’Bad’ Oil, ’Worse’ Oil and Carbon Misallocation *

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Abstract

Not all barrels of oil are created equal: their extraction varies in both private cost and carbon intensity. Leveraging a comprehensive micro-dataset on world oil fields, alongside detailed estimates of carbon intensities and private extraction costs, this study quantifies the additional emissions and costs from having extracted the ’wrong’ deposits. We do so by comparing historical deposit-level supplies to counterfactuals that factor in pollution costs, while keeping annual global consumption unchanged. Between 1992 and 2018, carbon misallocation amounted to at least 11.00 gigatons of CO_2-equivalent, incurring an environmental cost evaluated at $2.2 trillion (US$ 2018). This translates into a significant supply-side ecological debt for major producers of high-carbon oil. Looking forward, we estimate the gains from making deposit-level extraction socially optimal at about 9.30 gigatons of CO_2-equivalent evaluated at $1.9 trillion along a future aggregate demand pathway coherent with the objective of net-zero emissions in 2050, and document unequal reserve stranding across oil nations.

Keywords: Climate change, oil, carbon mitigation, misallocation, stranded assets.
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1 Introduction

The cost of extracting oil is twofold: the direct expenses borne by producers and the environmental toll from significant greenhouse gas (GHG) emissions released during extraction. These emissions vary dramatically across deposits due to differences in oil types, underlying geology, and extraction methods (Masnadi et al., 2018). For example, producing a barrel of oil from Canadian bitumen releases double the GHGs compared to a barrel from Saudi light crude. To curb global warming to 1.5 or 2° Celsius, a substantial portion of the world's oil reserves must remain untapped (Meinshausen et al., 2009; McGlade and Ekins, 2015; Welsby et al., 2021). This makes the selection of oil fields for extraction a critical decision for reducing emissions in an industry hard to decarbonize (Creutzig et al., 2015; IEA, 2021b) that is a major contributor to global GHG emissions.[1] Despite the longstanding recognition of climate change challenges, post the 1992 Earth Summit, the oil industry's production-related GHG emissions have largely been overlooked (World Bank, 2020). The lack of stringent regulations has led to carbon misallocation in this industry, with dirty oil (e.g., heavy oil) being extracted instead of lower carbon-intensity oil.

This paper is the first to quantify the environmental repercussions of misallocation in the global oil supply. We leverage an extensive dataset of world oil fields, along with detailed assessments of their carbon intensities and private extraction costs, to measure the excess emissions and associated costs from historical oil production since the 1992 Earth Summit benchmarked against the socially-efficient supply structure. Furthermore, we evaluate the potential social benefits of an optimal future supply, in contrast to a climate-ignorant competitive extraction that matches the same aggregate supply path. Overall, we show that supply recomposition can produce large emission reductions at zero or low cost, without altering consumer demand.

Our methodology quantifies past carbon misallocation by comparing the cumulative emissions from the historical oil supply curve with those from a socially optimal counterfactual that minimizes social costs from extraction, yet maintains the same annual global oil output. This approach underscores the environmental benefits of optimizing the oil supply structure, under fixed global production constraints. Specifically, we construct a hypothetical scenario with a socially optimal extraction regime spanning from 1992 to 2060. This scenario aligns annual global production from 1992 to 2018 with observed data and from 2019 to 2060 with levels consistent with achieving net carbon neutrality by 2050, as referenced in IEA (2021b). We then compare this scenario against the historical extraction data up to 2018 and a pro-

[1] In 2021, oil-related emissions represented around 22% of all-sectors world GHG emissions (see https://ourworldindata.org/) and 65% of oil was used in the transportation sector in 2018 (IEA, 2020).

jected future supply (with the same annual global production up to 2060) that we take to be socially optimal. This analysis reveals excess emissions attributable to carbon misallocation from 1992 to 2019, which cannot be offset by optimal extraction practices after 2019.

Key findings reveal that 11.00 gigatons of CO_2-equivalent ($GtCO_2eq$) could have been saved, had we begun restructuring optimally global oil supply in 1992, rather than delaying until 2019. These avoidable emissions are equivalent to two years' worth of the global transportation sector's life-cycle emissions, with an estimated cost of $2.2 trillion (US$ 2018, as in the rest of the paper). This cost assessment is based on a social cost of carbon (SCC) of $200 per ton of CO_2eq in 2018, in line with Lemoine (2021) and Rennert et al. (2022), and consistent with projections aimed at keeping the temperature rise below 2.5°C over the next century (Nordhaus, 2017). Yet, these inefficient emissions are of the same magnitude for a large range of SCC, varying from 7.45 to 12.03 $GtCO_2eq$ as the SCC rises from $50 to $400 per ton of CO_2eq.

Our analysis further demonstrates that an optimal reallocation of oil extraction across various deposits could not only reduce GHG emissions but also lower private extraction costs, addressing both carbon mispricing and other market inefficiencies. Though the historical deposit-level supplies reveal that deposits' carbon heterogeneity was ignored *and* extraction was not cost-effective, we document that inefficient emissions result from carbon mispricing, not from market distortions affecting private cost allocation. Addressing only the misallocation of private costs, by choosing cheaper oil barrels over more expensive ones without considering environmental impacts, would reduce emissions by merely 0.32 to 1.19 $GtCO_2eq$. This highlights a clear distinction between carbon misallocation and the misallocation of private costs. Furthermore, we show that past misallocation in private extraction costs is largely explained by other market distortions such as market power, countries' preferences for domestic production, and production taxes. We still find large environmental gains from removing carbon misallocation when these other market distortions are not corrected. In particular, recomposing past supply without changing countries' observed annual production still yields large emission reductions of about 8.50 $GtCO_2eq$ over the 1992–2018 period, due to significant within-country heterogeneity in carbon intensities.

In a next step, we map countries' supply-side 'ecological debts', i.e., their over-extraction from the comparison of their aggregate historical supply to their optimal supply. We in particular show that Annex B countries, which committed to mitigation targets in the 1997 Kyoto Protocol, over-extracted oil by 46% in the 1992–2018 period, whereas the Rest of the World under-extracted by 21%.

We then evaluate the benefits of future optimal resource extraction against a perfectly competitive supply that overlooks pollution heterogeneity, assuming both future aggregate supplies align with the 2050 carbon neutrality goal (IPCC, 2018; IEA, 2021b). Optimal oil extraction starting in 2019 could prevent 9.30 $GtCO_2eq$. Consequently, without implementing optimal extraction starting in 2019, carbon misallocation—both past and future—could amount to approximately 20.30 $GtCO_2eq$. We finally calculate the stranded oil reserves by country for 2019, the optimal share of their reserves that should remain underground, with figures ranging from 22% in Kuwait to 96% in Canada. Furthermore, we observe that countries' stranded assets in the future tend to be similar in the optimal future supply and the cost-effective supply that ignores heterogeneity in carbon intensities of oil barrels. Overall, limiting country-level production changes still leaves large potential gains from (past or future) supply recomposition, which alleviates feasibility concerns.

Our conservative estimates for the environmental benefits of supply recomposition, both historical and future, assume unchanged extraction technologies and carbon intensities due to data constraints on emission abatement costs at the field level (Malins et al., 2014b). Incorporating the potential for reduced deposit carbon intensities alongside supply recomposition suggests greater overall environmental benefits from climate actions. For example, eliminating gas flaring combined with future supply recomposition could enhance emission reductions by up to 41% compared to scenarios with fixed carbon intensities. Similarly, halving future methane emissions could yield comparable benefits to gas flaring elimination. Taking these additional mitigation opportunities into consideration, carbon mispricing from 1992 to 2060 could be responsible for more than 30 $GtCO_2eq$ of additional emissions, solely from the supply side.

Our findings inform the debate on climate-change mitigation costs, and yield three policy insights. Firstly, as the variation in oil carbon intensity originates in the extraction and refining sectors, any demand-side policy (e.g., fuel tax) or supply-side policy (e.g. extraction quotas), or a mix (Asheim et al., 2019), that treats all crudes similarly misses out on important mitigation opportunities.[2] A second policy recommendation concerns what can still be changed in the future. As the opportunity costs of using low-carbon resources are only small, delaying mitigation is costly. The post-2018 gains from optimal extraction would be almost the same were oil to have been extracted optimally since 1992. Lastly, the inefficiencies from inadequate carbon regulation diverge fundamentally from other inefficiencies like im-

[2]Upstream regulation typically falls outside the jurisdiction of consumer nations, yet efforts to lower fuel life-cycle emissions exist, such as the EU's Fuel Quality Directive aiming for a 6% reduction in automotive fuels' carbon footprint by 2020 from 2010 levels (Malins et al., 2014a). However, this directive standardizes the carbon intensity value across petroleum products, disregarding the carbon heterogeneity of the source. Transport sector mitigation strategies often overlook the potential for oil supply recomposition (Replogle et al., 2013; Vimmerstedt et al., 2015), focusing instead on transitioning to alternative fuels like natural gas or biofuels (Sims et al., 2014), despite significant adjustment costs and opposition from industry lobbyists (Knaus, 2019; Lipton, 2020).

perfect competition. This distinction underlines the critical need for specific environmental regulations that cannot be simply reformulated as pro-competition policies.

This paper is the first to empirically assess inefficiencies in global oil production, factoring in pollution. Environmental concerns are largely absent from the literature on misallocation, with the exception of some recent contributions: Sexton et al. (2018) and Lamp and Samano (2020) examine environmental misallocations in residential solar installations and Correa et al. (2020) in the copper industry. Our methodology is close to Borenstein et al. (2002) and Asker et al. (2019), who relate misallocation in production factors to the underutilization of observed lower-cost production units in a given sector. Our paper builds on the analysis of production misallocation due to market power in the oil industry in Asker et al. (2019). In contrast to their work, we consider an additional source of social inefficiency: heterogeneity in the carbon externality associated with extraction and refining. The only source of inefficiency in observed production in their paper comes from resource-extraction sequencing that does not correspond to Herfindahl 1967's "least-cost first" rule, i.e. extracting the cheapest resource first, as all deposits are eventually exhausted. By way of contrast, many deposits in a carbon-constrained world should be left untapped forever or be only partially exploited, and optimal deposit-selection depends on the trade-off between private and environmental costs.[3] This trade-off is empirically significant. At the fine level of disaggregation of our data, carbon intensities and private extraction costs are not strongly correlated, so the inefficiencies from omitted pollution costs do not mirror private extraction-cost inefficiencies. To compare the magnitude of misallocation due to OPEC market power with that due to carbon mispricing, we compute the total cost of misallocation attributable to OPEC market power as the cost of moving from the optimal supply to the second-best supply obtained under the constraint that each OPEC country maintains the same annual production as observed in the data. This cost amounts to \$1.70 trillion. In comparison, the misallocation cost attributable to carbon mispricing—defined as the cost of moving from the optimal supply to a competitive supply in which pollution is ignored—amounts to \$1.66 trillion.

