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Understanding future emissions from low-carbon power systems by integration of life-cycle assessment and integrated energy modelling

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Both fossil-fuel and non-fossil-fuel power technologies induce life-cycle greenhouse gas emissions, mainly due to their embodied energy requirements for construction and operation, and upstream CH_4 emissions. Here, we integrate prospective life-cycle assessment with global integrated energy–economy–land-use–climate modelling to explore life-cycle emissions of future low-carbon power supply systems and implications for technology choice. Future per-unit life-cycle emissions differ substantially across technologies. For a climate protection scenario, we project life-cycle emissions from fossil fuel carbon capture and sequestration plants of 78–110 $gCO_2eq\ kWh^{-1}$, compared with 3.5–12 $gCO_2eq\ kWh^{-1}$ for nuclear, wind and solar power for 2050. Life-cycle emissions from hydropower and bioenergy are substantial (~100 $gCO_2eq\ kWh^{-1}$), but highly uncertain. We find that cumulative emissions attributable to upscaling low-carbon power other than hydropower are small compared with direct sectoral fossil fuel emissions and the total carbon budget. Fully considering life-cycle greenhouse gas emissions has only modest effects on the scale and structure of power production in cost-optimal mitigation scenarios.

The Paris Agreement of COP21 confirmed the goal of limiting global temperature increase well below 2 °C and acknowledged the need to achieve net greenhouse gas neutrality during the second half of the century[1]. Previous research based on integrated energy–economy–climate models has shown that achieving these targets cost-effectively requires a rapid, almost full-scale decarbonization of the electricity system by mid-century[2,3]. In electricity production, ample low-carbon alternatives are available[4] and electricity is a potential substitute for fossil-based fuels in all economic sectors, which leads to final energy electricity shares of 25–45% in stringent mitigation scenarios[2].

The life-cycle assessment (LCA) literature illustrates that all energy transformation technologies are associated with upstream energy demands and corresponding indirect (that is, not caused by fuel-burning on site) greenhouse gas (GHG) emissions[4–7]. Concerns have been voiced that these can impair the emission reduction potential of low-carbon technologies[6,8,9]. However, LCA studies of electricity mostly focus on impacts on a per-kilowatt-hour basis in static settings, typically neglecting technology improvements in electricity generation technologies, as well as the effects of concurrent decarbonization measures in other sectors of the energy system and the economy[6,10,11].

Integrated energy–economy–climate modelling approaches estimate cost-optimal long-term strategies to meet the emissions constraints implied by climate targets[3]. Whereas direct combustion emissions as well as CH_4 from fossil fuel extraction and indirect land-use change emissions are accounted for by many state-of-the-art modelling systems, other indirect emissions, in particular those related to energy required for the construction of power plants and the production and transportation of fuels and other inputs (defined here as embodied energy use, EEU), are not considered in the optimization. We investigate to what extent this omission leads to incomplete internalization of externalities.

A previous study by Hertwich et al.[5] used prospective LCA to compare similar scenarios in terms of environmental impacts, but relied on exogenous scenarios for technology deployment, and focused on non-climate environmental impacts to assess co-benefits and trade-offs of climate change mitigation. Daly et al.[9] and Scott et al.[12] investigated the influence of national climate policy on domestic and non-domestic indirect GHG emissions and found them to have a large potential for carbon leakage, as the ratio of emissions caused domestically and overseas shifts to the latter due to imports of goods and services. However, their analysis considered only the United Kingdom, based carbon intensities on aggregate input–output relationships rather than process detail, and did not account for policy-induced non-domestic emission reductions in the context of coordinated international climate change mitigation efforts. Portugal-Pereira et al.[13] included LCA emission coefficients in an integrated assessment model (IAM) and studied the effect of taxing indirect emissions on the electricity mix. However, they considered only the Brazilian electricity system and used static LCA coefficients.

In this study, we present consistent and detailed modelling of EEU and indirect GHG emissions for global scenarios of future electricity systems. By linking an IAM with EEU coefficients from a prospective LCA model, we can provide a holistic and detailed perspective on future life-cycle greenhouse gas emissions of low-carbon technologies and power systems in the context of a universal climate change mitigation regime, thus closing an important research gap[14–16] by quantifying these emissions and their effect on the choice of low-carbon technologies in mitigation scenarios. This study combines results from the REMIND model[17,18], which details energy use and

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technology deployment for a 2 °C-consistent power-sector decarbonization scenario, with EEU coefficients from the prospective LCA model THEMIS[10,19] reflecting likely future technological progress and changes in background technologies, and detailed land-use and land-use-change (LULUC) emissions of bioenergy from the land-use model MAgPIE[20–22]. According to our analysis, the energy cost of constructing and operating power plants will, in 2050, be equivalent to 3–8% of electricity output for nuclear, wind and solar power, and more than 13% for other low-carbon technologies. Life-cycle GHG emissions for the three technologies range from 3.5 to 11.5 $gCO_2eq\ kWh^{-1}$, well below the range indicated by LCAs of current technologies. Including previously omitted indirect emissions has little effect on global mitigation scenarios.

