MIT CEEPR
Center for Energy and Environmental Policy Research

Working Paper Series

Abatement or Reallocation? Unilateral Methane Standards in a Globally Traded Gas Market

Muntasir Shahabuddin and Chi Kong Chyong

MAY 2026

CEEPR WP 2026-09

Working Paper Series.

Abatement or Reallocation? Unilateral Methane Standards in a Globally Traded Gas Market

Muntasir Shahabuddin[1] and Chi Kong Chyong[2]

Abstract

Natural gas is widely treated as a transitional fuel with a uniform emissions profile. We test that assumption by constructing a harmonised lifecycle dataset covering 333 gas fields across major exporting regions, comparing upstream, transport, and combustion emissions for LNG, pipeline gas, coal, and light fuel oil within consistent system boundaries. Upstream methane emissions vary by an order of magnitude, from below 20 gCO_2e/kWh for low-intensity pipeline systems to above 200 gCO_2e/kWh for selected high-intensity supply chains at the median. Lifecycle fuel rankings are therefore conditional on origin rather than intrinsic to fuel type. Under median assumptions and GWP100, export-facing gas does not exceed coal on a cradle-to-grave basis, although high-intensity cases narrow the margin substantially. Applying these findings to the EU Methane Regulation, we show that emissions are highly concentrated within exporting regions, implying that differentiated accountability can target high-intensity assets without wholesale regional disengagement. Large-scale diversion of displaced LNG to coal-dominated markets would require substantial price adjustments, suggesting that portfolio sorting rather than mechanical carbon leakage is the more plausible response. The results indicate that unilateral methane standards may induce selective trade reshuffling, with the climate impact depending on asset-level mitigation responses.

[1] Worcester Polytechnic Institute, USA
[2] Oxford Institute for Energy Studies, UK and MIT CEEPR, USA; corresponding author: kong.chyong@oxfordenergy.org

1. Introduction

Broad international consensus holds that fossil fuel use must be substantially reduced to avoid the most severe consequences of anthropogenic climate change (Deutch, 2020; Masson-Delmotte, 2018). Natural gas (NG) is likely to remain a significant part of the global energy mix for at least several decades (Energy Institute, 2024; von Hirschhausen et al., 2021), driven by energy security concerns, development priorities, and its role in displacing more carbon-intensive fuels. Given that NG will continue to be used, attention has increasingly turned to reducing emissions across its supply chain.

At combustion, NG exhibits relatively consistent emissions and energetic values (Energy Institute, 2024). However, combustion represents only part of its climate footprint. Total upstream emissions to the gate of consumption are reported to range between 0.3% and 30% of lifetime emissions, with considerable and contested variability; upstream emissions alone are estimated to be 1-5 times the lifetime emissions of solar photovoltaic electricity (Barkley et al., 2017; El-Houjeiri et al., 2013; Littlefield et al., 2022; Schultz & Carvalho, 2022; Weber & Clavin, 2012). A robust, data-driven understanding of upstream NG emissions, particularly relative to thermal coal and light fuel oils (LFO), is therefore central to credible energy and climate policy design.

Life cycle assessments (LCAs) are the principal tool for evaluating the environmental consequences of fuel choice, origin, transport mode, and end use (El-Houjeiri et al., 2013; Muthu, 2023). They underpin the widely held view that coal combustion carries higher lifecycle emissions than LFO and NG (Salvador, 2005), supporting coal-to-gas switching in many jurisdictions (Cronshaw, 2015; International Energy Agency, 2019). Gas-fired generation has expanded further due to its operational flexibility, complementing variable renewable energy supply (Sharifi et al., 2022). Under tightening emissions standards, NG is therefore expected to retain a meaningful role in energy systems (Energy Institute, 2024). Because natural gas supply chains differ in origin concentration, regulatory stringency, and transport modality, sourcing decisions influence not only lifecycle emissions but also exposure to supply coercion, trade reallocation, and long-term bilateral dependence, with direct implications for climate targets, energy security, and the stability of energy trade relationships.

Recent geopolitical developments have underscored these linkages. Russian gas accounted for roughly 40% of the European Union's (EU) natural gas imports in 2015, falling to about 8% in 2023 (Energy Institute, 2024; Ratner, 2020). Following Russia's invasion of Ukraine, EU imports from Russia declined by 81% between February 2022 and September 2023 (Papunen, 2024). EU LNG imports increased from 78.4 bcm in 2021 to 134.7 bcm in 2023, rising from 22.5% to 33.4% of total EU gas imports (Chatham House, 2024). The United States (US) emerged as the EU's largest LNG supplier by 2023, nearly tripling exports to Europe since 2021 (Energy Institute, 2024). Supply has been reallocated across North and Sub-Saharan Africa, Norway, Southeast Asia, and the Middle East. This reconfiguration has altered the emissions profile of the European fuel mix and may influence global fuel substitution decisions. Given substantial regional variation in NG production emissions, shifts in sourcing carry non-trivial climate implications, particularly as methane accountability in import supply chains tightens.

These regional differences are not only geographical but structural. Production systems differ in extraction technology, infrastructure age, and regulatory oversight, all of which shape methane leakage and energy intensity. Conventional production relies on natural reservoir pressure, which declines over time and can increase energy requirements. Unconventional production, such as shale gas recovery, creates artificial pressure through hydraulic fracturing (Jackson et al., 2014). These approaches can yield materially different fugitive emissions and lifecycle intensities.

Despite extensive study, disagreement persists. Omara et al. (2016) report that unconventional wells exhibit 23 times higher facility-level emissions, while conventional wells show higher emissions per unit of energy. Hultman et al. (2011) estimate that unconventional gas carries an 11% higher emissions burden than conventional gas. Emissions also vary across basins, including between the Marcellus and Permian basins in the United States (Zhu et al., 2024), and across extraction methods more broadly (Hultman et al., 2011; Skone, 2011; Stephenson et al., 2011; Venkatesh et al., 2011). Satellite observations confirm elevated methane leakage in both basins, underscoring the need to quantify methane intensity per unit of energy, particularly as US gas has become a major international export (Blake, 2023). Production emissions depend on regulatory enforcement, audit accuracy, technology age (Howarth, 2015;

Weber & Clavin, 2012), and operational conditions (Lavoie et al., 2017; MacKay et al., 2021). These factors complicate policy design and obscure the relative emissions performance of NG vis-à-vis coal and LFO.

A growing literature has examined emissions by origin and transport mode. Gan et al. (2020), analysing 104 international gas fields supplying China, including fields in Russia, Central Asia, Southeast Asia, and the Middle East, report median upstream emissions of 93.6 gCO_2e/kWh-thermal and identify elevated emissions from Northern Russian and Caspian gas (Feldman & McCabe, 2024; Gan et al., 2020). Other studies attribute high Russian pipeline emissions to governance failures and fugitive losses in domestic infrastructure (Lechtenböhmer et al., 2005; Roman-White et al., 2019). Research between 2016 and 2022 frequently ranks US LNG among the higher-emitting fuels delivered to Europe (Roman-White et al., 2019; Wachsmuth et al., 2019), though industry reporting suggests methane leakage reductions of roughly 25% between 2020 and 2022 (Karion et al., 2023; Petrich et al., 2024).

Initiatives such as the Oil Climate Index and the IEA Global Methane Tracker synthesise field- and product-specific methane data (International Energy Agency, 2024a; Rocky Mountain Institute, 2024). However, cross-regional comparability remains limited. Many LCAs of Middle Eastern gas (Ali, 2024; García-Gusano, 2014; Langshaw et al., 2020; Nie et al., 2020) rely heavily on a single Qatari case study lacking detailed methane-to-CO_2 breakdowns and stage-specific attribution (Korre et al., 2012). Satellite-based methane monitoring identifies major emitters in Iran, Saudi Arabia, and Turkmenistan (Chen, 2022; Gasim, 2024; Gordon et al., 2023), but translating atmospheric observations into emissions per unit of energy requires production-level data. LNG and pipeline transport emissions have been examined in vessel- and route-specific studies (Balcombe et al., 2022; Jordaan et al., 2022; Rosselot et al., 2023).

Existing studies thus demonstrate substantial heterogeneity across regions, extraction methods, infrastructure quality, and transport systems. Yet, emissions are not consistently attributed across supply chain stages and geographies in a manner that permits systematic cross-fuel comparison. Detailed case studies provide essential empirical foundations but do not yield the macroscopic perspective required for regulatory design in globally traded fuel markets.

This challenge is amplified by asymmetric climate governance. Climate policy is not globally harmonised. Central to this assessment is recognition that such penalties are not monolithic: they may manifest as import bans, emissions intensity-linked conditional market access, or explicit carbon pricing applied along the full supply chain emissions, including upstream and combustion emissions. Some importing jurisdictions are introducing carbon pricing, methane disclosure, and supply-chain due diligence requirements, while many exporting regions maintain weaker methane monitoring and control regimes. The EU's Methane Regulation (Regulation (EU) 2024/1787) represents a prominent example of unilateral demand-side climate action. The Regulation extends obligations to importers of gas, LNG, oil, and coal placed on the Union market, requiring traceability of origin and producer identity, and progressively mandating producer-level monitoring, reporting, and verification (MRV) equivalence. From 2028, the methane intensity of gas placed on the EU market must be reported, and from 2030, maximum methane intensity values may apply. Market access is therefore increasingly linked to upstream emissions performance.

However, the Regulation does not rank origin regions by lifecycle climate performance, nor does it predetermine how heterogeneous upstream emissions interact with cross-fuel substitution or global trade reallocation. Its climate effectiveness depends on whether upstream intensities vary materially across supply chains and on how markets respond to differentiated methane accountability. If high-emissions gas is excluded from one jurisdiction but remains competitive elsewhere, trade may be reconfigured without reducing aggregate emissions, a form of carbon leakage operating through fuel markets rather than through the relocation of production.

In this paper, we address three interrelated objectives: to account for regional variability in upstream LNG and pipeline gas emissions; to quantify emissions in regions with limited public information; and to generalise worldwide LNG, pipeline gas, LFO, and coal production emissions within a consistent lifecycle framework suitable for policy analysis. We construct a harmonised, regionally differentiated dataset disaggregating production, domestic transport, international shipment, and combustion across major exporting regions and fuel types. We quantify methane's contribution to total lifecycle emissions and show that upstream heterogeneity, including superemitting regions, can materially alter the conventional emissions hierarchy under plausible conditions. Most importantly, we evaluate the implications of this heterogeneity for unilateral methane regulation, using the EU Methane Regulation as a concrete case of demand-side climate governance, to assess whether import-based methane accountability can generate credible supply-side abatement incentives or risk displacing high-emissions gas to less regulated jurisdictions.

The remainder of the paper proceeds as follows. Section 2 reviews the literature on the role of natural gas in the energy transition. Section 3 presents the research methods. Section 4 reports the empirical findings. Section 5 concludes and discusses policy implications. Detailed methodological documentation is provided in the Supplementary Information.

2. Literature review

The literature does not converge on a single view of natural gas in the energy transition. Its climate performance is treated as contingent, shaped by methane leakage, metric choice, infrastructure configuration, carbon capture deployment, and institutional context (Shirizadeh et al., 2023; Dubey et al., 2023; Zhang et al., 2016; Hausfather, 2015; McGlade et al., 2018). As noted in Section 1, upstream emissions differ markedly across basins and regulatory regimes. Yet many studies continue to evaluate gas as a representative fuel category, abstracting from variation across specific supply chains. Table 1 organises the 30 papers reviewed into seven thematic clusters and highlights the principal mechanisms and policy implications that recur across them.

A recurring point of disagreement concerns methane and the time horizon. Several life-cycle and climate modelling studies conclude that coal-to-gas substitution reduces climate forcing when assessed over longer stabilisation periods. A multimetric assessment spanning China, Germany, India, and the United States finds that gas aligns with stabilisation objectives over 50-100 years across a broad range of leakage rates when evaluated using GWP100 and GTP100 (Tanaka et al., 2019). German evidence suggests leakage thresholds of roughly 4-5%, below which coal-to-gas switching delivers substantial emissions reductions, with observed leakage rates reported well below these levels (Ladage et al., 2021). Bounding exercises similarly estimate that leakage rates between 5.2% and 9.9% would be required for gas to match coal's 100-year radiative forcing, and indicate that new gas plants can operate for limited periods per unit of coal displaced without increasing long-run forcing when leakage remains around 2% (Hausfather, 2015). Outcomes also depend on plant efficiency and the timing of near-zero carbon deployment (Zhang et al., 2016).

Shorter-term metrics complicate this picture. Using a 20-year GWP framework, one analysis estimates shale gas methane leakage at approximately 5.8% and argues that near-term impacts may exceed those of coal or oil (Howarth, 2014). Scenario analysis further suggests that gas may play a transitional role under moderate stabilisation targets (550 ppm CO_2), but declines rapidly under more stringent 450 ppm pathways (Levi, 2013). Much of the disagreement, therefore, reflects metric choice and transition timing rather than fundamentally incompatible data. What remains largely unexplored is how origin-specific methane intensities interact with asymmetric regulation in traded fuel markets.

Lifecycle assessments reinforce the scale of heterogeneity. A global study of gas-fired electricity reports mean lifecycle emissions of 645 gCO_2e/kWh across 108 countries, with wide dispersion driven by methane leakage, plant efficiency, transport mode, and transmission losses (Jordaan et al., 2022). Multi-model abundant-gas scenarios show that expanded gas supply does not significantly reduce global CO_2 emissions in the absence of complementary policy, as coal displacement is partly offset by substitution away from renewables and nuclear and by lower energy prices stimulating demand (McJeon et al., 2014). U.S. modelling reaches similar conclusions, identifying modest short-term CO_2 reductions but potential long-run increases due to renewable crowd-out, alongside welfare and air quality gains (Gillingham & Huang, 2019). Case-based work on shale gas and LNG development in British Columbia raises concerns regarding liquefaction emissions, lifecycle uncertainty, and regulatory gaps (Stephenson et al., 2012). While these studies underscore the importance of infrastructure, geography, and governance, they seldom integrate origin-level heterogeneity into analyses of trade reallocation under asymmetric climate policy.

Energy system modelling indicates that carbon capture and storage (CCS) is a critical determinant of gas persistence. European modelling suggests that gas could represent 26% of primary energy by 2050 under best-available methane abatement, but only 9% under current emissions factors (Shirizadeh et al., 2023). Broader European assessments anticipate declining methane demand, with hydrogen and biomethane expanding, but insufficient to replace historical volumes without reforming plus CCS (Stern, 2020). IPCC-consistent 1.5°C pathways imply declines in gas use of 35% by 2050 and 70% by 2100 relative to 2019 levels, with continued use closely tied to CCS deployment (Dubey et al., 2023). UK modelling reaches similar conclusions: gas declines sharply after 2030 in the absence of CCS, but remains significant in industry and power generation when CCS is available (McGlade et al., 2018). German transmission modelling anticipates partial repurposing of infrastructure for hydrogen (Gillessen et al., 2019). Integrated assessment reviews caution that fossil fuel persistence pathways often rely on optimistic CCS assumptions and may underestimate the pace of renewable diffusion (Minx et al., 2024). Comparative sustainability analysis across India, Iran, Norway, and the UK identifies CCGT, CCS, and power-to-gas as enabling technologies, while noting methane leakage and infrastructure cost risks (Safari et al., 2019).

Institutional design also shapes substitution outcomes. In Great Britain, a stable carbon price floor accelerated coal-to-gas switching, reducing power-sector emissions by roughly 25% in 2016 (Wilson & Staffell, 2018). UK evidence also highlights rebound effects and the centrality of CCS for long-term alignment with net zero (Kinyar et al., 2025). In China, coal-to-gas substitution expands mitigation potential but is constrained by asymmetric information between central and local governments (Song et al., 2022). U.S. computable general equilibrium modelling suggests that abundant gas alone has a limited emissions impact, while carbon pricing significantly reduces the value of gas investment and infrastructure (Woollacott, 2020). These studies emphasise pricing and governance frameworks but largely focus on domestic policy settings rather than import-based methane accountability applied across heterogeneous supply chains.

Concerns about lock-in further complicate the narrative around bridge fuel. Critics argue that gas expansion may entrench long-lived infrastructure that delays renewable deployment and understates methane impacts (Kemfert et al., 2022). Systems analysis identifies rebound, crowd-out, and carbon lock-in dynamics (Gürsan & de Gooyert, 2021). Diffusion modelling across countries shows that renewables often exert competitive pressure on gas, although in some contexts, gas expansion slows renewable uptake (Bessi et al., 2021). Abundant gas scenarios reinforce the risk of renewable displacement (McJeon et al., 2014; Gillingham & Huang, 2019).

Other strands of the literature focus on development and welfare trade-offs. In China, higher gas consumption is associated with reductions in energy poverty, particularly in poorer regions (Dong et al., 2021). In Africa, natural gas is presented as a development instrument, and blanket finance bans are criticised as inequitable (Bugaje et al., 2022). Abundant gas scenarios yield welfare gains and reductions in air pollution, even when long-run CO_2 effects are modest (Gillingham & Huang, 2019). Discourse analysis shows that the bridge fuel metaphor is politically contested and interpreted differently across jurisdictions (Delborne et al., 2020; Stephenson et al., 2012; Janzwood & Millar, 2022).

Across these 30 papers, several themes recur: methane leakage is central to gas's climate profile; lifecycle emissions vary widely across supply chains; CCS conditions long-run compatibility in stringent pathways; and infrastructure expansion carries lock-in risks. Yet despite detailed modelling of methane metrics and transition scenarios, the interaction between unilateral demand-side regulation and heterogeneous upstream emissions in globally traded LNG markets remains underexamined. Gas is often treated as homogeneous within a given fuel type, superemitters are rarely incorporated into trade analysis, and methane intensity is seldom directly linked to sourcing behaviour under asymmetric climate governance.

As discussed in Section 1, the EU Methane Regulation introduces traceability requirements, MRV equivalence provisions, and the prospect of methane intensity thresholds for imported fuels. What remains unclear is how such unilateral accountability affects producer behaviour: it may encourage upstream abatement, but it may also redirect higher-emissions gas toward jurisdictions with weaker oversight. The existing literature has not systematically examined this trade dimension.

