

GHG Life Cycle Analysis
Literature Review of Shale Gas / LNG
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The following were the primary sources used or referred to in the evaluation of the importance of life cycle analysis in comparing fuels:

Fulton, M., et al., “*Comparing Life-Cycle Greenhouse Gas Emissions from Natural Gas and Coal*”, Deutsche Bank Climate Change Advisors (August 25, 2011).

This analysis assesses the then state of knowledge (2011) about the average GHG footprint of average coal and natural gas-fired electricity generation, how the growing share of natural gas production from shale formations could change this GHG footprint at the margin, and what the findings imply for policymakers, investors and the environment. The analysis finds that EPA’s updated estimates of fugitive methane emissions from natural gas systems are of concern as a GHG and require further attention. Base case comparisons are calculated on a kg CO₂e / MMBtu basis for delivered fuel, which depicts more accurately the energy that is actually available to the power plant versus other calculation methodologies. In determining the emissions factors for the combustion of natural gas and coal, the authors relied on Subpart C of EPA’s Greenhouse Gas Reporting Program which provides GHG emissions on an MMBtu basis of delivered fuel. These results were then converted to aMWh basis to account for differences in coal and natural gas power plant efficiencies.

Miller, S., et al., “*Anthropogenic Emissions of Methane in the United States*”, Proceedings of the National Academy of Sciences Early Edition (October 18, 2013).

This study quantitatively estimates the spatial distribution of anthropogenic methane sources in the United States by combining comprehensive atmospheric observations, extensive spatial datasets, and a high-resolution atmospheric transport model. Results show that current inventories from the EPA and Emissions Database for Global Atmospheric Research (EDGAR) underestimate methane emissions nationally by factors of approximately 1.5 and 1.7, respectively. EDGAR is the most comprehensive global methane inventory. The spatial patterns of emission fluxes and observed methane-propane correlations indicate that fossil fuel extraction and refining are major

contributors ($45 \pm 13\%$) in the south-central United States. This result suggests that regional methane emissions due to fossil fuel extraction and processing could be 4.9 ± 2.6 times larger than in EDGAR. These results cast doubt on EPA's recent decision to downscale its estimate of natural gas emissions by 25-30%. Overall, the authors conclude that methane emissions associated with the fossil fuel extraction and processing are likely a factor to two or greater than cited in existing studies.

Heede, R., *"LNG Supply Chain Greenhouse Gas Emissions for the Cabrillo Deepwater Port: Natural Gas from Australia to California"*, Climate Mitigation Services (May 17, 2006).

This analysis summarizes GHG emissions from the entire supply chain identified by BHP to deliver LNG to a receiving terminal offshore Los Angeles, California. Climate Mitigation Services (CMS) was commissioned by the Environmental Defense Center to identify the critical missing links in the delivery chain of natural gas from production to consumption. The specific area of interest in this analysis is the LNG processing consisting of liquefaction, tanker transport, and regasification. The liquefaction process is the preferred method of reducing the volume of natural gas in order to "economically" enable its long-distance transportation. It takes an enormous amount of energy to purify and cool the natural gas to its boiling point of -259°F (-161°C) which then turns to a liquid. The tanker transportation segment is also a large component of the life cycle analysis since LNG is primarily used in long-distance transport applications. CMS emissions analysis was converted to a normalized unit of measure of $\text{kg CO}_{2e} / \text{mmBtu}$ consistent with the DBCCA analysis. Due to high uncertainties with the various components, CMS "high" values were assumed reasonable. Even the "low" estimates show a significant LNG component to the overall GHG natural gas life cycle. Note, that these "high" CO_2 -equivalent values are already understated as CMS used methane $\text{GWP}_{100}=23$ versus 34 as is now being proposed by the IPCC.

"Working Group I Contribution to the IPCC Fifth Assessment Report Climate Change 2013: The Physical Science Basis", Final Draft (Sept. 30, 2013).

The Intergovernmental Panel on Climate Change (IPCC) has significantly increased methane 100-year Global Warming Potential (GWP) to 34, an increase of nearly 40% from the prior GWP of 25. In addition, the 20-year GWP for methane increased to 86, an increase of nearly 20% from the prior GWP of 72. These changes occurred during the Twelfth Session of Working Group I and the 36th Session of the IPCC, which were held

from September 23-26, 2013 in Stockholm, Sweden. During those sessions, the Summary for Policymakers of the Work Group I contribution to the IPCC Fifth Assessment Report was approved and the underlying scientific technical assessment was accepted. Before publication in final form, expected in early 2014, the report will undergo final copyediting. IPCC's previous GWP values for methane ($GWP_{100}=25$ and $GWP_{20}=72$) are the basis of numerous published analyses and therefore understate the life cycle impact of methane emissions

"Greenhouse Gas Reporting Rule", U.S. Environmental Protection Agency, Title 40, Code of Federal Regulations, §98 (Revised November 29, 2013).

