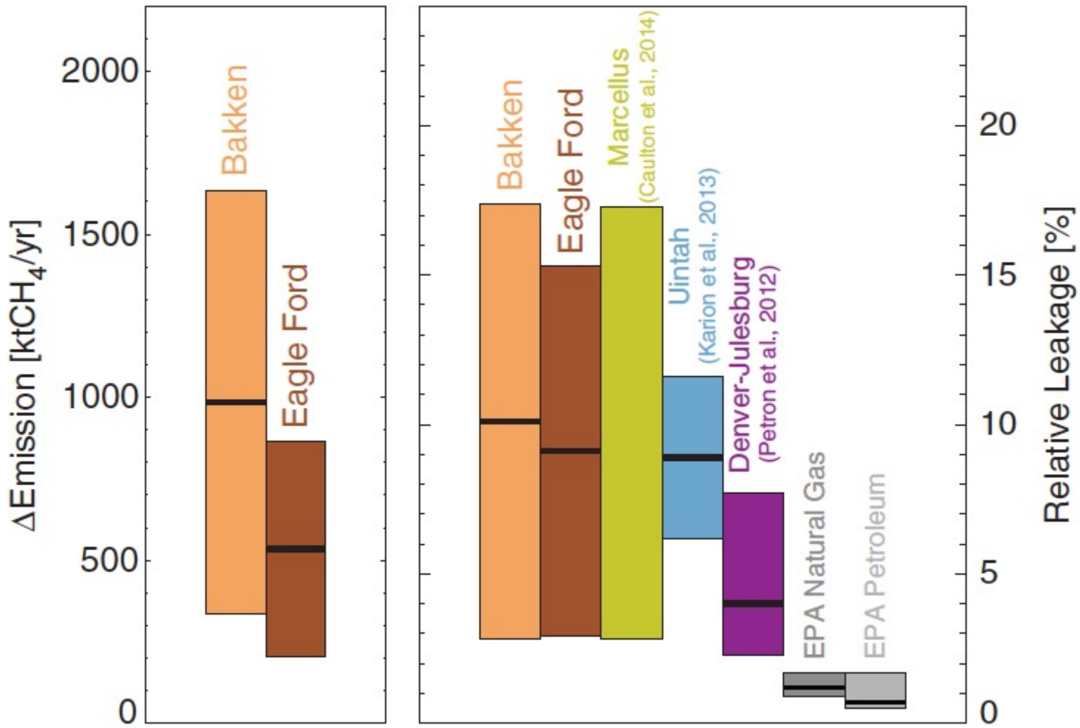

Figure 7. Estimated methane emissions are shown for the targeted regions Bakken in light brown, and Eagle Ford in dark brown. Shown are absolute emission increase (2009–2011 relative to 2006–2008) in the left panel, and the leakage rate relative to production in the right panel, in each case together with the 1σ-uncertainty ranges. For comparison, leakage estimates from previous studies in Marcellus (2012) [*Caulton et al.*, 2014], Uintah (2012) [*Karion et al.*, 2013], and Denver-Julesburg (2008) [*Pétron et al.*, 2012] (yellow, blue, and magenta) are shown together with the EPA bottom-up inventory estimates for natural gas and petroleum systems (2011) [*U.S. Environmental Protection Agency*, 2014] (grey) in the right panel.

Fig. 4. Chart from Schneising *et al*. (2014). (Figure and caption copied directly from Figure 7 of their report)

Conclusions and Recommendations

The potential total GHG emissions associated with these two proposed new pipelines could greatly increase emissions from this region for decades into the future. Hence, in an era where climate change mitigation will require reducing GHG emissions sharply, decision makers need to consider whether approval of these projects is consistent with national and international goals for climate mitigation.

Given the observed wide variation in methane emissions and the very high total potential GHG emissions, it is important that the transmission pipeline companies and FERC provide complete life-cycle estimates of methane and CO_2 emissions from their projects for the EIS for their proposed pipeline projects, together with detailed documentation of their assumptions so that the potential GHG emissions and other environmental impacts of the pipeline stage can properly be judged. It is clear that expanding gas usage and supporting it with new pipelines and production implies substantially greater total GHG emissions than appear when agencies or advocates focus on only one stage at a time and ignore the indirect impacts of the immediate project.

FERC must recognize that the emerging world commitment to cut GHG emissions, as evidenced by the recent UNFCCC COP21 agreement in Paris, will mean that the operating lives of new natural gas investments are likely to be substantially shorter than the traditional assumption that a pipeline will operate for thirty or more years. Expanding investments based on such rosy assumptions will lead to substantial stranded investments, in addition to increased global warming from excessive GHG emissions. These are ample grounds for rejecting certificate applications for expanded natural gas pipeline capacity. At a minimum, pipeline investors should be placed at risk for under-recovery of investments as a result of overcapacity for transportation of natural gas that cannot continue to be burned at historic, let alone expanded, levels for several decades into the future.

Furthermore, if FERC decides to allow either of the proposed pipelines to proceed, it should require detailed maintenance and emission monitoring plans for new and associated existing pipelines and compressor stations adequate to prevent leaks and detect all releases of methane to the atmosphere in a timely fashion so that substantial leaks can quickly be remedied, both for public safety and to minimize the climate impacts of GHG emissions.

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