Embodied energy use

The integration of LCA-based projections of the energy embodied in various forms of electricity generation[19] with technology deployment estimates from scenarios of the IAM REMIND allows us to estimate EEU. We define EEU as the energy required to build electricity generation capacities and to provide them with fuel and ancillary inputs, but excluding the energy content of the fuel burned. Up to now, IAMs have not tracked such EEU of power technologies. The LCA coefficients of embodied energy are derived from the prospective LCA model THEMIS[10], which includes life-cycle inventory data for a set of current and future electricity generation options, and integrates these data into all of its supply chain descriptions. THEMIS accounts for technological progress in power technologies, which, in particular for solar power, results in a gradual decline of EEU due to increasing material efficiency. Representations in THEMIS of industrial activities (which are inputs into power production technologies) other than electricity supply (which is modelled within REMIND) are based on data from the Ecoinvent LCA database[23], which are modified to reflect future improvements in emission intensities, and energy and process efficiencies for selected major industrial processes (for example, aluminium, clinker, copper, flat glass, iron and steel production; see ref. [10] and its supplementary material for details on the modelling of future technological change in THEMIS). A full description of the approach used to derive the LCA coefficients is available in ref. [19]. The LCA coefficients distinguish between four secondary energy carriers (electricity, gases, liquids and solids) that have different carbon intensities, and three life-cycle phases (operation, construction and end-of-life), either on a per-production or per-capacity basis. The LCA coefficients for operation and end-of-life are divided by the total electricity production over the technologies' lifetime (from the IAM scenarios) to derive per-kilowatt-hour EEU numbers.

Figure 1 shows the global average EEU for power plants built in 2050 in a model scenario compatible with the 2 °C target (see Methods), broken down by secondary energy carrier and expressed as a percentage of lifetime electricity production. We find that fossil fuels (coal and gas), bioenergy and hydropower have significantly higher EEU than nuclear, wind and solar power (by a factor of 1.7–8.7). Bioenergy and hydropower also exhibit very large variations of EEU compared with other technologies. For the fuel-burning technologies (coal, gas, biomass), most of the EEU occurs in the form of liquids and gases (78–93%) and is due to fuel production, handling and transportation, with carbon capture and sequestration (CCS) causing an increase due to reduced plant efficiency and additional material requirements (largely amine for CO_2 removal). Wind, hydropower and solar technologies require most of their indirect energy for construction (88–100%). In the case of hydropower, this is almost exclusively due to earthworks and road construction (using liquids) while wind and solar use more equal shares of all energy carriers. Nuclear power uses about one-fifth of indirect energy for construction and most of the remainder as electricity for uranium enrichment.

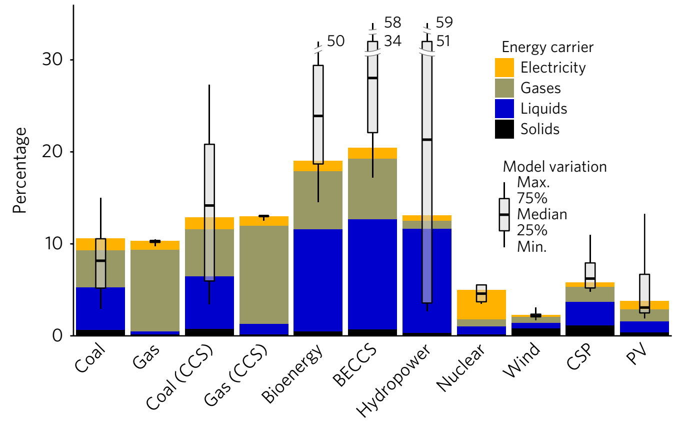

Fig. 1 | Embodied energy use of electricity production as a percentage of lifetime electricity production. Global average values are shown by secondary energy carrier (coloured bars) for capacities built in 2050. Combined model variations over both regions and technology variants (sample minimum, 25th percentile, median, 75th percentile, and maximum, see Methods) are shown as grey boxplots. See also Supplementary Table 1.

Combined ranges across regions and technology variants are included in Fig. 1 as measures of variability and uncertainty (see Methods). Nuclear and solar technologies show significantly smaller ranges than coal, biomass and hydropower. The large uncertainty for hydropower arises from the fact that only two very different case studies were available[19]. Coal and biomass show large variations due to regionally different needs for fuel transportation in the case of coal and farming and crop handling in the case of biomass[19]. CCS compounds these differences due to lower electric efficiency. Gas and wind show only small variations, as they are represented by only one technology variant (gas) or very similar technology variants (wind) in the LCA model[19]. A comparison with values from the literature is not practicable, because energy technologies have not been assessed for the year 2050 in a similar manner. For a comparison of coefficients for 2010 derived with the same methodology to literature values of current technologies, see ref. [19].

Specific life-cycle GHG emissions

For assessing the climate change mitigation potential of power-sector technologies, it is crucial to compare total (direct and indirect) GHG emissions per unit of electricity produced. It is important to note that future indirect GHG emissions from EEU depend not only on changes in the individual technologies, but also on changes in the carbon intensity of upstream energy and material requirements throughout the energy system, notably the degree to which electricity supply has already been decarbonized. We therefore compute specific (per-unit) emissions from construction and operation by combining EEU coefficients with IAM endogenous CO_2 intensities (see Methods).