Currently, as listed in Subpart A, EPA is using IPCC's previous values for GWP of methane ($GWP_{100}=25$) which is lower than recently published values. EPA notes that this is to increase the accuracy of the estimates and better inform EPA policies. EPA further states that IPCC's previous GWP values will complement the reporting metrics used in other U.S. climate programs as well as ensure compatibility with the President Obama's Climate Action Plan. Nonetheless, the life cycle analysis shows the impact of methane with increasing GWP values. Emissions for fuel combustion utilized the EPA's factors identified in Subpart C.

"Technology Roadmap High-Efficiency, Low-Emissions Coal-Fired Power Generation", International Energy Agency (2012).

In the context of a low-carbon energy future, International Energy Agency (IEA) is identifying ways to use coal more efficiently and to reduce its environmental footprint. The roadmap focuses on the development and deployment of high-efficiency, low-emissions (HELE) coal technologies for power generation. HELE is noted as a principle way to reduce emissions of CO_2 from coal-fired power plants and the need to deploy and further develop HELE coal technologies, i.e. use more efficient technology and continue to develop higher-efficiency conversion processes. IEA states that efforts to develop advanced ultra-supercritical technology could lower emissions to $670 \text{ g } CO_{2e} / \text{ kWh}$ ($670 \text{ kg } CO_{2e} / \text{ MWh}$).

"The CURC/EPRI Coal Technology Roadmap", Coal Utilization Research Council, (June 2012).

The Coal Utilization Research Council (CURC) along with the Electric Power Research Institute (EPRI) established a roadmap to achieve specific cost, performance, and

environmental goals. The CURC/EPRI Roadmap is a pathway for developing needed technologies through public and private collaboration. In the 2035 timeframe, with sufficient R&D funding, coal combustion efficiencies are targeted at 48%.

The following resources supported various ideas and concepts.

Alvarez, R., “*Greater Focus Needed on Methane Leakage from Natural Gas Infrastructure*”, Proceedings of the National Academy of Sciences Early Edition (December 21, 2011).

New natural gas power plants produce net climate benefits relative to efficient, new coal plants using low-gassy coal on all time frames as long as methane leakage in the natural gas system is less than 3.2% from well through delivery at a power plant. At higher emission rates, natural gas loses its climate advantage over coal.

Armendariz, A., “*Emissions from Natural Gas Production in the Barnett Shale Area and Opportunities for Cost-Effective Improvements*”, Environmental Defense Fund/Southern Methodist University (2009).

Predicted 2009 emissions of GHG like CO₂ and methane from the Barnett Shale of Texas were approximately 33,000 tons per day of CO₂-e. This is roughly equivalent to the expected GHG emissions from two 750 MW coal-fired power plants. The largest contributors to the Barnett Shale GHG emissions impacts were CO₂ emissions from compressor engine exhausts and fugitive methane emissions from all source types.

Banks, D., et al., “*U.S. Natural-Gas Use Must Peak by 2030*”, Center for American Program (July 2013).

Natural gas consists primarily of methane, which is a powerful GHG. Methane traps 72 times as much heat as CO₂ over a 20-year timeframe. Throughout the entire life cycle of natural gas, from drilling to transport to end use, methane leaks into the atmosphere. These fugitive methane emissions could offset some of the emission reductions of coal-to-natural gas switching. According to Ramon A. Alvarez and others, new natural-gas plants have emission benefits compared to new coal plants, over all time frames, if the methane leakage rate is below 3.2% from well-to-power delivery. Recent estimates of

the life cycle leakage rate range from less than 1% to 7.9%. The current 2013 EPA Inventory of US GHG Emissions and Sinks puts methane leakage at 1.4%. While the extent of natural gas leakage from natural gas operations is not yet settled, fugitive methane emissions pose a serious threat to the climate and should be reduced as much as possible.

“Gas Ceiling: Assessing the Climate Risks of an Overreliance on Natural Gas for Electricity”, Union of Concerned Scientists (September 2013).

While there is still uncertainty about the precise quantity of fugitive methane emissions from natural gas production, preliminary studies and field measurements range from 1% to 9% of total natural gas production (collecting and citing studies).

“Golden Rules for a Golden Age of Gas: World Energy Outlook, Special Report on Unconventional Gas”, International Energy Agency (2012).

Shale gas and tight gas have higher production-related GHG emission than conventional gas. In the case of flaring, total well-to-burner emissions are estimated to be 3.5% higher than for conventional gas, but this figure rises to 12% if the gas is vented. Different assumptions about the level and impact of methane emissions can have a profound effect on the perception of gas as a “cleaner” fossil fuel. Standard values (GWP of 25; 2-3% methane emissions as a percentage of total production) substantiate the widely accepted advantage of gas, thanks to its lower combustion CO₂ emissions per unit of energy; but it is clear that more pessimistic assumptions can make gas a worse GHG-emitter than coal. It is very important that additional scientific work should pinpoint the most relevant GWP value and that efforts are redoubled to measure methane emissions more systematically.