Our findings contrast with recent theoretical literature (Benchekroun et al., 2020) that has used a two-resource model to show how cartels like OPEC can actually speed up pollution by enabling producers of expensive and dirtier resources to enter the market earlier than they would have under perfect competition. We show that this mechanism is indeed at work

[3]The presence of 'oil abundance' and capacity constraints significantly influences the optimal extraction sequence, deviating from the "least-cost first" principle. Despite extensive theoretical exploration of multiple polluting resource extraction (Chakravorty et al., 2008; Van der Ploeg and Withagen, 2012; Michielsen, 2014; Fischer and Salant, 2017; Coulomb and Henriet, 2018), there is scant research on the characteristics of optimal extraction of various exhaustible resources, differentiated by private extraction costs and pollution levels.

here, but accounts for only a small part of carbon misallocation: switching to the competitive supply brings about an emission reduction that is between 3% and 10% of that of the optimal supply structure over the 1992–2060 period. There is significant pollution heterogeneity in the oil available within (or outside) OPEC, and there are cheap but polluting resources within (or outside) OPEC. This explains why a cost-effective supply brings little environmental gain, so that OPEC market power contributes little to carbon misallocation.[4]

Both Asker et al. (2019) and Benchekroun et al. (2020) relate supply inefficiencies to the wrong sequencing of deposits only: as all deposits are exhausted, there is no selection as to which to use and which to leave. On the contrary, we highlight that, in a carbon-constrained world, selecting deposits to use is key to lower social extraction costs. In our setting, environmental gains only come from changes in deposit-level cumulative productions.

Last, we contribute to the literature on stranded assets. The scientific literature has raised awareness of the issue of unburnable fuels (Meinshausen et al., 2009; McCollum et al., 2014) and their unequal distribution (McGlade and Ekins, 2015; Welsby et al., 2021). Recent research (McGlade and Ekins, 2014; Brandt et al., 2018) has acknowledged that oil carbon-intensity heterogeneity should be accounted for to mitigate future emissions, but does not provide any measure of carbon misallocation. As such, McGlade and Ekins (2014) and Brandt et al. (2018) do not explore the trade-off between private production costs and emission reductions. In contrast, we look at the social cost of extracting from the wrong deposits in the past and the future, and quantify carbon misallocation.

The remainder of this paper is organized as follows. Section 2 describes the oil-deposit data and the measurement of deposits' private extraction costs and carbon intensities. Section 3 presents the construction of optimal supply. Section 4 describes our methodology to quantify carbon misallocation in the past, emission reduction and social gains from past supply recomposition, and presents country carbon debts. Section 5 quantifies emission reductions and social gains from implementing future optimal supply recomposition, and assesses the size of countries' oil stranded assets in various scenarios of future demand and supply structure. Section 6 discusses market distortions that explain that historical supply is not cost-effective, and studies supply recomposition with constraints on production relocation across countries. Section 7 explores the sensitivity of our results to modeling changes, including changes in carbon intensity and private costs estimation. Finally, Section 8 concludes and elaborates on policies to implement field-level supply changes.

[4]Market power is generally viewed positively in terms of resource conservation (Hotelling, 1931; Solow, 1974) and pollution mitigation. This study does not delve into market power's effect on overall supply, maintaining a constant global oil consumption level to assess supply-side misallocation. Additionally, examining OPEC's market power (Hansen and Lindholt, 2008) and its interplay with carbon policies (Andrade de Sá and Daubanes, 2016; Van der Meijden et al., 2018) is beyond the scope of this paper.

2 Oilfield data, extraction costs and carbon intensities

Quantifying the carbon misallocation from the use of 'wrong' deposits (from a climate-wise perspective) first requires estimating field-level carbon intensities and private production costs of those parts of the oil supply chain in which these vary significantly across barrels. Our analysis thus focuses on oil extraction and refining carbon intensities and private extraction costs.[5] This section briefly presents the oilfield data and explains how we calculate field-level private extraction costs, capacity constraints and carbon intensities.

2.1 Oil-deposit data

The Rystad Upstream dataset. Our empirical analysis uses data from the Rystad UCube Database (Rystad Energy, 2022), one of the most comprehensive datasets of oil fields. This covers most of World oil production, with 12,463 active deposits between 1970 and 2018. It includes precise field-level data on oil production, exploitable reserves, discoveries, capital and operational expenditures from exploration to field decommission as well as production taxes, current governance (e.g., ownership and operators), field-development dates (discovery, license, start-up, and production end), oil characteristics (e.g., oil type, density and sulfur content), and reservoir information (e.g., water depth, basin and location). In certain cases, like some offshore oil platforms, a field might refer to a single oil well. However, in the majority of cases, especially for onshore oil fields, a field consists of multiple oil wells. We restrict the fields' sample to oilfields discovered before 2019 and with positive oil proven reserves in 1992.

The Rystad dataset does not contain information on fields' upstream carbon intensities but records the key variables that influence emissions from extraction or refining, such as oil type (e.g., bitumen or light), API gravity, gas-to-oil ratio, sulfur content, and the location of the field offshore or onshore.

Additional data. Two extraction techniques that affect emissions from extraction—methane flaring and steam injection— are not recorded precisely in Rystad. Flaring consists in the burning on-site of the methane that comes with oil. As only a minority of countries and companies collect and publish data on flared gas, this information is missing for nearly 95%

[5] In a nutshell, downstream emissions include mostly combustion-related emissions and transport to the end consumer. Combustion-related emissions are large (an average of 75.82 gCO_2eq/MJ, weighted by 2018 production) but do not vary much by crude origin for a given end-use. Transport emissions to consumers will be affected by the recomposition of supply. However, these emissions are small and do not vary much (see Appendix B.3). Refining and transportation costs to end consumers vary by oil feedstock, but are small relative to the standard deviation of crude extraction costs (see Appendix C.6).

of the fields in Rystad. We complement these data using the geocoded flaring volumes calculated by the Visible Infrared Imaging Radiometer Suite (VIIRS) algorithm from National Oceanic and Atmospheric Administration (NOAA) satellite observations (Earth Observation Group, 2021). Steam injection is a thermal Oil Enhanced Recovery (EOR) technique employed in some fields—mostly those producing heavy oil—to facilitate extraction. Rystad data identify the use of steam injection only for bitumen fields. We add steam-injection data from the International Energy Agency (International Energy Agency, 2018).

Appendix A provides a detailed description of our data.

2.2 Modeling deposit private extraction costs and extraction capacities

In modeling costs, we define a deposit, or a field, as the basic unit of analysis, aligned with the most detailed level of data we have.

Modeling increasing marginal costs. The empirical literature stresses two opposing forces governing the changes in private extraction costs at the field level: while depletion tends to increase marginal private extraction costs, learning-by-doing at the field level tends to reduce them (Brandt, 2011; Leighty and Lin, 2012; Luo and Zhao, 2012; Pashakolaie et al., 2015). In our main specification, we allow marginal private extraction costs to vary with depletion. More precisely, we allow two bins of constant marginal private cost within each field. We introduce a cutoff value, denoted as ψ, representing the percentage of depletion that delineates the boundary between the two bins:

$$c_{dt} = \begin{cases} c_{db_1} \text{ if } R_{dt} > (1-\psi)R_d \\ c_{db_2} \text{ otherwise} \end{cases} \tag{1}$$

Here c_{db_1} and c_{db_2} are the marginal private extraction costs of the first and second bin of deposit d, respectively, R_{dt} denotes its current reserves at time t, and R_d its initial reserves. With this specification, the marginal extraction cost of a field is only determined by the inherent characteristics of the field and of the hydrocarbons, and the current level of remaining reserves. This reflects that extraction methods, field installations and energy needs are largely determined by exogenous factors such as the physical properties of the hydrocarbons (e.g., viscosity and density) and the reservoir geophysical characteristics (e.g., rock porosity and permeability, and reservoir complexity and depth). For instance, oil located in ultra-deep or complex reservoirs is more expensive to extract (IEA, 2008).

We estimate the cutoff value ψ, as outlined in equation (1), along with the marginal private extraction cost for each bin within each field. This is done under the assumption that there is a common cutoff value applicable to all fields, and a uniform cost ratio between the two bins for each field. The expenditures included in our analysis are well and facility capital expenditures, along with operational expenses like selling, general and administrative costs, transportation, and production, as well as royalties, government profit oil, income tax, and operational taxes.

Our results indicate a cutoff value ψ at the point where 75% of a field's reserves have been depleted. At this stage, the marginal cost for the first bin is 87% of the average cost, while the cost for the second bin rises to 129% of the average.

Appendix C describes the data, our main approach to calculate field-level private extraction costs, and the alternative cost measures used in robustness checks.

Modeling annual capacity constraints. The amount of resources extracted annually from a deposit is constrained by its extraction capabilities. The extraction process at the field level typically unfolds in two main stages: an initial steady output phase, known as the plateau, followed by a decline phase. During the decline phase, the extraction rate is limited to a certain percentage of the remaining reserves (Fetkovich, 1980; Robelius, 2007; Höök and Aleklett, 2008; Höök et al., 2014; Jackson and Smith, 2014).

The "plateau" constraint forces a field's production to be below k_d, that we take equal to 2.5% of the field's reserves as of 1970 or to the maximal observed production of the field since 1970 if the latter is larger. The "decline" rate constraint forces a field's extraction rate to be below α_d, that we take equal to 5% of the field's current reserves or to be below the maximal observed extraction rate of the field since 1970 if the latter is larger. More details on the calibration of these constraints are provided in Appendix C.7

2.3 Measuring deposit carbon intensities

Upstream carbon intensity. Before oil extraction starts, GHG emissions are generated from field exploration and the setting up of injecting and extracting wells.[6] After production begins, activities such as well maintenance, oil extraction and surface processing, as well as transport to the refinery inlet, emit greenhouse gases.

Field-level carbon intensities are assumed to be exogenous to carbon policies and time-invariant in our main approach: this reflects the role of exogenous factors, such as oil viscosity and density, in emissions from extraction and refining. Emissions are also linked to extraction techniques, which are largely tied to oil type. For example, lifting heavy oils requires a more intensive use of Enhanced Oil Recovery (EOR) techniques, such as thermal EOR or Gas-

[6] We will use the terms carbon emissions, pollution and CO_2-equivalent (CO_2eq) to refer to GHG emissions, similarly carbon intensity must be understood as GHG intensity. Local (air/water/soil) pollution from oil extraction, transportation and refining is ignored.

EOR. Another example is flaring: methane flaring is typically associated with high carbon intensity, and is partly determined by exogenous factors such as the reservoir's gas-to-oil ratio and the distance to a significant consumer market for natural gas.[7]

We use the *Oil Production Greenhouse Gas Emissions Estimator* (OPGEE) of the Oil-Climate Index (Carnegie Endowment for International Peace) to estimate upstream emissions. We proceed as follows: we first run the OPGEE using data on 958 deposits, formatted to be used as model inputs and publicly available from Masnadi et al. (2018). These represent 54% of 2015 World production. We then match these deposits to those in the Rystad dataset, and select the estimation model that best explains OPGEE carbon intensities using the variables in the Rystad dataset and supplementary sources (IEA and NOAA-VIIRS). The explanatory variables are selected based on the scientific literature (Brandt et al., 2015; Gordon et al., 2015; Masnadi et al., 2018). We find that field upstream carbon intensity varies by oil type (e.g., regular or heavy), the gas-to-oil and flaring-to-oil ratios, and the use of steam injection. Offshore location and operator size also play a role, but to a lesser extent. Finally, we predict the carbon intensities of the remaining fields in the Rystad dataset using this model. Appendix B.1 describes OPGEE, the matching procedure and results, the estimation model and the robustness checks in more detail. To summarize, our sample of carbon intensities comes from direct computation within OPGEE (for those fields that have public information formatted to be used in OPGEE, that represent 54% of the World production in 2015) and from estimated carbon intensities for the rest of the fields.