Figure 2 shows global average per-kilowatt-hour GHG emissions for power plants built in 2050 derived from our 2 °C-consistent decarbonization scenario. In addition to the CO_2 emissions from EEU (see Methods), it includes direct CO_2 emissions from imperfect capture of fossil fuel technologies with CCS, negative CO_2 emissions from bioenergy with CCS (BECCS)[24], upstream CH_4 emissions from coal and gas production[24,25], biogenic CH_4 emissions from hydropower[26], and induced LULUC emissions (CO_2, CH_4 and N_2O) from biomass production[27–29] (see Methods).

Specific GHG emissions of coal, gas, bioenergy and hydropower are significantly higher than those of nuclear, wind and solar power, due to higher EEU (see above) and additional indirect emissions. For power supply from fossil fuels with CCS, bioenergy without

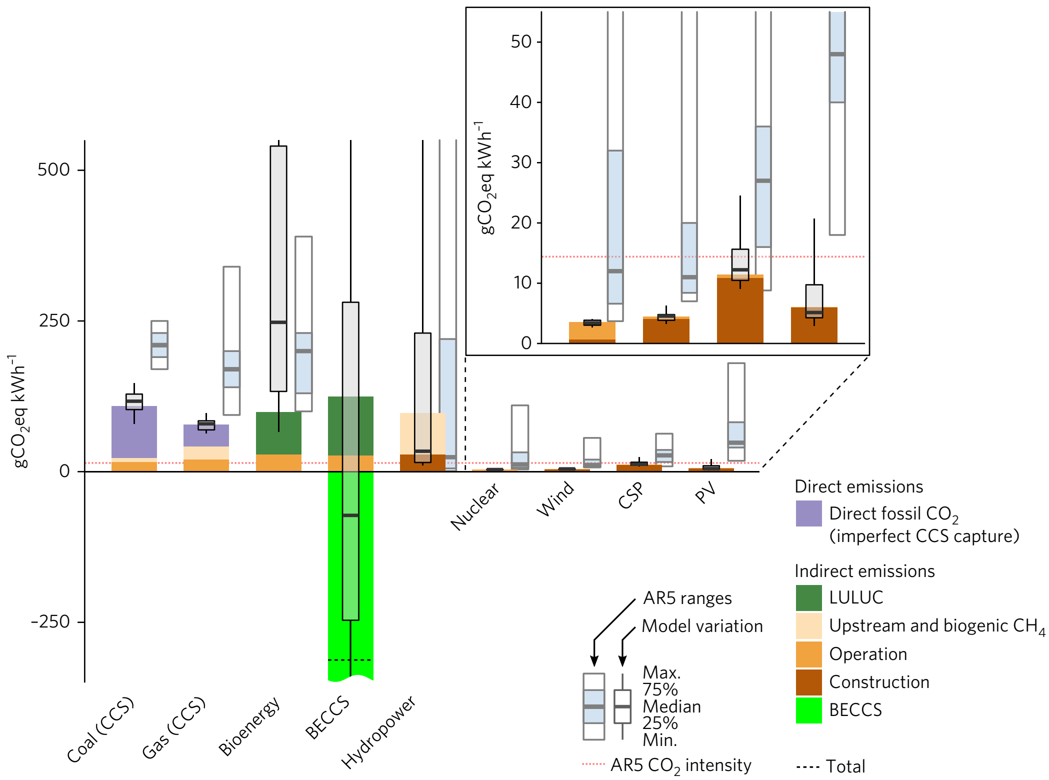

Fig. 2 | Specific direct and indirect GHG emissions. Global 2050 average of lifetime emissions over lifetime electricity production (solid coloured bars), for capacities built in 2050 in a 2 °C-consistent mitigation scenario. Model variations (sample minimum, 25th percentile, median, 75th percentile, and maximum, see Methods) across both regions and technology variants are shown as boxplots. Ranges of specific emissions from AR5, from section 7.8.1, Fig 7.6 in ref. [4] are shown as light blue ranges. BECCS is not assessed there. The (median) 2050 CO_2 intensity of electricity production for AR5 scenarios without CCS (technology category T3) reaching 430–480 ppm CO_2eq (climate category 1) is shown in red as a proxy for the level of specific net emissions (without negative emissions from BECCS) in line with the 2 °C target. See also Supplementary Table 2.

