Supplementary Materials: The Impact of Shale Gas on the Cost and Feasibility of Meeting Climate Targets—A Global Energy System Model Analysis and an Exploration of Uncertainties

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1. Sources on Fugitive Emissions

Table S1. A summary of literature on methane emissions associated with shale gas extraction.

Study	Methane Leakage Rate	Method/Description	Caveats/Criticisms
Sustainable Gas Institute, (Balcombe et al. 2015) [1]	Whole Supply Chain: up to ~4.7%, central estimate ~1.5% Extraction: 0.2%–1.8%	Critical Review. This report notes the existence a number of "super-emitters", defined as "an emission source that leaks far in excess of the average", which are not included in best practice emission ranges. The authors state an expectation that these could be largely eliminated if more stringent procedures were applied, but note technical uncertainty in some areas (liquids unloading, in particular), and challenges in monitoring wells which are yet to be resolved	Assuming best practice, excluding super emitters
Howarth, Santoro, & Ingraffea, 2011 [2]	Whole Supply Chain: 3.6%–7.9% Extraction: 2.2%–4.3%	Bottom-up summation of expected emissions during extraction stages, literature review on supply chain emissions. Significant extraction emissions, chiefly occurring during well-completion and routine venting	Assumptions surrounding flow rate during completions, and venting rather than flaring have been criticised [3]
Allen et al. 2013 [4]	Extraction: ~0.42% (all well types—shale and non-shale)	Bottom-up summation of emissions from known sources, as measured at selected onshore natural gas sites provided by participating utility companies in the USA	Reports by Howard et al. [5,6]. state that a sensor failure is likely to have led to significant underestimates in fugitive emissions in Allen's study Allen [7] has responded to some of these concerns. However, this remains an area of ongoing debate and analysis
Stephenson et al. 2011 [8]	Extraction: ~0.6%	Bottom-up summation of emissions from known sources	Assuming reduced emission completions and flaring rather than venting

Table S1. *Cont.*

Study	Methane Leakage Rate	Method/Description	Caveats/Criticisms
O'Sullivan & Paltsev, 2012 [9]	Extraction: 0.39%–0.99%	Bottom-up summation of emissions from known sources	Assuming reduced emission completions and flaring rather than venting
Zavala-Araiza et al. 2016 [10]	Extraction: 1.2%–2.7%, central estimate 1.8%	Bottom-up summation of emissions from known sources and top-down atmospheric measurements, each over several days, combined with spatially explicit list of all oil and gas infrastructure in the region created by combining all available data. Ethane also measured to distinguish bionic from fossil sources	Relies on accurate bottom-up information, and source apportionment challenging, but agreement bottom-up and top-down measurements is good
Karion et al. 2013 [11]	Extraction: 8.9% ± 2.7% (Utah)	Top-down atmospheric measurement	Difficulty of source apportionment represents a significant challenge
Caulton et al. 2014 [12]	Extraction: 3%–17% (Marcellus formation)	Top-down atmospheric measurement	Difficulty of source apportionment represents a significant challenge
Peischl et al. 2015 [13]	Extraction: 1.0%–2.1% (Haynesville), 1.0%–2.8% (Fayetteville), 0.18%–0.41% and 6%–20% (The authors describe the last of as "probably an overestimate", but note that it suggests significant emissions from inactive wells) (sites in Western Arkoma)	Top-down atmospheric measurement	Difficulty of source apportionment represents a significant challenge
Schneising et al. 2014 [14]	Extraction: 10.1% ± 7.3% (Bakken) 9.1% ± 6.2% (Eagle Ford)	Satellite measurements taken prior to (2006–2008), and during (2009–2011), the US shale gas (and oil) boom	Difficulty of source apportionment represents a significant challenge

2. Energy System Cost in All Scenarios

Table S2. Cumulative discounted cost of the energy system, and cumulative discounted cost of mitigation.

Conventional Gas Cost Scenario	Unconventional Gas Cost Scenario	Shale Gas Extraction Rate	Capital Financing Rates for Low Carbon Electricity Technologies	Present Value Energy System Cost over the Period 2012–2100 *		
				2 °C Scenario/ $trillion	Reference Scenario/ $trillion	Mitigation Cost/$trillion (%GDP)
LC	HS	Optimised †	10%	635.2	601.0	34.1 (1.09)
LC	NS	Optimised	10%	634.4 ‡	601.3	33.1 (1.05)
MC	LS	Optimised	10%	640.9	606.4	34.5 (1.10)
MC	MS	Optimised	10%	641.8	607.1	34.7 (1.11)
MC	HS	Optimised	10%	642.3	608.0	34.3 (1.09)
MC	NS	Optimised	10%	642.9	609.0	33.9 (1.08)
MC	NU	Optimised	10%	644.0	610.8	33.2 (1.06)
HC	LS	Optimised	10%	643.2	609.1	34.1 (1.09)
HC	NS	Optimised	10%	645.7	612.7	33.0 (1.05)
High Capital financing Scenarios						
LC	HS	Optimised	11%	636.7	601.0	35.6 (1.13)
MC	MS	Optimised	11%	643.0	607.1	35.9 (1.14)
HC	LS	Optimised	11%	644.2	609.1	35.1 (1.12)
LC	HS	Optimised	20%	652.8	601.0	51.7 (1.65)
MC	MS	Optimised	20%	659.5	607.1	52.5 (1.67)
HC	LS	Optimised	20%	660.9	609.1	51.8 (1.65)
Dash for Shale Scenarios						
LC	HS	Forced	10%	646.9	601.0	45.9 (1.46)
MC	MS	Forced	10%	649.0	607.1	41.9 (1.33)
HC	LS	Forced	10%	650.6	609.1	41.6 (1.32)
LC	HS	Forced	11%	648.8	601.0	47.8 (1.52)
MC	MS	Forced	11%	651.0	607.1	43.9 (1.40)
HC	LS	Forced	11%	652.7	609.1	43.6 (1.39)
LC	HS	Forced	20%	664.9	601.0	63.9 (2.03)
MC	MS	Forced	20%	667.5	607.1	60.5 (1.92)
HC	LS	Forced	20%	669.4	609.1	60.3 (1.92)