Howarth, R., et al., *“Methane and the Greenhouse-Gas Footprint of Natural Gas from Shale Formations”*, Climatic Change 106: 679-690 (2011).

Compared to coal, the footprint of shale gas is at least 20% greater and perhaps more than twice as great on the 20-year horizon and is comparable when compared over 100 years.

Howarth, R., et al., *“Methane Emissions from Natural Gas Systems: Background Paper Prepared for the National Climate Assessment”* (2012).

Concluding that methane emissions from shale gas production are likely underestimated both as to quantity and climate impacts.

Howarth, R., et al., “*Greenhouse Gas Footprint of Shale Gas Obtained by Hydraulic Fracturing*”, Presentation at ESA 2012 (2012).

Methane emissions from hydraulic fracturing are underestimated.

Howarth, R., et al., “*Venting and Leaking of Methane from Shale Gas Development: Response to Cathles et al.*”, *Climatic Change* 113: 537-549 (2012).

The latest EPA estimate for methane emissions from shale gas falls within the range of Howarth’s estimates but not those of Cathles et al. (2012), which are substantially lower. Cathles et al. (2012) believe that the focus should be just on electricity generation, and that the GWP of methane should be considered only on a 100-year time scale. The analysis covered by electricity (30% of U.S. usage) and heat generation (the largest usage), and evaluated both 20- and 100-year integrated time frames for methane. Both time frames are important, but the decadal scale is critical, given the urgent need to avoid climate-system tipping points. Using all available information and the latest climate science, it concludes that for most uses, the GHG footprint of shale gas is greater than that of other fossil fuels on time scales of up to 100 years. When used to generate electricity, the shale-gas footprint is still significantly greater than that of coal at decadal time scales but is less at the century scale. The report reiterates its conclusion from their April 2011 paper that shale gas is not a suitable bridge fuel for the 21st Century.

Hughes, D., “*Will Natural Gas Fuel America in the 21st Century?*”, Post Carbon Institute (2011).

Full GHG emissions from shale gas may be worse than previously estimated and possibly worse than coal.

Hughes, D., “*Lifecycle Greenhouse Gas Emissions from Shale Gas Compared to Coal: An Analysis of Two Conflicting Studies*”, Post Carbon Institute (2011).

Shale gas full-cycle GHG emissions are higher than those of coal when comparing both the existing electricity generating fleets and best-in-class electricity generation technologies for both fuels over a 20-year timeframe basis, but are lower than those of coal on a 100-year timeframe basis. This has significant policy implications for utilizing

natural gas as a transition fuel to a low carbon future in mitigating near-term GHG emissions.

Karion, A., et al., "*Methane Emissions Estimate from Airborne Measurements Over a Western United States Natural Gas Field*," *Geophys. Res. Lett.* (2013), 40, 4393-4307.

This study used atmospheric measurements in a mass balance approach to estimate methane emissions of $55 \pm 15 \times 10^3$ kg/h from a natural gas and oil production field in Uintah County, Utah on one day: February 3, 2012. This emission rate corresponds to a 6.2% to 11.7% (1σ) of average hourly natural gas production in Uintah County in the month of February. This study demonstrates the mass balance technique as a valuable tool for estimating emissions from oil and natural gas production regions and illustrates the need for further atmospheric measurements to determine the representativeness of this single-day estimate and to better assess inventories of methane emissions.

Leifer, I., et al., "*Transcontinental Methane Measurements: Part 2. Mobile Surface Investigation of Fossil Fuel Industrial Fugitive Emissions*," *Atmospheric Environment* 74 (2013) 432-441.

This study collected continental-scale (Florida to California) surface methane data to investigate the importance of fossil fuel industrial (FFI) emissions in the southern United States. A total of 6,000 measurements along 7,202 kilometers of roadways were made by flame ion detection gas chromatography onboard a nearly continuously moving vehicle in 2010. A second survey making use of a cavity ring-down spectrometer was conducted in southern California in 2012. Data revealed strong and persistent FFI methane sources associated with refining, oil & gas production, a presumed major pipeline leak, and a coal loading plant. Qualitative comparison of surface data with satellite data showed agreement of the large-scale methane patterns. Comparison with inventory models and seasonal winds suggested for some reasons and some portions of the Gulf of Mexico a non-negligible underestimation of FFI emissions.

Petron, G., et al., "*Hydrocarbon Emissions Characterization in the Colorado Front Range: A Pilot Study*," *J. Geophys. Res.* 117 (2012).