CCS and hydropower, specific GHG emissions range from 78 to 109 gCO_2eq kWh^{-1}, while nuclear, wind, photovoltaics (PV) and concentrating solar power (CSP) have specific emissions of 3.5–11.5 gCO_2eq kWh^{-1}. This compares with an average fossil fuel CO_2 intensity of global electricity supply of currently 504 gCO_2 kWh^{-1}, and 15 gCO_2 kWh^{-1} in 2 °C-consistent scenarios in 2050[3]. BECCS achieves net-negative emissions of −312 gCO_2eq kWh^{-1}. Under the assumption of a 90% capture rate, residual (unmitigated) direct CO_2 emissions from coal- and gas-fired CCS plants are substantial at 86 and 36 gCO_2 kWh^{-1}. In addition, CH_4 emissions from coal mining and natural gas handling account for additional 7–21 gCO_2eq kWh^{-1}. Indirect CO_2 emissions related to upstream energy inputs are smaller than the CH_4 and residual direct CO_2 emissions from incomplete capture, yet have a marked impact on the technologies' ability to provide near-zero carbon electricity. Embodied energy emissions of bioenergy are roughly twice as high as those for coal and gas, but are dwarfed by LULUC emissions, which are due to carbon released during land conversion for additional cropland (mostly from pastures) as well as N_2O emissions from fertilizer use[20–22]. If CO_2 emissions are priced consistently between energy and land-use systems, EEU and LULUC emissions combined offset a quarter of negative BECCS emissions and are thus curtailing the technology's potential for negative emissions[22,30]. However, in line with previous research[29], we find that LULUC emissions can become considerably higher (a main component of the model uncertainty for bioenergy and BECCS in Fig. 2) if a lower carbon price is applied to them, which amounts to their incomplete regulation under climate change mitigation policies. Hydropower has the highest indirect emissions apart from bioenergy, as it can cause high biogenic CH_4 emissions from biomass degrading in the reservoirs. These emissions are, however, highly uncertain in magnitude and regional distribution[26,31]. For nuclear, wind and solar power, by contrast, construction and operation are the only sources of life-cycle GHG emissions. As mentioned above, EEU for these technologies is lower than for fossil fuels, biomass and hydropower, resulting in much more favourable overall GHG balances.

Importantly, our specific emission estimates are lower than the estimates from existing LCA studies (up to 2013) as assessed in the Fifth Assessment Report of the Intergovernmental Panel on Climate Change[4] (blue shaded boxes in Fig. 2). The main reason is that we here present projections for 2050 under a 2 °C-consistent mitigation scenario, accounting for technological progress in energy technologies themselves, as well as the decarbonization of the energy supply system. In the absence of decarbonization of the background energy system, indirect emissions from EEU would be 30–250% higher for all technologies (see Supplementary Note 3).

Figure 2 also includes the ranges of specific emissions across model regions and technology variants (grey box plots) to assess the variability of our results. For all technologies the global average is below or close to the median of regional values, as deployment takes place in regions with favourable overall conditions (for example, high full-load hours for wind or PV). The ranges of the specific emissions of bioenergy (with and without CCS) and hydropower depend strongly on regional conditions and technological specifications of individual projects. Bioenergy emissions (including for BECCS) can reach levels even higher than those of coal- and gas-fired power plants without CCS if biomass were produced in less suitable regions and badly managed (see Methods). Emissions from hydropower may reach up to 2 $kgCO_2eq\,kWh^{-1}$ due to biogenic CH_4 emissions at poorly chosen sites[26].

Residual direct and indirect power-sector GHG emissions

We analyse total direct and indirect power-sector GHG emissions for a scenario compatible with the 2 °C limit (Policy), and compare them with those that would occur in absence of climate policies (Baseline scenario). For an analysis of policy scenarios with various restrictions on technology choice, see Supplementary Note 4. Figure 3 shows the global direct and indirect power-sector GHG emissions for the year 2050. Figure 4 shows the differences in indirect GHG emissions between the Baseline and Policy scenarios (Fig. 4a), as well as the differences in cumulated indirect GHG emissions from 2010 to 2050 (Fig. 4b). In addition to direct fossil fuel CO_2, upstream CH_4 from fossil fuel production and LULUC emissions from biomass production, which are typically included in IAMs[32], the Policy scenario also includes biogenic CH_4 emissions from hydropower and indirect CO_2 emissions from EEU in the optimization.

We find that not only direct but also indirect emissions are lower (by 54%) in the Policy than in the Baseline scenario in 2050 (Fig. 3), due to avoided emissions from coal and gas production and handling. At the same time, indirect emissions contribute more than half to gross total emissions (excluding negative BECCS emissions) and are more than twice as large as net direct CO_2 emissions (including negative BECCS emissions) in the Policy scenario, highlighting their increasing importance in technology choice in the power sector.

Indirect emissions are consistently lower for the Policy than for the Baseline scenario in the first half of the century (Fig. 4a) due to the fast phase-out of electricity production from coal and gas (see Supplementary Note 2). These reductions are partly offset by increased emissions from hydropower (mainly in China, Africa and Latin America), a large portion of which originates from biogenic CH_4. Although solar, wind and nuclear technologies contribute three-quarters to electricity production in 2050 in the Policy scenario (see Supplementary Note 2), their indirect emissions during the transition to low-carbon electricity supply are only marginally larger than in the Baseline scenario, as they benefit from technological advances and the decarbonization of electricity. This is also reflected in the cumulated indirect GHG emissions (Fig. 4b), which are only 3.1 $GtCO_2eq$ larger for these technologies. Hydropower, gas with CCS and BECCS contribute further to increased indirect GHG emissions of low-carbon technologies, which are more than compensated by reduced indirect GHG emissions from fossil fuel technologies without CCS. In total, cumulated indirect GHG emissions are reduced by 23 $GtCO_2eq$ over the 2010–2050 period, while the direct carbon intensity of electricity is reduced by 95% (see Supplementary Fig. 2). In relation to the budget of Kyoto gases (1,660 $GtCO_2eq$ over 2010–2050 in this scenario), the cumulated indirect emissions of the electricity sector (82 $GtCO_2eq$, see Supplementary Note 4) amount to less than 5% and play only a minor role.