Notes: * Discount rate 5% used to calculate cumulative discounted cost; † Here "optimised" means that extraction of shale gas occurs when it is cost-minimising for the energy system as a whole, with no specific additional constraints. All costs in 2005 $US. ‡ The slightly higher 2 °C scenario cost for LC_HS than LC_NS is likely to be the result of shale gas usage in the period up to 2020 (during which period the model is optimising towards meeting weak Cancun pledges) which turns out to be suboptimal to meet a 2 °C target up to 2100.

3. Reference Scenarios, Net Energy Consumption, and Energy Source Mix

Share of conventional and shale gas in in energy supply in a range of cost scenarios with no mitigation is presented in Figure S1. Absolute energy demand growth, and the evolution of the energy supply mix upto 2100, in 2 °C consistent and reference scenarios are presented in Figures S2 and S3 respectively. Energy demand growth and resource mix evolution is broadly in line with previous TIAM-Grantham runs included in previous AVOID2 analysis [15]. Finally, Figure S4 shows the difference in proportion of global energy demand supplied by a range of sources with and without shale gas in 2 °C consistent scenarios.

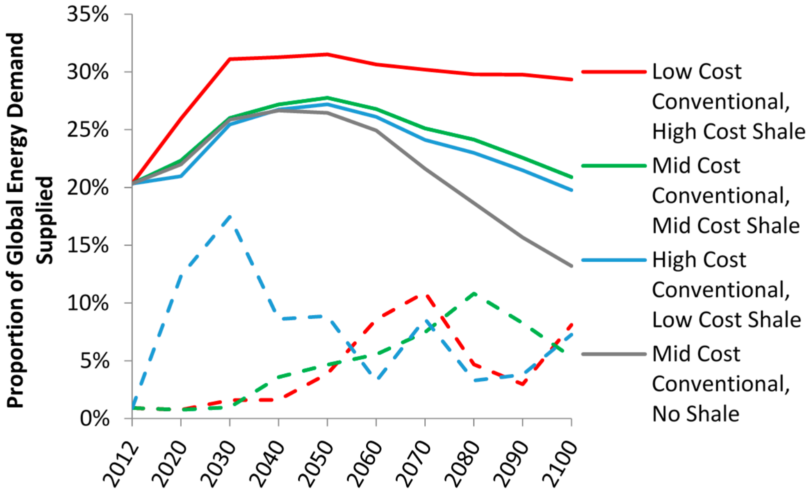


Figure S1. Share of global primary energy supplied by (solid lines) all natural gas, and (dashed lines) shale gas in reference energy systems with no mitigation action in a range of cost scenarios for conventional and shale gas.

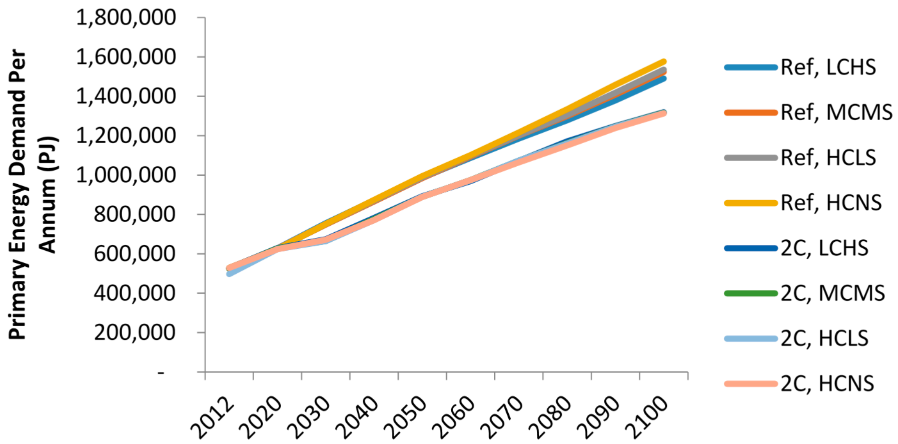


Figure S2. Total primary energy demand per annum in 2 °C and reference scenarios with no mitigation action for a range of cost scenarios for conventional and shale gas.