The multispecies analysis of daily air samples collected at the NOAA Boulder Atmospheric Observatory in Weld County in northeastern Colorado since 2007 shows highly correlated alkane enhancements caused by a regionally distributed mix of sources in the Denver-Julesburg Basin. To further characterize the emissions of methane and

non-methane hydrocarbons, a pilot study involving automobile-based surveys was carried out during the summer of 2008. The authors derived a range of bottom-up speciated emissions for Weld County in 2008. They used the observed ambient molar ratios and flashing and venting emissions to calculate top-down scenarios for the amount of natural gas leaked to the atmosphere and the associated methane and non-methane emissions. The analysis suggests that emissions are most likely underestimated in current inventories and that the uncertainties attached to these estimates can be as high as a factor of two. They specifically conclude that upstream methane emissions are 4.0% of total production, with a best estimate range of 2.3% to 7.7%.

Rich, A., et al., "*An Exploratory Study of Air Emissions Associated with Shale Gas Development and Production in the Barnett Shale*," J. of Air & Waste Management Ass'n, vol. 64 (2014).

Information regarding air emissions from shale gas extraction and production is critically important given that production is occurring in highly urbanized areas across the United States. Objectives of this exploratory study were to collect ambient air samples in residential areas within 61 meters (200 feet) of shale gas extraction/production and determine whether a "fingerprint" of chemicals can be associated with shale gas activity. Statistical analyses correlating fingerprint chemicals with methane, equipment, and processes of extraction/production were performed. Ambient air sampling in residential areas of shale gas extraction and production was conducted in six counties in the Dallas/Fort Worth metroplex from 2008 to 2010. The 39 locations tested were identified by clients that requested monitoring. Seven sites were sampled on two days, and two sites were sampled on three days, resulting in 50 sets of monitoring data. Twenty-four-four passive samples were collected using summa canisters. Gas chromatography/mass spectrometer analysis was used to identify organic compounds present. Methane was present in concentrations above laboratory detection limits in 49 out of 50 sampling data sets. Most of the areas investigated have atmospheric methane concentrations considerably higher than reported urban background concentrations (1.8-2.0 ppm).

Shinell, D., et al., "*Simultaneously Mitigating Near-Term Climatic Change and Improving Human Health and Food Security*," Science, vol. 335: 183-189 (2012).

Concluding that: (1) the climate system is more immediately responsive to changes in methane (and black carbon) emissions than CO₂; (2) unless emissions of methane (and

black carbon) are reduced immediately, the Earth will warm by 1.5°C by 2030 and by 2.0°C by 2045 to 2050 whether or not CO₂ emissions are reduced; (3) reducing methane (and black carbon) emissions, even if CO₂ is not controlled, would significantly slow the rate of global warming and postpone reaching the 1.5°C and 2.0°C targets by 12 to 15 years; and (4) controlling CO₂ as well as methane (and carbon black) emissions further slows the rate of global warming after 2045, through at least 2070.

“Testimony of VigneshGowrishankar, Ph.D., Staff Scientist, Natural Resources Defense Council, Hearing on Fugitive Methane Emissions from Oil and Gas Operations, Before the Committee on Environment & Public Works, Subcommittee on Oversight, U.S. Senate,” (November 3, 2013).

When natural gas is burned at the power plant to generate electricity it emits far less CO₂ than coal-based electricity. However, if methane leaks into the atmosphere during the production and transport of natural gas before it reaches the power plant (or other points of use), then the relative GHG benefit of natural gas versus other fossil fuels is diminished or even potentially eliminated depending on the actual methane leakage levels versus the alternative fossil fuel and use, and the time horizon, in questions. Natural gas provides a clear advantage over coal-fired electricity from a GHG perspective when the methane leakage rate as a fraction of total production is below 3%. If leakage rates are between 3% and around 7-8%, natural gas loses its advantage over coal in the near-term. If emissions exceed 7-8%, natural gas has no advantage over coal even over the long-term.

Tolleson, J., *“Methane Leaks Erode Green Credentials of Natural Gas,”* Nature, vol. 43, p. 12 (January 3, 2013).

Methane leakage rates of up to 9% show need for broader data on the U.S. natural gas industry’s environmental impact.