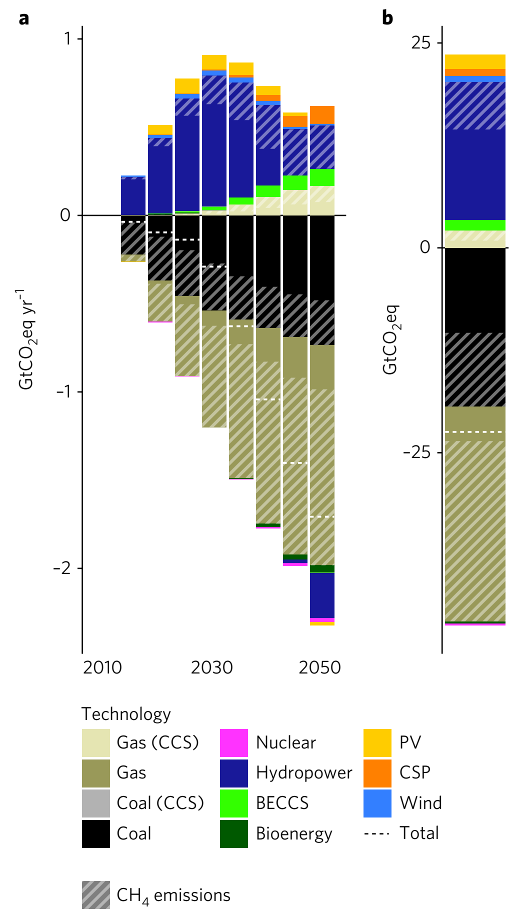

Fig. 4 | Differences between global indirect emissions. a,b, Differences between the Policy (2 °C-compatible) and Baseline (no climate policy) scenarios over time (**a**) and cumulated from 2010 to 2050 (**b**). Indirect emissions include those from construction, operation (except fuel burning), LULUC, and upstream and biogenic CH_4 emissions. See also Supplementary Table 4.

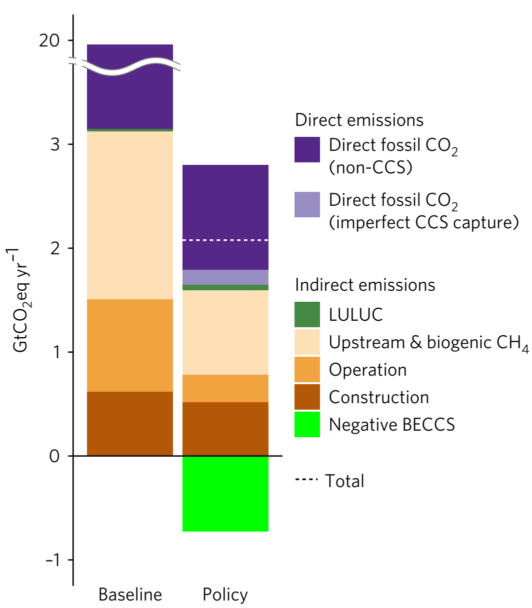

Fig. 3 | Total global 2050 emissions. Both direct and indirect emissions from global power production in 2050 for the Baseline (no climate policy) and the Policy (2 °C-compatible) scenario. Direct fossil fuel CO_2 (non-CCS) emissions derive from non-CCS fossil fuel plants, while direct fossil fuel CO_2 (imperfect CCS capture) from fossil fuel plants with CCS. See also Supplementary Table 3.

Impact on optimal technology choice

In view of differing embodied energy requirements and indirect GHG emissions, the question arises of how these affect optimal technology choice for climate change mitigation. In a comprehensive climate policy scheme, all GHG emissions in all sectors of the economy would be priced and thus included in decisions on technology deployment and operation. We here consider two accounting approaches for the Policy scenario, either accounting for no indirect emissions (direct only; omitting upstream CH_4 and LULUC emissions usually included in IAMs) or accounting for all indirect emissions (full accounting; including biogenic CH_4 emissions from hydropower and indirect emissions from EEU, usually not part of IAMs; see Methods for details of the implementation).