We respond by assembling regionally differentiated cradle-to-gate and cradle-to-grave emissions for LNG, pipeline gas, coal, and LFO within a consistent framework. We quantify methane's contribution under alternative climate metrics and consider how differences in emissions intensity shape substitution incentives when import regulation is asymmetric. Our objective is to assess whether demand-side methane governance can influence supply decisions in globally traded gas markets, or whether it primarily reshapes trade flows.

Table 1: Systematisation of the literature

Cluster	Papers	Method Type	Core Mechanism	Policy Implication
Climate Metrics	Tanaka et al. (2019); Ladage et al. (2021); Levi (2013); Zhang et al. (2016); Hausfather (2015); Howarth (2014)	LCA, climate modelling	Methane leakage + time horizon	Regulate leakage; metric choice matters
Lifecycle & System Effects	Jordaan et al. (2022); McJeon et al. (2014); Gillingham & Huang (2019); Stephenson et al. (2012)	LCA, IAM, CGE	Transport intensity + scale effects	Certification; prevent renewable crowd-out
Pathways	Shirizadeh et al. (2023); Stern (2020); Minx et al. (2024); Dubey et al. (2023); Gillessen et al. (2019); McGlade et al. (2018); Safari et al. (2019); Diluiso et al. (2021); Vinichenko et al. (2021)	Optimisation/IAM	CCS as condition for long-run gas compatibility	Gas persistence requires CCS
Governance	Wilson & Staffell (2018); Kinyar et al. (2025); Song et al. (2022); Woollacott (2020)	Empirical/CGE	Institutional design mediates substitution	Design instruments carefully
Lock-in	Kemfert et al. (2022); Gürsan & de Gooyert (2021); Bessi et al. (2021)	Systems/political economy	Crowding-out, stranded assets	Avoid infrastructure overbuild
Development	Bugaje et al. (2022); Dong et al. (2021)	Panel/CGE	Energy poverty & welfare trade-offs	Context-specific policy
Discourse	Delborne et al. (2020); Janzwood & Millar (2022)	Qualitative coding	Bridge-fuel narrative politics	Clarify transition criteria

Notes: LCA = life-cycle assessment; IAM = integrated assessment model; CGE = computable general equilibrium model; Panel = panel econometric analysis; Optimisation = energy system optimisation modelling; Qualitative coding = discourse or interpretive policy analysis. Papers are classified by their dominant analytical approach. "Core Mechanism" denotes the primary causal channel emphasised in each cluster; "Policy Implication" summarises the principal regulatory inference drawn in that strand of the literature.

3. Methods

To compare lifecycle emissions across LNG, pipeline natural gas, thermal coal, and light fuel oil (LFO), we assemble a harmonised dataset combining field-level production data with transport modelling and standard combustion factors (Table 2). The analysis is structured in two stages (Figure 1). We first estimate cradle-to-gate emissions, covering extraction, processing, and delivery to the import point. Combustion emissions are then added to obtain cradle-to-grave values.

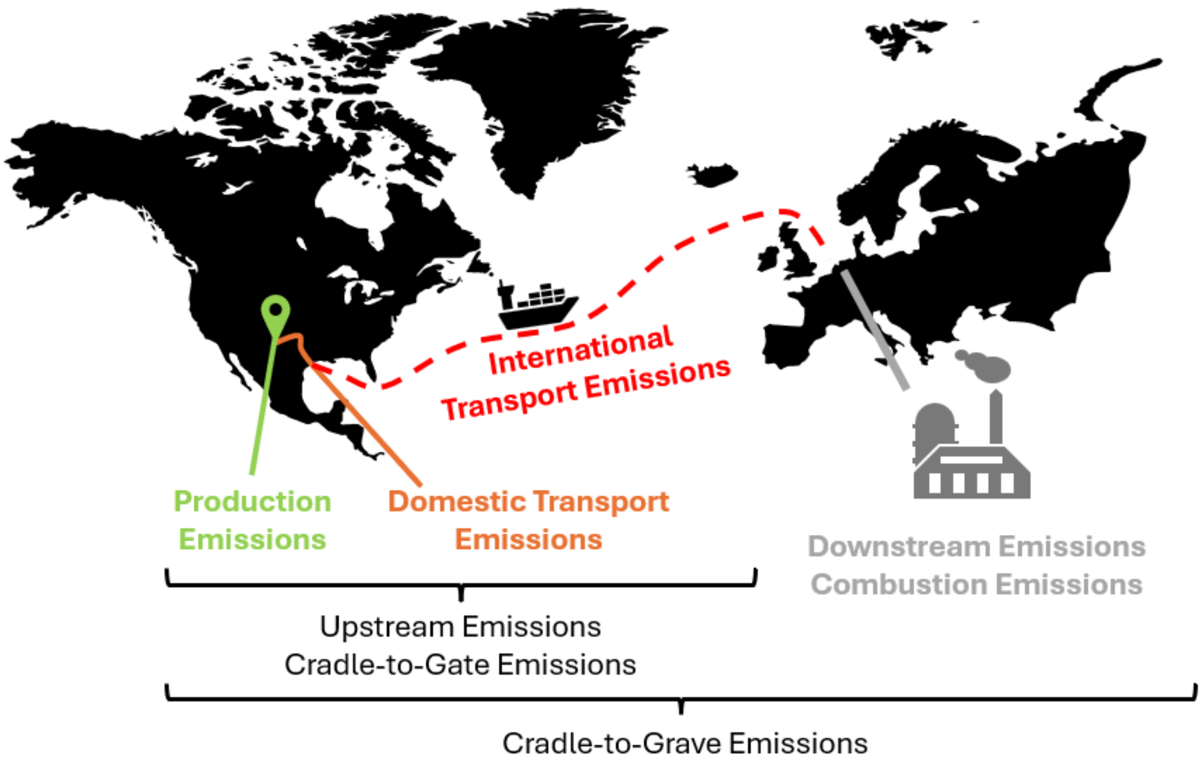


Figure 1: System boundaries of cradle-to-gate (of a consumption point) and cradle-to-grave (post-combustion) presented in this study.

Cradle-to-gate includes emissions from extraction and processing, domestic transport to export terminals, liquefaction (for LNG), regasification, storage, maritime shipment, and long-distance pipeline transmission to the import gate. Cradle-to-grave adds downstream combustion. Emissions between the import terminal and the final end use are assumed to be small relative to those from upstream and combustion stages. Results are reported per kWh-thermal, using fuel heating values, and presented using a 100-year global warming potential (GWP100) as the baseline metric. Results under GWP20 are reported separately in the Supplementary Information.

Upstream production and processing emissions are compiled from a consolidated database covering 333 international gas fields, drawing on peer-reviewed studies and established sources reporting methane leakage, venting, flaring, and processing emissions. Coal production emissions are based on CRU Group regional data (CRU Group, 2024), and LFO production emissions are taken from established lifecycle databases (Rocky Mountain Institute, 2024). The dataset incorporates emissions scenarios up to 2022. Individual measurements have been taken more recently, but predominantly report aggregate regional emissions totals without corresponding production volume figures, precluding conversion to emissions per unit thermal energy, the primary functional unit used in this study.

For each field or region, emissions intensities are standardised per unit of thermal energy output to enable cross-fuel comparison. Rather than relying on a single representative value, we retain observed dispersion and report median and upper-bound estimates where relevant. Data harmonisation procedures, conversion assumptions, and treatment of uncertainty are described in the Supplementary Information.

Table 2: Data sources, system boundaries, and calorific conventions for upstream emissions by fuel type

	Natural Gas / LNG	**Coal**	**LFO**
Primary emissions source	Gan et al. (2020); OCI; literature	CRU Group (2024)	OCI
Calorific basis	HHV	HHV	HHV
Upstream stages included	Extraction, processing, domestic transport, liquefaction, shipping, regasification	Mine extraction, domestic transport, international shipment	Extraction, processing, transport to export
Scope convention	Field-level total GHG	Scope 1+2 by activity	Field-level total GHG
CO_2/CH_4 split source	OCI field-level; regional median where unavailable	Global Energy Monitor	OCI field-level
Combustion factors	UK Government 2023 conversion factors	UK Government 2023 conversion factors	UK Government 2023 conversion factors
End-use emissions	Excluded from upstream; added uniformly at combustion stage	Excluded from upstream; added uniformly at combustion stage	OCI end-use excluded; UK Government factors applied

Notes: HHV = higher heating value. All upstream emissions are expressed per kWh-thermal on an HHV basis. Combustion emissions are drawn from UK Government (2023) Greenhouse Gas Reporting Conversion Factors and applied uniformly across all fuels and regions; they are excluded from the upstream stage for all fuels. CRU Scope 1 and 2 emissions are used for coal; Scope 3 is excluded. The CO_2/CH_4 split for coal is derived from the Global Energy Monitor Gas Infrastructure Tracker as CRU does not stratify by gas species. OCI end-use emissions are excluded from LFO upstream totals; UK Government combustion factors are applied instead to maintain consistency with other fuels. Field-level CO_2/CH_4 splits are available for over half of natural gas fields via OCI; regional median values are imputed for the remainder. Residual boundary differences across upstream modules reflect data availability constraints rather than methodological inconsistency.

Maritime LNG transport emissions are estimated using vessel-level data from Rosselot et al. (2023), including propulsion systems, fuel consumption, and methane slip across tanker classes. Operating assumptions, such as manoeuvring time, ballast share, and port duration, follow Balcombe et al. and Rosselot et al. Emissions are calculated per kilometre and per unit of LNG transported. Vessels are grouped by exporting country and averaged to obtain representative regional intensities. Nautical distances between origin and destination pairs are taken from Chyong and Schmidt (forthcoming), and all feasible export-import routes are considered. Results are expressed per kWh-thermal delivered. Full routing assumptions and parameter values are provided in the Supplementary Information.

Pipeline transport emissions are calculated following Jordaan et al. (2022), using compressor energy requirements from Balcombe et al. (2022) and leakage rates from Gan et al. (2020). Representative export terminals are identified using the Global Energy Monitor Gas Infrastructure Tracker. Route distances to the Rotterdam gate are calculated using haversine methods. Emissions per kilometre are derived from compressor fuel use and leakage intensity, generating region-specific transport factors. The main text reports representative origin-destination comparisons; the complete routing structure is documented in the Supplementary Information.

Combustion emissions for natural gas, coal, and LFO are drawn from the UK Government 2023 Greenhouse Gas Reporting Conversion Factors dataset and applied uniformly across regions to isolate variation arising from upstream production and transport. Methane slip during combustion is included using the same source. Emission factors and conversion values are listed in the Supplementary Information.

For each fuel and origin-destination pair, cradle-to-gate emissions combine production, domestic transport, international shipment (LNG or pipeline), and regasification where relevant. Cradle-to-grave values add combustion emissions. Where field-level data show dispersion, median values and upper-bound cases are reported to reflect observed variability, allowing lifecycle rankings to be evaluated under realistic heterogeneity rather than stylised average assumptions.

In the carbon pricing scenarios, we use 2024 yearly-averaged spot prices for each fuel, sourced from the Energy Institute (2024) and representative of pricing in the destination region; further details are provided in the Supplementary Information. To reflect end-use carbon costs, we convert fuel costs from a thermal to an electrical energy basis using standard thermal efficiency values drawn from the IEA (International Energy Agency, 2025): 43% for coal, 59% for LNG, and 39% for LFO. These figures represent median efficiencies across real-world technologies and global facilities: subcritical, supercritical, and ultrasupercritical plants for coal; combined cycle gas turbine (CCGT) systems for LNG; and open-cycle gas turbines for LFO, covering the EU, United States, Russia, China, Japan, India, the Middle East, Africa, and Brazil. Assumed efficiency values do not deviate by more than 4% from median point estimates across these regions.

In the main manuscript, we consider a base-case carbon price scenario reflecting average 2024 prices: €65/tCO_2 in the EU and €10/tCO_2 in China and India. The Supplementary Information additionally explores a low-carbon price scenario (EU: €25/tCO_2[3]; India/China: €5/tCO_2) and a high-carbon price scenario (EU: €450/tCO_2[4]; India/China: €75/tCO_2).

4. Results

4.1. Upstream heterogeneity and the conditional fuel hierarchy

Figure 2 reports cradle-to-gate emissions for LNG, pipeline gas, coal, and LFO delivered to the Rotterdam gate. Production, domestic transport, and international transport are shown separately. Error bars represent the 5th and 95th percentiles.

The dispersion across origin regions is marked. Russian pipeline gas and North American LNG lie toward the upper end of the upstream distribution in median terms. North African LNG also sits above the lower-intensity cluster. The upper bound for Southeast Asian LNG is especially high, reflecting the influence of a small number of superemitting fields rather than

[3] Average 2020 EU ETS1 carbon price
[4] A carbon price of €450/tCO_2 aligns with the European Commission's projection of an ETS1 price required to reach net zero by 2050 (see Chyong and Schmidt, 2026)

uniformly elevated regional performance. By contrast, gas sourced from the Middle East, Sub-Saharan Africa, and Norway consistently occupies the lower end of the upstream range. Norway's position aligns with its comparatively stringent methane monitoring and regulatory framework (Haugland, 2021).

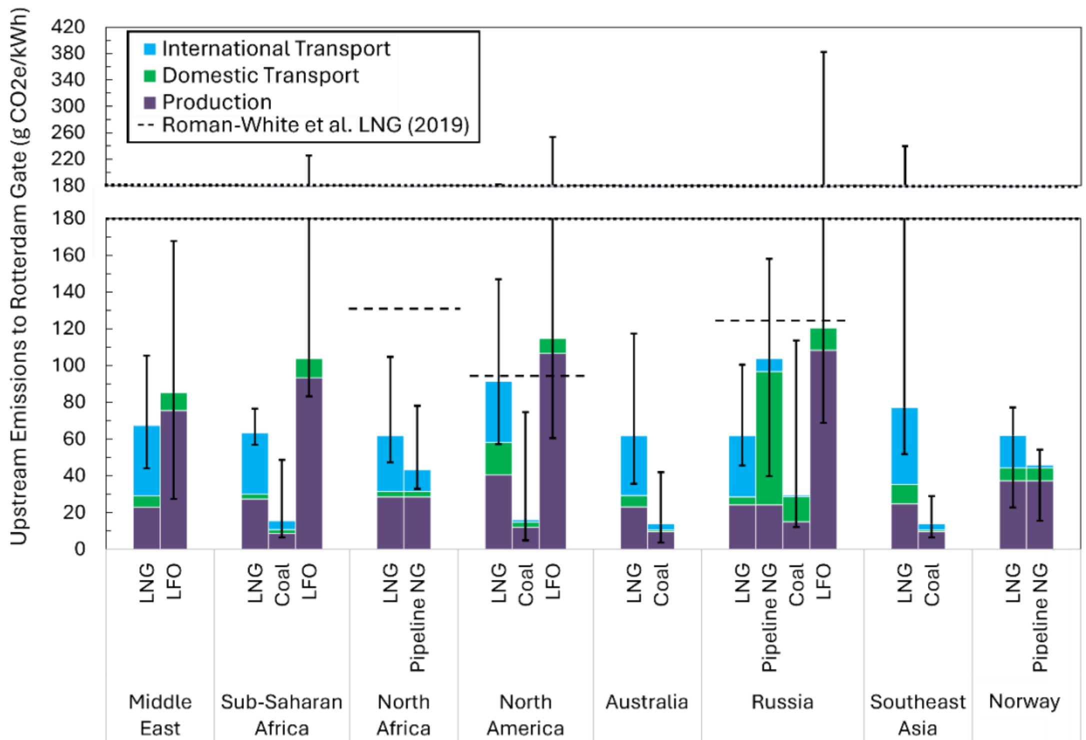


Figure 2: Average production and transportation emissions for LNG, pipeline natural gas, coal, and light fuel oils from various origin regions to the gate of Rotterdam, Netherlands.
Notes: Error bars indicate 5th and 95th percentile values; Russia's LNG is the Yamal LNG project

In conventional lifecycle comparisons, fossil fuels are typically ranked by emissions from lowest to highest: pipeline gas, LNG, LFO, and coal (Burnham et al., 2012; Cohan & Sengupta, 2016; Jaramillo et al., 2007). This ordering largely reflects combustion. LFO emits roughly 30% less CO_2 than coal during combustion, and LNG close to 50% less (Burnham et al., 2012; Cohan & Sengupta, 2016; Jaramillo et al., 2007). On a cradle-to-grave basis under GWP100, these combustion differences dominate.

When upstream emissions are considered separately, the picture is less straightforward. LFO and LNG are commonly associated with oil and gas reservoirs where fugitive methane can be significant (Zhang et al., 2020). Coal mining also releases methane, particularly in coalbed systems, but the physical structure of solid-bed mining generally limits gaseous escape relative to oil- and gas-associated reservoirs (Hunt, 1991; Zhang et al., 2020). Coal's upstream advantage, however, is outweighed by its higher combustion emissions.

Transport further differentiates fuels. Coal and LFO incur relatively modest transit emissions compared with LNG and pipeline gas. LNG supply chains require liquefaction, regasification, and maritime propulsion, while pipeline systems depend on compressor fuel use and fugitive leakage. Under GWP100, these differences remain secondary to combustion. Under GWP20, however, methane's higher weight increases the contribution of upstream losses, and in upper-bound cases, lifecycle emissions of high-intensity gas supply chains approach, and in extreme instances exceed, those of coal (Howarth, 2014).

Across fuels, coal exhibits the lowest upstream intensity. LNG and LFO upstream emissions are typically two to six times higher. Once combustion is included, coal retains the highest cradle-to-grave intensity (Figure 4). LNG generally exhibits lower upstream emissions than LFO, though this does not hold for certain outlier producers. Excluding those outliers, pipeline gas tends to display the lowest upstream emissions among gas supply options, reflecting the absence of liquefaction and regasification losses.

Avoiding liquefaction reduces transport-related emissions relative to LNG, consistent with earlier findings on LNG processing's energy intensity (Shaton et al., 2020). The pattern is not uniform across regions. Russian pipeline gas shows elevated upstream emissions, driven largely by fugitive methane losses along domestic transmission infrastructure (Gan et al., 2020; Roman-White et al., 2019). These elevated emissions reflect the domestic pipeline segment, where region-specific leakage and infrastructure conditions are encoded in the dataset. International pipeline transport from the export border to the destination is modelled separately using uniform distance-based parameters, as described in SI1.2.