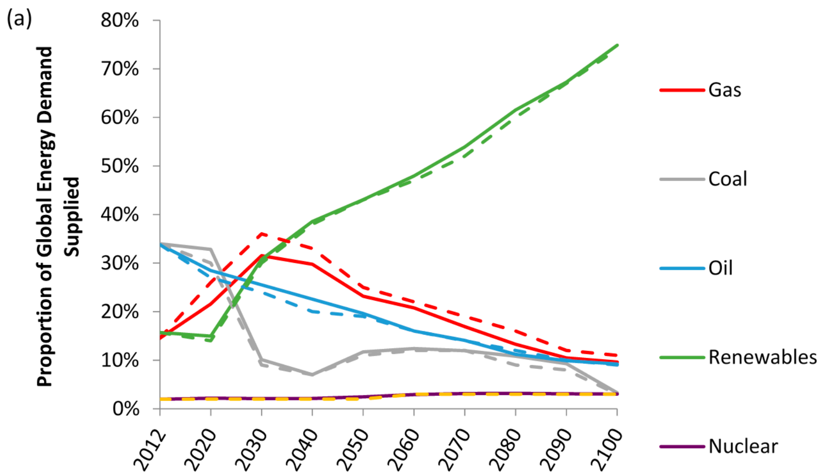


Figure S3. *Cont.*

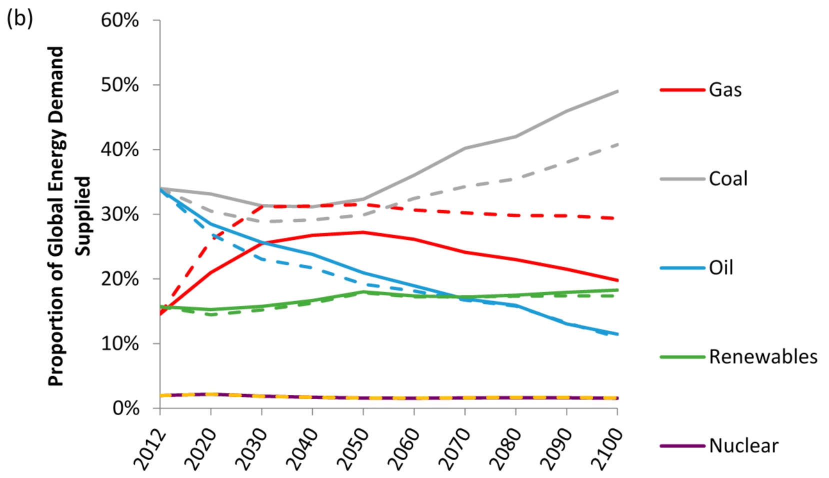


Figure S3. Energy supply from a range of sources over time in (**a**) 2 °C-consistent and (**b**) reference scenarios with no mitigation action. Solid and dashed lines are results from model runs using the HC_LS and LC_HS cost scenarios, respectively.