Midstream carbon intensity. After reaching a refinery, crude oil from different fields is combined and refined into petroleum products, such as gasoline and other fuels. We employ the OCI *Petroleum Refinery Life-Cycle Inventory Model* (PRELIM) to assess midstream carbon intensities that mostly consist of CO_2, CH_4 and N_2O (see Appendix B.2). This engineering-based model requires very detailed information on the physical and chemical properties of oils ("crude assays"). As detailed oil properties are only partially available in Rystad, we proceed as follows. We first run PRELIM with the 149 assays of major oil crudes (from companies, specialized websites and past research) that are publicly available with PRELIM. We associate these crudes to their extraction site using operator and crude names, and location information in Rystad data. We then estimate PRELIM carbon intensities using the Rystad variables related to oil characteristics and known to impact refining carbon intensity: the API gravity index and the sulfur content. These determine the level of

[7]Less flaring could, however, in theory be implemented by operators. Because of data limitations on the field-level costs of abating flaring emissions (Malins et al., 2014b), and the difficulty in relating less flaring to true GHG-emission reductions due to the possibility of an increase in venting,—the direct release of methane into the atmosphere—, accompanying flaring reduction (Farina, 2011; Calel and Mahdavi, 2020), our main specification assumes fixed flaring-to-oil ratios.

processing intensity. Our approach assumes that refineries are fixed,[8] so that heterogeneity in pollution due to installations or country particularities (from local air pollutant regulations, for example) can be ignored. We here focus on those refining emissions that are tied to the nature of the extracted oil, i.e. that could be affected by a change in deposit extraction. Our parsimonious model explains more than half of the total variance in refining carbon intensity. Last, we predict refining carbon intensities for the rest of the crudes/fields in the Rystad dataset.

2.4 Descriptive evidence

This section provides descriptive evidence that: (i) the carbon intensity of oil extraction (and that of crude refining to a lesser extent) differs significantly across deposits; (ii) carbon intensities and private extraction costs are not strongly correlated; and (iii) proven oil reserves exceed climate-wise future demand.

Carbon intensity varies across oil deposits. From our estimation, the average upstream carbon intensity (CI) of oil in 2018 was 10.15 gCO_2eq/MJ, while average midstream carbon intensity was 5.15 gCO_2eq/MJ. The distribution of upstream carbon intensities across deposits has considerable variance: 25% of the upstream CI distribution is under 6.65 gCO_2eq/MJ, 50% under 8.55, and 75% under 10.84. There is less variance in midstream carbon intensity: 25% of the midstream CI distribution is under 4.24 gCO_2eq/MJ, 50% under 4.87, and 75% under 5.19.

The combined extraction-refining carbon intensities of oil barrels extracted since 1992 vary by oil type (Figure 1(a)). Unconventional oil, such as extra-heavy oil, is about twice as polluting as conventional oil, such as light oil. Flaring and steam injection also play a role, and partly explain the large variation in carbon intensity within oil categories. As countries have different kinds of oil, the average carbon intensity of an oil barrel varies by country of extraction (Figure 1(b)): oil extracted in Indonesia, Algeria, and Canada generates about twice as many emissions than the average barrel pumped in Kuwait or Saudi Arabia. There exists significant within-country heterogeneity: for instance, Canada is host to very different types of oils (oil sands, shale oil, conventional oil), whereas some other countries, such as Saudi Arabia or Kuwait, have more homogeneous oil located in only a few fields. OPEC members (the grey bars in the figure) are not a homogeneous group in terms of oil carbon intensity. As is apparent in Figure 1(b), since 1992, polluting oil types have been extracted,

[8] Assuming that refining technologies could change, or new refineries could be set up with the best-in-class climate-wise process, would add another lever of carbon mitigation and bring overall larger emission reductions (Jing et al., 2020). Our approach also assumes that refineries that treat heavy oil can be reconfigured at low cost to refine lighter oil. This aligns with the need of complex configurations for refining heavy oil, which also include units for refining lighter oil. (see e.g., U.S. Energy Information Administration, 2020).

refined and combusted instead of cleaner—and sometimes cheaper—alternatives.

Alternative carbon intensity metrics are available, notably from the International Association of Oil and Gas Producers (IOGP), which presents an average carbon intensity for its member companies. This figure is roughly 2.7 times lower than the estimates provided by the Oil Production Greenhouse Gas Emissions Estimator (OPGEE). Those IOGP estimates are based on self-declared GHG emissions from 38 Oil & Gas companies that cover at best 28% of the world production of hydrocarbons. The disparity between IOGP and OPGEE estimates can be attributed primarily to two factors. Firstly, IOGP estimates relate to a narrower scope of upstream activities. Second, they used reported flaring and methane venting levels that are at odds with estimates computed from satellite imagery (Plant et al., 2022; World Bank, 2023a). After aligning IOGP model boundaries to that of OPGEE and adjusting input data for flaring volume, flaring efficiency and venting emissions, the gap in estimates becomes negligible (see Appendix B.1.1).[9]

Little correlation between carbon intensities and private extraction costs. Private extraction costs vary with oil type (Appendix Figure G3, top panel), which translates into some countries, e.g. Kuwait, having average private extraction costs around three times lower than those in countries with the most expensive oil, e.g. Canada (Appendix Figure G3, bottom panel). These figures are consistent with the rankings based on country of extraction or/and oil types in IEA (2008) and Wood Mackenzie (2019).

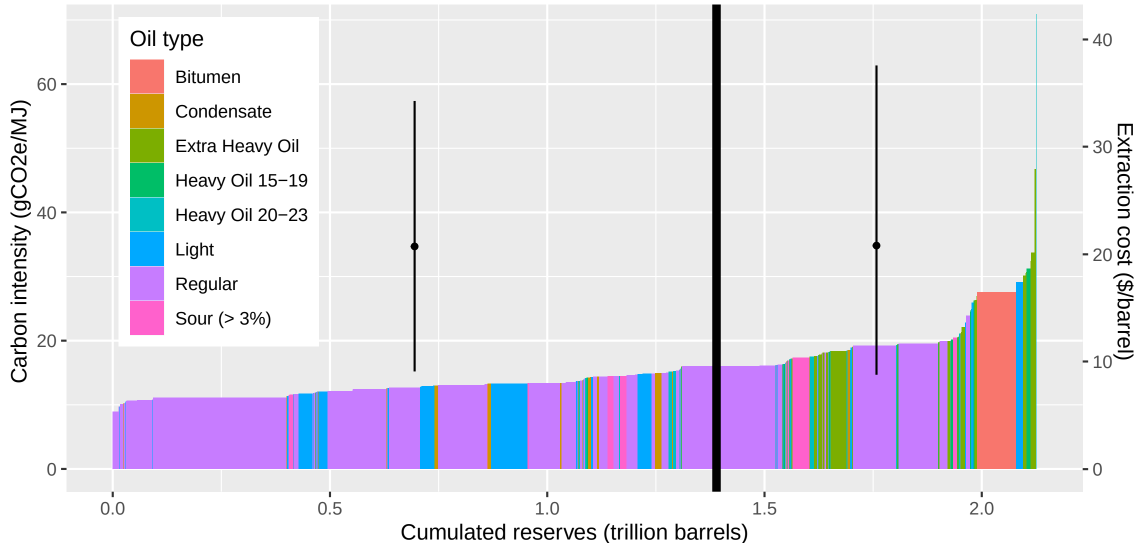
At the fine level of disaggregation of our data, there is only little correlation between carbon intensity and private extraction cost as apparent from Figure 2.[10] We then conjecture that cost-effective carbon mitigation in the oil industry implies a very different extraction path to that under a pro-competition policy that ignores pollution. The reason why carbon intensities and extraction costs are poorly correlated are twofold: first, flaring, venting and land use are important contributors of upstream GHG emissions (about 50% of the upstream emissions according to OPGEE, the rest being mostly emissions related to energy use), and they are not positively correlated to private production costs. Second, GHG emissions related to energy use are more correlated with private extraction costs, yet the correlation is not perfect since the carbon footprint of a given level of energy consumption varies with the

[9]There is also a gap in estimates between OPGEE and those derived from National Emission registries. As those registries are mostly fed with data reported by Oil & Gas firms, adjusting boundaries to include the full upstream emissions and correcting methane leaks and flaring levels to match observed data from satellite reduce most of the gap in estimates. However, in one instance (Norway), OPGEE's figures are still higher than the adjusted estimates from both IOGP and national registries. For the specific case of Norway, we thus conducted a robustness check in which we used carbon intensity figures aligned with the revised estimates from both IOGP and national registries, instead of relying on the initial data from OPGEE.

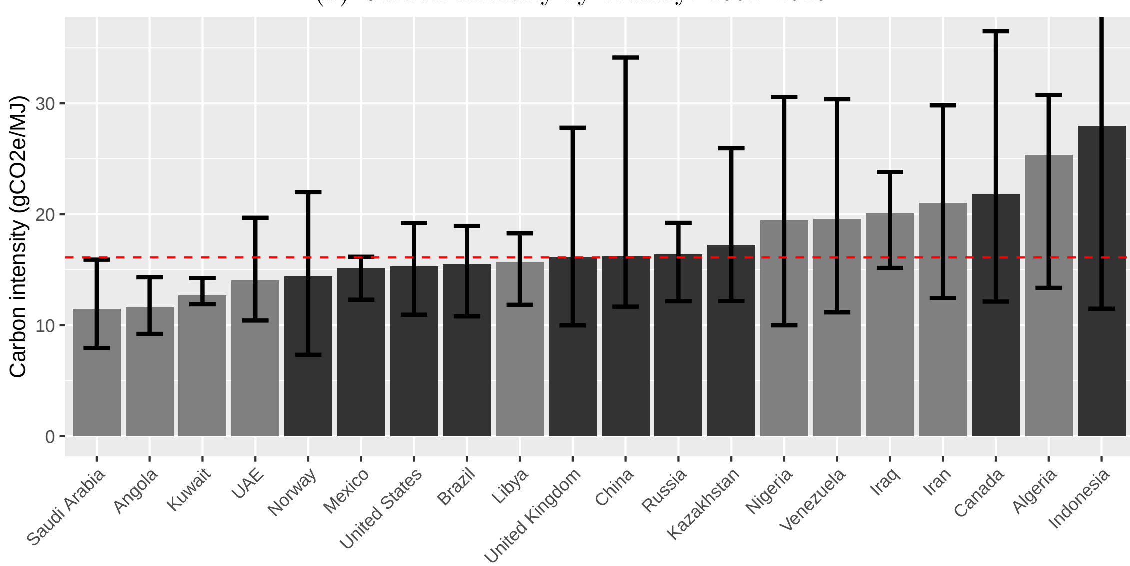
[10]This observation holds also if we narrow our sample of fields to those with a carbon intensity calculated directly in OPGEE (i.e., without relying on our estimation procedure).

