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LETTER

Emissions in the stream: estimating the greenhouse gas impacts of an oil and gas boom

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Abstract

The Shale Revolution has stimulated a large and rapid buildout of oil and gas infrastructure in the Gulf and Southwest regions of the United States (US), expected to unfold over decades. Therefore, it is critical to develop a clearer understanding of the scale and composition of the likely greenhouse gas (GHG) emissions associated with this activity. We compile a detailed inventory of projected upstream oil and gas production expansions as well as recently and soon-to-be built midstream and downstream facilities within the region. Using data from emissions permits, emissions factors, and facility capacities, we estimate expected GHG emissions at the facility level for facilities that have recently been constructed or are soon to be constructed. Our central estimate suggests that the total annual emissions impact of the regional oil and gas infrastructure buildout may reach 541 million tons of CO_2 equivalent (CO_2e) by 2030, which is more than 8% of total US GHG emissions in 2017 and roughly equivalent to the emissions of 131 coal-fired power plants. A substantial fraction of the projected emissions come from petrochemical facilities (38%) and liquefied natural gas terminals (19%). Researchers have largely focused on upstream emissions such as fugitive methane (CH_4) associated with new US production; our findings reveal the potentially greater prominence of midstream and downstream sources in the studied region.

1. Introduction

The Shale Revolution has transformed North American and global energy markets. It has reduced energy prices (Hausman and Kellogg 2015, Kilian 2016); shifted electricity production from coal toward natural gas, reducing local and regional air pollution (Johnsen *et al* 2019); provided a source of employment and income during the Great Recession (Feyrer *et al* 2017); and allowed the US to approach the point at which it exports more energy than it imports (EIA 2018)[5]. There have also been harmful impacts (Olmstead *et al* 2013, Graham *et al* 2015, Hill and Ma 2017, Komarek and Cseh 2017).

This study quantifies the long-run greenhouse gas (GHG) impacts of the ongoing buildout of oil and gas infrastructure in the US Gulf region including on- and offshore facilities in Texas (TX) and Louisiana (LA). We refer to the geographic scope of the study as the Gulf even though it includes plays in TX that extend into the Southwest[6]. Our scope comprises portions of the oil and gas value chain from production (upstream), to transmission and distribution (midstream), to industrial end

[5] A controversy exists about the extent to which CH_4 emissions from natural gas extraction could mean that GHG emissions increase rather than decrease from switching from coal to natural gas as an energy source (Howarth *et al* 2011, Wigley 2011). However, some research suggests this effect may be overstated (Cathles *et al* 2012, Jenner and Lamadrid 2013).

[6] The scope includes upstream activities in TX and LA (including the Permian, Barnett, and Eagle Ford areas) and offshore in the broader Gulf of Mexico, and midstream and downstream facilities in TX and LA.

uses (downstream)[7]. Because of the path dependency of industrial development and high adjustment costs of fuel switching, further transition toward oil and gas may mean larger future use of fossil fuels relative to renewables (Unruh 2000). Therefore, it is critical to develop a clearer understanding of the scale and composition of the GHG impact of these new oil and gas resources.

Facility-level research on industrial GHG emissions is limited (Hamit-Haggar 2012, Ryan 2012). In contrast, methane (CH_4) emissions from upstream oil and gas production have received significant attention (Alvarez *et al* 2012, Howarth 2014, Elvidge *et al* 2018). This study accounts for emissions produced by the industrial development that an oil and gas boom stimulates in downstream sectors such as petrochemicals and refining, as well as those from oil and gas production. Rather than retrospectively examine a past buildout of oil and gas infrastructure or use a model to simulate future development, we inventory recently or soon-to-be built facilities from government, industry, and media sources. This provides a detailed picture of expected emissions from new facilities and other infrastructure, based on data from the regulators who permit these facilities and the industries that invest in them.

Results suggest that the total annual emissions impact of the oil and gas infrastructure buildout in the Gulf may reach 541 million tons of carbon dioxide equivalent (CO_2e) by 2030, more than 8% of total US GHG emissions in 2017 (EPA 2019a). While impacts on upstream emissions such as fugitive CH_4 are discussed in the literature, our findings reveal the potentially greater prominence of mid- and downstream sources in some areas.

1.1. Trends in oil and gas development in the gulf region

The earliest TX oil discoveries date to the 1860s. Discoveries offshore in Galveston Bay followed several years later, and the region has continued to develop since. Figure S1 in the supplemental information (SI) shows the evolution of oil and gas production in the region and for the US as a whole since 1996. Trends since the mid-2000s reflect increases in production from the Permian Basin, Eagle Ford Play, Barnett Play, and TX-LA-Mississippi Gulf Basin (also called the Salt Basin) as well as those elsewhere in the US such as the Bakken and Marcellus.

A major result of the recent boom is the transition away from coal and towards natural gas in electricity generation, which has lowered the carbon intensity of electricity in many parts of the US. However, the broader impacts on GHG emissions of new gas production are uncertain, particularly if natural gas prices remain low (Chen *et al* 2019) and/or fugitive CH_4 is high (OGJ 2019). The boom in oil production in this region and elsewhere is likely to increase GHG emissions both indirectly, if it puts downward pressure on global oil prices, and directly due to emissions from the upstream, midstream, and downstream activities we describe in this paper.