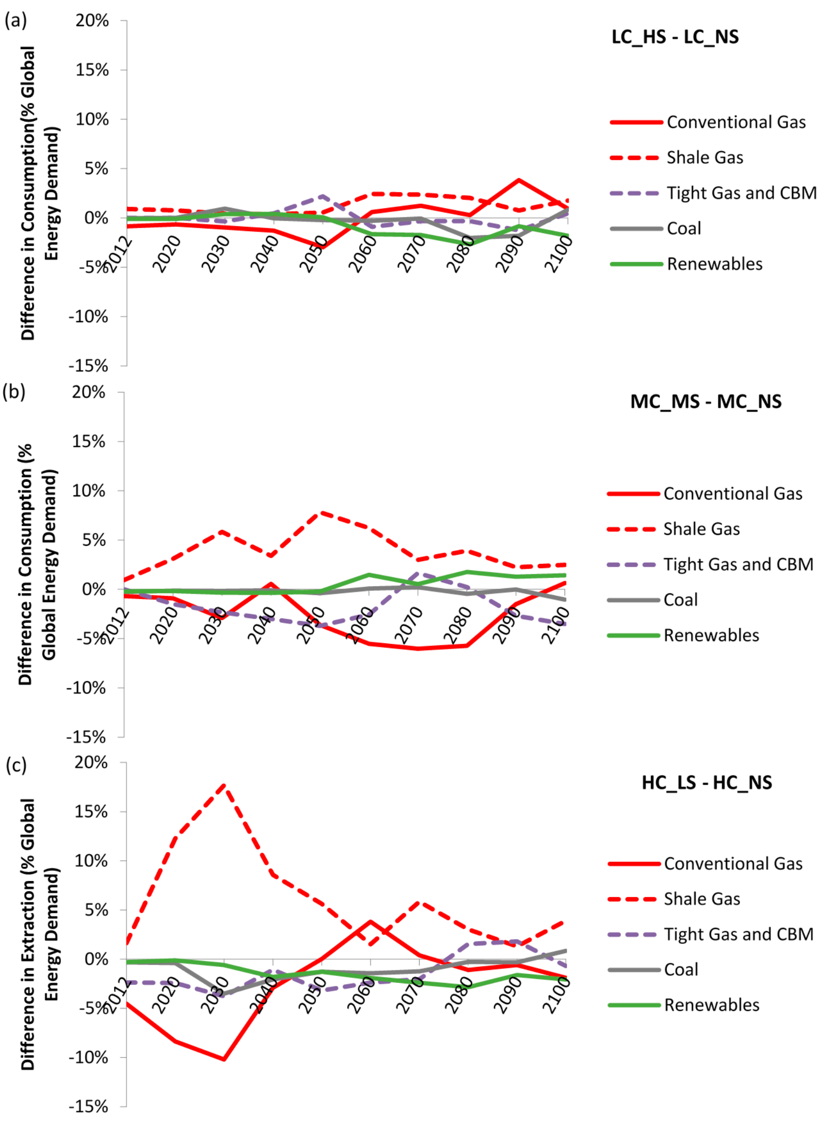


Figure S4 Difference in energy consumption from a range of sources between scenarios with and without shale gas: (**a**) between LC_HS and LC_NS; (**b**) between MC_MS and MC_NS; and (**c**) between HC_LS and HC_NS. Oil and nuclear differ by less than 1% in each scenario throughout the time horizon, and are not plotted here.

4. Sectorial Results

In this annex, we examine global energy supply and sectorial demand mix in a range of 2C scenarios in 2030, the period of peak natural gas usage in our model runs.

Figure S5 shows the global energy supply mix in 2030. Total primary energy production in this year is similar in all scenarios except for one in which there is a dash for shale gas, where total primary energy production is 21% higher. In the HCLS scenario relative to the HCNS scenario, gas production is 14% higher (equivalent to 3.7% of world energy production), mostly displacing coal production, which is 26% lower (equivalent to 3.5% of world energy production). The remaining difference in supply is chiefly compensated for by a 2.3% decrease in both oil and biomass production. Energy production from nuclear, hydro, wind, and geothermal each reduce by less than 2% with the reduction of shale gas. Energy production from solar accounts for 0.3% of global energy production in HCNS in 2030, and falls by 7% in HCLS. This fall is more significant in 2050, in which year solar accounts for 2% of global energy demand in HCNS, and falls by 53% in HCLS.

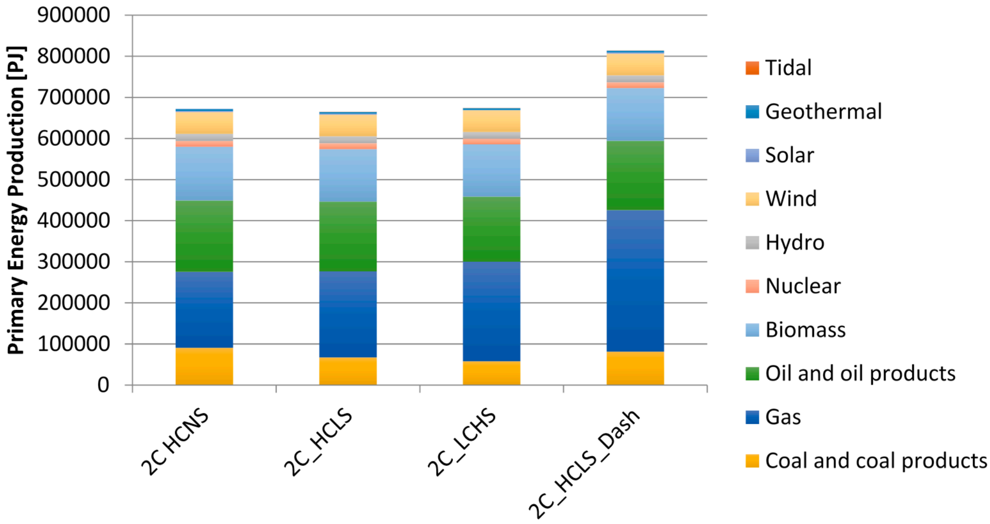


Figure S5. 2030 Annual Primary Energy Production from a Range of Sources in a Range of Scenarios.

In LCHS, significantly more gas is available at a lower extraction cost, and the balance of displaced fuels differs significantly from HCLS. In the LCHS scenario relative to the HCNS scenario, gas production is 31% higher (equivalent to 8.5% of world energy production), whilst coal production falls by 36% (equivalent to 4.9% of world energy production). A 9% decline in oil production (equivalent to 2.3% of world energy production), combined with a 3% decline in biomass production (equivalent to 0.6% of world energy production) are also associated with the increase in natural gas production between these scenarios. Relative to HCNS, decline in solar power is more significant in LCHS than HCLS, falling by 69% by 2030, and 63% by 2050.

Figure S6 shows the breakdown of energy demand by fuel in a range of sectors in a range of scenarios, and Figure S7 summarises differences in sectorial in sectorial fuel consumption between HCNS and HCLS scenarios. In the "dash for shale gas" scenario, significant quantities of natural gas are stockpiled for use later in the model, whilst in other scenarios resource use is broadly in line with supply.

The industrial sector makes the largest contribution to shift in fuel mix use between HCNS and HCLS scenarios, accounting for 68% of the global decline in coal usage, and 57% of the increase in gas usage. Approximately half of this change occurs within the chemical industry, with the remainder shared between a range of industrial processes.