Figure 1: Heterogeneity in upstream and midstream carbon intensities.

(a) Carbon-intensity-based oil supply: as of 1992

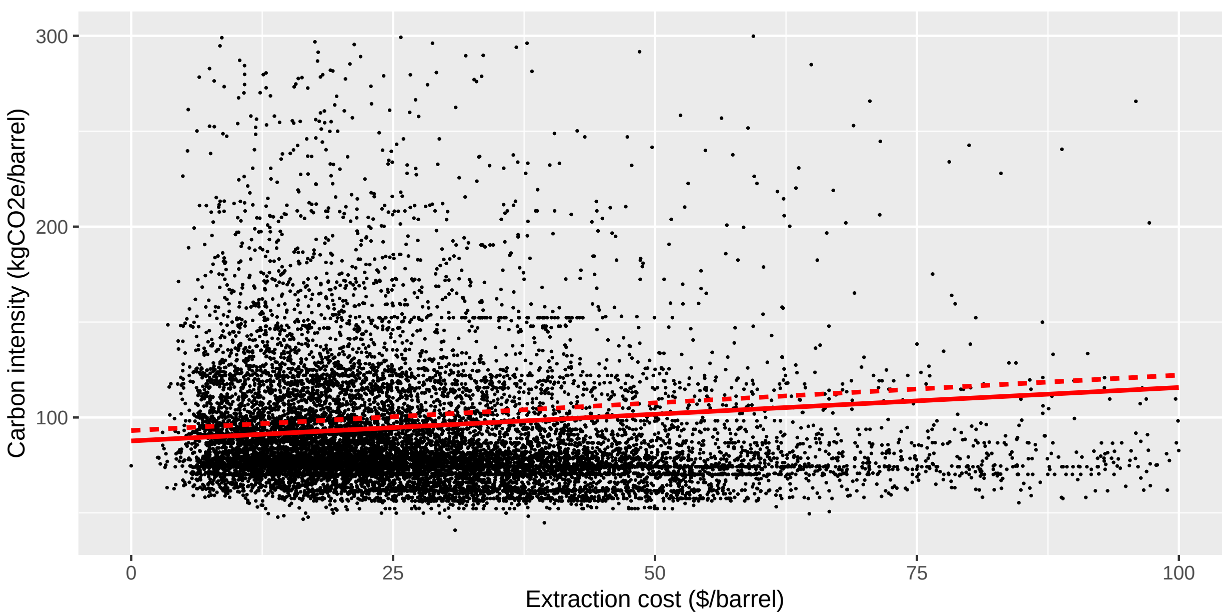


(b) Carbon intensity by country: 1992–2018



Notes: Panel (a) depicts carbon intensities of the available reserves in 1992 (colored bars, left-hand axis), aggregated by oil type and country for visibility, and the average private extraction cost per barrel (dots and lines, right-hand axis) of resources on the left and on the right of the vertical line (aggregate demand). The dots represent the mean private extraction cost per barrel, while the extremities of the lines represent the 10% and 90% deciles. Reserves are resources that are economically and technologically recoverable over the post-1991 extraction sequence using the Rystad definition. Some extra-heavy reserves such as Venezuela and Canada's main reserves are de facto excluded from this figure, as they are not economically recoverable according to Rystad. The vertical line represents the cumulative oil demand to satisfy over the 1992–2060 period. Panel (b) represents the combined extraction-refining carbon intensity per megajoule (MJ) based on observed production over the 1992–2018 period by producing country. The bar height represents the average (weighted by production), and the extremities of the lines the 10% and 90% deciles. Only the top 20 oil producers over the period are represented, and OPEC country carbon intensity bars appear in light grey. The red dashed line corresponds to the World average figure. OPEC, as of 2019, included Algeria, Angola, Congo, Ecuador, Equatorial Guinea, Gabon, Iran, Iraq, Kuwait, Libya, Nigeria, Saudi Arabia, the UAE, Venezuela, and the Neutral Zone shared by Kuwait and Saudi Arabia. Section 2.3 and Appendices B–D provide detailed information on the estimation of carbon intensities, the reserves data, post-1992 demand and the estimation of private costs.

Figure 2: Deposit-level private extraction costs and carbon intensities.



Notes: Each data point is a deposit with positive cumulative production over the 1992–2018 period. The unbroken red line represents the best linear fit when deposits are weighted by their 1992 reserves, and the dashed red line the best linear fit when deposits are weighted by their total production over 1992–2018. The correlation coefficients between carbon intensity and private extraction cost are 0.07 and 0.04 when deposits are weighted by their 1992 reserves and total productions over the period 1992–2018, respectively. Section 2.3 and Appendix B describe the estimation of carbon intensities, and Appendix D the reserves data and the estimation of the private extraction costs. The figure displays the average costs measure, so that one dot represents one field. Fields with either carbon intensities above 300 or private extraction costs above 100 are excluded from the graph for visibility reasons.

type of energy used on site (electricity, oil, gas from in situ sources or imported) and some oil and reservoir characteristics require more capital expenditures per unit of energy use for extraction.[11]

Too much oil. The scientific literature has highlighted that oil assets are too abundant, given the estimated carbon budgets, to curb global warming to 1.5 or 2°C throughout the century (Meinshausen et al., 2009; McCollum et al., 2014; McGlade and Ekins, 2014; Welsby et al., 2021). Using our carbon intensity estimates, extracting, refining and burning all proven reserves of oil (as recorded in Rystad) would generate about 692.5 $GtCO_2$eq, which

[11] To illustrate this lack of correlation, one can examine the two following fields: Canada Hibernia and Canada Cold Lake. Canada Hibernia produces a light, sour oil. The field is located offshore with deep reservoirs of low GOR. It has a private extraction cost of 44.3 $/bbl, and an upstream carbon intensity of 26 $kgCO_2$eq/bbl. Most of upstream emissions are due to venting, fugitive, and flaring emissions. Midstream emissions account for about 25 $kgCO_2$eq/bbl (Medium Conversion). Canada Cold Lake produces an extra-heavy, high-sulfur bitumen. Extraction is located onshore, and resource access is shallow. The private extraction cost amounts to about 32.1 $/bbl, and upstream carbon intensity is 138 $kgCO_2$eq/bbl. Upstream emissions are due to drilling (including land use), production and venting, fugitive and flaring. Production is very polluting since extraction is done using steam injection techniques. Midstream emissions amount to about 63 $kgCO_2$eq/bbl, due to the Deep Conversion process the sour extra-heavy oil requires.

is about 1.5 times the average *total* remaining carbon budget (that encompasses emissions from oil, gas and coal, and land transformation) required to keep the temperature increase below 1.5°C (IEA, 2021b). Figure 1(a) depicts the carbon intensity of remaining recoverable reserves in 1992—the year of the Rio Summit—together with the post-1992 demand to fulfill. These reserves vary significantly in carbon intensity, and a third of them should be left untapped.

Oil abundance in a carbon-constrained world, together with deposit heterogeneity in terms of private extraction costs and carbon intensity, emphasizes the importance of deposit selection and extraction order. Assuming no annual extraction limits and all of the resources available in 1992, a social planner interested only in reducing emissions would extract deposits to the left of the cumulative demand (vertical bar) in Figure 1(a); if only private extraction costs mattered, the preferred supply would chronologically follow a least-cost-first pattern (Appendix Figure G4). With a mixed objective including both pollution costs and private economic costs, the selection of the deposits to exploit depends on the trade-off between private production and environmental costs. Section 3 clarifies this trade-off and the construction of the social planner's preferred counterfactual supply.

3 Building optimal counterfactual supplies

To evaluate potential misallocation associated with a particular oil extraction sequence, it is necessary to begin by outlining the hypothetical optimal supply. In this section, we explain the social-planner optimization program. We initiate our analysis in 1992, the year of the Rio Summit, where participating countries acknowledged the necessity to abate GHG emissions and promote cost-effective ways of doing so. This historical moment, detailed further in Appendix F, serves as our starting point for evaluating misallocations in the oil supply.

The optimal extraction path minimizes the discounted social cost of extraction (that factors in pollution), assuming that baseline annual demands are met.[12] We assume that the social cost of carbon is exogenous to upstream and midstream emission reductions induced by supply recomposition. In most of our analysis, the current value of the marginal carbon cost, denoted by μ_t, increases at the rate of the social discount rate, denoted r. The 2018 cost of a ton of CO_2eq, that we note μ, is then constant over all emission years:

$$\mu_t = \mu e^{r(t-2018)} \text{ for all } t. \tag{2}$$

[12] As our supply recomposition does not come with a change in aggregate supply, the 'optimal counterfactual' is actually the optimal structure of the aggregate supply, and thus represents a second-best.

Environmental costs are only a function of accumulated emissions, and the timing of pollution does not matter.[13] In our main exercise, the social cost of carbon (SCC) in 2018 is set to $\mu =$ \$200 per ton of CO_2eq. This is in line with the SCC in DICE2016R when the temperature increase is kept strictly below 2.5°C over the next 100 years (Nordhaus, 2017). This value of the social cost of carbon is coherent with recent literature (Lemoine, 2021; Rennert et al., 2022) as discussed in Appendix D.5. As deposits have different carbon contents per barrel (θ_d), the carbon cost per barrel ($\theta_d \mu_t$) varies across deposits.

The construction of the (optimal) counterfactual supply is restricted by a number of feasibility constraints. First, a deposit's cumulative extraction is capped by its exogenous reserves. Second, extraction from a deposit can only start after its historical discovery year. We include development lags after a field discovery before production can start as in Arezki et al. (2017); Bornstein et al. (2017). We assume for all oil types, except shale and tight oil, production can only begin after five years post-discovery or the year following first observed production, whichever is earlier. For shale and tight oil, a one-year lag is applied.[14] Third, a deposit's annual production is limited by its extraction capacities, as outlined in Section 2.2.

Let T_0 be the starting date of supply recomposition, T_f the end of the oil era, x_{dt} deposit d's annual production in barrels in year t, θ_d its exogenous carbon content per barrel, c_{dt} its (current value) private extraction cost which is function of the depletion level, k_d its extractive capacities during the plateau phase, α_d its maximal extraction rate during the decline phase, t_d the year the deposit becomes available for extraction ($t_d \leq T_f$), R_{dt} its reserves at the beginning of year t, and D_t the exogenous World oil demand at date t.

[13]The scientific literature shows that temperature increase is proportional to cumulative carbon emissions at a given time horizon, and independent of emission pathways (Allen et al., 2009; Matthews et al., 2009; Meinshausen et al., 2009; Gillett et al., 2013; Stocker, T. and Xie, 2014; Allen, 2016). This evidence serves as a rationale for mitigation targets formulated in terms of carbon budgets (Rogelj et al., 2019).

[14]All fields in our sample have been discovered before 2019, field discoveries realized over the 1992–2018 period are considered as perfectly anticipated in the benchmark specification.