Figure 5 shows global electricity production for both accounting schemes for the years 2010, 2030 and 2050, as well as the differences between them in 2050. Electricity production in 2050 is primarily met by PV, nuclear, wind and hydropower, while gas and bioenergy (with and without CCS) and CSP contribute sizeable shares. If all indirect emissions are accounted for (full accounting), total electricity production decreases only slightly (by 3 EJ, less than 2%), as additional priced emissions or their mitigation increases costs. Production from gas, hydropower and bioenergy decreases significantly by 15 to 33%, due to the high specific emissions caused by LULUC and upstream/biogenic CH_4. CCS technologies see stronger reductions, as they cause higher specific emissions. These reductions are offset by increased production from CSP, wind and nuclear, which have the lowest specific indirect GHG emissions (see Fig. 2).

The effect of including indirect GHG emissions (and options for their abatement, see Methods) on technology choice and total electricity production is therefore quite small on the global scale. However, regions with large shares of technologies with comparatively high specific indirect emissions (hydropower in Russia and Latin America, and gas with CCS in the Middle East and Northern Africa) show larger reductions (see Supplementary Fig. 7). Since large fractions of indirect GHG emissions (from upstream CH_4 and LULUC) are already accounted for in many state-of-the-art IAMs[32] (including REMIND), the effect of additionally including emissions so far omitted is even smaller (see Supplementary Note 5).

Discussion

Our study provides a comprehensive global analysis of EEU and indirect GHG emissions from all relevant power-sector technologies, combining the strengths of integrated assessment modelling and LCA approaches. Important features are the process-detailed integration of life-cycle energy requirements and technology operation (for example, load factors of renewable power plants) in a global climate change mitigation framework, the endogenous representation of CH_4 emissions from fossil fuel supply and CO_2 intensities of energy carriers required for power-technology construction and operation. We find substantial differences across technologies, with electricity production based on biomass, coal, gas and hydropower inducing much higher specific indirect energy inputs and specific indirect GHG emissions than nuclear-, wind- and solar-based power supply.

Our findings have important implications for climate and energy policy. First, they underline that an almost full-scale decarbonization of the global power sector would induce only modest indirect GHG emissions. In other words, if power-sector decarbonization is embedded in a cross-sectoral mitigation strategy, the indirect GHG emissions induced by upscaling wind, solar and nuclear power are small compared with other emission sources, and thus do not impede the transformation towards climate-friendly power supply. At the same time, the relative importance of indirect emissions increases over time in stringent mitigation scenarios, and can be of the same order of magnitude as direct emissions in 2050.

Second, our findings demonstrate that different low-carbon electricity supply options are not equally effective. Rather, they differ substantially in terms of specific GHG emissions. A consistent and comprehensive regulation of GHG emissions in all sectors and world regions in line with the 2 °C target is instrumental for minimizing residual indirect emissions from power supply. Our findings demonstrate that emission reduction strategies for power supply focused on non-combustion low-carbon technologies other than hydropower, namely wind, solar and nuclear, will result in the lowest residual sector emissions. On a per-kilowatt-hour basis, the residual GHG emissions from fossil fuel CCS (mostly due to imperfect capture and upstream CH_4 emissions) exceed the average power-sector emissions intensity required for 2 °C stabilization by a factor of five. The specific emissions of hydropower can be strikingly high, but are also highly variable, uncertain and dependent on

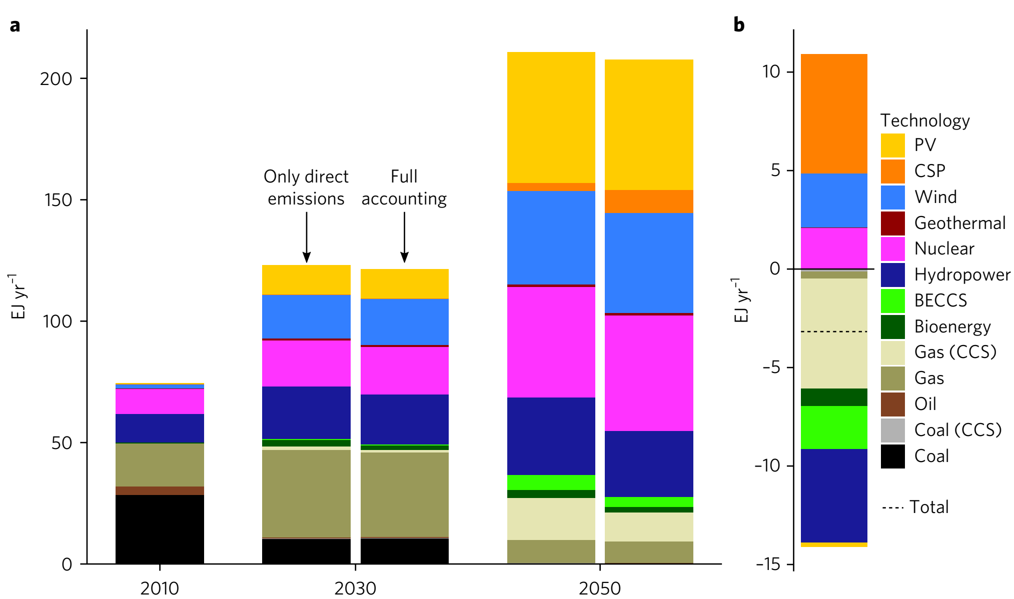

Fig. 5 | Impact on optimal technology choice. a,**b**, Electricity production by technology for two variants of the Policy (2 °C-compatible) scenario, accounting only for direct emissions or all indirect emissions (**a**) and differences between the two variants in 2050 (**b**). Accounting for the effect of indirect emissions (upstream and biogenic CH_4, LULUC and life-cycle CO_2 emissions) reduces electricity production by about 3 EJ yr^{-1} in 2050 (**a**). Technologies with comparatively high specific indirect emissions (gas, hydropower and bioenergy) produce significantly less electricity, which is largely offset by increased production from technologies with lower specific indirect emissions (wind, nuclear and CSP) (**b**). See also Supplementary Table 6.