In HCLS in the electricity sector, natural gas generation with CCS replaces approximately a quarter of coal electricity generation in HCNS. This change accounts for 15% of the global decline in coal production, and 15% of the increase in gas usage. In the transport sector, natural gas is only used in road transport, where it displaces 14% of gasoline and diesel, accounting for 16% of global increase in gas usage. In the building sector, natural gas chiefly displaces demand for electricity and kerosene, accounting for 12% of the total increase in gas usage.

When gas becomes significantly less expensive in LCHS, gas extraction relative to HCNS increases by more than double that by which it increases in HCNS. However, in this case, only 37% of this additional gas usage is used in industrial processes, with around 12% displacing coal in the electricity sector, 12% displacing gasoline and diesel in the transport sector.

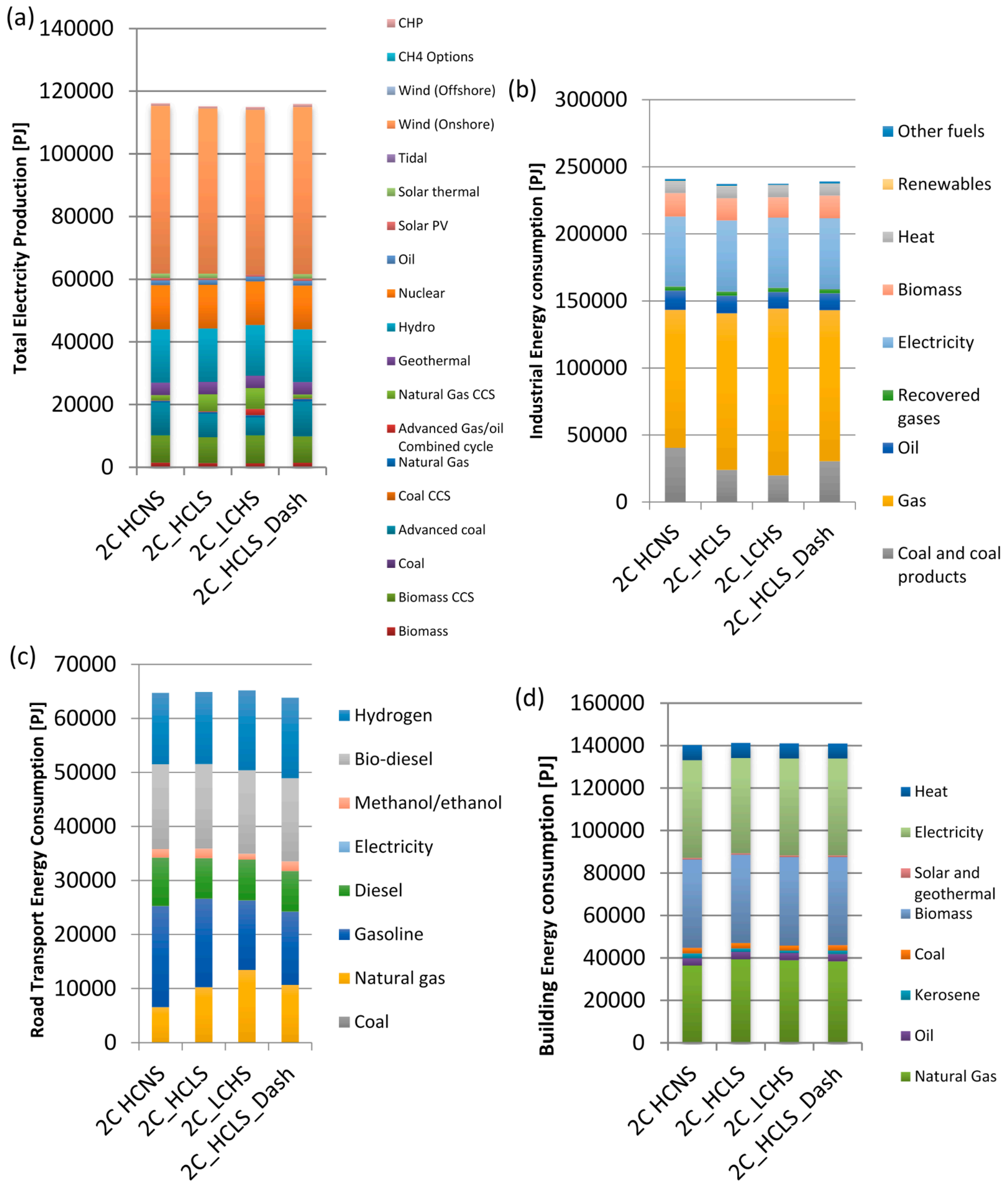


Figure S6. 2030 Annual Primary Energy Demand from a Range of Sources in a Range of Scenarios broken down by Sector: (**a**) electricity; (**b**) industry; (**c**) transport; (**d**) residential and commercial buildings.