1.2. Relation to the existing literature

The ongoing expansion of production in the Gulf and Southwest regions, particularly in the Permian Basin, has been described in the literature (Wallace 2019)[8]. Newell and Raimi (2014) use the EPA Inventory of GHG Emissions and Sinks and EIA National Energy Modeling System (NEMS) data to predict a small increase in GHGs by 2040 from new production, depending on oil prices, extraction technology, and the global warming potential (GWP) of CH_4. Hausman and Kellogg (2015) predict damages from increased emissions of $2.5–15 billion per year. Both studies predated awareness of the full extent of oil and gas resources in the Permian (Gaswirth *et al* 2018). Newell and Raimi (2014) project emissions based on oil and gas production, using emissions factors that reflect average mid- and downstream emissions. They do not project emissions at the facility level. In addition, the focus of that study is national, including impacts through fuel substitution and trade, as well as those from the use of oil and gas for electricity and transportation, not considered here.

A large engineering literature models climate impacts of the fossil fuel sector (DeLuchi 1993, Davis *et al* 2010, Alvarez *et al* 2012, Burnham *et al* 2012, Allen *et al* 2013, Subramanian *et al* 2015, Zimmerle *et al* 2015, Alvarez *et al* 2018, Tong *et al* 2019). In contrast to the current approach, these studies apply modeling assumptions about future oil and gas infrastructure and then extrapolate expected emissions from a simulated buildout. This literature has been extremely helpful for characterizing the largest sources of future GHG emissions.

The approach taken here addresses a gap in the literature, examining individual facilities that have actually been built or will soon be built, and estimating their associated emissions. We focus on the most densely developed region of oil, gas, and petrochemical infrastructure in the US. However, given that these commodities are transported long distances and traded in international markets, where end uses and associated carbon intensity may depend critically on

[7] The upstream scope includes production expansions from new and existing wells. Industrial downstream uses considered here include a variety of petrochemical activities described in the supplemental information (SI) table S1 available online at stacks.iop.org/ERL/15/014004/mmedia.

[8] This includes the Wolfcamp Shale and Bone Spring Formation, estimated in November 2018 to be collectively the largest continuous oil and gas resource ever identified (Gaswirth *et al* 2018). The expansion of production continues, though rig counts have at least temporarily fallen (Blum 2019).

market conditions, we restrict the focus of our analysis to a subset of activities described in section 2.

Alvarez *et al* (2018) corroborate bottom-up estimates of existing facility-level emissions with top-down observations and find US CH_4 emissions between 8 400 and 15 000 Gg per year. Our estimates of CH_4 emissions are consistent with these in that they do not exceed their total emissions numbers, but we only account for a small subset of oil and gas production considered in that study, so the scope is different. Tanaka *et al* (2019) perform LCA for the coal-to-gas shift to determine the climate impacts. Estimates of CO_2 and CH_4 emissions from our study are not larger than theirs, but again, their analysis is national, so the comparison cannot tell us whether the regional estimates in this paper are consistent with their results.

Other studies project the future inventory of industrial facilities using current sector-level emissions estimates along with assumptions about future changes in the age distribution of facilities (Davis *et al* 2010, Tong *et al* 2019). While these assumptions enable global forecasts, they necessarily extrapolate from one sector or dataset[9]. Our inventory approach uses estimates of actual facility-level production and emissions, compiled from regulatory agencies, industry reports, and other primary sources, rather than simulating emissions using models that aggregate facilities sectorally, nationally, or globally. The results from our granular approach can be used to validate the emissions projections from more aggregated models. In addition, identifying the sources of significant potential emissions growth is critical for formulating effective mitigation strategies.

The approach taken here is generally one described in the engineering literature as 'bottom-up' in that we apply emissions factors facility-by-facility and aggregate. Other approaches use aircraft or satellite measurements of regions to produce 'top-down' estimates. Comparisons of the two approaches suggest that the 'bottom-up' approach understates total emissions in many cases (Allen 2016).

The expansion of the oil and gas sector in the Gulf region has reduced the cost of natural gas and petroleum and, in turn, lowered the cost of producing petrochemical products at scale (EIP 2018). Cumulative petrochemical investments related to unconventional oil and gas are estimated at \$204 billion from December 2010 to May 2019 (ACC 2019b). What could account for this massive buildout? A lower natural gas price means greater availability of petrochemical feedstocks (e.g. ethane from natural gas liquids). It also means that the cost of energy used to fuel conversion of feedstocks into refined products (e.g. ethane crackers that produce ethylene) has fallen. This is borne out in market conditions for ethylene and other petrochemical derivatives, where prices are falling and production is growing (Hay 2019). All of this increases the supplies of these products and their corresponding GHG emissions (SI figure S2).