Taking 2018 as the reference year, the social-cost minimization program is then:

$$\mathcal{P}_1(T_0, T_f, \mu_t): \quad \min_{x_{dt}} \quad \sum_{T_0}^{T_f} \sum_d (c_{dt} + \theta_d \mu_t) x_{dt} e^{-r(t-2018)}$$

s.t.

$$\sum_d x_{dt} \geq D_t \text{ for all } t \tag{3}$$

$$\sum_{T_0}^{T_f} x_{dt} \leq R_{dT_0} \text{ for all } d \tag{4}$$

$$0 \leq x_{dt} \leq k_d \text{ for all } t,\, d \tag{5}$$

$$x_{dt} \leq \alpha_d R_{dt} \text{ for all } t,\, d \tag{6}$$

$$x_{dt} = 0 \text{ for all } d,\, t < t_d \tag{7}$$

where (3) ensures that annual demands are met, (4) that the cumulative production of a deposit does not exceed its reserves, (5) that the annual production of a deposit is below its plateau-phase extractive capacities, (6) that the annual production of a deposit is below its decline-phase extractive capacities, (7) that extraction cannot start before the year the field is available for extraction. In the optimal counterfactual, the time path of the social cost of carbon is given by (2). The social discount rate is set to 3%. Private extraction costs c_{dt}, carbon intensities θ_d and reserves R_{dt} are described in Section 2 and Appendices B–D.

The extraction path solution of $\mathcal{P}_1(T_0, T_f, \mu_t)$ is not trivial. We show in Appendix E that the Herfindahl (1967)'s least-cost-first principle of extraction, generalized by Asker et al. (2019) with capacity constraints[15] when all oil deposits end up being exhausted, does not hold in our context where oil is abundant.

4 What is too late: carbon misallocation 1992–2018

In this section, we measure past carbon misallocation. We then quantify countries' over- or under-extraction over the 1992–2018 period. We then separate the social gains from carbon pricing from those that relate to correcting pure private-cost misallocation in the past.

4.1 Measuring past carbon misallocation

Accounting for the dynamics. To measure carbon and private-cost misallocations, we compare the actual supply structure to the counterfactual that factors in deposit pollution

[15] This principle amended to account for exogenous capacity constraints can be formulated as: in any year, using a deposit implies that the capacity or reserve constraints bind for all cheaper deposits that year.

Table 1: Counterfactuals labeling.

	Past: Observed	Past: $\mu_t = 0$	Past: $\mu_t = 200e^{r(t-2018)}$
Future: $\mu_t = 0$	*Cost-effective future* Obs.+ $\mathcal{P}_1(2019, 2060, \mu_t = 0)$	—	—
Future: $\mu_t = 200e^{r(t-2018)}$	***Clean future*** Obs.+ $\mathcal{P}_1(2019, 2060, \mu_t = 200e^{r(t-2018)})$	*Cost-effective past* $\mathcal{P}_1\left(1992, 2060, \mu_t = \begin{cases} 0 & \text{if } t \leq 2018 \\ 200e^{r(t-2018)} & \text{otherwise} \end{cases}\right)$	***Optimum*** $\mathcal{P}_1(1992, 2060, \mu_t = 200e^{r(t-2018)})$

costs, holding total annual consumption constant. Were oil to no longer be used after 2018, this would boil down to comparing the social cost of the observed 1992–2018 production sequence to that of the counterfactual in which this cost is minimized over the same period. However, using low-carbon barrels before 2018 likely incurs an opportunity cost, as these barrels become unavailable for future use. Thus, assessing carbon misallocation must consider the value of preserving reserves for later.

We measure misallocation in this dynamic context by comparing an *Optimum* scenario that represents an ideal extraction pattern over the entire 1992–2060 period, to a baseline composed of actual deposit-level extraction data from 1992 to 2018 followed by a projected optimal path from 2019 to 2060. This baseline scenario is labelled *Clean future* in Table 1. Exogenous annual demands are the same in both the *Clean future* and the *Optimum* over the 1992–2060 period. The pre-2018 annual oil demands are the observed ones. Post-2018 annual demands are consistent with the scenario in which demand falls to reach net carbon neutrality in 2050 from IEA (2021b), in line with IPCC (2018) and European Council (2019).

Past misallocation or gains from early action. The difference between social costs of the *Optimum* counterfactual and the *Clean future* scenario is a measure of past misallocation. In both scenarios, the future supply is optimal, so this comparison reveals the missed opportunities of carbon mitigation. It also represents the social gains from starting optimal extraction in 1992 rather than 2019. These early-action gains are the opportunities we missed *irreversibly* as they cannot be mitigated by post-2018 optimal extraction. They represent a lower bound of misallocation costs over the 1992–2018 period.

Let $\tilde{x}_{dt}$ be the baseline production of deposit d in year t in the *Clean future* scenario, and $\tilde{c}_{dt}$ the corresponding marginal private extraction cost. We denote by x^*_{dt} the optimal production of deposit d in year t in the *Optimum* scenario, and c^*_{dt} the corresponding marginal private extraction cost. The (full) Misallocation Cost ($\mathcal{MC}$) of the baseline over the 1992–

2060 period with environmental damage valued at $\mu_t = \mu e^{r(t-2018)}$, where $\mu = 200$, is:

$$\mathcal{MC} \equiv \underbrace{\sum_{1992}^{2060} \sum_d (\tilde{c}_{dt}\tilde{x}_{dt} - c^*_{dt}x^*_{dt})e^{-r(t-2018)}}_{\text{Private gains}} + \underbrace{\sum_{1992}^{2060} \sum_d \theta_d \mu_t (\tilde{x}_{dt} - x^*_{dt})e^{-r(t-2018)}}_{\text{Environmental gains}} \tag{8}$$

These misallocation costs are equal to the policy gains of suppressing the misallocation: throughout the paper, we will refer either to the misallocation costs of the baseline or the policy gains from supply restructuring.

The corresponding fall in CO_2eq emissions is:

$$\sum_{1992}^{2060} \sum_d \theta_d (\tilde{x}_{dt} - x^*_{dt}) \tag{9}$$

Misallocation channels. The *Optimum* counterfactual supply reduces the social production cost (as compared to the baseline) via two channels. Firstly, changing the total amount of oil extracted from each deposit can lower environmental and private costs. Environmental costs can only be reduced through this channel, since the carbon (discounted) cost per pollution unit remains constant over time in the benchmark analysis. In contrast, the extraction order is a second channel through which private economic costs can be reduced. Even if the total extraction from each deposit remains the same as in the baseline, reorganizing the extraction sequence can lead to economic gains due to discounting.

4.2 Gains from past supply recomposition: results

The results of this exercise, i.e. the social gains and emission reductions from optimal supply recomposition in the past, appear in the first row of Table 2. The first column shows the drop in CO_2eq emissions given in (9), the second column the corresponding environmental gains with emission reductions valued at \$200/tCO_2eq, the third column lists the private gains, and the fourth column shows the total gains given in (8), from both reduced private extraction costs and lower emissions. Starting optimal extraction in 1992 instead of 2019 would have generated emission reductions of 11.00 GtCO_2eq. These environmental gains are economically significant: they are valued at \$2.20 trillion when the social cost of carbon is \$200/tCO_2eq (2018 present value).

One striking result is that implementing the *Optimum* in 1992 produces a lower social cost of \$5.90 trillion relative to the baseline (the last column and first row in Table 2), of which \$3.70 trillion corresponds to a reduction in private extraction costs. The environmental gains come with large private economic gains. Do the lower extraction costs show that clean oil is also the cheapest? That there is little correlation between private extraction costs and carbon intensities for all reserves available in 1992, as can be seen in Figure 2, suggests that this is not so. To demonstrate more rigorously that solving private extraction-cost misallocation alone is not the principal source of environmental gains, we consider another counterfactual that solves only misallocation in private extraction costs in the past, with a future supply that takes into account pollution. To do so, we build a counterfactual in which the discounted social cost extraction is minimized over the entire period (1992–2060) but pollution costs are ignored before 2018. We label this counterfactual *Cost-effective past* in Table 1. We compare the social cost of this new counterfactual to the social cost of the baseline (observed field extraction until 2018 followed by an optimal supply after 2019). If solving private extraction-cost misallocation alone is an important source of environmental gains, we should find that the *Cost-effective past* supply is significantly cleaner than the baseline. The social gains here appear in the second row of Table 2: total costs fall by \$4.24 trillion, of which \$4.18 trillion refer to lower private extraction costs.[16] The corresponding drop in carbon emissions is only 0.32 GtCO$_2$eq, i.e., about 3% of the *Optimum* figure. Overall, carbon misallocation has little to do with private-cost misallocation.[17]

Comparing the social gains in the *Optimum* and the *Cost-effective past* counterfactuals (the first and second lines in the last column of Table 2), the specific social gains from taking pollution into account instead of only minimizing private extraction costs amount to \$1.66 trillion ($= 5.90 - 4.24$), representing emission reduction of 10.68 GtCO$_2$eq ($= 11.00 - 0.32$). This figure represents inefficient emissions due to the absence of carbon pricing in the past.

The order of magnitude stays the same in both exercises, comparing the *Optimum* to the *Cost-effective past* or to the *Clean future*: around 11.00 GtCO$_2$eq could have been saved on the supply side by optimal carbon pricing in the past. How does this compare with what would have been achieved with a similar tax on the demand side? In our analysis, we fix yearly oil consumption to focus on carbon pricing's impact on the allocation across fields of a fixed total oil supply. Introducing a \$200 carbon tax on upstream and midstream emissions would affect oil prices and, therefore, demand. From 1992 to 2018, such a tax could have lifted World average gasoline prices from 9.2% to 20%, with an average increase of 12.4%,

[16]Our results point in the direction of significant misallocation in private costs in observed extraction. In Section 6, we identify some of the distortions in the oil industry behind this misallocation.

[17]The low emission reduction in the *Cost-effective past* scenario partly comes from the assumption that the clean future is expected. This makes profitable to keep cleaner resources for a future use. We can alternatively compute the gains from implementing a cost-effective scenario (that ignores pollution) in 1992 instead of 2019, i.e., comparing a *Cost-effective future* baseline to a counterfactual scenario in which private extraction costs are minimized over the whole time path, absent any carbon pricing. This would bring emission reduction of 1.19 GtCO$_2$eq that represents about 10% of the emission reduction from the optimal supply in the past.

Table 2: Gains from supply recomposition in 1992.

	CO_2eq decrease ($GtCO_2$eq)	Environmental gains (trillion US$)	Private gains (trillion US$)	Total gains (trillion US$)
Optimum	11.00	2.20	3.70	5.90
Cost-effective past	0.32	0.06	4.18	4.24

Notes: Each row refers to a distinct counterfactual supply and the columns *CO_2eq decrease* (in gigatons of CO_2eq), *Environmental gains*, *Private gains* and *Total gains* (in trillions of US Dollars) are calculated relative to the baseline composed of observed field-level productions over the 1992–2018 period followed by an optimal future supply. *Optimum*: the extraction path is optimized over the 1992–2060 period, factoring in pollution costs. *Cost-effective past*: the sum of discounted private extraction costs is minimized over the 1992–2018 period (pollution costs are ignored), anticipating carbon pricing post-2018. Private economic costs used to construct the baseline and counterfactual supplies are exclusive of production taxes. The future aggregate supply is the net-zero in 2050 scenario in both the baseline and in the counterfactuals. See the main text as well as Appendix D.4 for detail, and Table 1 for the labels of counterfactuals. *CO_2eq decrease* is calculated as the difference in cumulative emissions over the 1992–2060 period between between the baseline and the counterfactual of interest. *Environmental gains* are gains associated with CO_2eq emission decrease, each ton of CO_2eq being valued at US$ 200 in 2018. *Private gains* are calculated as the difference in discounted private extraction costs (2018 value) between the baseline and the counterfactual of interest. *Total gains* are the sum of private and environmental gains.

assuming a full pass-through of the carbon tax to retail prices. This, given a demand elasticity of -0.5, might have resulted in a 19 $GtCO_2$eq reduction in oil emissions over this period, translating to a 6.1% decrease in demand.[18] This contrasts with the 11.00 $GtCO_2$eq reduction achieved through optimal supply reallocation alone, without demand reduction or consumer welfare costs. However, achieving full tax pass-through is unlikely. Facing a global carbon tax, OPEC would probably maintain consumer oil prices marginally below clean energy alternatives to remain competitive, as Andrade de Sá and Daubanes (2016) posits, by lowering producer prices instead of altering supply. This strategy is feasible owing to OPEC's minimal marginal production costs, allowing profit reductions without supply changes.[19] Thus, a CO_2 tax might not lessen supply but would affect producer profits, aligning with OPEC's price stabilization objective, corroborated by Pescatori and Nazer (2022).