Life Cycle Analysis Must be Considered When Comparing Fuels

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Current Regulatory Approach

End Use Only Methodology Distorts True GHG Emissions Picture

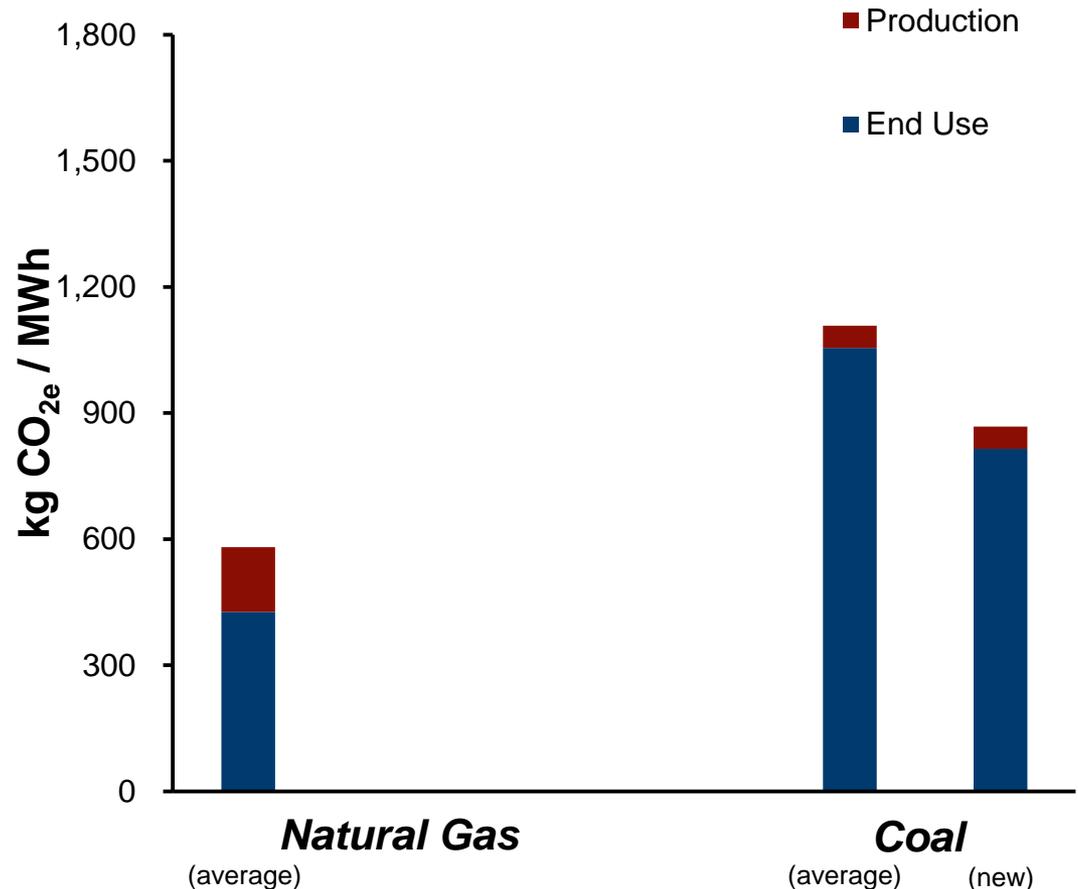
- Existing government climate regulations and energy policies focus only on emissions from natural gas' ultimate end use (e.g., combustion in the power plant), thereby overstating the fuel's climate benefits.
 - For example, the U.S. EPA's recently proposed GHG emissions standards for new power plants do not consider: (i) life cycle GHG emissions; and (ii) methane emissions at all.
- A growing body of peer-reviewed data and analyses suggests that natural gas' claimed climate benefits are overstated.
 - “Bottoms Up” analyses versus “Top Down” are overlooking various aspects of emissions sources for ease of calculations.



Life Cycle Analysis

Life Cycle Analysis Must be Considered When Comparing Fuels.

- End use combustion (facility stack) is why natural gas is claimed to have lower GHG emissions than coal.
- Until existing emissions data from oil & gas production is considered, proposed new climate policies will be biased against coal.
- Peer-reviewed research is showing that shale gas development has a life cycle GHG footprint that approaches parity with 21st century coal combustion technology.