[9] In Tong *et al* (2019), the authors construct emission estimates 'assuming that the age distribution and survival curves of each region's industry infrastructure are consistent with its electricity infrastructure' (p 378). In Davis *et al* (2010), the authors acknowledge that they 'make the arbitrary assumption that CARMA's emissions and energy data for 2009 (or, occasionally, 2004) are an accurate estimate throughout a plant's lifetime (despite evidence to the contrary)' (p 2), referring to their use of the Carbon Monitoring for Action (CARMA) database.

2. Data and methodology

We build a detailed inventory of facilities using data from a variety of sources. Our analysis of the midstream and downstream segments of the value chain operates at the facility level, where the inventory tracks construction of new facilities and expansion of existing facilities. The timing of planned or under-construction facilities is difficult to ascertain and subject to change. Furthermore, facilities not yet announced (and thus excluded from our inventory) may become operational prior to the completion of some facilities we do observe. Therefore, the timeframe for considering new midstream and downstream facilities naturally corresponds to the announcement/planning, approval, and construction timelines of the facilities for which information is available. Initial data collected provide the location, production type, and in most cases the expected production capacity of each facility.

Our classification of facilities as down- versus midstream is based on where they fall in the regional production process, which may differ from studies with a national or global focus. Refining of oil and gas products into fuels or chemical products (e.g. ethane cracking, which is classified as 'petrochemical' in our analysis) is classified as downstream production. Natural gas and oil storage and export, however, are classified as midstream, with the understanding that these products will eventually be used in some downstream process elsewhere.

For facilities where emissions permits are already approved, we use permit data to quantify expected emissions. For those without permits, we use volumetric emissions factors to predict what emissions will likely be given the production activity and reported facility capacity. Permitted emissions may over- (or under-) state actual emissions to the extent that individual facilities fall below or exceed permitted levels. Emission factors may also deviate from actual emissions if individual facility production processes emit more or less than the average facility in our data. For upstream oil and gas production, we track projections of future development to 2030 and assume that the mid- and downstream projects in our inventory are fully operational by that date. Accidents release large amounts of GHGs and may not be captured in either approach, which would mean we are understating emissions[10]. Section 3.4 discusses sensitivity analysis related to some of these sources of uncertainty.

2.1. Data sources

2.1.1. Inventory of new facilities

Table 1 groups the components of the present analysis into segments of the regional oil and gas stream. We separate compression, boosting, fractionization, and other activities from upstream oil and gas production, because we observe new facilities and infrastructure related to these activities, whereas we rely on production projections to predict upstream (well-level) emissions. We also include fuel terminals, refining, and petrochemicals in the downstream segment based on the set of activities covered in our analysis, acknowledging that in other frameworks these may be midstream activities[11].

Table 2 presents a summary of the 327 mid- and downstream facilities in our data. New facility announcements and their associated production capacities come from company websites, industry and media sources, the American Chemistry Council, and environmental advocacy websites (BMI/Fitch 2018, Fitch 2018, ACC 2019a, EIP 2019)[12]. Where permits exist, permitted emissions levels come from an online database of Federal Energy Regulatory Commission, Environmental Protection Agency (EPA), TX Commission on Environmental Quality (TCEQ), and LA Department of Environmental Quality regulatory documents[13]. The classification of facilities into segments of the value chain is not always straightforward. One comparator is the OPGEE model (El-Houjeiri *et al* 2018), which covers activities in the stream up to but not including refining, and is distinct from our own framing of the oil and gas value chain. Figure 1 illustrates the share of each facility type in the inventory at each development stage (planned, under construction, completed, and unknown).

2.1.2. Upstream production

Projections of upstream oil and gas production in the Gulf region are obtained from the EIA Annual Energy Outlook (EIA 2019). These projections are based on NEMS scenario results, combining data on domestic and international supply and demand factors and economic forecasts to predict the evolution of oil and gas prices and quantities. We consider projections from several different NEMS scenarios.

2.2. Approach for estimating emissions

Table 3 reports the emissions factors applied in our analysis. SI figure S3 provides a visual summary of the emissions factor estimation process, and how it differs for upstream versus downstream and permitted versus unpermitted facilities. Where facility permits include emissions, we use these data to construct our estimates. Where facility-level permitted emissions are unavailable, we employ a variety of approaches to obtain emissions factors that represent GHG emissions per unit of output. An alternative approach would be to use energy input emissions factors and multiply these by facility-level fuel use. Unfortunately, we cannot reliably obtain fuel specifications and projected fuel use for the facilities in our data[14]. This also means that we do not capture emissions associated with off-site electricity use or diesel from railcars or other oil and gas transportation. CH_4 emissions are converted to CO_2e based on 100 year GWP from the Intergovernmental Panel on Climate Change (IPCC), with a value of 32 for CH_4; alternative GWPs are considered in section 3.1. We ignore emissions of fluorinated gases and N_2O. These high-GWP gases are harder to forecast by facility and constitute a small share of GWP from the oil and gas sector.

2.2.1. Upstream emissions factors

For upstream production, we cannot disentangle production forecasts by drilling method, so we ignore non-CH_4 emissions and focus exclusively on vented, flared, or fugitive CH_4 released during production, using estimates from Brandt *et al* (2014) for natural gas and Cai *et al* (2014) for oil[15]. Again, note that we do not include the combustion of fuels for energy at well sites or farther downstream (say, for power generation), acknowledging that they contribute the bulk of eventual downstream emissions from these fuel sources[16].