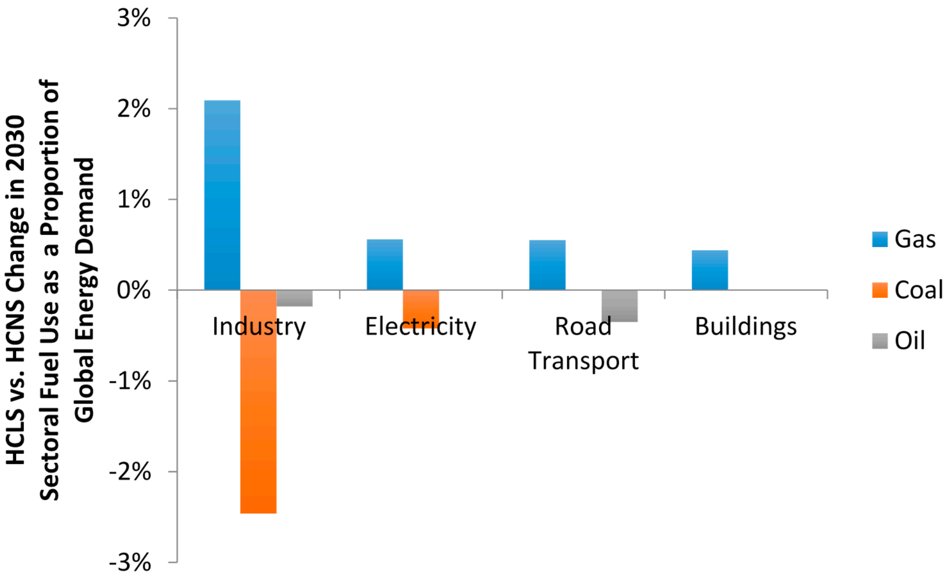
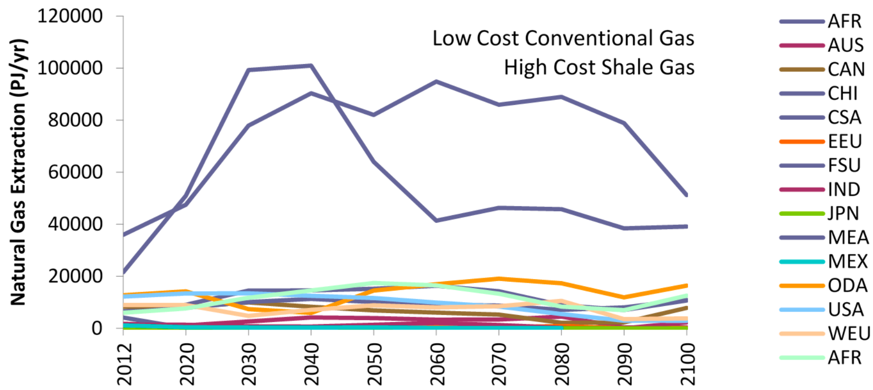


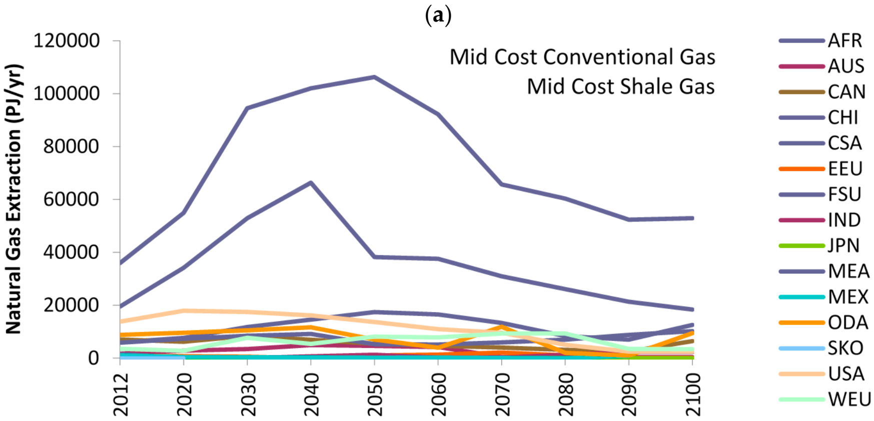
Figure S7. Change in 2030 sectorial fuel use in HCLS scenario compared to HCNS scenario as a proportion of global energy demand.

5. Regional Results

Annualised extraction of natural gas from all sources, shale gas alone, and coal, broken down by region for each core scenario, are presented in Figures S8–S10.

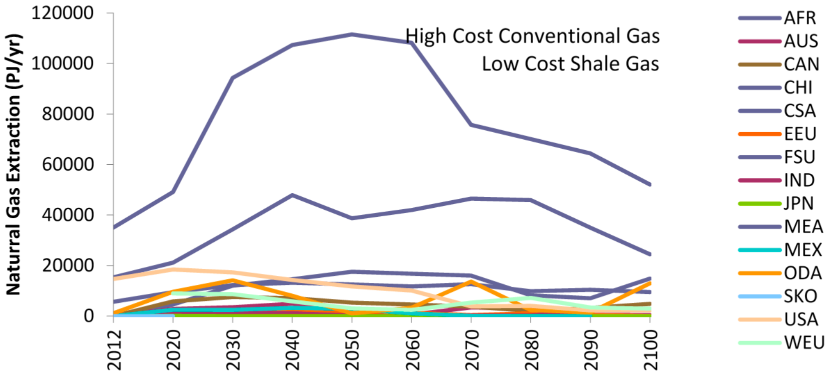


(**a**)