geography. This uncertainty indicates the need for further research and suggests that careful assessment of individual hydropower projects prior to implementation is required to ensure that such projects deliver an actual climate change mitigation benefit[26]. In view of potentially substantial biogenic CH_4 emissions, currently used estimates of sustainable hydropower resources[33] may have to be corrected downwards. Bioenergy is a special case. Its indirect GHG emissions may exceed even those of fossil-fuel-based electricity, due to high LULUC emissions. It can nonetheless play an important role for climate protection by providing substantial net-negative emissions if combined with CCS and if LULUC emissions are subject to comparably stringent regulations to those from the energy and industry sectors. Importantly, other sustainability dimensions beyond life-cycle greenhouse gas emissions need to be considered[34,35]. For instance, nuclear power, while favourable in terms of GHG emissions, faces low societal acceptance in many countries due to concerns about safety and radioactive waste[36], which has quite uncertain life-cycle impacts potentially extending beyond the time horizons of our models[37].

Our study responds to recent calls for wider system boundaries in integrated assessment modelling of climate change mitigation[38]. State-of-the-art IAMs, including the REMIND model used here, already account for imperfect capture of CO_2 in CCS plants, CH_4 emissions from fossil fuel extraction and handling[39], and LULUC emissions from biomass production[32], but represent indirect energy requirements only implicitly via the models' general energy demand for industrial production. The models therefore do not account for differences across technologies and differences in energy intensity of economic activity within and outside the power sector. While our analysis shows that the net effect of this omission on the total level of electricity production is small, it may introduce biases for and against individual technologies that might prove pivotal in designing regional climate change protection policies and should not be disregarded in IAMs. This is especially true for biogenic CH_4 emissions in regions where hydropower is a primary option for low-carbon electricity production.

Methods

Integrated assessment model. We use the integrated assessment model REMIND[17,18] that combines an inter-temporal general equilibrium model of the macroeconomy with a detailed energy system model that explicitly represents vintage capital stocks for more than 50 conventional and low-carbon energy conversion technologies and tracks energy flows from primary through secondary to final energy. It maximizes inter-temporal welfare of 11 world regions that are linked by trade in primary energy carriers, an aggregated trade good, and in the case of climate policy emission permits. The macroeconomic production function has labour, capital and various final energy carriers as inputs (which can be substituted for one another with constant elasticities of substitution), while economic output is used for consumption, trade, investments into the macroeconomic capital stock, and energy system expenditures. The macroeconomic and the energy system modules are hard-linked via final energy demand and costs incurred by the energy system. Energy production and final energy demand are determined by market equilibrium (that is, between marginal utility and marginal costs of energy use). REMIND also accounts for technological learning of wind and solar technologies, as well as alternative transport technologies. It is therefore capable of representing path dependencies such as lock-ins into long-lived capital stocks and learning-by-doing. It operates on five-year time steps from 2005 to 2060 and ten-year time steps until 2100.

Non-biomass renewable energies (hydropower, wind, solar PV and CSP) are represented by regional potentials classified into grades differing in capacity factors. Superior grades allow for more full-load hours and are utilized first, which contributes to a gradual expansion of renewables utilization. Variable renewable energies (VREs; wind, PV and to some extent CSP) require storage and grid expansion to guarantee a stable electricity supply. REMIND therefore includes requirements for storage and transmission that increase with rising market share of VREs and incur investment and operation costs. Since these requirements are more characteristic of the power system as a whole than the individual VRE technologies, they are not included in the analysis of EEU and indirect emissions in this study.

IAM scenarios. The Baseline scenario describes welfare-optimal investments in and utilization of energy transformation capacities, and reflects current energy policies (for example, taxes and subsidies) but no explicit climate policies, such as the nationally determined contributions[1]. It projects electricity consumption of 194 EJ in 2050, based on 57% fossil fuel energy carriers, 33% renewables and 10% nuclear. In the 2 °C Policy scenario, a uniform carbon tax of 2005 US$25.5 per tCO_2 in 2020, growing by 5% per annum, is imposed to limit warming to well below 2 °C throughout the twenty-first century. 2050 electricity consumption increases to 210 EJ due to higher electrification (primary energy use is reduced by one-quarter). The share of renewables increases to 66% and that of nuclear to 22%, while the share of fossil fuels (including CCS) declines to 10%. For more details, see Supplementary Note 1.