[10] Brandt *et al* (2014) show that differences between bottom-up and top-down emissions estimates may be explained to a large extent by these events, which are not incorporated in the latter (which includes EPA's GHG Reporting Program).

[11] In table S1, we itemize the set of facility types classified as Petrochemicals in our data. Further information about data construction can be found in the SI, section B.

[12] All sources used to construct these data are provided in SI tables S2 and S3.

[13] These documents are publicly available from the Environmental Integrity Project in an online database (EIP 2019).

[14] A common approach in the energy engineering literature applies emissions factors from lifecycle analysis (LCA), either based on volumes of fossil fuel extraction or end use. This study does not use LCA-based emission factors as they would likely lead to double counting of emissions at multiple points of the value chain.

[15] These factors are based on volumetric leak, vented, and flared emissions from CO_2 and CH_4 reported in the supplemental data of Brandt *et al* (2014). We test the robustness of emissions estimates to variation in these upstream emission factors by considering an alternative set of factors based on Alvarez *et al* (2018). This sensitivity exercise is discussed in more detail in section 3.4 and in the supplemental information.

[16] A referee pointed out the importance of CO_2 emissions for oil wells with enhanced oil recovery (Brandt *et al* 2018, Masnadi *et al* 2018). While these emissions are critical in evaluating crude production nationally or globally, the basins in this study have not yet applied these techniques on a meaningful scale (Du and Nojabaei 2019).

Table 1. Oil, gas, and petrochemical activities included and not included in this study.

		Upstream	Midstream	Downstream
Included	Petroleum	Exploration abd development*, Production inside the Southwest and Gulf Basins*	Transport	Export terminals*, Refining, Petrochemical production
	Natural Gas		Processing*, Compression*, Storage*, Transport*	
	Natural Gas Liquids		Fractionation, Transport	
Not included		Production outside of Southwest and Gulf Basins, emissions from electricity use/combustion at well level	Electricity generation/combustion done off-site	Electricity generation/combustion done off-site, combustion or fugitive emissions from end-uses* (e.g. from gasoline for transportation)

Note. Processes with an asterisk (*) include CH_4 emissions from venting, flaring (along with CO_2 emissions), or fugitive sources.

2.2.2. Mid- and downstream emissions factors

Where facilities in our inventory have already been permitted by the EPA, we obtain facility-level emissions estimates (EPA 2019b). When this is not the case, we adopt two alternative approaches. Where we have permit data for some facilities of a given type, we calculate the average CO_2e emissions per unit of output across permitted facilities of that type, and use that average factor for any facilities without permit data[17]. For facility types lacking permitted emissions data for even a single facility, we use emissions factors from the literature. Factors for petrochemical facilities are more challenging to construct because they vary depending upon the particular processes employed and chemicals produced. We construct a more refined set of factors for these facilities by facility process type in SI table S1[18].

Given the literature's strong focus on upstream oil and gas emissions, why should petrochemicals account for such a substantial share of total emissions in our analysis? Among the highest emitting facilities in our data, the largest proportion are LNG terminals (19%), ethane crackers (13%), and those producing polyethylene and ethylene derivatives (9%), methanol (6%), and fertilizers (5%). This is consistent with lower costs of natural gas extraction driving growth in domestic and export-oriented production of precursors to plastic production, methanol for fuel and plastics, and fertilizers for agriculture. Moreover, the large share of LNG terminal emissions in our database reflects the extent to which the saturation of low-cost natural gas in the US market is increasing exports. Seven of the eight largest US refineries (EIA 2019) and the vast majority of current and expected future US LNG export capacity (EIA 2018) are on the TX and LA Gulf coasts. The region contains the 'highest collective concentration of petroleum refining and petrochemical production capacity of just about anywhere in the world' (Dismukes *et al* 2019). In this setting, downstream emissions likely represent a substantial share of the total.

We do not estimate emissions for 17 inventoried facilities. Six of these projects are on hold, so emissions may not materialize. Two are transboundary pipelines with the majority in Mexico, outside of our scope. The remaining nine omitted facilities are eight petrochemical facilities and one natural gas liquids terminal for which we are unable to obtain relevant emission factors. A complete description of data sources is provided in the SI (tables S2 and S3).

3. Results

3.1. Upstream emissions

Figure 2 presents projections of oil and gas production based on EIA NEMS data for 2017–2030[19]. Panel A shows oil and gas production by region for the reference case scenario, a business-as-usual (BAU) forecast of economic and market conditions[20]. The figure reflects the growing importance of Permian oil and gas as well as onshore Gulf Coast (Salt Basin) and Eagle Ford resources. The large difference between gas and oil emissions reflects the fact that a larger share of

[17] Before calculating the emission factor based on the average for each facility type, we remove outliers in the relationship between production capacity and emissions.

[18] For three petrochemical facility types lacking permit data, we use LCA-based emission factors from *ecoinvent* (Frischknecht *et al* 2005). These facilities account for a very small amount of total emissions in our analysis (157 thousand tons of CO_2e per year, or 0.03% of total emissions).