Additionally, applying the tax to downstream emissions, and presuming total tax pass-through again, could theoretically result in a 31% reduction in total oil demand from 1992 to 2018. This likely overstates the feasible reduction due to anticipated low pass-through rates and pre-existing taxes on downstream emissions in some countries, making an extra $200 per ton of CO2eq tax on these emissions less likely. Nevertheless, it underscores the critical need to not only reorganize supply but also substantially decrease the overall oil consumption.

[18]Gasoline prices derived from World Bank (2023b). Consult Dahl (2012), Labandeira et al. (2017), and Huntington et al. (2019) for gasoline price elasticities.

[19]In our counterfactual scenario with a carbon tax on upstream and midstream emissions, the 99th percentile of tax-included extraction costs (upper bound of black segments in Appendix Figure G1) is below the 99th percentile of observed costs without the tax (upper bound of dark grey segments) annually.

Table 3: Production changes in the Top-15 producing countries.

	Observed production 1992–2018 (% of global production)	Change in production 1992–2018 (% of 1992–2018 baseline production)	
		Optimum	Cost-effective past
Saudi Arabia	14	131	63
Russia	12	-9	8
United States	10	-58	-56
Iran	5	32	74
China	5	-89	-87
Mexico	4	-29	-21
UAE	4	92	44
Canada	4	-78	-75
Venezuela	4	-58	-23
Iraq	3	186	277
Norway	3	-61	-66
Kuwait	3	142	144
Nigeria	3	-64	-44
United Kingdom	2	-97	-89
Brazil	2	-97	-92
OPEC	43	61	54
Annex B	32	-46	-39

Notes: The *Observed production 1992–2018* column shows the share of world cumulative production over the 1992–2018 period for each of the Top-15 oil producers. Column *Change in production 1992–2018: Optimum* lists the change in cumulative production over the 1992–2018 period when production is optimal over the whole 1992–2060 period, compared to the baseline. The baseline is composed of observed field-level productions over the 1992–2018 period followed by an optimal future supply. Column *Change in production 1992–2018: Cost-effective past* shows the change in cumulative production over the 1992–2018 period, when the sum of discounted private extraction costs is minimized over the whole 1992–2018 period (pollution is ignored) and carbon pricing in the future is expected, compared to the baseline. Private economic costs used to construct counterfactuals are exclusive of production taxes. See the notes to Figure 1(b) for the composition of OPEC (as of 2019). See Appendix F for Annex B's composition.

4.3 Country carbon debts: 1992–2018

The environmental gains from the optimal counterfactual come from extracting cleaner oil deposits. Table 3 shows the change in cumulative 1992–2018 production of the main oil producers when pollution starts to be accounted for in 1992 rather than 2019. These changes can be interpreted as their carbon debts or credits as of 2019. Had carbon been priced properly and production been optimal, 78% of the oil that Canada extracted between 1992 and 2018 should have stayed underground. In contrast, Saudi Arabia should have increased its extraction by 131% compared to its actual extraction figure. The Annex B countries, the advanced economies that committed to reduce their emissions in the Kyoto Protocol, over-extracted oil in the past: they should have extracted 46% less oil than they actually did, while the Non-Annex B countries should have extracted 21% more. OPEC as a whole should have extracted 61% more oil, which would have translated into a market share of 69% compared to their historical market share of 43% over the 1992–2018 period.

Starting optimal extraction in 1992 instead of 2019 would have generated emission reductions of 11.00 $GtCO_2eq$, and yielded significant reallocation of production between countries. Now, what if carbon pricing is also not properly implemented from 2019? We compare the *Optimum* to a scenario in which the observed pre-2019 sequence is followed by a cost-effective supply that ignores pollution after 2018 (*Cost-effective future)*: emissions drop by 20.30 $GtCO_2eq$ over the full 1992–2060 period in the *Optimum*. This is much larger that the 11.00 $GtCO_2eq$ drop in emissions obtained from past supply recomposition only and suggests that environmental gains from an optimal allocation of supply are important also in the future.

5 What can still be changed: future supply structure

In this section, we estimate the social gains and emission reductions from starting the optimal supply recomposition in 2019 compared to a cost-effective supply that ignores pollution. We then quantify countries' future oil stranded assets.

5.1 Measuring future carbon misallocation

To quantify carbon misallocation in the future, for a given aggregate demand path, we compare the optimal future supply (*Clean future*) to the counterfactual that minimizes the sum of discounted future private costs but is ignorant of pollution (*Cost-effective future*) that now serves as a baseline. When assessing the gains from supply recomposition starting in

2019, the future annual global demands are kept unchanged across the two counterfactuals.

We consider three alternative pathways for the future aggregate demand. First, we consider post-2018 annual demands consistent with a scenario in which net carbon neutrality is reached in 2050 (*Net-zero in 2050*). This is the same future aggregate demand path as the one used in the previous section to capture opportunity costs in resource use when quantifying past carbon misallocation. This pathway is expected to limit temperature increase to 1.5°C over the century (with a 50% chance) compared to pre-industrial levels. Second, a future pathway coherent with strict carbon neutrality in 2050, in which the demand falls linearly from 2018 to reach zero in 2050 (*Strict-zero in 2050*). Finally, we consider a future aggregate demand coherent with countries' pledges regarding their decarbonization pathways (*Announced Pledges Scenario* from IEA 2021b). This last pathway is expected to limit the increase in temperature to about around 2.1°C (50% chance) above pre-industrial levels by the end of the century. See Appendix D.4 for detail on future demand scenarios.

5.2 Gains from future supply recomposition: results

When considering our benchmark scenario for the future aggregate demand pathway (*Net-zero in 2050*), we find emissions that are 9.30 $GtCO_2$eq lower in the *Clean future* than in the *Cost-effective future* with associated social gains of \$1.24 trillion (first and fourth columns and the first row in Table 4). These results call for three comments. First, factoring pollution costs in when deciding on future oil extraction will bring large environmental gains, valued at \$1.86 trillion, that come with an increased private cost of about \$0.62 trillion. This reflects that reserves as of 2019 are abundant and differ significantly in their private extraction costs and carbon intensities. Second, this reduction of 9.30 $GtCO_2$eq is close to the 9.04 $GtCO_2$eq reduction over the same period (2019–2060) when the *Optimum* is implemented over the entire 1992–2060 period, compared to the *Cost-effective future*. In other words, the correction of carbon misallocation in the past would not preclude the large gains from the recomposition of current and future supply. This reflects that lower-carbon emission oil is relatively abundant. The third, and related, comment is that future emission reductions are much lower than the emissions drop of 20.30 $GtCO_2$eq over the 1992–2060 period from optimal supply recomposition starting in 1992 compared to the *Cost-effective future* scenario, in which the observed sequence pre-2019 is followed by a cost effective-future that ignores pollution after 2018. The opportunity cost of using clean resources in the past is small and does not prevent large gains later on in the extraction sequence. The missed opportunities of carbon mitigation in the past are then truly lost.

Now, considering that the demand, in both the *Cost-effective future* and in the *Clean*

Table 4: Gains from supply recomposition in 2019.

	CO_2eq decrease ($GtCO_2$eq)	Env. gains (trillion US$)	Private gains (trillion US$)	Total gains (trillion US$)
Clean future (Net-zero in 2050)	9.30	1.86	-0.62	1.24
Clean future (Strict-zero in 2050)	6.22	1.24	-0.41	0.83
Clean future (Announced Pledges Scenario)	7.17	1.43	-0.45	0.99

Notes: Each row refers to a distinct scenario of future aggregate supply. See the main text for detail as well as Appendix D.4. *Clean future*: the extraction path is optimized over the future, factoring in pollution costs, and pre-2019 fields' productions are the observed ones. The columns *CO_2eq decrease* (in gigatons of CO_2eq), *Environmental gains*, *Private gains* and *Total gains* (in trillions of US Dollars) are calculated relative to the *Cost-effective future*, in which the future supply minimizes the sum of discounted future private extraction costs, and pre-2019 fields' productions are the observed ones. Private economic costs used to construct the the future supplies are exclusive of production taxes. *CO_2eq decrease* is calculated as the difference in cumulative emissions over the 2019–2060 period between the *Cost-effective future* and the *Clean future*. *Environmental gains* are gains associated with the CO_2eq emission decrease, each ton of CO_2eq being valued at US$ 200 in 2018. *Private gains* are calculated as the difference in discounted private extraction costs (2018 value) between the *Cost-effective future* and the *Clean future*. *Total gains* are the sum of private and environmental gains.

future, follows a linear decrease from 2019 to reach zero in 2050 (*Strict-zero in 2050*), we find emissions that are 6.22 $GtCO_2$eq lower in the *Clean future* with associated social gains of $0.83 trillion: see the first and fourth columns and the second row in Table 4.

Finally, considering that the demand, in both the *Cost-effective future* and in the *Clean future*, follows a pathway coherent with the *Announced Pledges Scenario* in which all major national announcements on country mitigation targets for 2030 and 2050 are assumed to be implemented, we find emissions that are 7.17 $GtCO_2$eq lower in the *Clean future* with social gains of $0.99 trillion: see the first and fourth columns and the third row in Table 4.

There are two elements to increasing the future aggregate demand to satisfy in both the baseline and the counterfactual. First, the greater the demand, the more opportunities there are to improve the baseline. Second, oil abundance is reduced: were oil demand sufficient to exhaust all deposits, supply recomposition could not generate environmental gains. Environmental gains from optimal supply recomposition in the *Net-zero in 2050* aggregate demand scenario are larger than in the *Strict-zero in 2050* pathway (the latter corresponds to a smaller demand): the first effect dominates. Yet, environmental gains with the greater demand of the *Announced Pledges Scenario* are smaller compared to those gains if future demand follows the *Net-zero in 2050* pathway: the second effect here dominates.

We can compare the change in the carbon footprint of the extraction-refining segment of the oil supply coming from supply recomposition to a change in aggregate demand. The cumulative future carbon emissions associated with *Net zero in 2050* are 45% lower than in the *Announced Pledges Scenario* (APS), when considering *Clean future* in both cases. Changing the demand size from the APS to net-zero in 2050 (i.e., closing the "ambition gap") would save 44.2 $GtCO_2$eq in the oil industry. Gains from supply recomposition along net-zero represents about 20% of the expected emission reduction from closing the ambition gap in the oil industry.