Following Russia's invasion of Ukraine in 2022, EU imports of Russian gas declined sharply (BP Global, 2022; Energy Institute, 2024), with North American LNG filling much of the gap. This shift reduced exposure to Russian pipeline leakage but increased reliance on production and long-distance transport from North America. Emissions within North America vary substantially across basins. Satellite evidence identifies elevated emissions in specific areas, yet per-unit energy leakage rates differ widely and do not map neatly onto geography alone (Weber & Clavin, 2012). This variation is explored in Figure 3.

North America's decentralised production system contributes to longer domestic transport distances and extended maritime routes to Europe. In the dataset, average Russian LNG emissions are roughly 40% lower than those of North American LNG. The difference is driven primarily by higher North American production emissions (about 80% higher) and domestic transport emissions (approximately three times higher). These ranges are consistent with Roman-White et al. (2019). Russian pipeline emissions reflect ageing infrastructure and comparatively weaker methane regulation (Klimenko et al., 2023). By contrast, Yamal LNG benefits from short, dedicated pipelines linking fields directly to export terminals. This is further confounded by the extraction method, i.e., unconventional versus conventional processes, which we elaborate on in SI-Figure 2.

Lifecycle rankings are therefore not intrinsic properties of fuel type. They depend on origin-region practices, methane control, infrastructure condition, and transport configuration. Upstream variation is large enough to narrow the conventional gas-coal ordering materially, and, in theoretical upper-bound cases, to reverse it. Under median assumptions, the ordering holds for all export-facing supply chains, though the margin is smallest for Russian pipeline gas. The significance of this finding lies not in frequent crossovers but in the scale of heterogeneity: upstream variation warrants differentiated accountability rather than treating natural gas as a uniform fuel category.

4.2. Concentration of emissions and targeted mitigation potential

The upper bound of U.S. LNG in Figure 2 approaches that of Russian pipeline gas. Inspection of the dataset shows that part of the upper tail reflects inclusion of values from Howarth et al. (2011). Removing these observations reduces the North American upper bound by roughly 10 gCO_2-eq/kWh, while leaving median and lower-bound values largely unchanged. The ranking of median emissions across regions under GWP100 remains intact. Sensitivity results are reported in the Supplementary Information.

At the median, North African pipeline gas and Norwegian gas, whether supplied as LNG or pipeline, exhibit the lowest cradle-to-gate emissions among the supply options considered. These systems combine relatively low production emissions with shorter transport distances and limited liquefaction losses for pipeline supply. North African LNG is more emissive than North African pipeline gas, largely due to the energy required for liquefaction and, in some cases, longer maritime routes.

Australian, Middle Eastern, Sub-Saharan African, and median Southeast Asian LNG generally fall below North African LNG but remain above North African pipeline gas. Russian pipeline gas and selected North American and Southeast Asian LNG fields occupy the upper end of the distribution.

In Southeast Asia, emissions are concentrated in a small number of fields, notably Helang-Layang, Kebabangan, and Bongkot. Excluding these outliers reduces the regional upper bound to approximately 116 gCO_2-eq/kWh, close to Australian LNG. Regional averages, therefore, conceal significant intra-regional dispersion.

Abstracting from cost, contracts, and geopolitical constraints, the lowest-intensity supply options for the EU are Norwegian gas and North African pipeline gas, followed by Middle Eastern, Sub-Saharan African, Australian, and median Southeast Asian LNG. North American LNG is generally more emissive than these alternatives but less so than Russian pipeline gas.

Emissions ranking alone does not determine trade flows. Capacity constraints, pricing, contracts, and political risk all matter. The concentration results make clear that upstream intensity is not evenly distributed: a relatively small share of production accounts for a disproportionate share of emissions. This has direct implications for the design of targeted methane accountability under asymmetric regulation.

4.3. Superemitters and the Limits of Static Leakage Intuition

Figure 3 presents cradle-to-grave emissions, separating CO_2 and CH_4 contributions for LNG delivered from each origin to multiple destination regions. Production, domestic transport, shipment, and combustion are included. Uncertainty ranges reflect cumulative dispersion across stages.

The supply chains with the highest total lifecycle intensity, namely North American LNG, Russian pipeline gas, and Southeast Asian LNG, also display the largest methane shares. For upper-bound cases, methane accounts for roughly 23% of total emissions for North American LNG, 26% for Russian pipeline gas, and 24% for Southeast Asian LNG. These shares vary little across destination regions, indicating that international transport contributes little to the variance in methane shares for a given origin. More broadly, lifecycle variance across supply chains originates upstream rather than at combustion.

In some cases, upstream emissions are large enough to challenge conventional fuel hierarchies. Coal combustion remains more carbon-intensive than LFO or gas, but elevated upstream emissions in North American and Russian LFO production can bring cradle-to-grave intensities close to coal. Under theoretical upper bounds, LNG and pipeline gas supply chains can exceed LFO and, in extreme cases, converge toward coal under GWP100. Under GWP20, such crossovers become more frequent across a wider range of regions, though they remain theoretical extremes under the same bounding assumption.

The dispersion in Figure 3 is concentrated. A limited number of Southeast Asian fields, along with Russian pipeline systems and certain North American basins, account for much of the upper-tail intensity. Targeted mitigation in these segments would yield larger reductions than uniform abatement across already low-intensity regions.

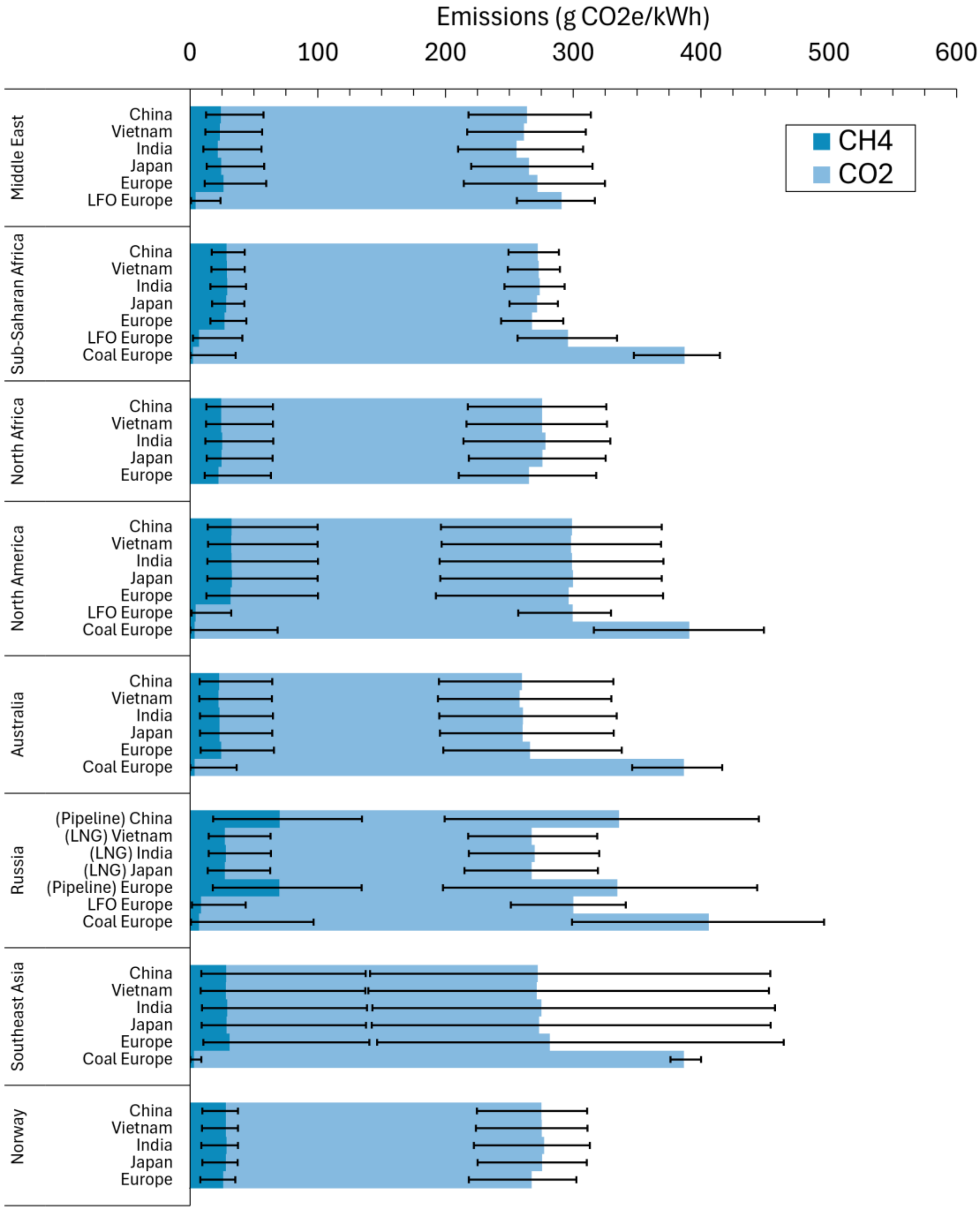


Figure 3: Cradle-to-grave CO_2 vs CH_4 emissions in LNG delivered from a given origin region to a destination region/country. This represents production in the origin region, domestic transport within the origin region, international shipboard transport from the origin to the destination, and combustion in the destination region.

Notes: Unless otherwise labelled, values represent LNG delivered from the origin region (leftmost labels) to a destination region. Uncertainty bounds associated with methane and CO_2 are cumulative.

Regulatory pressure can arise at the production stage or at the point of import. Under asymmetric climate governance, demand-side standards in one market may alter trade flows without reducing global emissions. High-intensity gas excluded from a regulated market can be redirected to jurisdictions with weaker constraints. This resource shuffling dynamic is familiar from other energy markets (Bushnell et al., 2014). Conventional emissions leakage logic through trade reshuffling often treats fuels as homogeneous and assumes stable emissions rankings. Our results suggest otherwise: lifecycle intensities vary substantially by origin, and most variation lies upstream rather than at combustion. Import-based methane accountability, therefore, primarily operates through production systems.

Whether unilateral regulation reduces emissions or reshapes trade depends on substitution conditions. If displaced high-intensity LNG remains competitive against coal or LFO elsewhere, redirection is plausible. If carbon pricing materially alters competitiveness, demand contraction may follow. Figure 3 shows that some high-intensity supply chains already approach coal's lifecycle intensity, narrowing the substitution margin. Outcomes depend on methane intensity differentials, fuel prices, carbon costs, and substitution elasticities, which Section 4.4 examines through price-based comparisons across major importing regions.

4.4. Import-Based Methane Accountability and Trade Reallocation

Figure 4 combines lifecycle emissions with illustrative carbon pricing to examine how upstream heterogeneity affects trade incentives (SI-Figures 3-5 explore lower and higher carbon price and GWP assumptions).

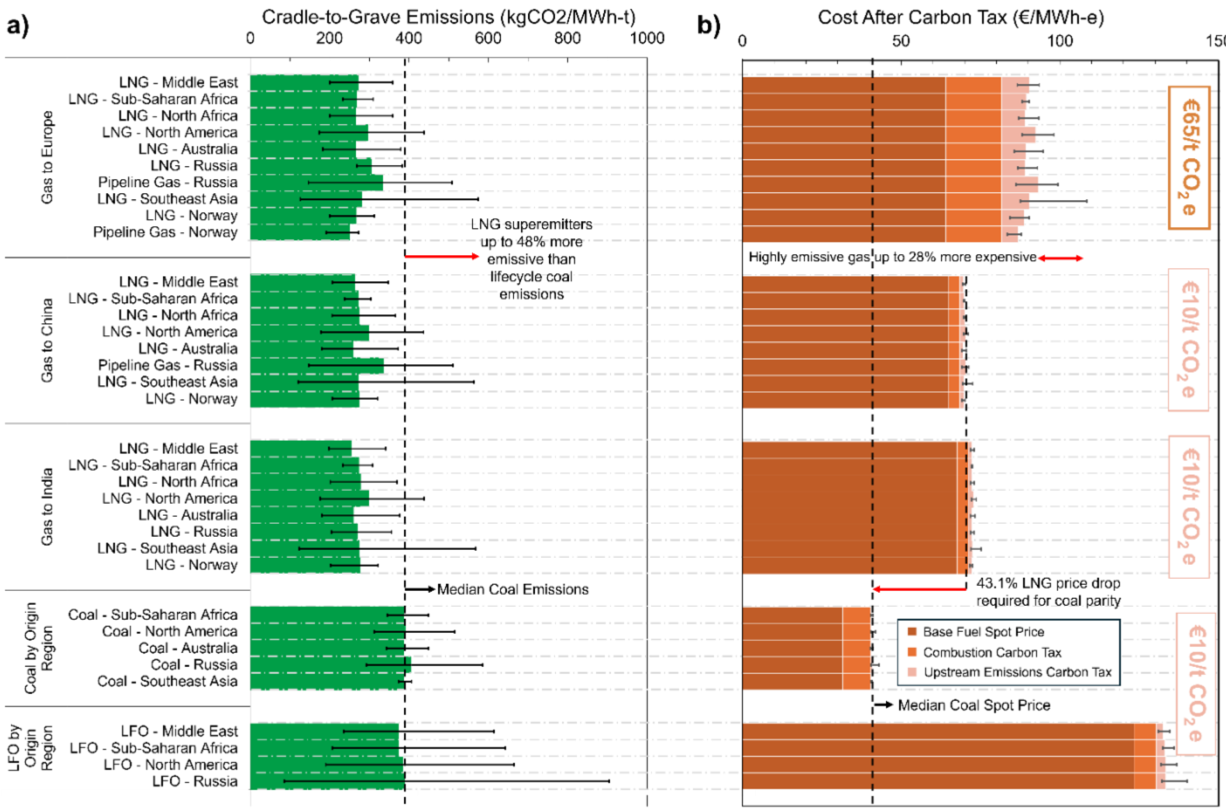


Figure 4: a) Cradle-to-grave emissions of thermal fuels delivered to Europe, China, and India, showing superemitting natural gas fields bearing higher lifecycle emissions than the median coal and LFO. b) Regional LNG, LFO, and coal costs suggest carbon leakage requires a 43% reduction in regional natural gas costs to meet parity with thermal coal, placing immense pressure on superemitting supply chains.

Panel 4(a) confirms that lifecycle differences depend more on origin than on destination. Combustion emissions are similar across importing regions and account for most of the total emissions; upstream stages drive dispersion. Superemitting LNG supply chains exceed the median coal supply chain on a cradle-to-grave basis under GWP100. Fields such as Bongkot, with upstream emissions of approximately 200 gCO_2e/kWh, yield cradle-to-grave totals that cross the coal threshold based on measured field data alone; propagated upper bounds extend this margin further, with superemitting supply chains exceeding median coal and LFO by up to 48% under GWP100. The assumption of fixed fuel-type rankings no longer holds when upstream heterogeneity is included. Panel 4(b) shows that under a €65/tCO_2 carbon price (including upstream emissions), high-intensity LNG delivered to Europe becomes roughly 28% more expensive than median LNG, differentiating competitiveness within the fuel category.

Standard leakage intuition suggests that high-intensity LNG supply would be redirected to other markets, where it competes with coal and LFO. In China and India, coal's cost advantage remains central to this dynamic. Based on 2024 coal and gas prices and carbon costs in Figure 4(b), displaced LNG would need to fall by roughly 43% to match coal, significantly eroding producer revenues and suggesting that a full large-scale redirection at existing price levels faces substantial economic constraints. These are illustrative parity conditions rather than equilibrium outcomes; actual responses would depend on contract structures, price flexibility, and the relative size of alternative markets. Two indicative adjustment channels follow: producers lower methane intensity to regain market access, or output contracts where price adjustment is infeasible.

The sensitivity analysis (Figure 5) helps identify when diversion is likely and when EU methane screening could affect more than just the composition of the gas Europe buys. In the base carbon price scenario, LNG costs remain well above coal costs in China and India, meaning that redirecting large volumes from Europe would require substantial price cuts. In the stricter carbon price case, coal costs move much closer to LNG costs in China and India, making it easier for gas displaced from Europe to find buyers in Asia and to replace some coal. Whether this benefits the climate depends on the emissions intensity of the diverted gas.

In practice, the EU Methane Regulation matters most for suppliers that both sell into Europe and exhibit widespread methane emissions across projects. These conditions point most clearly to North American LNG and, historically, Russian pipeline gas, both of which span a wide enough emissions distribution that screening could affect which supplies reach European markets and which are redirected elsewhere. Under GWP100 and in the typical case, these supplies still have lower cradle-to-grave emissions than coal, so coal-to-gas switching can reduce overall emissions if it happens at scale. The complication is that a carbon-pricing regime in Asia that covers only combustion emissions fails to distinguish between cleaner and more emissive gases. It can therefore encourage coal-to-gas switching while allowing more emissions-intensive gas supply chains to compete and displace coal. In that situation, EU Regulation mainly affects which gas replaces coal, rather than whether coal is replaced. Should emissions intensities have shifted materially between 2023-2026, for instance, through accelerated infrastructure investment of regulatory-driven abatement, the precise quantitative estimates presented may require revision.

However, the structural findings concerning carbon leakage and demand destruction are primarily governed by the significant differences in superemitting field emissions intensities and pricing across fuel types.