[19] Production for 2017–2018 is actual rather than projected, but is included for illustrative purposes.

[20] Onshore Gulf production includes coastal TX, LA, Mississippi, Alabama, and Florida (dominated by production in the first two states). Southwest production includes western TX and eastern New Mexico.

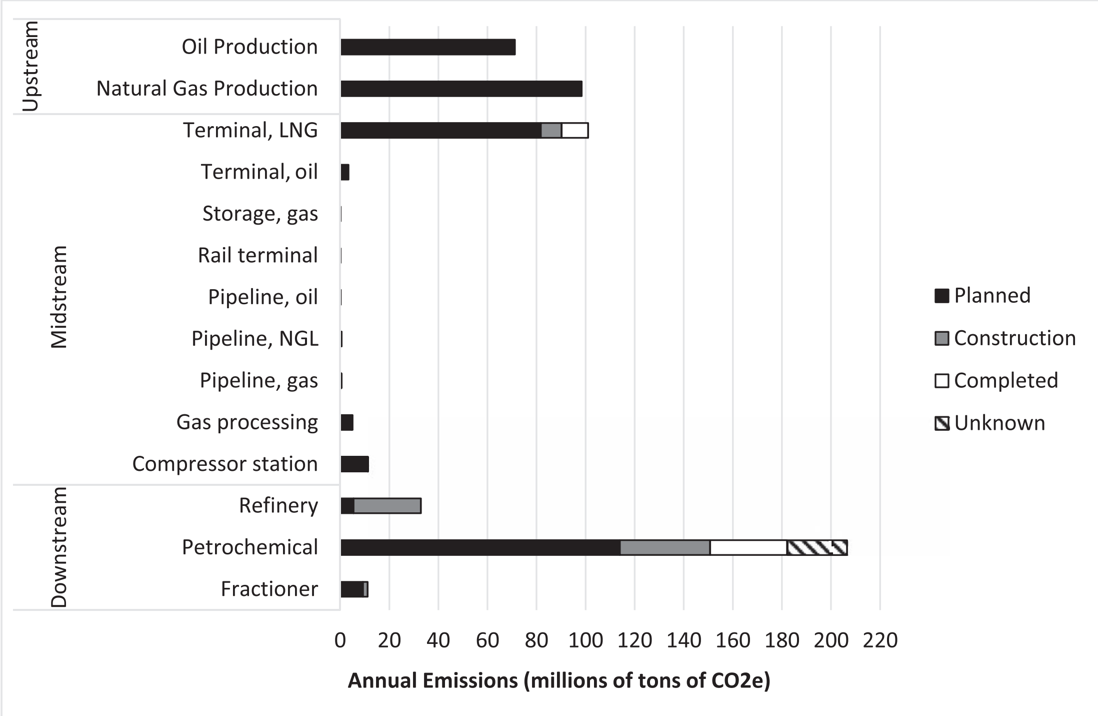

Figure 1. Estimated annual emissions by facility type and project completion status. *Notes*: results in the figure do not include emissions for 17 facilities. For six of them the project is on hold, two are transboundary pipelines, two are pipelines with insufficient data to approximate emissions, and the remaining nine are petrochemical facilities and an NGL storage facility for which we are unable to estimate emissions.

Table 2. Number of facilities by Facility Type And Project Status.

	Planned	Construction	Completed	Unknown	Total in TX	Total TX and LA	% of Grand Total
Midstream	**117**	**37**	**4**	**1**	**118**	**159**	**48.62%**
Compressor station	12	0	0	1	3	13	3.98%
Gas Processing	18	2	0	0	17	20	6.12%
Pipeline, Gas	22	18	1	0	28	41	12.54%
Pipeline, NGL	11	4	2	0	17	17	5.20%
Pipeline, Oil	24	10	0	0	31	34	10.40%
Rail Terminal	1	1	0	0	2	2	0.61%
Storage, Gas	1	1	0	0	2	2	0.61%
Terminal, Oil	12	0	0	0	11	12	3.67%
Terminal, LNG	16	1	1	0	7	18	5.50%
Downstream	**84**	**43**	**34**	**7**	**112**	**168**	**51.38%**
Fractionator	9	3	0	0	11	12	3.67%
Petrochemical	65	23	34	7	81	129	39.45%
Refinery	10	17	0	0	20	27	8.26%
Total in TX (Mid- and Downstream)	140	61	23	6	230		
Grand Total	**201**	**80**	**38**	**8**	**230**	**327**	

gas emissions occurs further upstream in the value chain than for oil[21].

Figure 2, panel (B) demonstrates the variation in projected emissions for four alternative NEMS scenarios: high and low expected oil prices, and high and low resource extraction and technology costs. These cases produce a range of 140–200 million tons of expected CO_2e emissions annually by 2030 from upstream production alone. We can also bound these estimates by adjusting the assumed GWP to the lower value used by the US EPA or the higher 20 year IPCC value (IPCC 2014). Assuming a GWP for CH_4 of 86, the high emissions case rises to 531 million tons of CO_2e. With

[21] We report projected oil and gas production for different parts of the Gulf and Southwest regions in SI figure S4.