An important feature of our Policy scenario is the implementation of climate change mitigation across all world regions through a globally uniform carbon tax. This policy assumption reflects internationally concerted efforts as envisaged in the COP21 Paris Agreement[1]. As a result, the main cause for carbon leakage (fragmented climate protection policies between countries that lead to regionally differentiated carbon intensities) is not present in our scenarios.

Embodied energy use coefficients. These are derived from the multi-regional prospective LCA modelling framework THEMIS[10,19] and are subdivided by secondary energy carrier (solids, liquids, gases and electricity) and life-cycle phases (construction, operation and end-of-life) of power-sector technologies on a per-capacity (for example, $GJ_{el}\ MW^{-1}$) or per-production (for example, $GJ_{solids}\ kWh^{-1}$) basis. They also account for different energy mixes in scenarios with and without climate mitigation (see Supplementary Note 3). EEU related to bioenergy production was derived from results on crop yields, land requirements, irrigation water use, and nitrogen and phosphorus fertilizer use of the global land-use allocation model MAgPIE[20], which minimizes costs for the fulfilment of exogenous food, livestock and bioenergy demands, subject to biophysical and socio-economic constraints. Nine different scenarios were assessed, for which the type of biomass used for bioenergy production (traditional rain-fed, traditional and purpose-grown rain-fed, and traditional and purpose-grown irrigated) and the level of CO_2 taxes applied in the agricultural sector (0, 5 or 2005 US$30 per tCO_2 in 2020, increasing exponentially with 5% per annum) were varied. The US$30 scenario reflects consistent pricing of GHG emissions between the land-use and other sectors, whereas the others reflect inconsistent pricing and result in insufficient mitigation activities within the land-use sector. All values were obtained by comparing a scenario with 100 EJ yr^{-1} primary energy production from biomass in 2050 (most of which is used outside the power sector) with one without bioenergy production. The modelling results (weighted means) are based on a scenario of traditional and purpose-grown rain-fed biomass production with a 2005 US$30 per tCO_2 tax in the agricultural sector in 2020, which is consistent with REMIND scenario assumptions.

Emissions. REMIND accounts for residual CO_2 emissions from imperfect capture within coal- and gas-fired CCS plants and negative emissions from BECCS plants, assuming capture rates of 90%. It furthermore endogenously represents upstream CH_4 emissions from coal and gas production and their abatement following the approach of Strefler et al.[40] and Lucas et al.[41].

To derive indirect specific CO_2 emissions from EEU, EEU derived from the LCA methodology was combined with the CO_2 intensities of secondary energy carriers endogenous to REMIND, summed over the technologies' lifetimes and divided by the total electricity produced over the lifetimes. The results in terms of grams of CO_2 per kilowatt hour can be compared with direct CO_2 and other GHG emissions. Since end-of-life energy use is very small compared with that of construction, both figures were combined, which slightly overestimates the GHG emissions of technologies (as carbon intensities decrease over time).

Indirect emissions from EEU were implemented in REMIND using mark-ups on the investment and operation and maintenance (O&M) costs that determine technology use in the model[18]. The price mark-ups were derived by multiplying EEU for construction and operation (either per capacity or per electricity produced) with the CO_2 intensities of energy carriers and the CO_2 price (both model endogenous). They reflect energy used and thus emissions caused during construction and operation and account for the fact that the REMIND parameterization of future investment and operation and maintenance (O&M) costs does not account for likely price increases in CO_2-intensive goods and services such as cement, steel and transportation. Note that this accounting is only financial (averting double-counting of emissions), since the physical emissions of the steel, cement, other industry and transport sectors are already implicitly accounted for in the general equilibrium formulation of the REMIND model.

Emissions from LULUC were used directly from the MAgPIE results[21,22]. As the conversion of areas for agricultural use entails large non-recurring emissions of CO_2, these have been calculated as the quotient of cumulated CO_2 emissions and cumulated bioenergy production. N_2O and CH_4 emissions from land-use change are used directly.

Regional and technology variance. The THEMIS modelling framework considers individual technology variants (with differing demands for embodied energy)[19], where the REMIND model uses only one aggregate technology (for example, solar PV is represented in THEMIS by six different technology variants: polycrystalline silicon, cadmium telluride and copper indium gallium selenide modules, mounted

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either on rooftop or on the ground). Average life-cycle demands are computed on the basis of market shares assumed within THEMIS[19].

The figures for EEU and specific emissions are global averages of capacities installed in 2050; that is, global EEU or emissions over global lifetime electricity production. The ranges across individual life-cycle demands of technology variants, the nine MAgPIE scenarios for biomass production and values for the 11 individual REMIND regions were used as a measure of variance.

Data availability. The data that support the plots within this paper and other findings of this study are available from the corresponding author upon reasonable request.

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Author contributions

M.P. and G.L. designed the research with input from A.A. and E.H. LCA data were provided by A.A. and E.H. Land-use modelling was performed by F.H. and A.P., and A.A. integrated the results into the LCA framework. M.P. performed the IAM scenario modelling and integration of LCA data. M.P. and G.L. wrote the paper with contributions and edits by all authors.

Competing interests

The authors declare no competing financial interests.

Additional information

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