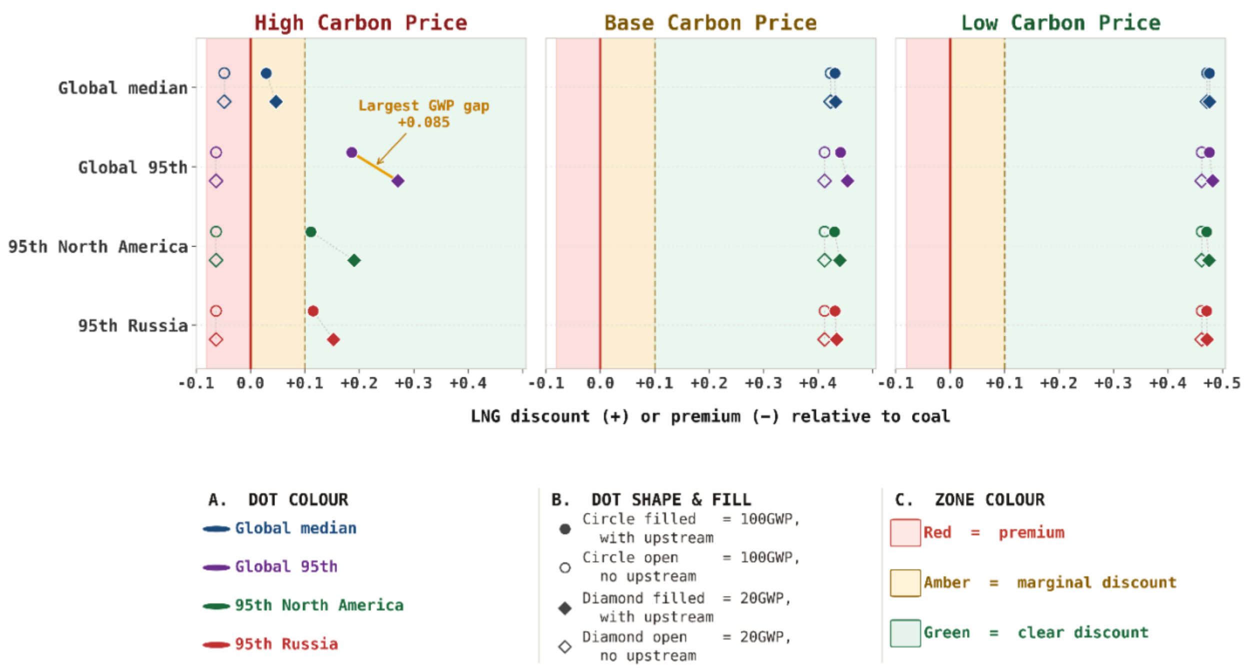


Figure 5: LNG vs. Coal: Price Breakeven Thresholds Across Carbon Price Scenarios and Methane Accounting Methods

Notes: Each panel represents a carbon price scenario (High, Base, or Low). Within each panel, the x-axis shows the price adjustment LNG would need relative to coal to reach lifecycle emissions-cost parity. Positive values indicate LNG is more expensive than coal and would require a price discount to compete; negative values indicate LNG is already cheaper than coal and no discount is needed. Each row corresponds to a regional upstream methane emissions profile; Dot colour identifies the region. Dot shape distinguishes the GWP metric. Dot fill indicates whether upstream methane emissions are included in carbon pricing. Background shading signals the competitiveness of LNG vs coal. Connecting lines between a circle and diamond of the same fill type illustrate the sensitivity of the breakeven point to the choice of GWP metric: a longer line indicates greater sensitivity to methane accounting.

The cost-parity analysis of the 95th percentile emissions for North American and Russian supply chains reinforces this point (Figure 5). Under a high carbon price in China and India, and if the carbon price is applied only to combustion emissions, even the more emissive segments of North American and Russian supply can remain close to coal on cost, so diversion into coal-replacing uses remains plausible. If carbon costs also cover upstream emissions, more emissive supplies require much larger price discounts to compete with coal, an effect that is stronger under

GWP20. Any global emissions benefit from EU methane regulation is therefore more likely when Asian climate policy is stringent and covers upstream emissions, rather than combustion alone.

A separate supply-side adjustment channel operates within exporting regions. In North America, producers facing methane screening may reallocate lower-intensity supply to regulated markets while absorbing higher-intensity production domestically. Portfolio reshuffling does not necessarily reduce aggregate emissions. Where heterogeneity is large, regulatory screening binds first on the most emissions-intensive segment of the distribution.

The present analysis does not model equilibrium responses. It does show that emissions are highly concentrated, though the degree of concentration varies across regions. In the United States, the top quintile by emissions intensity accounts for approximately 6% of production and 10% of upstream emissions, a relatively dispersed distribution suggesting that meaningful pressure on emissive US producers would require moderately broader sourcing adjustments than in more concentrated regions. In Southeast Asia, the top quintile by emissions intensity accounts for 38% of regional emissions from 27% of production; in Russia, the top quintile accounts for roughly 25% of emissions from approximately 12% of production. In both cases, relatively targeted sourcing adjustments would yield disproportionately large reductions in regional upstream emissions. Such concentration implies that methane differentiation could exert targeted pressure on high-intensity assets without requiring disengagement from entire regions.

These findings do not rule out emissions leakage via trade shuffling. They indicate that outcomes depend on price differentials, methane intensity gaps, policy scope (combustion-only versus upstream-inclusive carbon pricing), and substitution elasticities. Where highly emissions-intensive LNG approaches coal's lifecycle intensity, particularly under GWP20, and coal remains the marginal fuel, the sign of net climate impacts becomes ambiguous unless methane-intensive supply chains are constrained or abated. Conversely, where methane differentiation induces abatement at the most emissions-intensive assets and limits their participation in coal displacement, unilateral methane regulation can contribute to global emissions reductions rather than merely shifting emissions geographically.

Unilateral methane regulation, therefore, does not mechanically generate carbon leakage. Its effect depends on upstream heterogeneity and market structure, as well as on whether the policy mix targets upstream methane explicitly. Differentiated carbon pricing or methane emissions screening standards alter competitiveness across fuel categories and may, under certain conditions documented in SI-Figures 3-5, reduce aggregate emissions rather than merely reshuffling trade flows.

5. Conclusions and policy implications

We asked whether variation in upstream methane emissions across natural gas supply chains is large enough to affect lifecycle comparisons across fuels, and what that implies for unilateral methane regulation in an internationally traded gas market. Three results are central.

First, upstream methane emissions differ sharply across origin regions and, just as importantly, across production systems within the same region. Median upstream emissions for Norwegian and North African pipeline gas are 60-70 gCO_2e/kWh. Russian pipeline gas is higher, at around 104 gCO_2e/kWh at the median. North American LNG sits only modestly below Russian pipeline gas at the median, and the upper tails converge. By contrast, many Middle Eastern, Sub-Saharan African, Australian, and median Southeast Asian LNG supply chains fall into a lower upstream range, though dispersion remains wide. A small number of superemitting fields in Southeast Asia, specifically Malaysian Helang-Layang and Kebabangan, Thai Bongkot, and Indonesian Tangguh, exceed 200 gCO_2e/kWh upstream and drive much of the regional upper bound.

Second, this dispersion is large enough to make lifecycle fuel rankings conditional. Combustion emissions from natural gas remain broadly stable at around 204 gCO_2e/kWh, but upstream emissions account for roughly one quarter of cradle-to-grave emissions for low-intensity supply chains and more than 40-50% for high-intensity systems. In that upper range, median cradle-to-grave emissions for Russian and North American supply chains approach or exceed those of LFO. Under theoretical upper bounds, some supply chains from these regions move toward coal even under a 100-year GWP. Under a 20-year GWP, such convergences become more frequent across regions, though they remain theoretical extremes under the same bounding assumption (see

SI-Figure 5). The standard ordering, pipeline gas < LNG < LFO < coal, should therefore be treated as an outcome that depends on upstream performance rather than a fixed property of the fuel type.

Third, emissions are concentrated. A small share of production accounts for a disproportionate share of upstream methane intensity. That concentration matters for policy: differentiation aimed at the upper tail of emissions intensity can deliver much larger gains than uniform tightening across already low-intensity supply chains.

These findings are directly relevant to the EU Methane Regulation. The Regulation establishes a staged framework combining traceability, MRV equivalence, methane intensity disclosure, and the possibility of performance standards. As illustrated in Figure 6, importers must report origin and producer identity, demonstrate equivalence of monitoring and verification frameworks, disclose methane intensity from 2028, and may face maximum intensity limits from 2030. In practice, this creates transparency and a screening mechanism at the point of import. What it does not do is prescribe sourcing outcomes or rank exporting regions by lifecycle performance. Whether it delivers global emissions reductions depends on the scale of upstream heterogeneity and on how fuel substitution plays out in destination markets.

With respect to cross-border redirection, the analysis suggests that large-scale diversion of gas displaced from Europe into coal-dominated markets such as China and India is limited under current price and policy settings. In the base case, LNG remains well above thermal coal, so producers would need to offer very large discounts to reach coal parity, substantially reducing revenues. The sensitivity analysis shows that this constraint weakens if carbon prices in China and India become much more stringent: in that setting, LNG can move closer to coal on cost and diversion becomes more plausible. Whether such redirection would reduce global emissions depends on which supply chains are diverted. If Asian carbon pricing covers only combustion emissions, coal is penalised more than gas, so even relatively emissions-intensive LNG can remain competitive. If upstream emissions are also priced, or if an EU-type methane standard is applied in Asia, higher-emissions supply chains face a much larger cost penalty and are less likely to compete unless they reduce methane emissions.

A more plausible adjustment margin sits within exporting jurisdictions. Where methane intensities vary widely across basins and assets, suppliers can respond to EU screening by directing lower-intensity supply to Europe. At the same time, higher-intensity output is absorbed domestically or routed to less-regulated segments within the same jurisdiction. In North America, where dispersion across production systems is pronounced, that kind of portfolio sorting is technically feasible. In that case, the Regulation can lower the average methane intensity of gas consumed in Europe even if aggregate production, and at least in the short run, global methane emissions, change little.

Experience in other commingled commodity markets points in the same direction. In the case of electricity imports subject to California's carbon regulations, regulators encountered resource shuffling: lower-emissions generation was redirected toward the regulated market, while higher-emissions generation was absorbed elsewhere, leaving aggregate output broadly unaffected (Bushnell et al., 2014). Electricity and natural gas share relevant structural features: fungibility once injected into networks, heterogeneous supply portfolios, and asymmetric regulation across jurisdictions. These conditions create room for reallocation in response to unilateral standards.

The climate impact of unilateral methane regulation, therefore, turns on whether regulatory pressure leads to abatement at high-intensity assets rather than reshuffling within portfolios. The concentration patterns documented here suggest that screening based on verified methane intensity can place focused economic pressure on superemitting systems. Because a relatively small share of assets accounts for a large share of upstream methane intensity, relatively limited changes in market access can affect the economics of those assets and strengthen incentives to mitigate. At the same time, without complementary mechanisms that reduce scope for portfolio sorting and trade reshuffling, the most certain outcome is a change in trade composition and a decline in the methane intensity of EU imports; the extent of global emissions reduction remains dependent on producer response.

One limitation is institutional. The Regulation relies mainly on producer-level MRV equivalence and shipment-level disclosure. It does not provide a systematic way to track production-weighted methane intensity at the basin or jurisdiction level over time. Without that context, it is difficult to separate genuine mitigation from reallocation within a heterogeneous portfolio.

A possible refinement would be the creation of a Commission-led methane trade observatory publishing basin- or jurisdiction-level production-weighted methane intensity and absolute methane emissions for major exporting regions supplying the EU. Drawing on facility-level MRV disclosures, production data, national inventories, and independent satellite-based observations, such an observatory would serve an evaluative function rather than impose new compliance obligations. If methane intensity declines for EU-bound imports while basin-level intensity remains unchanged, this would indicate portfolio reallocation rather than asset-level abatement. Conversely, sustained reductions in production-weighted intensity would provide evidence of genuine mitigation. Integrating such reporting into the Regulation's periodic review process would allow policymakers to assess effectiveness and, where persistent reshuffling is observed, consider progressive tightening of methane intensity thresholds. The effectiveness of such tightening would depend on threshold stringency relative to the distribution of methane intensities within exporting portfolios and on the relative size of the EU market in those systems.

Several broader policy implications follow. Measurement quality and independent verification are foundational, particularly given the concentration of emissions in high-intensity assets. Assessments of methane regulation also need to account for cross-fuel substitution at the thermal margin, since treating gas as homogeneous can overstate inevitable leakage. Stronger carbon pricing amplifies lifecycle differences and can strengthen abatement incentives, while weaker pricing mutes those signals. Outcomes will also depend on contract structures, market elasticities, and domestic demand conditions in exporting jurisdictions.

Natural gas cannot be treated as a uniform transitional fuel. Its climate performance depends on upstream governance, infrastructure integrity, and the metric applied. Unilateral demand-side methane regulation does not mechanically induce leakage, nor does it automatically deliver global abatement. Its impact depends on how different suppliers are in methane emissions, on whether firms clean up or reroute supply, and on whether gas actually replaces coal in other markets.

Our results indicate that differences in upstream emissions across supply chains are large enough to warrant differentiation in accountability rather than treating natural gas as a uniform fuel. Assessing methane abatement policy cannot stop at the average import intensity. What ultimately matters is how producers adjust their portfolios when regulation applies in some markets but not others, and whether those adjustments translate into real mitigation or simply a reshuffling of supply.

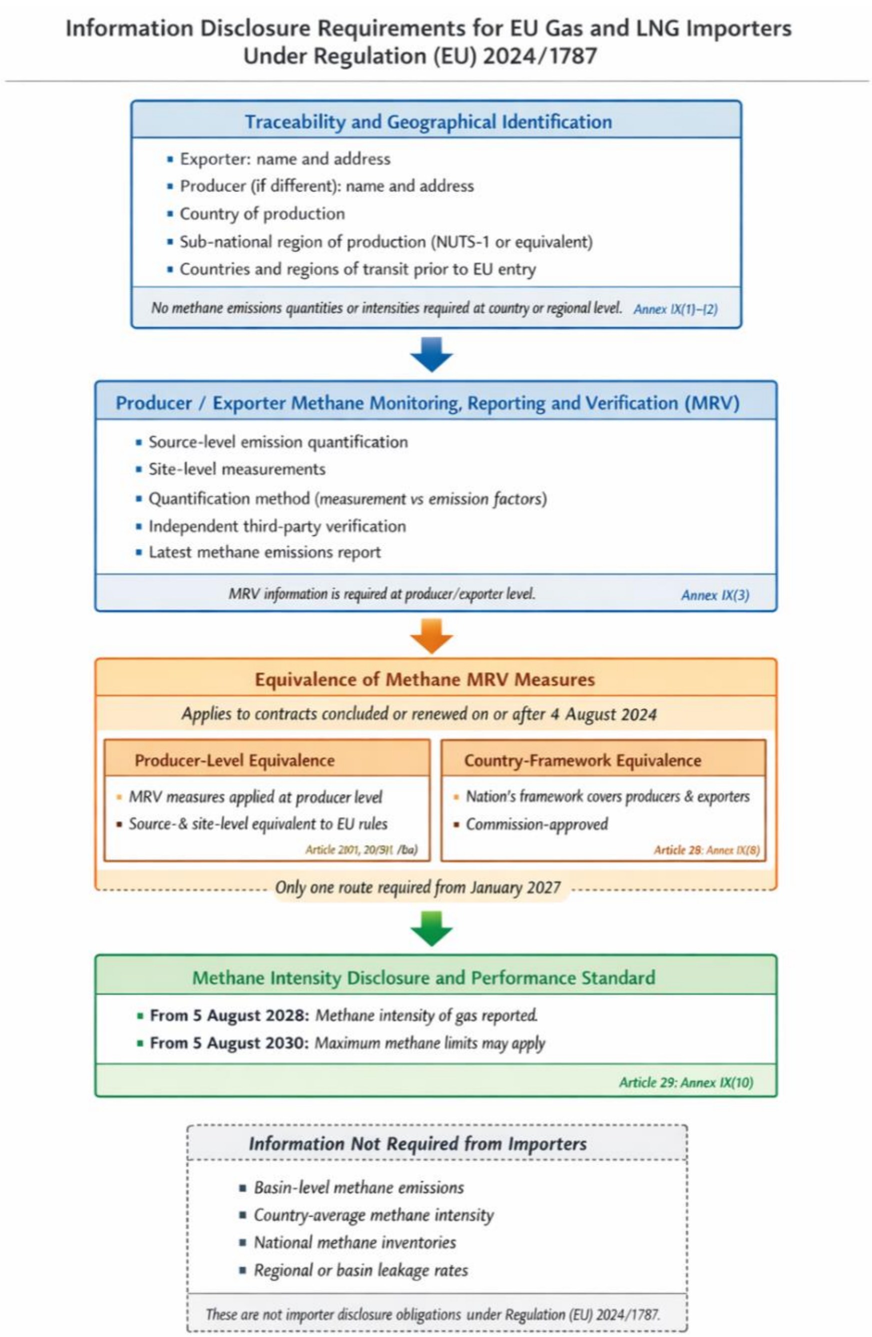


Figure 6: Information Disclosure requirements under the EU Methane Regulation

Like all large-scale lifecycle assessments drawing on heterogeneous data sources, this study is subject to limitations that point toward productive directions for future research. Regional emissions distributions are constructed from unweighted averages across gas fields, aggregated from field to country and country to region, as consistent field-level production volume data are not available across all sources used. The distributions therefore reflect variation across infrastructure sites rather than fully production-weighted supply shares. A volume-weighted replication, made possible as field-level MRV disclosures under the EU Methane Regulation accumulate, would represent a valuable extension of this work. Field-level CO_2/CH_4 splits are directly measured for a little over half the dataset via the OCI; regional median values are used for the remainder. This conservative approach compresses rather than inflates variance, meaning tail findings are if anything understated relative to what full measurement coverage would produce.

Uncertainty ranges for cumulative supply chain emissions are reported as Fréchet-Hoeffding bounds, which establish the mathematical outer limits of the emissions distribution by assuming perfect dependence across supply chain stages. These bounds are intentionally conservative and wider than standard probabilistic methods would produce. However, the key finding that high-intensity gas supply chains can approach or exceed coal on a cradle-to-grave basis is grounded in directly measured field-level emissions and does not depend on these outer bounds. Future work deploying Monte Carlo or first-order uncertainty propagation would yield tighter, probabilistically interpretable confidence intervals.

The pipeline transport module applies uniform parameters across regions, with emissions varying primarily by distance. Infrastructure-specific differences are partially captured in the domestic segment via region-specific data but are not encoded in the international segment. The price parity analysis in Section 4.4 uses illustrative spot prices and carbon cost scenarios and does not model equilibrium responses or contract dynamics. The quantified discount ranges required for displaced LNG to reach coal parity should be read as an indicator of the scale of adjustment required under current market conditions rather than a modelled prediction. Integrating the emissions heterogeneity documented here into a formal equilibrium trade model, accounting for contract rigidities, demand and supply elasticities, and domestic absorption in exporting jurisdictions, remains an important avenue for future research.