Table 3. Facility-level emissions factors by facility type.

Category	Facility type	Value	Unit	Source
Upstream	Gas (CH4)	6.63×10^{6}	Mil Ton of CO2e/Mil cubic feet of gas	Brandt *et al* (2014)
Upstream	Oil (CH4)	3.58×10^{-9}	Mil Ton of CO2e/MMBtu	Cai *et al* (2014)
Midstream	Compressor station (CO2)	0.0960	Mil Ton Per Year of CO2e/bcfd	Averaged from Permit Data
Midstream	Gas Processing	0.898	Mil Ton Per Year of CO2e/bcfd	Averaged from Permit Data
Midstream	Pipeline, NGL (CH4)	3.59×10^{-5}	Mil Ton of CO2e/Mi	EPA (2017b)
Midstream	Pipeline, Oil (CH4)	1.73×10^{-7}	Mil Ton of CO2e/Thousand cubic meters of oil	Picard (1999)
Midstream	Rail Terminal (CH4)	8.00×10^{-7}	Mil Ton of CO2e/Thousand cubic meters of oil	Picard (1999)
Midstream	Rail Terminal (CO2)	2.30×10^{-9}	Mil Ton of CO2e/Thousand cubic meters of oil	Picard (1999)
Midstream	Storage, gas (CH4)	2.42×10^{-5}	Mil Ton of CO2e/Mil cubic meters of gas	Picard (1999)
Midstream	Terminal, LNG	2.25	Mil Ton Per Year of CO2e/bcfd	Averaged from Permit Data
Midstream	Terminal, Oil	3.60×10^{-8}	Mil Ton Per Year of CO2e/bpd	Averaged from Permit Data
Downstream	Fractionator	2.42×10^{-6}	Mil Ton Per Year of CO2e/bpd	Averaged from Permit Data
Downstream	Refinery	1.65×10^{-5}	Mil Ton Per Year of CO2e/bpd	Averaged from Permit Data
Downstream	Petrochemical		*Depends on Process, see SI table A1.*	

Note. Emissions factors are based on observed unit CO2e emissions per unit of output where permit data is available as denoted by 'Averaged from Permit Data.' Where not available, factors have been obtained from technical documents or research papers cited in the rightmost column. 100 year global warming potential of CH_4 is assumed to be 32 following EPA (2017a).

the low-case GWP of 25, the low emissions case falls to 108 million tons of CO_2e. Assuming our baseline GWP for CH_4 of 32, our results then predict an increase in annual emissions from 2017 to 2030 ranging between 34–99 million tons of CO_2e. The reference case, used below for aggregate emissions, is an increase of 67.5 million tons of CO_2e[22].

3.2. Midstream and downstream emissions

Table 4 reports estimates of total emissions by facility type and project completion status. By a simple count from table 2, petrochemical plants and pipelines comprise the largest numbers of new facilities, reflecting, in part, variation in the scale of activity per facility by type (e.g. one new refinery constitutes a large relative increase in total refining capacity in the region). Mid- and downstream emissions are expected to be 371.7 million tons of CO_2e per year by 2030.

Table 4 shows the large impact of petrochemical emissions, totaling 206.3 million tons of CO_2e annually, as well as that of downstream emissions as a whole (250.3 million tons). While we cannot pinpoint the exact timing of the construction of these facilities, 22% of expected downstream emissions come from facilities already completed or under construction, 74% from those planned, and only 4% from facilities where we are unable to ascertain project status.

3.3. Aggregate emissions

If all of the projects in table 2 come to fruition by 2030, total emissions (including upstream) would increase by about 541.1 million tons of CO_2e annually by that year based on the reference case scenario. Assuming a GWP for CH_4 of 32, upstream emissions increases could vary by 65 million tons depending upon the relevant scenario. Assuming that projects currently under construction come online in 2021, and that planned projects and those with unknown status come online in 2024, total cumulative emissions from 2017 to 2030 would be 2.6 billion tons CO_2e[22]. With a discount rate of 3% and a global social cost of carbon ranging between \$39 and \$50/ton (Interagency Working Group 2016), this would imply additional external damages just from GHG emissions of \$112 billion, relative to 2017 emissions.

3.4. Uncertainty analysis

In SI section A, a sensitivity analysis explores how our estimates vary with key input assumptions. Our approach implies potential ranges of upstream emissions between 138 and 200 million tons of CO_2e per year, and a potential reduction of our central estimate for mid- and downstream facilities from 371.7 million tons of CO_2e per year down to 142 million if planned facilities do not materialize[23]. Additionally, because actual emissions may vary from permitted emissions, we use reported emissions from EPA FLIGHT to characterize expected variation in realized emission rates. We find that while permitted and reported emissions per facility are similar on average, accounting for this variation could reduce our estimate of total emissions to 374 million tons of CO_2e per year. Thus, even the most conservative assumptions about upstream oil and gas production, the completion of planned mid- and downstream facilities, and permitted versus actual emissions imply a large GHG emissions contribution of the regional buildout.