Table 5: Countries' stranded reserves (% of 2019 reserves) and 2019 Reserves.

	Net-zero in 2050		Strict-zero in 2050		Announced Pledges Scenario		Reserves (Gb)
	Clean	Cost-effective	Clean	Cost-effective	Clean	Cost-effective	
Saudi Arabia	22	23	36	43	14	14	286
Russia	53	47	73	72	20	16	143
US	56	66	86	96	21	25	190
Iran	57	25	70	48	22	15	90
China	84	90	94	97	35	46	46
Mexico	57	78	84	85	23	27	25
UAE	23	31	40	45	14	15	72
Canada	96	96	98	100	61	47	101
Venezuela	89	88	92	92	34	29	34
Iraq	56	24	71	41	20	16	122
Norway	44	74	63	92	21	30	21
Kuwait	22	21	35	35	14	14	61
Nigeria	83	88	89	92	29	40	26
UK	87	99	98	99	30	55	13
Brazil	77	100	98	100	28	40	62
OPEC	41	33	54	50	18	17	760
Annex B	64	68	84	90	30	28	476
Global	52	52	69	69	23	23	1518

Notes: This table lists the share of the reserves of each of the Top-15 producers over the 1992–2018 period that should stay forever underground (as a % of the observed reserves in 2019) under two supply structures (*Cost-effective future* and *Clean future*) for each of the three future aggregate supply scenarios considered in our analysis. For the description of the different aggregate supply scenarios, see the main text as well as Appendix D.4. For the description of the counterfactuals, see the main text and Table 1. The private economic costs used to construct both the *Clean future* and the *Cost-effective future* are exclusive of production taxes. *Reserves* are the reserves as of the beginning of 2019, recorded in Rystad UCube. See the notes to Figure 1(b) for the composition of OPEC (as of 2019). See Appendix F for Annex B's composition.

5.3 Country stranded assets

Where are the stranded assets in 2019, and how should their breakdown change if pollution is accounted for in 2019? We answer this question considering the three same alternative pathways for the future demand (*Net-zero in 2050*, *Strict-zero in 2050*, *Announced Pledges Scenario*) we used to assess future gains from supply recomposition. For each pathway, we compute the stranded assets in the *Cost-effective future*, i.e., when carbon cost is not factored in but private extraction costs are minimized from 2019 onwards, and the stranded assets in the *Clean future* scenario, i.e., when oil is optimally extracted from 2019 onwards.

A country's stranded assets are expressed as the share of its 2019 recoverable reserves that is left underground under a specific scenario. For each field (discovered before 2019), we compute its 2019 oil reserves as the sum of its future productions up to 2100 based on Rystad business-as-usual (BAU) scenario, as done in the rest of the paper (see Appendices D.1 and D.2). This reserve measure thus excludes resources that are never expected to be economically or technically recoverable. The "stranded assets" can thus be interpreted as the assets that become unburnable due to mitigation policy (here the joint effect of demand drop in the future compared to a BAU and supply recomposition).[20] The last column of

[20]The amount of oil underground exceeds the proven reserves in our analysis. But oil resources not

Table 5 gives the 2019 reserves by country, and global reserves of about 1,518 Gb. Overall, our global reserves estimates are on par with those of the rest of the literature (BP, 2019; IEA, 2019; OPEC, 2019; BGR, 2020; EIA, 2021; Welsby et al., 2021) with an average value of 1,598 Gb, a maximum of 1,790 Gb (BGR, 2020) and a minimum of 1,276 Gb (Welsby et al., 2021).

Assuming the future aggregate demand pathway is the *Net-zero in 2050*, 52% of global oil reserves should stay underground due to the shrinking of future demand. The share of stranded reserves varies greatly across countries. If the future is optimal, the country with the smallest share of stranded assets is Saudi Arabia, with a percentage figure of only 22%, while 96% of Canadian resources are stranded. OPEC has globally a lower share of their reserves stranded than the rest of the Word, in contrast to Annex B countries.[21] The stranded-assets percentage is similar in most countries for the *Clean future* and the *Cost-effective future*. Iran, Iraq, and Norway are exceptions, as they have oil that ranks well in one dimension—private extraction costs or pollution contents—but badly in the other. For instance, Norway has expensive but not very polluting oil: it thus has fewer stranded assets in the optimal scenario than in the competitive scenario. On the contrary, Iran has cheap but polluting oil; it thus has more stranded assets in the optimal future than in the baseline. In the future, optimal taxes that reflect carbon-intensity heterogeneity rather than uniform oil taxation thus tackle important redistribution problems for only a few countries. Overall, there is significant room today for welfare-improving supply recomposition within countries, which partly alleviates political-feasibility issues. We discuss this in more detail in Section 6.

Considering now a smaller future aggregate demand (*Strict-zero in 2050*), 69% of global oil reserves should stay underground. The reduction in demand compared to the *Net-zero in 2050* scenario translates into larger stranded asset shares for all countries in both supply structures. With a larger future demand, coherent with current country decarbonization pledges (*Announced Pledges Scenario*), the share of global stranded reserves falls to 23% and stranded assets are considerably reduced for all countries in both supply structures.

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included in Rystad reserves (not profitable in Rystad business-as-usual scenario) would be unextractable in our counterfactuals if they were included in our analysis. Adding those resources in our analysis would simply affect our measure of stranded assets via change in reserve size. However, as these resources are unburnable under any policy, we do not classify them as "stranded" due to the policy.

[21] Welsby et al. (2021) found that about 58% of 2018 oil reserves should be left untapped to limit global warming to 1.5°C (50% chance), these represent 744 Gb of unburnable oil. This is comparable to the global share of stranded assets of 52% we found in the net-zero in 2050 scenario with 793 Gb of unburnable oil. Appendix Table G8 records reserve estimates and the share of stranded assets per World region from our analysis and from Welsby et al. (2021).

6 Market distortions and feasibility constraints

This section explores feasibility constraints that could make supply recomposition difficult to implement. It also investigates the market failures behind the substantial past misallocation in private costs found in Section 4.

6.1 Constrained past supply recomposition

It can be argued that the environmental gains from the optimal extraction sequence in the past would be difficult to obtain in practice as other sources of misallocation, such as market power, work in the opposite direction, or because countries would refuse to correctly price their domestic emissions were doing so to be to the detriment of their domestic oil industry. The significant private cost misallocation observed in the past also suggests that other distortions or feasibility constraints are inherently present, causing the oil supply to be inefficient even without considering environmental costs.

The second column of Table 3 shows that OPEC's share of global production over the 1992–2018 period in the *Optimum* (past) counterfactual is 61% higher than its observed share over the same period. Would significant emission reduction be achievable without increasing OPEC's market share? We first address this issue in another counterfactual that constrains annual joint production of OPEC to be equal to their historical value over the 1992–2018 period, we then impose annual production in each OPEC member country to be equal to their historical value over the 1992–2018 period.[22] With these exercises, we do not imply that OPEC would have continued producing at their observed level if a carbon tax had been put in place in 1992. These exercises have two objectives. First, we intend to verify that significant carbon mitigation can be achieved, even without increasing OPEC's production over the 1992–2018 period.[23] A second objective is to provide comparable measures of misallocation attributable to OPEC market power and misallocation attributable to carbon mispricing. The results appear in the first two panels of Table 6. Maintaining the annual productions of each OPEC country to their historical values does not prevent significant emission reductions. We find environmental gains of carbon pricing of 9.46 $GtCO_2eq$, valued at \$1.89 trillion. This constraint reduces total gains via increased private extraction costs: the gain in private

[22] We first abstract from market-power considerations after 2018, as some recent literature has argued that OPEC market power has been considerably reduced (Huppmann and Holz, 2012; Berk and Çam, 2020) but we study this possibility later in this section. The current consensus in the academic literature suggests that OPEC tends to act as a non-cooperative oligopoly (see Huppmann and Holz 2015; Okullo and Reynès 2016; Ansari 2017; Behar and Ritz 2017 for studies of OPEC behavior in recent years).

[23] Intuition actually suggests that OPEC reaction to a carbon tax in the past could have been to increase extraction if the organization adopted a limit-pricing strategy and the carbon tax drove out of the market expensive oil from outside OPEC.

extraction costs falls to \$2.31 trillion, compared to \$3.70 trillion without the constraint.[24] Second, the difference between this constrained counterfactual and the optimum, which can be interpreted as the loss from OPEC's market power, is \$1.70 trillion (= 5.90 − 4.20). By way of comparison, the difference between the *Optimum* and the *Cost-effective past* counterfactuals without the OPEC constraint is \$1.66 trillion. This last difference can be interpreted as the social gains from carbon pricing. The gains from removing misallocation caused by each of these two distinct market failures—imperfect competition and carbon misallocation—are of the same magnitude.

Supply recomposition can lead to large welfare changes across countries. Although the winners from optimal supply recomposition could in theory compensate adversely-affected countries, this compensation is politically difficult to establish. Countries may have a preference for domestic production, for job-related, public-finance or energy-security reasons. These preferences may explain part of the private-cost misallocation we identify. Country preferences may pose a problem of feasibility for any ambitious supply reallocation. We thus re-run our main exercise constraining counterfactual annual productions in each country to match observed productions over the 1992–2018 period. The results are shown in the third panel of Table 6. Recomposing supply still produces large social gains and emission reductions. When country-level productions are kept at their observed levels, emission reductions allowed by the recomposition of supply from 1992 instead of 2019 are 8.50 $GtCO_2eq$, to be compared to 11.00 $GtCO_2eq$ when there is no such constraint. Adjusting production within countries only, over the 1992–2018 period, would still have reduced emissions by 8.50 $GtCO_2eq$. This result comes from the fact that countries can host different oil fields with different carbon intensities. Canada, for instance, is host to light oil in offshore conventional reservoirs, light oil in tight oil reservoirs (requiring fracking and horizontal drilling to be lifted up) in Manitoba and Saskatchewan (Bakken formation), and oil sands in Alberta that can be mined for deposits near the surface (about 20% of the deposits) or recovered with in situ technology such as steam injection (CAPP, 2023). Another example is the US, with significant variation in fields' carbon intensities: with heavy and medium oil in California, mostly light oil in tight oil reservoirs in Montana and North Dakota (Bakken formation), and light oil in conventional reservoirs in Texas (EIA, 2016). In contrast to environmental gains, social gains fall by \$2.64 trillion (from 5.90 to 3.26 in Table 2), mainly because of lower private economic gains of about \$2.14 trillion (from 3.70 to 1.56).

Within-country private-cost misallocation therefore accounts for about 42% of total private-extraction-cost misallocation (= 1.56/3.70). This is of the same order of magni-

[24] The discounted profit of the OPEC over the 1992–2018 period increases in the *Optimum* counterfactual, which partly alleviates political feasibility issues.

tude as the estimates in Asker et al. (2019) for the 1970–2014 period, albeit smaller because the periods of analysis and the extraction models are different. While total emission decrease is relatively stable, private economic gains are significantly reduced by the country-specific constraints.[25] This reveals that there is relatively more within-country variation in carbon intensities than in private extraction costs.