Supplementary Information

Abatement or Reallocation? Unilateral Methane Standards in a Globally Traded Gas Market

Muntasir Shahabuddin[5] and Chi Kong Chyong[6]

SI1 Methods

SI1.1 Data Overview

Natural gas production emission data was collected from 333 international gas fields and lumped per country and region. Gan et al. (2020) quantify the cradle-to-gate emissions of LNG supplied to China, detailing the emissions breakdowns of 104 international gas fields (Gan et al., 2020). Alongside these gas fields, we also collect additional lifecycle emissions data representative of 47 locations from literature and an additional 182 from the Oil Climate Index (OCI) (Rocky Mountain Institute, 2024), totalling 333 gas fields. These data are primarily taken from publicly available reports as of 2016 (Gan et al., 2020) (Gan et al., 2020), with the supplementary 47 literature points from 2011-2020 and 182 OCI points representing field data from 2020-2022. The median emissions cases of the data from 2016-2019 vs. the data from 2022 do not differ significantly.

SI-Table 2:Sources of aggregated natural gas production emissions data

Source	Number of Points	Timeframe Captured	Granularity	Notes
Gan et al. (2020)	104	2016	Field	~60 Chinese fields
Oil Climate Index Database	182	2020-2022	Field	
Other Literature/Reports	47	2011-2020	Field/Basin	

In the main draft, we discuss that excluding Howarth et al. (2011) data points does not significantly affect the median or lower bounds of North American emissions but does reduce the upper bound by about 10-20 gCO2e/kWh. This impact persists even when applying a 100-year GWP.

If we further exclude all data points from before approximately 2020 - effectively omitting the Gan et al. database and attempting to isolate any significant improvement in production emissions over time - there are minimal differences in emissions estimates (see SI-Table 2). This suggests that upstream emissions have not significantly improved over the past decade. A possible explanation is that investing in alternatives to natural gas has offered a better cost-benefit ratio for emissions reduction than attempting to enhance existing technologies, which can never completely

[5] Worcester Polytechnic Institute, USA
[6] Oxford Institute for Energy Studies, UK; corresponding author: kong.chyong@oxfordenergy.org

eliminate emissions. It follows that efforts to reduce demand and end-use consumption might be more impactful than incremental technological improvements with intended obsolescence.

Outliers that drive emissions beyond expected ranges - above the 75th percentile - are often associated with specific super-emitting fields, such Helang-Layang and Kebabangan in Malaysia, Ughelli in Nigeria, Tangguh in Indonesia, and Bongkot in Thailand. Although not considered in much of our analysis because it is a net importer, highly emissive Chinese fields like Changlin, Dongfang, and Sulige are found to be heavily emissive (>100 gCO-eq/kWh). Notably, most outliers skew toward higher emissions, while the 5th percentile emissions across all regions are relatively consistent, hovering around ~15-20 gCO_2-eq/kWh. This consistency at the lower end may indicate a point of diminishing returns in emission reductions. An exception is the Norwegian supplier Equinor, which reports production emissions as low as 5.76 gCO_2-eq/kWh - an outlier that reflects Norway's stringent methane regulations.

A lack of fully comprehensive and standardised data remains a significant challenge. Despite aggregating several datasets, substantial gaps persist. For example, we highlight that Russian fields are highly emissive within our dataset, yet lack data for some fields in operation, like Verkhnechonskoye. Similarly, data availability is notably limited in developing regions, particularly Sub-Saharan Africa; however, this scarcity generally corresponds with the lower relative output of these areas.

SI-Table 3: Comparison of regional production emissions results when striating portions of the dataset

Region		Percentile (gCO^2-e/kWh-thermal) 5th	50th	95th
China	Full Dataset	16.987	36.445	94.610
	Only after 2020	15.738	17.038	163.375
	No Lit Points	16.987	36.445	94.610
Southeast Asia	Full Dataset	16.364	24.558	174.768
	Only after 2020	15.912	26.145	198.450
	No Lit Points	16.364	24.558	174.768
Russia	Full Dataset	18.057	24.029	48.491
	Only after 2020	17.046	28.464	49.718
	No Lit Points	17.830	23.724	39.625
Caspian Region	Full Dataset	16.561	29.040	57.906
	Only after 2020	16.443	20.009	58.500
	No Lit Points	16.561	29.040	57.906
Middle East	Full Dataset	15.746	22.847	50.065
	Only after 2020	15.735	23.716	50.999
	No Lit Points	15.743	22.770	50.299
Australia	Full Dataset	13.405	23.034	66.204
	Only after 2020	16.840	22.979	52.883
	No Lit Points	16.884	23.034	65.653
Scandinavia	Full Dataset	9.489	37.269	42.323
	Only after 2020	9.075	37.350	42.450
	No Lit Points	34.678	38.642	42.576
North America	Full Dataset	19.980	40.320	81.034
	Only after 2020	17.906	36.590	71.297
	No Lit Points	19.737	37.783	64.886
North Africa	Full Dataset	18.295	28.373	63.110
	Only after 2020	18.295	28.373	63.110
	No Lit Points	18.278	26.049	64.030
Sub-Saharan Africa	Full Dataset	15.864	27.917	72.683
	Only after 2020	15.864	27.917	72.683
	No Lit Points	15.864	27.917	72.683
Indian Subcontinent	Full Dataset	15.726	25.266	44.208
	Only after 2020	15.726	25.266	44.208
	No Lit Points	15.726	25.266	44.208
Eastern Europe	Full Dataset	15.911	17.040	18.168
	Only after 2020	15.911	17.040	18.168
	No Lit Points	15.911	17.040	18.168
Western Europe	Full Dataset	15.798	17.964	28.000

Only after 2020	15.798	17.964	28.000
No Lit Points	15.798	17.964	28.000

SI1.2 GHG Emissions Calculations

To compare the environmental impacts of emissions from LNG, pipeline natural gas, thermal coal, and LFO, emissions associated with international mine and gas field data were combined with previously published LNG and pipeline gas transport models. The analysis can be summarised in two steps (as visualised in Figure 1 in the main text) the collection of mine and gas field data to calculate a "cradle-to-gate" emissions factor, including the *production* of the fuel and *transportation* modelling and emissions quantification for each fuel, and 2) the inclusion of downstream combustion emissions to quantify "cradle-to-gate" emissions.

Thus, *cradle-to-gate* in this study refers to emissions associated with production, domestic transport to an LNG terminal, and then the liquefaction, gasification, storage, and tanker transport to the import gate of the destination country/region. *Cradle-to-grave* emissions are the same emissions value, with the addition of combustion emissions. We implicitly assume that the emissions from the import terminal to the end-use point are marginal. This study presents greenhouse gas emissions with a 100-year outlook/global warming potential (GWP) as a baseline, with data for 20-year GWP presented in the supplementary information and considered a sensitivity analysis. All emissions results are presented in kWh-thermal based on a given fuel's thermal heating value rather than end-use energy.

Origin Point Source (Production and Processing) Emissions

Natural Gas

To calculate regional and country-level emissions, we take each gas field's origin and calculate the median, 5th percentile, and 95th percentile cradle-to-gate emissions (the sum of extraction, processing, transmission to origin port, liquefaction emissions, and international transport). A brief description of the dataset is shown in SI-Table 2

All data is collected from publicly available natural gas field emissions data, with the emissions for each stage of natural gas production tracked: gas extraction ($E_{extract}$), gas processing (E_{proc}), gas transmission (E_{trans}), and gas liquefaction and gas regasification $E_{liq,regas}$. LNG "indirect" production emissions include emissions of extraction and processing:

$$E_{i,LNG,production} = E_{extract} + E_{proc} \tag{1}$$

While for domestic transportation emissions along pipelines, the gas transmission data collected from literature is interpolated based on the pipeline distance from the associated study and the distance from a given collected gas field to the nearest port in this study:

$$E_{i,transport,domestic} = \frac{E_{trans,lit}}{d_{trans,lit}} d_{study}, \tag{2}$$

where $E_{trans,lit}$ is the domestic pipeline emission data from the literature, $d_{trans,lit}$ is the corresponding distance of the pipeline from the literature, and d_{study} is this study's calculated domestic transport distance to the nearest port. $E_{i,transport,domestic}$ is the calculated domestic pipeline emissions.

Country-averaged and regionally-averaged production emissions were calculated using the same process shown in SI-Figure 1: fields are annotated by country, and emissions from all fields in a given country are averaged. Similarly, the average emissions of all countries in a given region are averaged for a "regional" emissions value. These averages are unweighted by production volume, as consistent field-level production data are not available across all sources used (Gan et al., 2020; Rocky Mountain Institute, 2024). The resulting distributions therefore reflect the variation across infrastructure sites rather than production-weighted supply shares. Where OCI data provide production volume ranges, these are used to support the concentration statistics reported in Section 4.4, though they represent ranges rather than precise volume estimates.

Field level CO2/CH4 emissions ratios are calculated using the OCI database, which publishes methane and total emissions by field and portion of the supply chain (Rocky Mountain Institute, 2024). All gas field and regional emissions data are available are reported here, along with specific CH_4 emissions ratios which can be found in SI-Table 4:.

Uncertainty ranges are reported as Fréchet-Hoeffding bounds, which represent mathematical extremes under assumptions of perfect positive dependence (upper bound) and perfect negative - countermonotonic - dependence (lower bound) across sequential supply chain stages. These bounds are wider than would result from standard uncertainty propagation and should not be interpreted as probabilistic percentiles or empirically probable outcomes. The lower bounds are particularly affected for high-intensity regions: the countermonotonic pairing with high upper bounds pulls lower bounds to physically implausible levels - in some cases below combustion emissions alone. This is a mathematical artefact rather than a physical result. Since combustion emissions are treated as a deterministic positive constant (SI-Table 5) and upstream emissions are constrained to be non-negative, combustion represents the appropriate physical floor for interpreting lower bounds. Full Fréchet-Hoeffding bounds are reported in all figures for reproducibility; for physical interpretation, readers should treat the combustion emissions value as the effective lower bound.

SI-Table 4: Fraction of methane emissions attached to production and processing activity in each region (reported in 100-yr GWP)

Region	**Fraction of CH4 attached to Production Emissions (100-yr GWP)**		
	5th Percentile	**50th Percentile**	**95th Percentile**
Australia	0.211	0.551	0.737
Sub-Saharan Africa	0.214	0.517	0.866
Middle East	0.223	0.522	0.745
North America	0.175	0.373	0.835
Russia	0.325	0.625	0.822
Southeast Asia	0.051	0.531	0.652
North Africa	0.243	0.480	0.822
Norway	0.380	0.470	0.529

Light Fuel Oils

Information for LFO production emissions was collected from the Oil Climate Index (OCI) dataset, which provides detailed metrics on methane and CO_2 emissions across different stages of the oil supply chain attached to particular hydrocarbon products from individual extraction sites (International Energy Agency 2024a; Rocky Mountain Institute 2024). Emissions data were collected for ultra-light, light, and/or medium crude oils, as these are representative of the fuels commonly employed in electricity generation. The total upstream emissions - encompassing extraction, processing, and transportation - that align with the system boundaries depicted in Figure 1 are collected for each field as specified in the OCI database.

Field/extraction site-level data is then aggregated by region to calculate the range of emissions for LFO produced in a given region. This approach captures regional variations in upstream emissions without confounding effects from end-use combustion. We excluded the end-use emissions reported in the OCI dataset to maintain consistency with our system boundaries. Instead, we applied combustion emissions values for light fuel oils specified by the Energy Institute, which is discussed in the Combustion emissions section of the methodology section.

Thermal Coal

The coal emissions data employed in this study were provided by the Commodity Research Unit (CRU) (CRU Group, 2024) (also used by IEA in its 2023 Global Methane Tracker (International Energy Agency, 2024b), striating the dataset by activity (i.e. mine extraction, domestic transport, and international shipboard transport) and by boundary within each activity - delineated by Scope 1, 2, and 3 emissions. In summary, this study uses the scope 1 and 2 emissions for each portion of supply chain activity (production/processing, domestic transport, and international transport). The CRU uses ISO definitions for Scopes 1, 2, and 3, which are as follows:

Scope 1 greenhouse gas (GHG) emissions originate from sources directly controlled by the mine or plant and fall within its operational boundaries. These emissions stem from on-site activities such as the combustion of fuels during extraction processes. Importantly, if a mine or plant includes an internal power generation facility primarily used for its operations, the emissions from this electricity production are also classified as Scope 1.

Scope 2 GHG emissions encompass those associated with generating electricity and other forms of energy purchased from external sources and consumed within the mine or plant's operational boundaries. This can include emissions from imported electricity and acquired thermal energy, such as purchased steam or heat streams.

Scope 3 GHG emissions represent indirect emissions from the mine or plant's activities but outside its immediate operational boundaries within the broader commodity value chain. These emissions can arise from upstream processes, like the extraction and production of purchased materials, and downstream activities, such as the distribution, use, and end-of-life treatment of the commodity produced by the mine or plant.

The CRU emissions data are available on a per-mine basis. Similar to the previous sections, this study aggregates individual mine data into country and region-level datasets. Each activity's total scope 1 and 2 emissions are considered per activity - e.g. the scope 1 and 2 emissions for mine extraction are considered total production emissions, with the same process for domestic and international emissions). We assume a coal heating value of 23.6 MJ/kg to convert between mass and energetic values.

Transportation

Nautical LNG Shipping Emissions

Nautical LNG shipping emissions were calculated using marine transportation data from Rosselot et al. (2023), which includes overall emissions associated with individual marine tanker vessels (Rosselot et al., 2023). These emissions include information bespoke to each ship, including propulsion type - steam, Dual and Tri-Fuel Diesel Electric (DFDE/TFDE), Flexible Dual Fuel (X-DF), M-type Electronically Controlled Gas Injection (Me-GI), and Steam Turbine and Gas

(STaGE) engines - each with engine-contingent methane slip adopted from (Rosselot et al., 2023) A given vessel's specified capacity, boil-off rate, and fuel consumption contingent on propulsion type were tabulated in Rosselot et al.'s study and adopted in this study as follows.

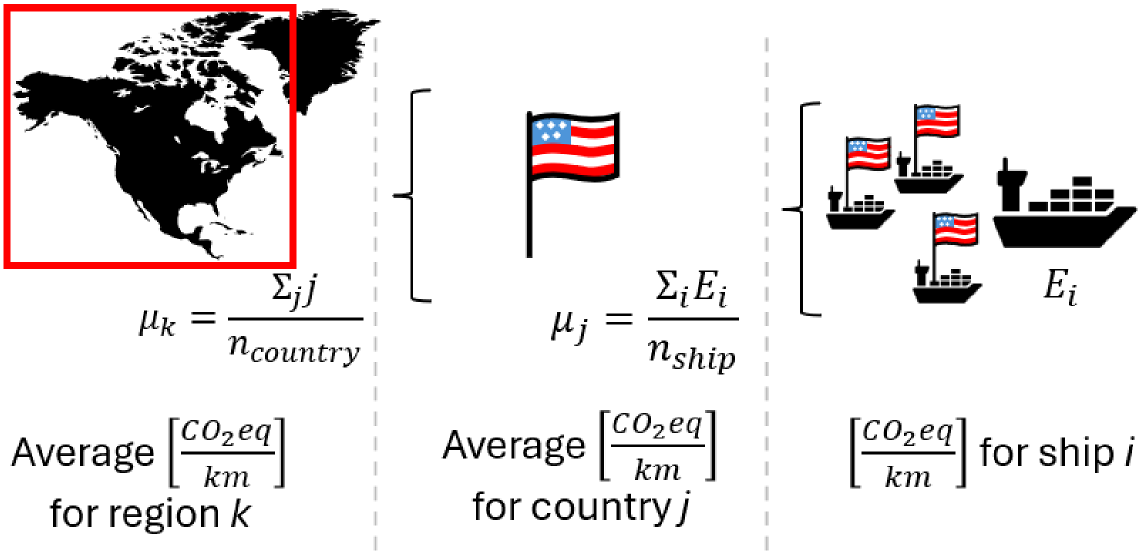
Boil-off rates and methane emissions data from Balcombe et al. (2022)'s study of the Gaslog Galveston LNG tanker were used to calculate emissions per unit distance for the average ship from a given country (Balcombe et al., 2022). It is assumed that each vessel spent approximately 1.7 days manoeuvring and 3.3 days docked, with a 2.5% ballast, aligning with the analysis of the Gaslog Galveston in Balcombe et al. (2022) and used similarly in Rosselot et al. (2023)'s work. The per-distance emissions were calculated for each vessel with these operating conditions held constant but with the ship-specific parameters listed above. Although Rosselot et al. (2023) lay this methodology in greater detail, a given emission can be summarised as follows:

$$\underbrace{E_i(d, t_{dock}, t_{man})}_{emissions} = \left[\underbrace{C_{A,i} * C_{con,i}}_{ship-specific\ factor} \left(\underbrace{r_d d}_{distance} + \underbrace{r_{dock} t_{dock}}_{dock\ time} + \underbrace{r_{man} t_{man}}_{maneuvering}\right)\right] * \left(\left(1 - C_{eng,i}\right) * EF_{CO_2} + \underbrace{C_{eng,i}}_{engine-specific\ slip} * GWP_{CH_4}\right) \tag{3}$$

where $C_{A,i}$, $C_{con,i}$ and $C_{eng,i}$ are ship-specific constants associated with surface area, container technology, and engine type for a given ship i. $d, t_{dock}$and t_{man} are travel distance, time spent docked, and time spent manoeuvring. r_d, r_{dock}, r_{man}, are per-ton boiloff rates per km distance traveled, per day of dock time, and per day of manoeuvring time. Each term includes fuel consumption and boil-off associated with a specified ship/engine type. Finally, engine specific slip is converted to CO_2-eq basis, and the remaining boiloff is burned as fuel (and converted to tons CO_2 via EF_{CO_2}. This is lumped into per-km emissions estimates for each ship which are averaged around a trip distance of 10,000 km - the median trip distance between LNG maritime vessels from Chyong and Schmidt (*forthcoming*) collected database of shipboard port-to-port transport. That is, the per-km emissions were calculated as:

$$\overline{E_i} = \frac{E_i(10{,}000km\ , 3.3d, 1.7d)}{10{,}000\ km} \left[\frac{kg\ CO_2eq}{km}\right] \tag{4}$$

Vessels were then categorised according to their country of origin; emissions of each LNG shipping vessel from a given country were averaged to calculate the emissions for a representative "average" vessel from that country. For region-to-region comparisons, these values were further extrapolated to the average emissions of all vessels associated with the region. The final international shipping emissions are then the sum of the liquefaction, storage, regasification, and shipboard transport emissions quantified using Eq 5.