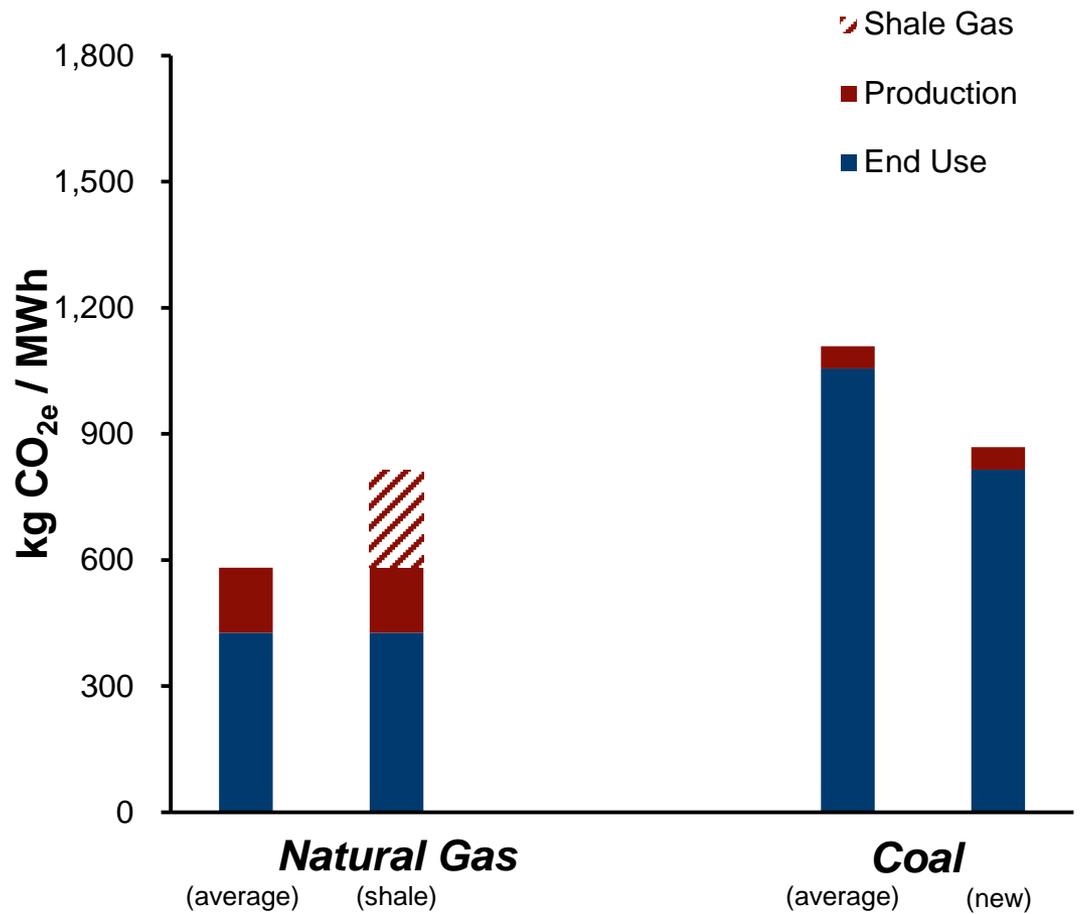




Shale Gas is the U.S. Primary Source of Incremental Natural Gas Supply

Life Cycle Analyses Estimate the GHG from Shale Gas are Likely a Factor of Two or Greater Than Previous Studies.

- Peer-reviewed studies from leading academic institutions and federal government agencies suggest that fugitive methane emissions from natural gas production may be 9% or more.
- Vast range of uncertainties continue to exist due to new data, adjusting measurements techniques, and evolving methodology.