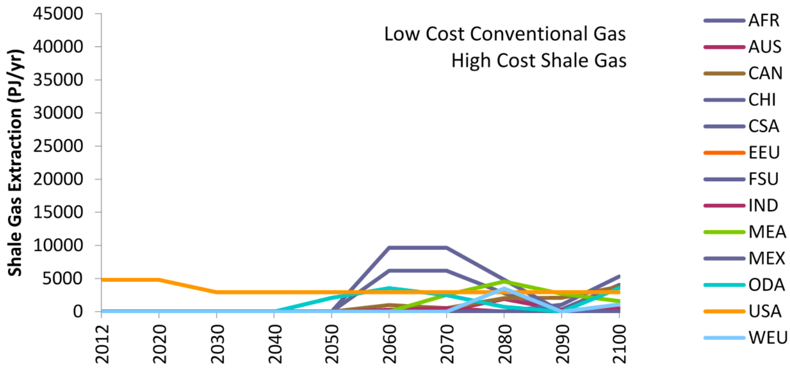
(**b**)

Figure S8. *Cont.*

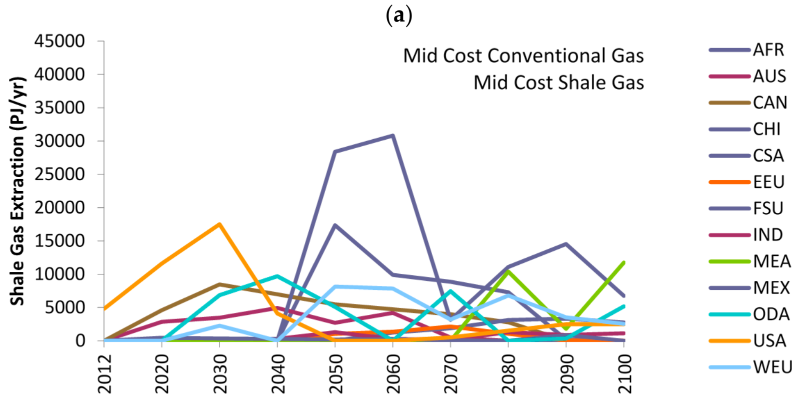


(**c**)

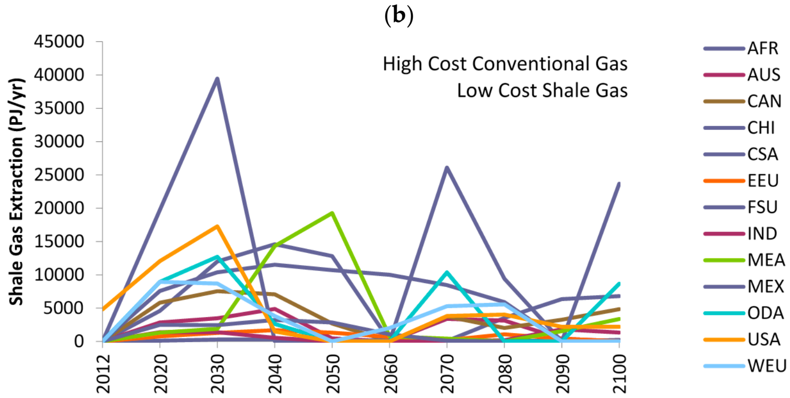
Figure S8. Annualised extraction of natural gas from all sources, broken down by region in a range of supply/cost scenarios: (**a**) low cost conventional, high cost shale gas; (**b**) mid cost conventional, mid cost shale gas; (**c**) high cost conventional, low cost shale gas.



(**a**)



(**b**)



(**c**)

Figure S9. Annualised extraction of shale gas, broken down by region in a range of supply/cost scenarios: (**a**) low cost conventional, high cost shale gas; (**b**) mid cost conventional, mid cost shale gas; (**c**) high cost conventional, low cost shale gas.