SI-Figure 1: *Average emissions (μ) calculated for a given ship **i** are averaged per country, then per region to quantify shipping emissions with per-country **j** and per-region **k** granularity.*

Nautical distances from origin to destination were obtained from Chyong and Schmidt (*forthcoming*), and emissions as a function of distance were derived from each point source equation on an emissions -per km -per unit LNG shipped. For cases where there are multiple routes for each origin-destination pair, all available routes are collected and included in the supplementary database of nautical nodes. The complete dataset of international shipboard emissions between two regions or countries combinatorically includes all origin ports and routes to all possible destination ports. To convert between mass, volume, and energy, we assume a fixed LNG higher heating value (HHV) of 52.225 MJ/kg, and density of 450 kg/m³ (Wang et al., 2021).

Rosselot et al., (2023) provide detailed per-ship emissions by CO_2 and fugitive CH_4 through their database of a generator and propulsion-dependent boil-off and methane slip at each stage of travel, manoeuvring, and while docked. We adopt this database to calculate the ratio of CH_4 emissions from each ship and, when performing country or region-level calculations, collect the aggregate CH_4 emissions ratios from all ships from the origin region to calculate averages and confidence intervals.

Pipeline Emissions

Pipeline transport emissions are calculated in two segments: domestic transport from producing fields to the export border, for which region-specific parameters from Gan et al. (2020) are used; and international transport from the export border to the destination gate, for which uniform compressor consumption and leakage parameters are applied over haversine distances via Eq. 6. Attribution of elevated Russian pipeline emissions to infrastructure degradation and regulatory gaps refers to the domestic segment and is supported by the region-specific data used for that stage.

To calculate international pipeline emissions, we adopted the interstate and domestic pipeline emissions methods described by Jordaan et al., (2022). Specifically, Balcombe et al. (2022) and Jordaan et al. (2022) approximate a pipeline compressor consumption rate of 0.001% of (energetic) natural gas per kilometre of pipeline, as detailed in Balcombe et al., (2017). Balcombe et al., (2022) and Roman-White et al. (2019) found that 0.96% of the natural gas is consumed at compressor stations when tracking natural gas consumption over a US-based pipeline over 970 km (Balcombe et al., 2022; Roman-White et al., 2019). Jordaan et al. (2022) take this consumption rate alongside Balcombe et al.'s estimates for compressor station spacing every 120km (Balcombe et al., 2022). Gan et al. (2020) use estimates from Zimmerle et al. (2015) of a 4.02e-6 kg methane/kg-km (2.77e-7 kg CH_4/kWh-km) fugitive emissions/leakage rate (Gan et al., 2020; Zimmerle et al., 2015). We approximate these in tandem with the rate of CO_{2eq} emitted per distance of the pipeline. These criteria are converted to pipeline emissions via Equation (5):

$$GHG_{pipeline} = EF_{CO_2} * d * e_{CH_4 delivered} * 0.00001 + 28 * 2.77 * 10^{-7} * d * e_{CH_4,delivered}, \quad (5)$$

where $GHG_{pipeline}$ are the total emissions associated with a given pipeline from source to destination, EF_{CO2} is the emissions factor for CO_2 per unit energy of natural gas consumed(2020), d is the distance in kilometres, and $e_{CH4,delivered}$ is the total delivered or specific energy of natural gas.

The above applies generically to all pipeline emissions used in Jordaan et al., where they consider gross domestic and interstate pipeline emissions as a function of total pipeline network distance in a given country (Jordaan et al., 2022). For our study, we consider only internodal distances; therefore, the generic pipeline emissions model presented above is considered adequate. Note, however, that this may not reflect recent infrastructure improvements or emissions of new pipeline infrastructure with limited information, for example in new pipeline routes between Russia and China and an increase in rates through existing pipelines. The exact pipeline emissions specified in Gan et al. are used in granular studies of pipeline emissions (for example, pipeline emissions from specific Russian fields to destination regions). Otherwise, we calculate a linear extrapolation of per-distance pipeline emissions from Gan et al. based on the relative distance between the field and the destination.

To calculate pipeline distances, a representative natural gas terminal from each region was determined using the Global Energy Monitor Gas Infrastructure Tracker (Global Energy Monitor, 2024) (as specified in **SI-Table 5**), and the haversine/great circle distance was calculated from the origin terminal to the Rotterdam Gate terminal (this is used as an example here in the main text but for the system modelling all relevant export and import locations are considered). To simplify the comparison and analysis presented in the Discussion section, we limit the choices of origins and destinations in Table 1 to selected points only.

SI-Table 5: *Representative terminals for each pipeline region under study.*

From Region	To Region	From Pipeline Terminal/Gas Field	To Pipeline Terminal/Gas Field	Great Circle Distance (km)
Russia	Netherlands	Yamal	Rotterdam	3880.55
Sub-Saharan Africa	Netherlands	Angola	Rotterdam	6507.05
North Africa	Netherlands	Arzew	Rotterdam	1825.12
Norway	Netherlands	Kollsnes	Rotterdam	955.92
Russia	Slovakia	Bovanenkovo	Rubanisko Power Plant	3583.4
Caspian Region	Greece	Sangachal	Revithoussa	2256.6
Caspian Region	Italy	Sangachal	Piombino	3224.36
Russia	China	Bovanenkovo	Pinghu	5451.87

Russia	China	Chayanda	Shanghai	3303.72
Russia	China	West Siberia	Shanghai	4793.81
Russia	China	Sakhalin	Shanghai	2506.16
Russia	Netherlands	Yamal	Rotterdam	3880.55
Russia	Netherlands	West Siberia	Rotterdam	4232.95

Combustion

Combustion and methane emissions data were obtained from the GOV.UK database: "Greenhouse Gas Reporting: Conversion Factors 2023" dataset (2023). The database includes detailed emissions factors for NG, coal, and LFO combustion in CO_2-eq per unit of energy and methane emissions per unit of energy. The corresponding values are specified in **SI-Table 6**.

SI-Table 6*: Fuel Combustion and Methane Emissions*

Combusted Fuel as Listed	Total Emissions (g CO_2-e/kWh)	Methane Emissions From Combustion (g CO_2-e/kWh)
Natural Gas	203.4	0.31
Light Fuel Oil (Distillate Oil)	269.7	0.31
Coal (electricity generation)	376.4	0.10

Conversion to 20-Year outlook

The emissions values presented in this study correspond to a 100-year global warming potential (GWP) outlook. There is a growing movement in the community to consider natural gas as primarily a transitional fuel to be phased out in the next 20 years, and this is being used to promote studies to use a 20-year outlook. (Howarth, 2024; Peters et al., 2011) We use the 100-year GWP as our baseline and provide and use the 20-year GWP as a sensitivity analysis.

To convert between a 100-year GWP and a 20-year GWP, we assume the global warming potentials of CH_4 to be 28 and 82, respectively, consistent with IPCC Sixth Assessment Report values (Forster et al., 2021). The fractions of upstream methane emissions for a given region are then converted to the desired outlook, and the overall fraction of methane relative to total emissions is then recalculated.

All baseline calculations are performed using a 100-year GWP (GWP100 = 28 for CH_4), consistent with Forster et al. (2021). Conversion to a 20-year GWP (GWP20 = 82) is applied post-hoc at the regional level using overall regional methane splits derived from the OCI database and SI-Table 3, rather than being recalculated through every sub-equation. This approach is necessitated by the varying levels of granularity in methane attribution across the aggregated dataset - not all sub-calculations have explicit CO_2/CH_4 splits at the field level. The regional-level conversion yields a conservative estimate of GWP20 impacts and is consistent with the imputation approach described in SI1.2.

Where field-level measurements of CO_2/CH_4 splits were not available for a given coal, LFO, or natural gas field, we use regional median values to convert the carbon pricing shown in Figures 4 and 5 to a 20-year global warming potential (GWP) basis. This approach still yields a conservative estimate. We use Frechét-Hoffding bounds to propagate uncertainty.

Fuel and Carbon Price Calculations

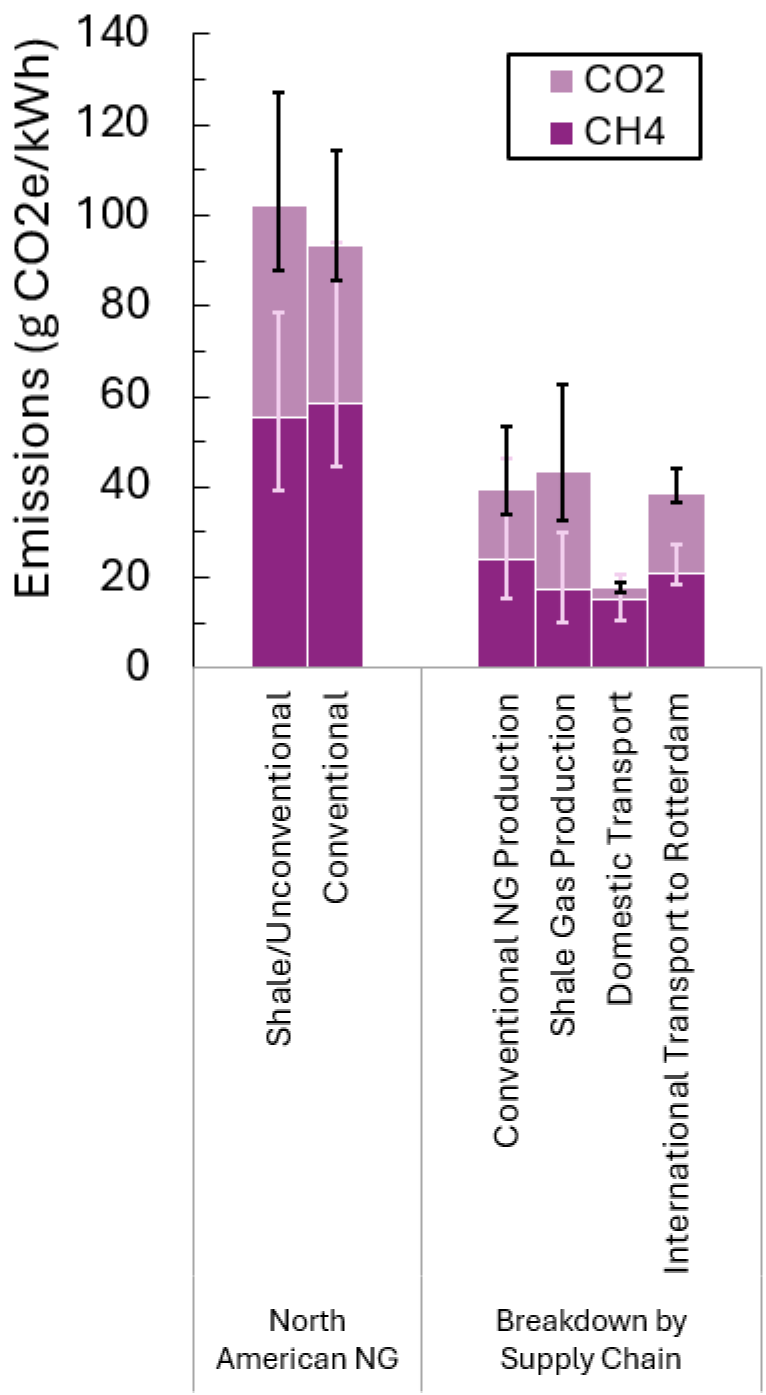
For all fuels, we use destination region spot prices to represent the cost of fuel supplied to that region, regardless of where the fuel originated. Fuel spot prices are sourced using the 2024 average from the Energy Institute (Energy Institute, 2024). Specifically, Indian LNG prices were based on the Platts West India Marker spot price, Chinese prices on the Mainland spot price, and European prices on the TTF spot price.

For coal and LFO, a single global median spot price is applied uniformly across all three destination regions (Europe, China, and India). This differs from the destination-region approach used for LNG, where regional price differentials are material — TTF, Platts West India Marker, and Mainland China spot prices diverge significantly. For coal and LFO, regional deviations from the global median are small: Russian coal is approximately 25% above the median and Southeast Asian coal approximately 18% below, while remaining regions deviate by no more than 1%. For LFO, no regional deviation exceeds 4%. Given these modest differentials, a uniform global median price introduces negligible distortion in the cross-fuel cost comparisons in Figure 4b. Coal and LFO spot prices are sourced from the Energy Institute's 2024 worldwide data.

SI-Table 7: *Glossary of Variables*

Variable	Description
$E_{extract}$	Emissions from gas extraction.
E_{proc}	Emissions from gas processing.
E_{trans}	Emissions from gas transmission.
$E_{liq,regas}$	Emissions from gas liquefaction and regasification.
$E_{i,LNG,production}$	Indirect LNG production emissions (sum of extraction and processing emissions).
$E_{i,transport,domestic}$	Domestic transportation emissions along pipelines.
$E_{trans,lit}$	Domestic pipeline emission data from the literature.
$d_{trans,lit}$	Corresponding distance of the pipeline from the literature.
d_{study}	Study's calculated domestic transport distance to the nearest port.
$E_{CH_4,domestic}$	Total methane emissions associated with natural gas production and domestic transportation.
$NG_{total\ domestic}$	Total natural gas production by country/region.
$f_{CH_4,domestic}$	Fraction of methane emissions associated with domestic production and transport emissions.
$C_{A,i}$	Ship-specific constant related to surface area.
$C_{con,i}$	Ship-specific constant related to container technology.
$C_{eng,i}$	Ship-specific constant related to engine type.
d	Travel distance in kilometers.
t_{dock}	Time spent docked.
t_{man}	Time spent maneuvering.
r_d	Per-ton boiloff rates per km distance travelled by LNG tanker
r_{dock}	Per-ton boiloff rates per day docked by LNG tanker
r_{man}	Per-ton boiloff rates per day maneovring by LNG tanker
GWP_{CH_4}	Global warming potential of methane
$E_{i(d,t_{dock},t_{man})}$	Emissions associated with travel, docking, and maneuvering.
$\overline{(E_i)}$	Per-kilometer emissions estimate for each ship.
$GHG_{pipeline}$	Total greenhouse gas emissions associated with a pipeline.
EF_{CO_2}	Emission factor for CO2 per unit energy of natural gas consumed.
$e_{CH_4,delivered}$	Total delivered or specific energy of natural gas.
LNG_{HHV}	Higher heating value of LNG (assumed 52.2 MJ/kg).
$LNG_{density}$	Density of LNG (assumed 450 kg/m^3).
$C_{pipeline}$	Pipeline compressor consumption rate.

SI2 Supplementary Results



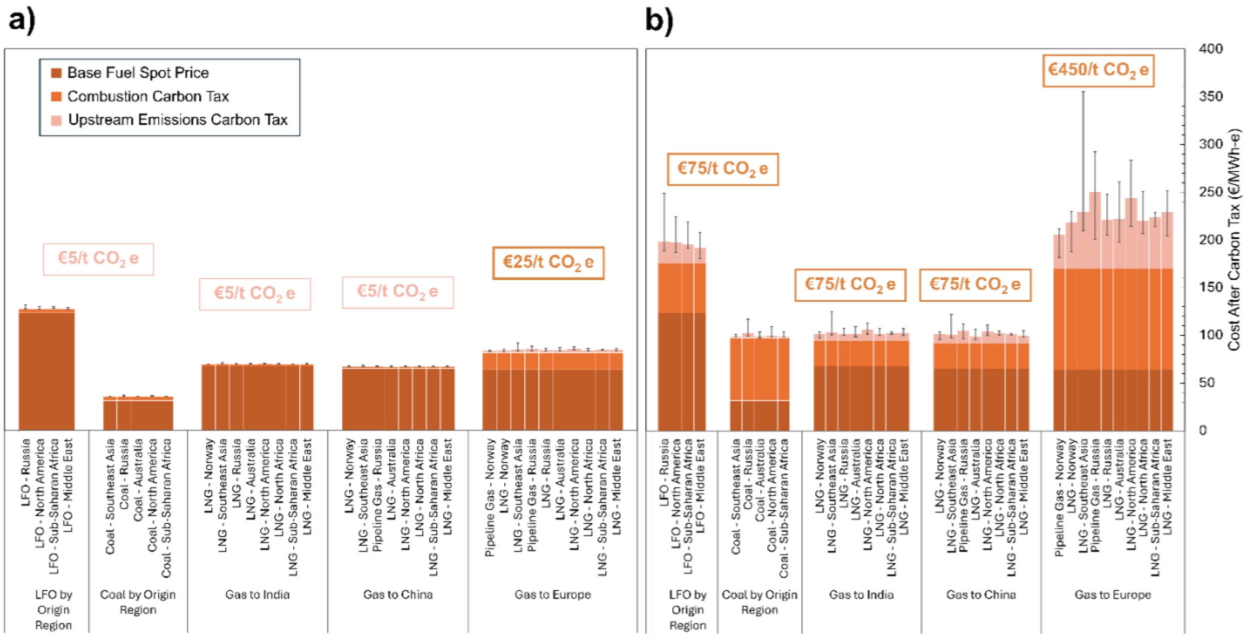
***SI-Figure 2**: CO_2 vs CH_4 emissions breakdown in portions of the supply chain in shale vs conventional NG delivered to Rotterdam city gate.*

The variance in US-sourced natural gas is explored in **SI-Figure 2**, which illustrates how regulatory pressures to reduce methane emissions vary across the overall emissions profiles of conventional and unconventional gas. The extent to which these pressures affect the cost of natural gas can be sensitive to the proportion of methane emissions.