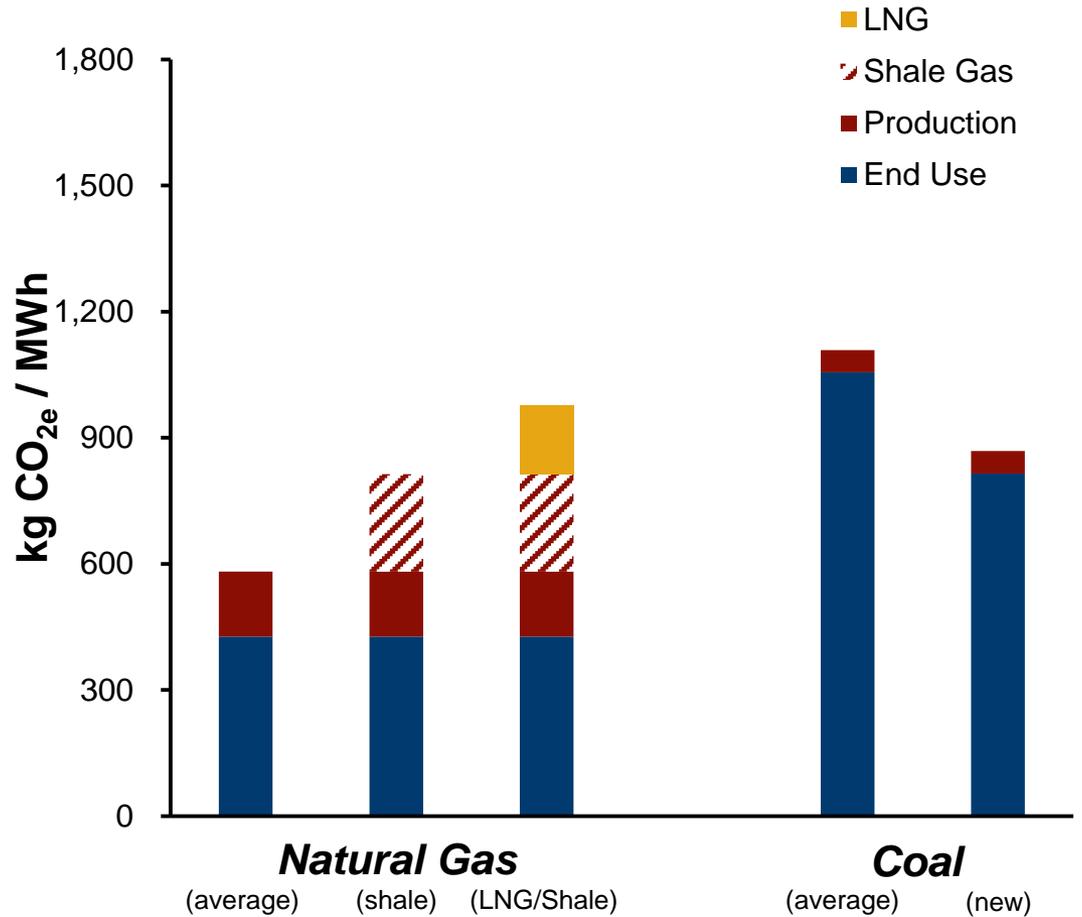
Life Cycle Analysis



More Governments Are Supporting Global Natural Gas Trade

Shale Gas / LNG has a Materially Higher Life Cycle GHG Emissions Than Conventional Natural Gas and State-of-the-Art Coal.

- LNG process uses enormous amounts of energy and is a significant component of natural gas life cycle GHG emissions.
- LNG terminals also have non-GHG air quality, water quality, and marine life, and other environmental impacts.



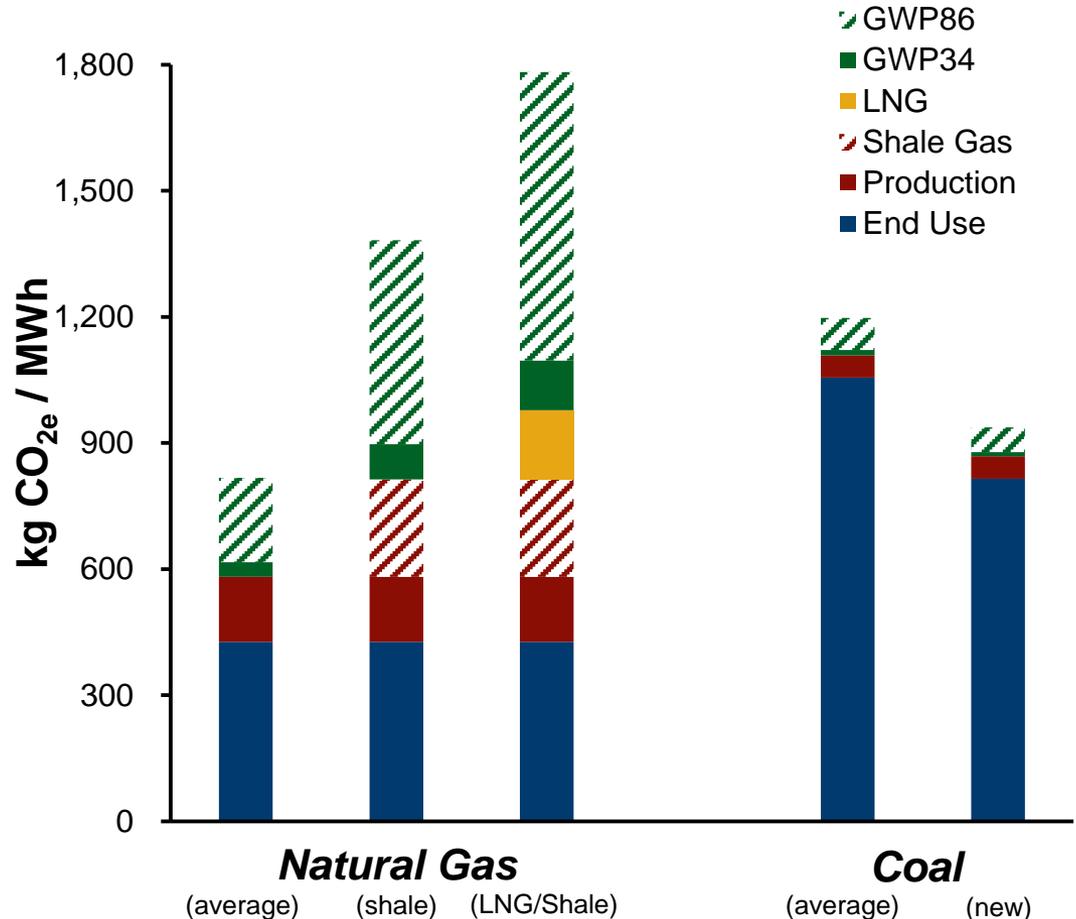
Life Cycle Analysis



Global Warming Potential (GWP)

Research is Revealing Methane is a More Potent Greenhouse Gas Than Previously Understood.

- GWP of methane is greater than previously thought, according to the recent 2013 IPCC AR5 assessment.
- Methane 100-year GWP increasing from 25 to 34.
- Methane 20-year GWP increasing from 72 to 86.
- With mid-century climate goals approaching, 20-year GWP is growing in importance.