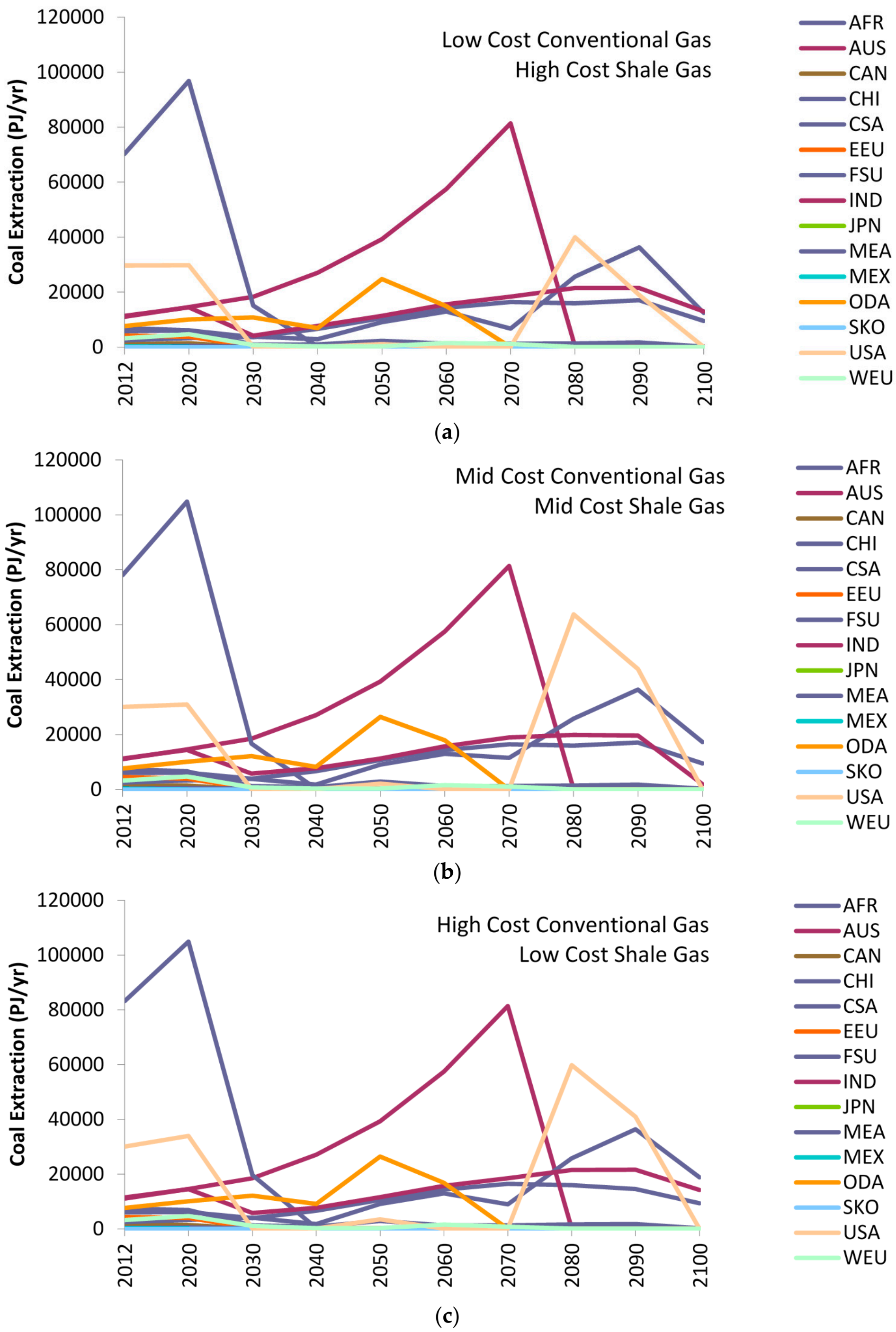


Figure S10. Annualised extraction of coal, broken down by region in a range of supply/cost scenarios: (**a**) low cost conventional, high cost shale gas; (**b**) mid cost conventional, mid cost shale gas; (**c**) high cost conventional, low cost shale gas.

6. Global Temperature Impact of Methane Leakage in "Dash for Shale Gas" Scenarios

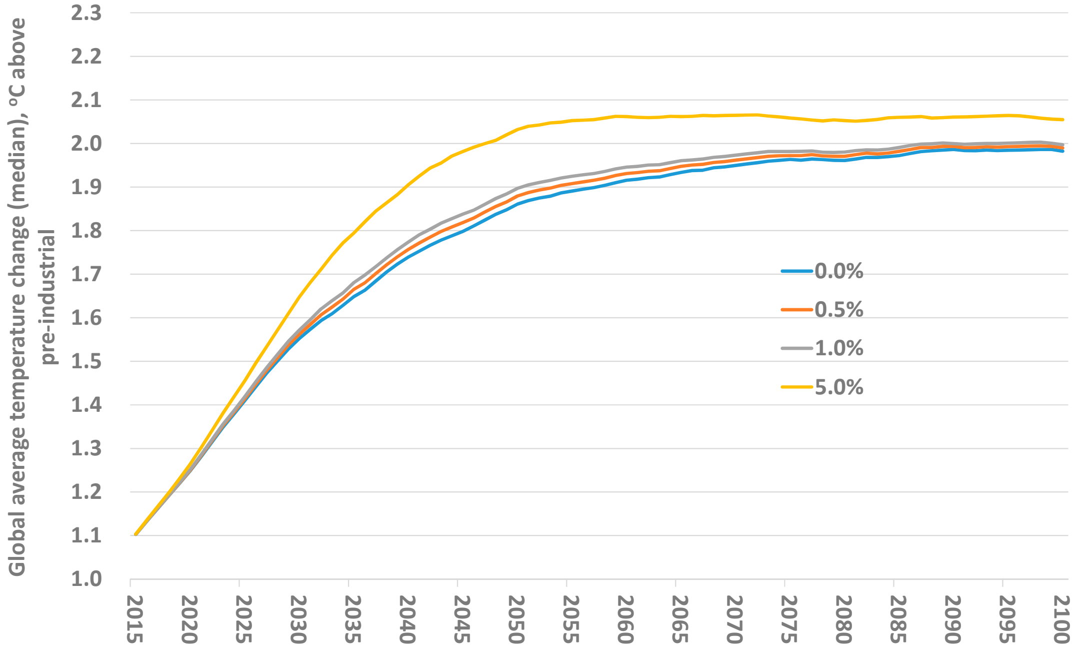


Figure S11. Median temperature change with different assumptions on unmitigated fugitive methane leakage from shale wells, high cost conventional, low cost shale (HC_LS) with "dash for shale gas" scenario.

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