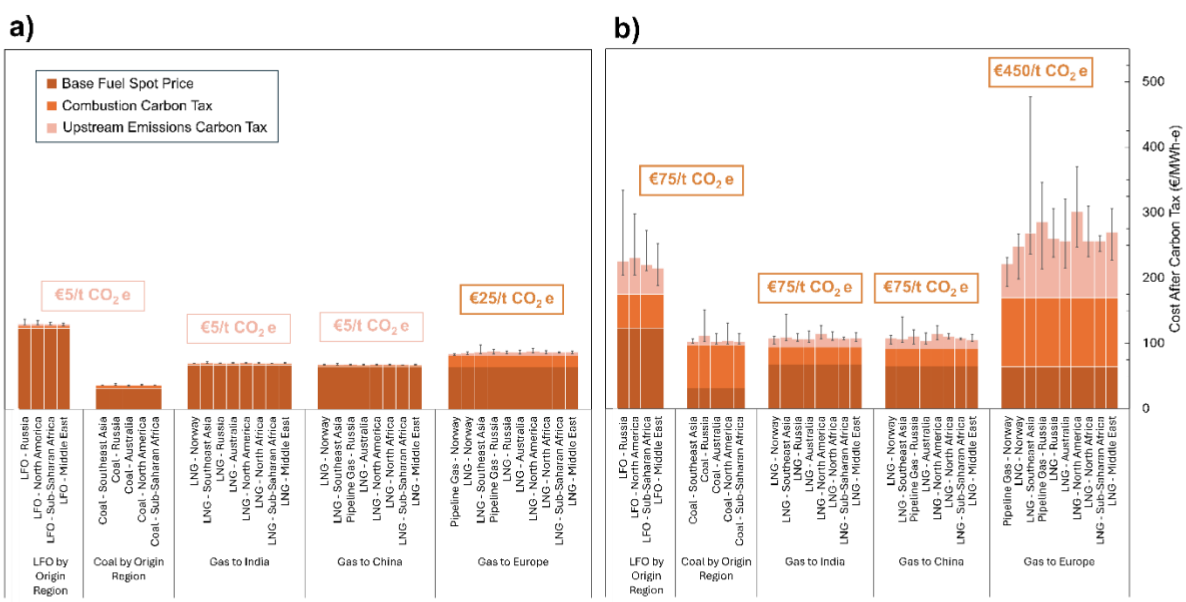
Unconventional natural gas production is predominantly concentrated in the United States - this study's dataset includes 18 North American unconventional fields, but only one in Russia and one in the Middle East. **SI-Figure 2** indicates that unconventional production results in higher total emissions. However, a larger share of emissions from conventional production is attributed to methane. This is likely because methane is often a byproduct or co-product of crude oil extraction in conventional operations and because conventional gas wells require open venting during unloading when excessive pressure drop occurs(Stanley et al., 2016). In contrast, methane is the primary product in unconventional production, creating an economic incentive to capture and utilise as much gas as possible. Still, the energy-intensive actions of fracking (i.e. artificially inducing hydraulic pressure) and flaring during well completion contribute to higher CO_2 emissions(Weber & Clavin, 2012).

We cannot assert with certainty that these factors directly cause the observed emissions patterns, especially given that the results in **SI-Figure 2** indicate that, in the median case, the difference between conventional and unconventional production is marginal. Both of these findings contradict the common criticism of unconventional extraction(Burnham et al., 2012; Howarth, 2014) while validating others(Clark et al., 2012; Stephenson et al., 2011; Weber & Clavin, 2012): that conventional gas appears to have a higher proportion of methane emissions, and unconventional gas appears to be only marginally more emissive in net exporting regions.

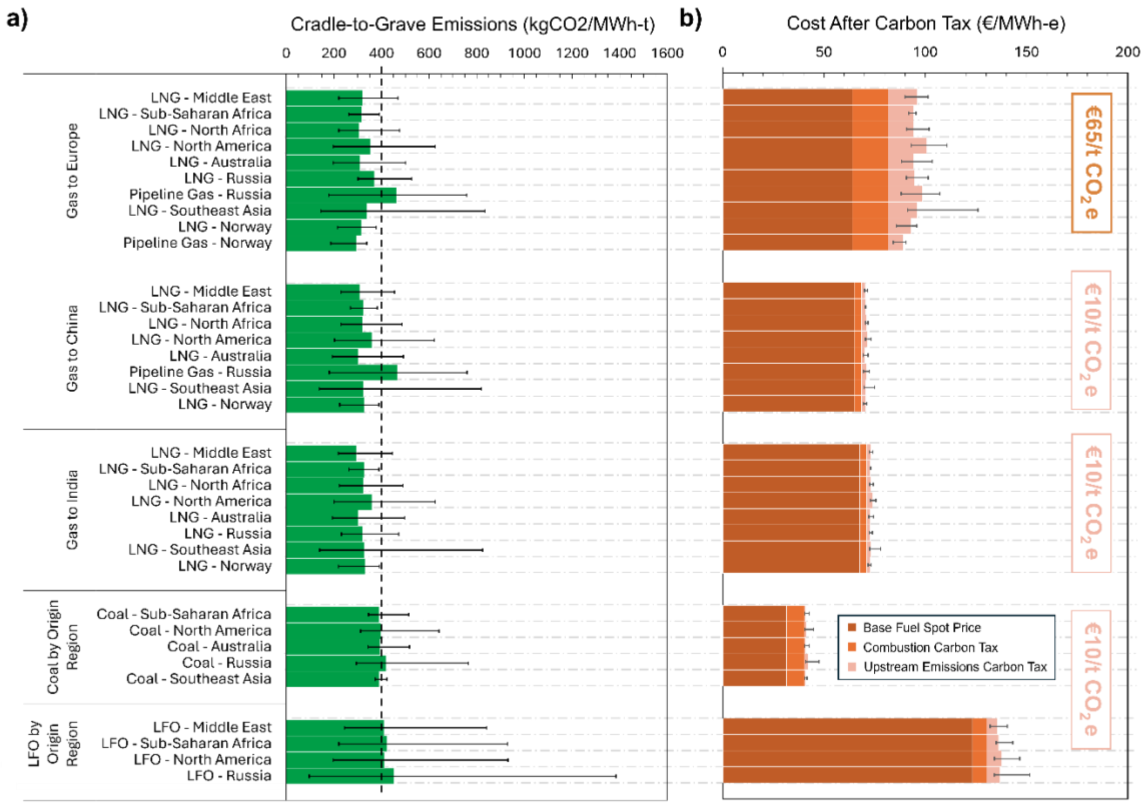
Stricter oversight of fugitive methane emissions would improve production emissions across all regions. However, the broad and nearly congruent range of emissions for unconventional and conventional gas in the United States challenges the notion that one method is inherently better or worse than the other. If we aim to reduce emissions while continuing to use natural gas, the potential upside of mitigating methane emissions from conventional gas production is even greater.



SI-Figure 3*: Regional LNG, LFO, and coal costs under a) "low carbon price" scenario where the EU eases carbon pricing to €25/ tCO_2 and China and India set carbon pricing at €5/ $tCO_2$and b) a stringent "high carbon price" future scenario in which the EU sets stringent carbon pricing at €450/tCO_2 and China and India set carbon pricing at €75/ tCO_2. In the more stringent scenario, the price difference between global LNG and coal is diminished, punitively lowering the impact of the proposed demand destruction mechanism because LNG prices meet price parity with coal post-price.*



SI-Figure 4*: Identical carbon pricing regimes as SI-Figure 3, but considering a 20-yr GWP. These are the regional LNG, LFO, and coal costs under a) "low carbon price "regime where the EU attenuates carbon pricing to €25/ tCO_2 and China and India set carbon pricing at €5/ $tCO_2$and b) a stringent "high carbon price" future scenario in which the EU sets carbon pricing* *at €450/tCO₂ and China and India set carbon pricing at €75/tCO₂. In the base case considered in the manuscript, carbon accounting using a 20-yr GWP results in a median 39% increase in carbon costs attached to upstream emissions for LNG to any region vs. 100-yr GWP. However, this increase in upstream costs amounts to only a 1-8% increase in total LNG costs when including combustion carbon costs and base fuel costs. The high carbon cost scenario b) represents a 1-2% increase in LNG costs to India/China, and a 3-8% increase in LNG costs to the EU vs. a 100-yr GWP.*



SI-Figure 5*: Analogous to Figure 4 in the main manuscript, a) cradle-to-grave emissions of thermal fuels delivered to Europe, China, and India using 20-year GWP carbon cost accounting. b) Regional LNG, LFO, and coal fuel costs and upstream/combustion carbon costs when using a 20-yr GWP. This recapitulates the results of SI-Figure 4, where only a 1-8% increase in total fuel costs are incurred when considering a 20-yr GWP. However, considering a 20-yr GWP has outsized emissions impact when sourcing LNG - across all origin and destination regions, median cradle-to-grave LNG emissions increase by 19% vs. a 100-yr GWP. Under a 100-yr GWP, only select superemitting fields from two regions, based on directly measured field-level emissions, emit more than median coal lifecycle emissions. Under a 20-yr GWP, theoretical upper bounds for fields from nearly all regions exceed median coal lifecycle emissions, reflecting the amplified weight of methane under the shorter time horizon.*

References

Ali M., Hamid. A., Castro de la Mata G., Amato A. (2024). Historical and Future Global Emissions Reductions due to Qatar's LNG Exports. https://erf.org.eg/publications/historical-and-future-global-emissions-reductions-due-to-qatars-lng-exports

Balcombe, P., Anderson, K., Speirs, J., Brandon, N., & Hawkes, A. (2017). The Natural Gas Supply Chain: The Importance of Methane and Carbon Dioxide Emissions. ACS Sustainable Chemistry & Engineering, 5(1), 3-20. https://doi.org/10.1021/acssuschemeng.6b00144

Balcombe, P., Heggo, D. A., & Harrison, M. (2022). Total Methane and CO2 Emissions from Liquefied Natural Gas Carrier Ships: The First Primary Measurements. Environmental Science & Technology, 56(13), 9632-9640. https://doi.org/10.1021/acs.est.2c01383

Barkley, Z. R., Lauvaux, T., Davis, K. J., Deng, A., Miles, N. L., Richardson, S. J., Cao, Y., Sweeney, C., Karion, A., Smith, M., Kort, E. A., Schwietzke, S., Murphy, T., Cervone, G., Martins, D., & Maasakkers, J. D. (2017) Quantifying methane emissions from natural gas production in north-eastern Pennsylvania. Atmospheric Chemistry and Physics, 17(22), 13941-13966. https://doi.org/10.5194/ACP-17-13941-2017

Bessi, A., Guidolin, M., & Manfredi, P. (2021). The role of gas on future perspectives of renewable energy diffusion: Bridging technology or lock-in?. Renewable and Sustainable Energy Reviews, 152, 111673.

Blake, W. (2023). US LNG Boom Puts Producers on Pace To Lap the Competition. Journal of Petroleum Technology, 75, 32-39. https://doi.org/10.2118/0423-0032-jpt

BP Global. (2022). Statistical Review of World Energy. https://www.bp.com/content/dam/bp/business-sites/en/global/corporate/pdfs/energy-economics/statistical-review/bp-stats-review-2022-full-report.pdf

Bugaje, A. A. B., Dioha, M. O., Abraham-Dukuma, M. C., & Wakil, M. (2022). Rethinking the position of natural gas in a low-carbon energy transition. Energy Research & Social Science, 90, 102604.

Burnham, A., Han, J., Clark, C. E., Wang, M., Dunn, J. B., & Palou-Rivera, I. (2012). Life-Cycle Greenhouse Gas Emissions of Shale Gas, Natural Gas, Coal, and Petroleum. Environmental Science & Technology, 46(2), 619-627. https://doi.org/10.1021/es201942m

Bushnell, J., Chen, Y., & Zaragoza-Watkins, M. (2014). Downstream regulation of CO2 emissions in California's electricity sector. Energy Policy, 64, 313-323. https://doi.org/10.1016/j.enpol.2013.08.065

Chatham House (2024). resourcetrade.earth. Retrieved from https://resourcetrade.earth/

Chen Z., Jacob D., Gautam R., Omara M., Stavins R., Stowe R., Nesser H., Sulprizio M., Lorente A., Varon D., Lu X., Shen L., Qu Z., Pendergrass D., Hancock S. (2022). Satellite quantification of methane emissions and oil/gas methane intensities from individual countries in the Middle East and North Africa: implications for climate action. Atmospheric Chemistry and Physics 23(10) https://doi.org/10.5194/acp-23-5945-2023

Chyong, C. K., & Schmidt, H. (forthcoming). Stress-Testing the EU Energy System: Modelling Resilience Without Russian Gas. Forthcoming in iScience

Chyong, C. K., & Schmidt, H. (2026). Modelling decarbonisation pathways in Europe: Balancing ambition and economic feasibility. Energy Policy, 209, 114967.

Clark, C. E., Han, J., Burnham, A., Dunn, J. B., & Wang, M. (2012). Life-cycle analysis of shale gas and natural gas. Argonne National Laboratory https://www.osti.gov/biblio/1044520

Cohan, D. S., & Sengupta, S. (2016). Net greenhouse gas emissions savings from natural gas substitutions in vehicles, furnaces, and power plants. International Journal of Global Warming, 9(2), 254-273. https://doi.org/10.1504/IJGW.2016.074960

Council of the European Union. (2024). Where does the EU's gas come from? https://www.consilium.europa.eu/en/infographics/where-does-the-eu-s-gas-come-from/

Cronshaw, I. (2015). World Energy Outlook 2014 projections to 2040: natural gas and coal trade, and the role of China. Australian Journal of Agricultural and Resource Economics, 59(4), 571-585. https://doi.org/10.1111/1467-8489.12120

CRU Group. (2024) Emissions Analysis Tool [Dataset]. CRU Asset Platform.

Delborne, J. A., Hasala, D., Wigner, A., & Kinchy, A. (2020). Dueling metaphors, fueling futures:"Bridge fuel" visions of coal and natural gas in the United States. Energy Research & Social Science, 61, 101350.

Deutch, J. (2020). Is Net Zero Carbon 2050 Possible? Joule, 4(11), 2237-2240. https://doi.org/10.1016/j.joule.2020.09.002

Diluiso, F., Walk, P., Manych, N., Cerutti, N., Chipiga, V., Workman, A., ... & Minx, J. C. (2021). Coal transitions—part 1: a systematic map and review of case study learnings from regional, national, and local coal phase-out experiences. Environmental Research Letters, 16(11), 113003.

Dong, K., Jiang, Q., Shahbaz, M., & Zhao, J. (2021). Does low-carbon energy transition mitigate energy poverty? The case of natural gas for China. Energy Economics, 99, 105324.

Dubey, L., Speirs, J., Balcombe, P., Tariq, N., Brandon, N., & Hawkes, A. (2023). Future use of natural gas under tightening climate targets. Futures, 150, 103158.

El-Houjeiri H. M., Brandt A. R., & Duffy J. E. (2013). Open-Source LCA Tool for Estimating Greenhouse Gas Emissions from Crude Oil Production Using Field Characteristics. Environmental Science & Technology, 47, 5998-6006. https://doi.org/10.1021/es304570m

Energy Institute. (2024). Statistical Review of World Energy. https://www.energyinst.org/statistical-review

Eurostat. (2024a). Gas prices for non-household consumers - bi-annual data (from 2007 onwards) https://ec.europa.eu/eurostat/databrowser/product/view/nrg_pc_203

Eurostat. (2024b). Natural gas prices for non-household consumers. European Union Retrieved from https://ec.europa.eu/eurostat/statistics-explained/index.php?title=Natural_gas_price_statistics

Feldman, L., & McCabe, D. (2024). Analysis of Lifecycle Greenhouse Gas Emissions of Natural Gas and Coal Powered Electricity. https://www.catf.us/resource/analysis-lifecycle-greenhouse-gas-emissions-natural-gas-coal/

Forster, P., Storelvmo, T., Armour, K., Collins, W., Dufresne, J.-L., Frame, D., Lunt, D.J., Mauritsen, T., Palmer, M.D., Watanabe, M., Wild, M., & Zhang, H. (2021). The Earth's Energy Budget, Climate Feedbacks, and Climate Sensitivity. In V. Masson-Delmotte, P. Zhai, A. Pirani, S.L. Connors, C. Péan, S. Berger, N. Caud, Y. Chen, L. Goldfarb, M.I. Gomis, M. Huang, K. Leitzell, E. Lonnoy, J.B.R. Matthews, T.K. Maycock, T. Waterfield, O. Yelekçi, R. Yu, & B. Zhou (Eds.), Climate Change 2021: The Physical Science Basis. Contribution of Working Group I to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change (pp. 923-1054). Cambridge University Press. https://doi.org/10.1017/9781009157896.009

Gan, Y., El-Houjeiri, H. M., Badahdah, A., Lu, Z., Cai, H., Przesmitzki, S., & Wang, M. (2020). Carbon footprint of global natural gas supplies to China. Nature Communications, 11(1), 824. https://doi.org/10.1038/s41467-020-14606-4

García-Gusano, D. (2014). Long-Term Analysis of the Spanish Environmental Policies using the Life Cycle Assessment Method and Energy Optimisation Modelling Universidad Rey Juan Carlos. Móstoles, Spain.

Gasim A., Matar. W., Muhsen A., Anand S., Guery J.,. (2024). Using Satellite Technology to Measure Methane Emissions in Arabian Gulf Countries. King Abdulla Petroleum Studies and Research Center. https://www.kapsarc.org/our-offerings/publications/using-satellite-technology-to-measure-methane-emissions-in-arabian-gulf-countries/

Gillessen, B., Heinrichs, H., Hake, J. F., & Allelein, H. J. (2019). Natural gas as a bridge to sustainability: Infrastructure expansion regarding energy security and system transition. Applied energy, 251, 113377.

Gillingham, K., & Huang, P. (2019). Is abundant natural gas a bridge to a low-carbon future or a dead-end?. The Energy Journal, 40(2), 1-26.

Global Energy Monitor. (2024). Gas Infrastructure Tracker [Dataset]. Global Energy Monitor. https://globalenergymonitor.org/projects/global-gas-infrastructure-tracker/

Gordon, D., Reuland, F., Jacob, D. J., Worden, J. R., Shindell, D., & Dyson, M. (2023). Evaluating net life-cycle greenhouse gas emissions intensities from gas and coal at varying methane leakage rates. Environmental Research Letters, 18, 084008. https://doi.org/10.1088/1748-9326/ace3db

Gürsan, C., & de Gooyert, V. (2021). The systemic impact of a transition fuel: Does natural gas help or hinder the energy transition?. Renewable and Sustainable Energy Reviews, 138, 110552.