Life Cycle Analysis



Coal for People and the Environment

Natural Gas is Not a Carbon Answer

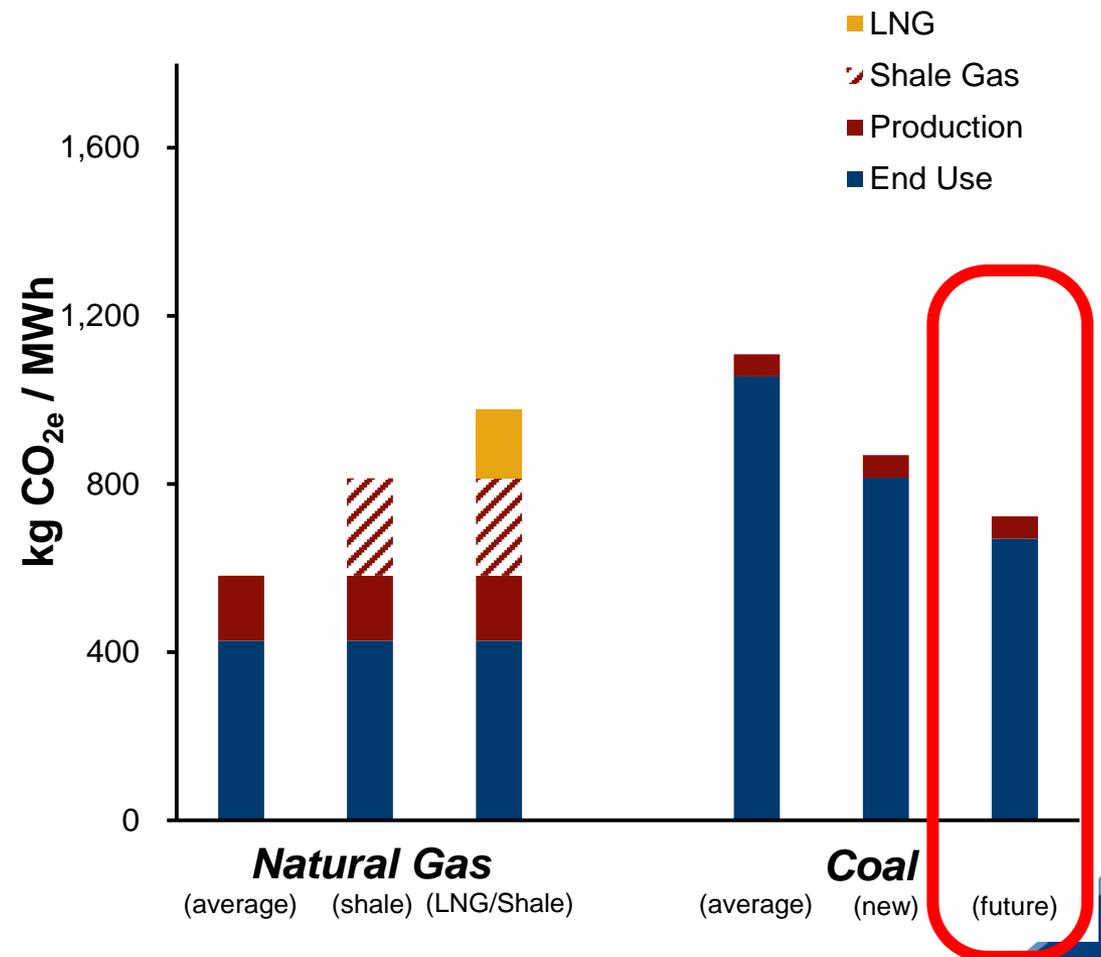
- Natural gas' claimed climate advantage over coal is overstated once lifecycle GHG emissions are taken into account, according to recent peer-reviewed studies.
- Natural gas' lifecycle GHG emissions will only increase as more shale gas and LNG comes online.
- Coal's GHG emissions can decrease through efficiency improvements, innovative generation processes; and, when it is commercially demonstrated, Carbon Capture & Storage (CCS).
- Fuel-switching from coal to natural gas will not only increase electricity prices and lower reliability, it will frustrate, not advance, current climate policies by retarding policy advances in CCUS for both coal and gas.



21st Century Coal Combustion Technology is a Better Climate Answer than Gas

Robust R&D Programs are Needed to Continue the Trend of Improving Coal Power Generation Efficiency.

- CURC/EPRI Roadmap shows key technological improvements can lead to coal combustion efficiencies approaching 48%.
- IEA states a principle way to reduce CO₂ emissions is through High-Efficiency Low-Emissions (HELE) plants, predominantly supercritical coal PC, with target emissions of 670 kg CO_{2e} / MWh.



Life Cycle Analysis