4. Discussion and conclusions

We construct an inventory of recently or soon-to-be built facilities that are part of the rapid buildout of oil and gas infrastructure in the US Gulf region. Expected GHG emissions from each facility are obtained directly from emissions permits or indirectly by deriving emissions factors and multiplying them by anticipated facility capacity. This approach enables us to assess the scale of the aggregate GHG emissions impact of the oil and gas boom in the region and decompose it by value chain segment, facility type, and project completion status.

Our main estimate suggests that the buildout will increase annual GHG emissions by about 541 million tons of CO_2e by 2030, amounting to more than 8% of total US GHG emissions in 2017 (EPA 2019a). For context, this is roughly equivalent to the CO_2e emissions of 131 coal-fired power plants, or 82% of Texas' total 2016 GHG emissions. The downstream segment of the buildout—especially petrochemical facilities, which account for more than one-third of estimated aggregate emissions—is a major contributor. LNG terminals, in the midstream segment, comprise more than one-fifth of the total. While prior work highlights upstream emissions such as fugitive CH_4, our findings suggest that the mid- and downstream infrastructure buildouts stimulated by the oil and gas production expansion may have comparable or greater GHG impacts in this region. To put this into perspective, the buildout documented here suggests potential mid- and downstream emissions will be 384.4 million tons of CO_2e, which is 7% larger than total US industrial emissions in 2017 (EPA 2019a).

[22] How to apply GWPs to emission estimates is an open question, with alternative approaches discussed by Allen *et al* (2016) and Tanaka *et al* (2019).

[22] Because we are unable to explicitly link the different production expansion scenarios to resulting changes in the levels of mid- and downstream activities, we cannot consider the extent to which alternative upstream scenarios might alter mid- and downstream emissions.

[23] Upstream emissions sensitivity is based on EIA production scenarios based on the high and low cases in the trajectory of oil prices and oil and gas technology's effect on production. We also consider an alternative set of emission factors based upon Alvarez *et al* (2018), and find that it increases natural gas emissions by roughly an order of magnitude (325 million tons CO_2e per year by 2030) and decreases oil emissions by a smaller proportion (16 million tons CO_2e per year by 2030). These factors may not be as appropriate as those used in our baseline estimates because the production sites only include one of the plays (Barnett Shale) in our analysis.