Haugland, T. (2021). Regulations and public private partnership to improvement knowledge about methane emissions and mitigation options - Norway. https://unece.org/DAM/energy/images/MMNG/Case_Study_V_-_Norway.pdf

Hausfather, Z. (2015). Bounding the climate viability of natural gas as a bridge fuel to displace coal. Energy Policy, 86, 286-294.

Howarth R. (2015). Methane emissions and climatic warming risk from hydraulic fracturing and shale gas development: implications for policy. Energy and Emission Control Technologies, 3, 45-54. https://doi.org/10.2147/EECT.S61539

Howarth, R. W. (2014). A bridge to nowhere: methane emissions and the greenhouse gas footprint of natural gas. Energy Science & Engineering, 2(2), 47-60. https://doi.org/10.1002/ese3.35

Howarth, R. W. (2014). A bridge to nowhere: methane emissions and the greenhouse gas footprint of natural gas. Energy Science & Engineering, 2(2), 47-60.

Howarth, R. W. (2024). The greenhouse gas footprint of liquefied natural gas (LNG) exported from the United States. Energy Science & Engineering, 12(11), 4843-4859. https://doi.org/10.1002/ese3.1934

Hultman, N., Rebois, D., Scholten, M., & Ramig, C. (2011). The greenhouse impact of unconventional gas for electricity generation. Environmental Research Letters, 6(4), 044008. https://doi.org/10.1088/1748-9326/6/4/044008

Hunt, J. M. (1991). Generation of gas and oil from coal and other terrestrial organic matter. Organic Geochemistry, 17(6), 673-680. https://doi.org/10.1016/0146-6380(91)90011-8

International Energy Agency. (2019). The Role of Gas in Today's Energy Transitions. https://www.iea.org/reports/the-role-of-gas-in-todays-energy-transitions

International Energy Agency. (2024a). Global Methane Tracker. International Energy Agency (IEA).

International Energy Agency. (2024b). Global Methane Tracker Documentation. International Energy Agency (IEA).

International Energy Agency. (2025). *World Energy Outlook 2025*. https://www.iea.org/reports/world-energy-outlook-2025

Jackson, R. B., Vengosh, A., Carey, J. W., Davies, R. J., Darrah, T. H., O'Sullivan, F., & Pétron, G. (2014). The environmental costs and benefits of fracking. Annual Review of Environment and Resources, 39, 327-362. https://doi.org/10.1146/annurev-environ-031113-144051

Janzwood, A., & Millar, H. (2022). Bridge fuel feuds: The competing interpretive politics of natural gas in Canada. Energy Research & Social Science, 88, 102526.

Jaramillo, P., Griffin, W. M., & Matthews, H. S. (2007). Comparative Life-Cycle Air Emissions of Coal, Domestic Natural Gas, LNG, and SNG for Electricity Generation. Environmental Science & Technology, 41(17), 6290-6296. https://doi.org/10.1021/es063031o

Jordaan, S. M., Ruttinger, A. W., Surana, K., Nock, D., Miller, S. M., & Ravikumar, A. P. (2022). Global mitigation opportunities for the life cycle of natural gas-fired power. Nature Climate Change, 12(11), 1059-1067. https://doi.org/10.1038/s41558-022-01503-5

Jordaan, S. M., Ruttinger, A. W., Surana, K., Nock, D., Miller, S. M., & Ravikumar, A. P. (2022). Global mitigation opportunities for the life cycle of natural gas-fired power. Nature Climate Change, 12(11), 1059-1067.

Karion, A., Ghosh, S., Lopez-Coto, I., Mueller, K., Gourdji, S., Pitt, J., & Whetstone, J. (2023). Methane Emissions Show Recent Decline but Strong Seasonality in Two US Northeastern Cities. Environmental Science & Technology, 57(48), 19565-19574. https://doi.org/10.1021/acs.est.3c05050

Kemfert, C., Präger, F., Braunger, I., Hoffart, F. M., & Brauers, H. (2022). The expansion of natural gas infrastructure puts energy transitions at risk. Nature Energy, 7(7), 582-587.

Kinyar, A., Bothongo, K., & Doytch, N. (2025). Rebound in oil and natural gas emissions amid coal-phase out: Implications for the UK's net-zero strategy. Energy, 138506.

Klimenko, A. V., Tereshin, A. G., & Prun, O. E. (2023). Prospects for reducing greenhouse gas emissions in Russia. Izvestiya Akademii Nauk. Energetika, (2), 3-15. https://doi.org/10.31857/S0002331023020036

Korre, A., Nie, Z., & Durucan, S. (2012). Life Cycle Assessment of the natural gas supply chain and power generation options with CO2 capture and storage: Assessment of Qatar natural gas production, LNG transport and power generation in the UK. Sustainable Technologies, Systems & Policies, 2012. https://doi.org/10.5339/STSP.2012.CCS.11

Ladage, S., Blumenberg, M., Franke, D., Bahr, A., Lutz, R., & Schmidt, S. (2021). On the climate benefit of a coal-to-gas shift in Germany's electric power sector. Scientific reports, 11(1), 11453.

Langshaw L., Ainalis D., Acha S., Shah N., & Stettler M. E. J. (2020). Environmental and economic analysis of liquefied natural gas (LNG) for heavy goods vehicles in the UK: A Well-to-Wheel and total cost of ownership evaluation. Energy Policy, 137, 111161. https://doi.org/10.1016/j.enpol.2019.111161

Lavoie, T. N., Shepson, P. B., Cambaliza, M. O. L., Stirm, B. H., Conley, S., Mehrotra, S., Faloona, I. C., & Lyon, D. (2017). Spatiotemporal Variability of Methane Emissions at Oil and Natural Gas Operations in the Eagle Ford Basin. Environmental Science & Technology, 51, 8001-8009. https://doi.org/10.1021/acs.est.7b00814

Lechtenböhmer, S., Dienst, C., Fischedick, M., Hanke, T., Langrock, T., Assonov, S., & Brenninkmeijer, C. (2005). Greenhouse gas emissions from the Russian natural gas export pipeline system: Results and extrapolation of measurements and surveys in Russia. Wuppertal Institute for Climate, Environment and Energy. https://epub.wupperinst.org/frontdoor/deliver/index/docId/2136/file/2136_GEPS_en.pdf

Levi, M. (2013). Climate consequences of natural gas as a bridge fuel. Climatic change, 118(3), 609-623.

Littlefield, J., Rai, S., & Skone, T. J. (2022). Life Cycle GHG Perspective on U.S. Natural Gas Delivery Pathways. Environmental Science & Technology, 56, 16033-16042. https://doi.org/10.1021/acs.est.2c01205

MacKay, K., Lavoie, M., Bourlon, E., Atherton, E., O'Connell, E., Baillie, J., Fougère, C., Risk, D. (2021). Methane emissions from upstream oil and gas production in Canada are underestimated. Scientific Reports, 11. https://doi.org/10.1038/s41598-021-87610-3

Masson-Delmotte, V., Zhai, P., Pörtner, H.-O., Roberts, D., Skea, J., Shukla, P. R., Pirani, A., Moufouma-Okia, W., Péan, C., Pidcock, R., Connors, S., Matthews, J. B. R., Chen, Y., Zhou, X., Gomis, M. I., Lonnoy, E., Maycock, T., Tignor, M., & Waterfield, T. (Eds.). (2018). Global warming of 1.5°C: Summary for policymakers. In Global warming of 1.5°C: An IPCC special report. Cambridge University Press.

McGlade, C., Pye, S., Ekins, P., Bradshaw, M., & Watson, J. (2018). The future role of natural gas in the UK: a bridge to nowhere?. Energy Policy, 113, 454-465.

McJeon, H., Edmonds, J., Bauer, N., Clarke, L., Fisher, B., Flannery, B. P., ... & Tavoni, M. (2014). Limited impact on decadal-scale climate change from increased use of natural gas. Nature, 514(7523), 482-485.

Minx, J. C., Hilaire, J., Müller-Hansen, F., Nemet, G., Diluiso, F., Andrew, R. M., ... & Wiseman, J. (2024). Coal transitions—part 2: phase-out dynamics in global long-term mitigation scenarios. Environmental Research Letters, 19(3), 033002.

Muthu, S. S. (2023). Life Cycle Assessment & Circular Economy. Springer Nature. https://doi.org/10.1007/978-3-031-33982-0

Nie, Y., Zhang, S., Edward, R., Daniel, L., Roda-Stuart, J., Ravikumar, A. P., Bradley, A., Masnadi, M. S., Brandt, A. R., Bergerson, J., & Bi, X. T. (2020). Greenhouse-gas emissions of Canadian liquefied natural gas for use in China: Comparison and synthesis of three independent life cycle assessments. Journal of Cleaner Production, 258, 120701. https://doi.org/10.1016/j.jclepro.2020.120701

Omara M., Sullivan M. R., Li X., Subramanian R., Robinson A. L., & Presto A. A. (2016). Methane Emissions from Conventional and Unconventional Natural Gas Production Sites in the Marcellus Shale Basin. Environmental Science & Technology, 50, 2099-2107. https://doi.org/10.1021/acs.est.5b05503

Papunen, A. (2024). Economic impact of Russia’s war on Ukraine: European Council response (Briefing No. 757783). European Parliamentary Research Service. https://www.europarl.europa.eu/RegData/etudes/BRIE/2024/757783/EPRS_BRI(2024)757783_EN.pdf

Peters, G. P., Aamaas, B., T. Lund, M., Solli, C., & Fuglestvedt, J. S. (2011). Alternative "Global Warming" Metrics in Life Cycle Assessment: A Case Study with Existing Transportation Data. Environmental Science & Technology, 45(20), 8633-8641. https://doi.org/10.1021/es200627s

Petrich, I., Gutentag, J., Volkmer, N., & Leahey, H. (2024). U.S. emissions stocktake: Methane mitigation drives decline (Energy Transition Research, No. 94747). Enverus Intelligence Research. https://intelligence.enverus.com/research/94747

Ratner M., Nelson G., Belkin P., Woehrel S., (2020). Europe's energy security: Options and challenges to natural gas supply diversification. Congressional Research Service. https://www.congress.gov/crs_external_products/R/PDF/R42405/R42405.24.pdf

Rocky Mountain Institute. (2024). Profiling Supply Chain Emissions (Rocky Mountain Institute Oil Climate Index+ (RMI OCI+). https://ociplus.rmi.org/supply-chain

Roman-White, S., Rai, S., Littlefield, J., Cooney, G., & Skone, T. J. (2019). Life Cycle Greenhouse Gas Perspective on Exporting Liquefied Natural Gas from the United States: 2019 Update. National Energy Technology Laboratory.

Rosselot, K. S., Balcombe, P., Ravikumar, A. P., & Allen, D. T. (2023). Simulating the Variability of Methane and CO2 Emissions from Liquefied Natural Gas Shipping: A Time-in-Mode and Carrier Technology Approach. ACS Sustainable Chemistry & Engineering, 11(43), 15632-15643. https://doi.org/10.1021/acssuschemeng.3c04269

Safari, A., Das, N., Langhelle, O., Roy, J., & Assadi, M. (2019). Natural gas: A transition fuel for sustainable energy system transformation?. Energy Science & Engineering, 7(4), 1075-1094.

Salvador, A. (2005). Electricity: Generation and Consumption. Energy, 123-129. https://doi.org/10.1306/1032781SP226

Schultz, H. S., & Carvalho, M. (2022). Design, Greenhouse Emissions, and Environmental Payback of a Photovoltaic Solar Energy System. Energies, 15, 6098. https://doi.org/10.3390/en15166098

Sharifi, V., Abdollahi, A., Rashidinejad, M., Heydarian-Forushani, E., & Alhelou, H. H. (2022). Integrated Electricity and Natural Gas Demand Response in Flexibility-Based Generation Maintenance Scheduling. IEEE Access, 10, 76021-76030. https://doi.org/10.1109/ACCESS.2022.3191781

Shaton, K., Hervik, A., & Hjelle, H. M. (2020). The Environmental Footprint of Natural Gas Transportation: LNG vs. Pipeline. Economics of Energy & Environmental Policy, Volume 9(Number 1), 223-242.

Shirizadeh, B., Villavicencio, M., Douguet, S., Trüby, J., Bou Issa, C., Seck, G. S., ... & Reigstad, G. A. (2023). The impact of methane leakage on the role of natural gas in the European energy transition. Nature Communications, 14(1), 5756.

Skone, T. J., Littlefield, J., & Marriott, J. (2011). Life cycle greenhouse gas inventory of natural gas extraction, delivery and electricity production (DOE/NETL-2011/1522). U.S. Department of Energy, National Energy Technology Laboratory.

Song, M., Mangla, S. K., Wang, J., Zhao, J., & An, J. (2022). Asymmetric information,"coal-to-gas" transition and coal reduction potential: An analysis using the nonparametric production frontier method. Energy Economics, 114, 106311.

Stanley, N., Kiran, T.-M., Paul, E., & Colin, H. (2016). Environmental implications of flaring and venting in crude oil and natural gas production. International Journal of Environmental Monitoring and Analysis, 4(6), 154-159. https://doi.org/10.11648/j.ijema.20160406.13

Stephenson, E., Doukas, A., & Shaw, K. (2012). Greenwashing gas: Might a 'transition fuel'label legitimize carbon-intensive natural gas development?. Energy policy, 46, 452-459.

Stephenson, T., Valle, J. E., & Riera-Palou, X. (2011). Modeling the Relative GHG Emissions of Conventional and Shale Gas Production. Environmental Science & Technology, 45(24), 10757-10764. https://doi.org/10.1021/es2024115

Stern, J. (2020). The role of gases in the European energy transition. Russian Journal of Economics, 6(4), 390-405.

Tanaka, K., Cavalett, O., Collins, W. J., & Cherubini, F. (2019). Asserting the climate benefits of the coal-to-gas shift across temporal and spatial scales. Nature climate change, 9(5), 389-396.

U.S. Environmental Protection Agency. (2020). Inventory of US greenhouse Gas Emissions and Sinks. https://www.epa.gov/system/files/documents/2022-04/us-ghg-inventory-2022-main-text.pdf

UK Department for Energy Security and Net Zero. (2023). Greenhouse gas reporting: conversion factors 2023. https://www.gov.uk/government/publications/greenhouse-gas-reporting-conversion-factors-2023

Venkatesh, A., Jaramillo, P., Griffin, W. M., & Matthews, H. S. (2011). Uncertainty in Life Cycle Greenhouse Gas Emissions from United States Natural Gas End-Uses and its Effects on Policy. Environmental Science & Technology, 45(19), 8182-8189. https://doi.org/10.1021/es200930h

Vinichenko, V., Cherp, A., & Jewell, J. (2021). Historical precedents and feasibility of rapid coal and gas decline required for the 1.5 C target. One Earth, 4(10), 1477-1490.

von Hirschhausen, C., Kemfert, C., & Praeger, F. (2021). Fossil natural gas exit-A new narrative for the European energy transformation towards decarbonization. Economics of Energy & Environmental Policy, 10(2), 115-132.

Wachsmuth, J., Oberle, S., Zubair, A., & Köppel, W. (2019). Wie klimafreundlich ist LNG? Umweltbundesamt (German Environment Agency). https://www.umweltbundesamt.de/publikationen/wie-klimafreundlich-ist-lng

Wang, M., Elgowainy, A., Lee, U., Bafana, A., Banerjee, S., Benavides, P., Bobba, P., Burnham, A., Cai, H., Gracida, U., Hawkins, T., Iyer, R., Kelly, J., Kim, T., Kingsbury, K., Kwon, H., Li, Y., Liu, X., Lu, Z., & Zhang, G. (2021). Greenhouse gases, regulated emissions, and energy use in technologies model (GREET®). Argonne National Laboratory https://www.osti.gov/doecode/biblio/63044

Weber, C. L., & Clavin, C. (2012). Life Cycle Carbon Footprint of Shale Gas: Review of Evidence and Implications. Environmental Science & Technology, 46(11), 5688-5695. https://doi.org/10.1021/es300375n

Wilson, I. G., & Staffell, I. (2018). Rapid fuel switching from coal to natural gas through effective carbon pricing. Nature Energy, 3(5), 365-372.

Woollacott, J. (2020). A bridge too far? The role of natural gas electricity generation in US climate policy. Energy Policy, 147, 111867.

Zhang, R., Liu, S., He, L., Blach, T. P., & Wang, Y. (2020). Characterizing Anisotropic Pore Structure and Its Impact on Gas Storage and Transport in Coalbed Methane and Shale Gas Reservoirs. Energy & Fuels, 34(3), 3161-3172. https://doi.org/10.1021/acs.energyfuels.0c00109

Zhang, X., Myhrvold, N. P., Hausfather, Z., & Caldeira, K. (2016). Climate benefits of natural gas as a bridge fuel and potential delay of near-zero energy systems. Applied energy, 167, 317-322.

Zhu, Y., Allen, D. T., & Ravikumar, A. P. (2024). Geospatial life cycle analysis of greenhouse gas emissions from U.S. liquefied natural gas supply chains. ACS Sustainable Chemistry & Engineering. https://doi.org/10.1021/acssuschemeng.4c07255

Zimmerle, D. J., Williams, L. L., Vaughn, T. L., Quinn, C., Subramanian, R., Duggan, G. P., Willson, B., Opsomer, J. D., Marchese, A. J., Martinez, D. M., & Robinson, A. L. (2015). Methane Emissions from the Natural Gas Transmission and Storage System in the United States. Environmental Science & Technology, 49(15), 9374-9383. https://doi.org/10.1021/acs.est.5b01669

Contact.

MIT CEEPR Working Paper Series
is published by the MIT Center for Energy and Environmental Policy Research from submissions by affiliated researchers.
For inquiries and/or for permission to reproduce material in this working paper, please contact:

General inquiries: ceepr@mit.edu
Media inquiries: ceepr-media@mit.edu

MIT CEEPR
Center for Energy and Environmental Policy Research

MIT Center for Energy and
Environmental Policy Research
Massachusetts Institute of Technology
77 Massachusetts Avenue, E19-411
Cambridge, MA 02139-4307
USA

ceepr.mit.edu

MASSACHUSETTS INSTITUTE OF TECHNOLOGY