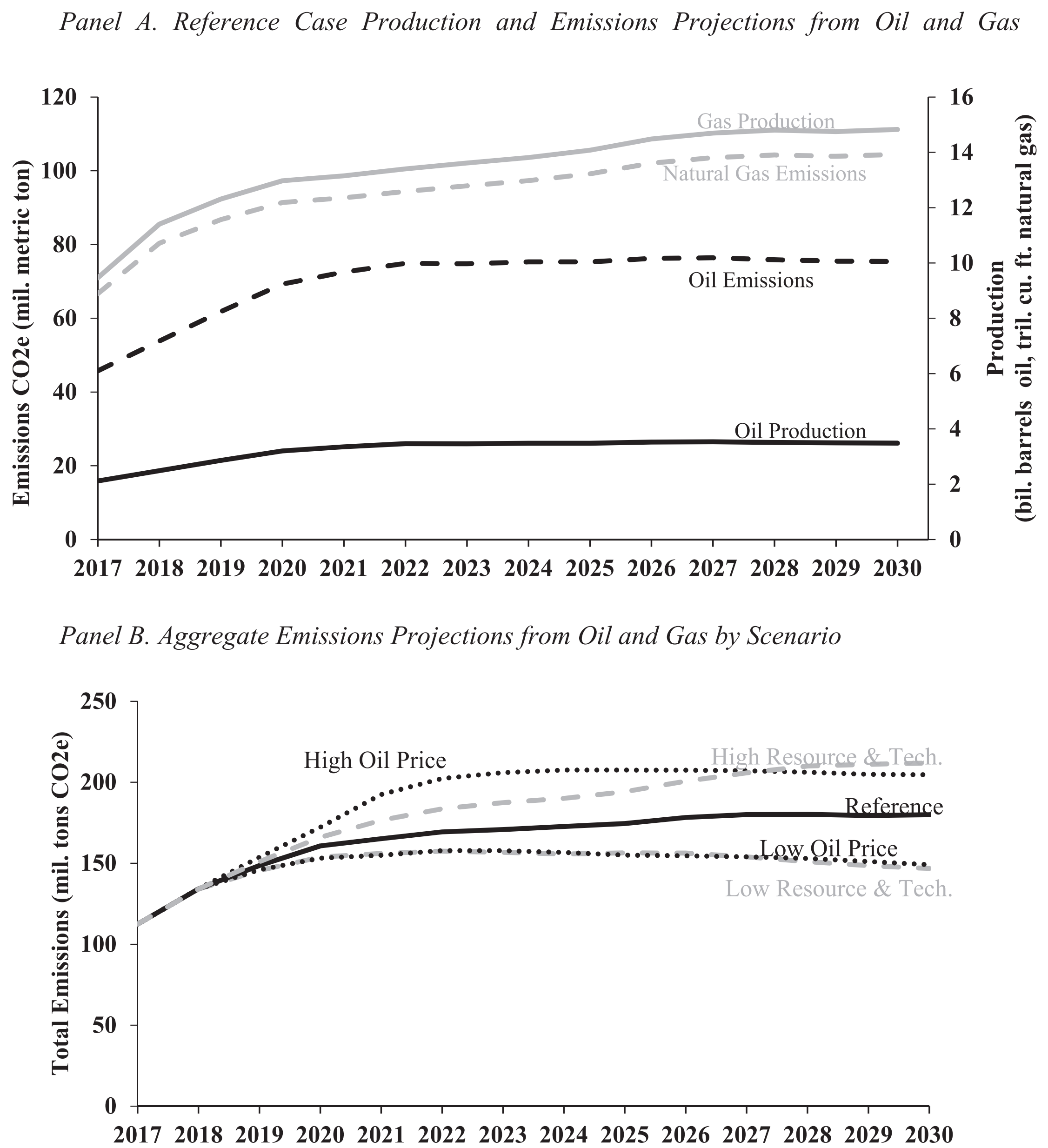

Figure 2. Emissions Estimates by Region and EIA Scenario. *Notes:* panel (A) graphs annual production estimates based on EIA reference scenario. Panel (B) includes production for EIA Southwest, Gulf Onshore, and Gulf Offshore regions. Emissions estimates are based on emissions factors from Alvarez *et al* (2018). Panel (B) emissions estimates based on five separate production scenarios for Southwest, Gulf Onshore, and Gulf Offshore regions. Onshore Gulf production corresponds to coastal TX, LA, Mississippi, Alabama, and Florida. Southwest production includes western TX and eastern New Mexico.

More and better data (e.g. emissions factors) are needed to enable future research projecting mid- and downstream emissions and developing mitigation strategies. Only about 30% of the facilities in our database are already operating or under construction, thus our results can inform decision-making on policy and technology strategies for planned facilities. Our estimates assume a BAU scenario for the emissions intensities of industrial processes. Through a variety of voluntary or regulatory approaches, emissions could be lower. While we focus on GHG emissions, the regional human health implications of associated emissions of local pollutants, such as particulate matter and ozone precursors, could have higher economic damages.

Should steps be taken to reduce the buildout we describe in the Gulf region, because all of the relevant markets cross regional and national boundaries, much of that buildout might occur elsewhere. Thus, the counterfactual to the buildout investigated here could involve either higher or lower emissions, depending on how much of the buildout would be displaced, and where it would locate.

Our approach has several limitations. Most importantly, we limit our scope to the oil and gas value chain within the Gulf region in the US. We do not consider the GHG impacts of fuel use and substitution in other end uses (e.g. residential, commercial, electricity, transportation) or changes in oil and gas trade

Table 4. Total emissions in million tons of CO2e by Facility Type and Project Status.

	Planned	Construction	Completed	Unknown	Total in TX	Total TX and LA	% of Grand Total
Upstream	**169.4**					**169.4**	**31.31%**
Natural Gas Production	98.3					98.3	18.17%
Oil Production	71.1					71.1	13.14%
Midstream	**101.3**	**9.3**	**10.8**	**0.0**	**40.4**	**121.4**	**22.4%**
Compressor Station	11.0			0.0	0.4	11.0	2.04%
Gas Processing	4.6	0.4			4.4	5.0	0.92%
Pipeline, Gas	0.1	0.3	0.0		0.4	0.4	0.08%
Pipeline, NGL	0.4	0.0	0.0	0.0	0.5	0.5	0.09%
Pipeline, Oil	0.1	0.0			0.1	0.14	0.03%
Rail Terminal	0.0	0.0			0.0	0.005	0.00%
Storage, Gas	0.0	0.0			0.0	0.03	0.01%
Terminal, Oil	3.3			0.0	3.3	3.3	0.61%
Terminal, LNG	81.7	8.5	10.8		31.2	101.0	18.66%
Downstream	**128.5**	**66.2**	**31.3**	**24.2**	**138.3**	**250.3**	**46.3%**
Fractionator	9.2	1.9		0.0	11.1	11.1	2.06%
Petrochemical	113.9	36.9	31.3	24.2	107.3	206.3	38.1%
Refinery	5.4	27.5		0.0	19.9	32.9	6.07%
Total in TX (Mid- and Downstream)	114.5	41.9	16.9	5.4	178.7		
Grand Total	**399.2**	**75.5**	**42.2**	**24.2**	**178.7**	**541.1**	

Note. Natural Gas and Oil Production are restricted to vented, flared, or fugitive emissions from exploration, development, and production. Petrochemical activities include a wide variety of outputs, described by process in SI table S1.

resulting from expanded regional production. We focus on permitted emissions or those based on average emissions factors, which may over- or understate emissions. Facilities' realized emissions may differ from permitted levels. Rough sensitivity analysis around major sources of uncertainty suggests that even lower-bound estimates of the incremental emissions from the regional buildout are large.

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Data availability statement

The data that support the findings of this study are available from the corresponding author upon reasonable request.

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