Finally, we take into account existing potentially distorting production taxes. We have gathered tax data at the field level from Rystad company since 1992. Rystad analysts collect detailed information on fiscal regimes of each asset of the UCube dataset from governments and Oil & Gas operators. There are 847 distinct fiscal regimes that apply to oil fields. Each fiscal regime provides information on tax bases and rates that relate to four groups of taxes: royalties, government profit oil, OPEX taxes, and income taxes with deductible input costs. These tax data thus include subsidies in the form of tax rebates. These taxation channels can distort producer's supply away from the competitive allocation. Panel (4) of Table 6 records gains from country-constrained counterfactual supplies but with private economic costs augmented of production taxes when constructing counterfactuals.[26] In this approach, our supply recomposition policy can be interpreted as the result of a carbon pricing policy *without* neutralizing the distorsive effects of other pre-existing production taxes. As these taxes are considered as simple transfers between the producers and the social planner, those taxes are not accounted for when computing private economic gains. Environmental gains are robust to that change and amount to 8.17 $GtCO_2$eq. As clear from the second row of Panel (4) of Table 6, private economic gains from the *Cost-effective past* counterfactual amount to only \$0.17 trillion compared to \$4.18 trillion in Table 2: this counterfactual, when taking into account all production taxes in the optimization program and restricting each country's annual productions to their observed values, has a private cost similar to the private cost of the observed path.

Finally, we also consider past supply recomposition assuming country annual productions can depart from their observed values but existing production taxes are maintained.

[25]Private economic gains from the *Cost-effective past* counterfactual, with country annual production fixed in the past, amount to \$2.04 trillion in Table 6, compared to \$4.18 trillion in Table 2. Some alternative anticipated future scenarios could make the actual allocation even more similar to the *Cost-effective past* allocation over the 1992–2018 period: an oil producer's allocation over the 1992–2018 period indeed depends on what they believe will follow after 2018. Gains from the *Cost-effective past* counterfactual, with country annual productions fixed in the past, when anticipated future demand is the pathway "Announced Pledges Scenario" (APS) with a future SCC of 200\$ per ton of CO_2eq, amount to \$1.68 trillion. Thus, the misallocation in private costs from the perspective of a global social planner, estimated at \$4.18 trillion in Table 2, can be mostly (at 60%) explained by market power, country-level distortions and anticipations about the future. The remaining within-country private cost distortions can be attributed to political economy considerations to direct production to specific regions, local taxes, or local risk factors, among other reasons.

[26]In all counterfactuals, total cumulative supply is exogenous since our focus is on supply recomposition and not on the effect of production-based taxes on aggregate supply reduction studied in Ahlvik et al. (2022).

Table 6: Gains from supply recomposition: Fixing country or OPEC annual productions.

	CO_2eq decrease ($GtCO_2$eq)	Environmental gains (trillion US$)	Private gains (trillion US$)	Total gains (trillion US$)
(1) OPEC annual joint productions fixed				
Optimum	10.73	2.15	2.85	5.00
Cost-effective past	-0.20	-0.04	3.26	3.22
(2) OPEC-member annual productions fixed				
Optimum	9.46	1.89	2.31	4.20
Cost-effective past	-0.07	-0.01	2.73	2.72
(3) Country annual productions fixed				
Optimum	8.50	1.70	1.56	3.26
Cost-effective past	-0.07	-0.01	2.04	2.03
(4) Country annual productions fixed: maintaining production taxes				
Optimum	8.17	1.63	-0.28	1.35
Cost-effective past	0.41	0.08	0.17	0.25

Notes: This table shows the results from our main exercises but with additional feasibility constraints. Each line refers to a distinct counterfactual supply. For the description of the different counterfactuals, see the note to Table 2. The future aggregate supply is the net-zero in 2050 scenario in the baseline and in the counterfactuals. See the main text for detail as well as Appendix D.4. There is no constraint on country productions in the future, thus the future is always the *Clean future*. Each sub-panel corresponds to a variation in constraints over country past production in counterfactual supplies: (1), *OPEC annual joint productions fixed*, annual productions of OPEC as a whole are equal to their baseline values over the 1992–2018 period; (2), *OPEC-member annual productions fixed*, annual productions in each OPEC country are equal to their baseline values over the 1992–2018 period. See the notes to Figure 1(b) for the composition of OPEC (as of 2019); (3), *Country annual productions fixed*, the counterfactual production each year over the 1992–2018 period in each country is assumed to be the country's historical production that year; (4), *Country annual productions fixed: maintaining production taxes*, the counterfactual production each year over the 1992–2018 period in each country is assumed to be the country's historical production that year and private costs are augmented of production taxes to construct counterfactual supplies.

Emissions gains are stable, evaluated at 10.27 $GtCO_2$eq (first row of Table 7).[27]

6.2 Constrained future supply recomposition

As noted in Subsection 5.3, when calculating country stranded assets for different future supplies, we observe that the size of the future aggregate demand is what matters the most: for a given aggregate supply, the share of stranded assets of each country tends to be similar in the *Clean future* and the *Cost-effective future*. This points toward an optimistic message: constraining country production in the *Clean future* would bring similar environmental gains as when allowing across-country supply reallocation compared to the cost-effective baseline.

[27]Our tax data may not fully capture local subsidies or export taxes and subsidies. Nonetheless, environmental gains remain significant even when incorporating Rystad production taxes into private costs.

Table 7: Gains from supply recomposition: maintaining production taxes.

	CO_2eq decrease ($GtCO_2$eq)	Environmental gains (trillion US$)	Private gains (trillion US$)	Total gains (trillion US$)
Optimum	10.27	2.06	0.39	2.45
Cost-effective past	0.64	0.13	0.31	0.45
Clean future	9.14	1.83	-0.10	1.72
Clean future: fixed OPEC share	9.04	1.81	-0.31	1.50

Notes: Each row refers to a distinct counterfactual supply. Private economic costs used to construct counterfactual supplies are inclusive of production taxes. See the main text and the notes to Tables 2 and 4 for the description of counterfactuals. *Clean future: fixed OPEC share*: the OPEC's share of global production is each year in the future counterfactual supplies (*Clean future*, *Cost-effective future*) equal to their observed production share in 2018 (the aggregate demand follows the Net-zero in 2050 scenario). See the notes to Figure 1(b) for the composition of OPEC (as of 2019).

But in the *Clean future* counterfactual, 62.6% of World production comes from OPEC countries. This is much higher than OPEC's historical share of World production over the 1992–2018 period (42.8%) or its share in 2018 (42.0%). What are the future gains from supply recomposition if OPEC's future production share is maintained at its observed 2018 share? In Table 7, we build a counterfactual with private economic costs augmented of production taxes and in which OPEC's joint production share in the future remains at its 2018 level (fourth row). This leaves the magnitude of future environmental gains unchanged with emission reduction of 9.04 $GtCO_2$eq.

Abstracting from constraints on country aggregate productions but maintaining existing production taxes, we find that optimal supply recomposition in the future generates emission reduction of 9.14 $GtCO_2$eq (third row of Table 7) similar to benchmark gains of 9.30 $GtCO_2$eq (first row of Table 4).

7 Sensitivity analysis

In this section, we study how emission reductions and social gains from supply recomposition vary after changing our model parameters. More precisely, we reproduce the simulations used to construct Table 7 changing model parameters one by one.

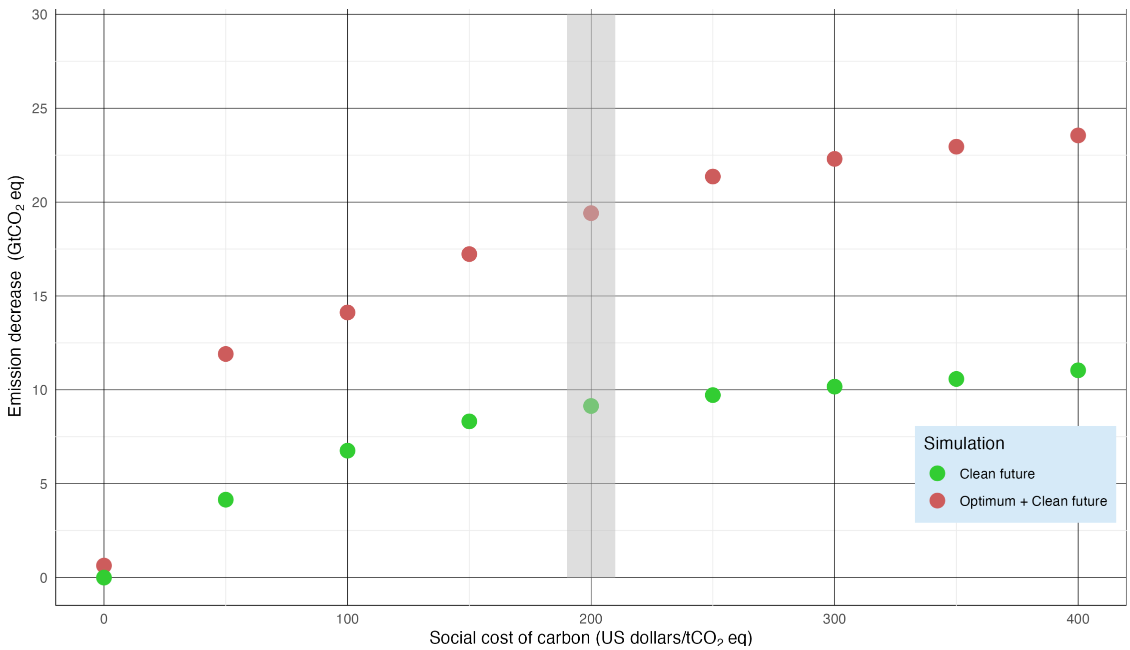
7.1 The social cost of carbon

Figure 3 shows the emission reductions from optimal supply recomposition in the past (i.e. the gains from the *Optimum* scenario compared to the *Clean future*, gaps between red and green dots) and future optimal supply recomposition (i.e., gains from the *Clean future* scenario compared to the *Cost-effective future*, green dots), as a function of the social cost of carbon (SCC). Emission reductions from supply recomposition rise with the SCC, but are very stable over a large SCC range. At $100, the emission reductions from the *Optimum* and the *Clean future* are about 3/4 of those from the main exercise with a \$200 SCC. The misallocation due to the 1992–2018 period, represented by the gap between the red and green dots, is remarkably constant: it varies from 7.76 to 12.51 $GtCO_2$eq as the SCC rises from \$50 to \$400/tCO_2eq. The potential misallocation in the future, represented by green dots, also exhibits some stability: it increases from 4.15 to 11.04 $GtCO_2$eq as the SCC rises from \$50 to \$200/tCO_2eq, but the variation is limited over the SCC range of \$150–400/tCO_2eq; the gains from the *Clean future* increase over that interval from 8.32 to 11.04 $GtCO_2$eq. These results are important, as they indicate that most of the emission reductions in our main analysis would be worth doing even for a SCC figure as low as \$50 and for the whole range of SCC discussed in the literature (see Appendix D.5).[28]

Our main specification considers that the discounted cost of emitting GHG is not time-dependent. The reason for this modelling choice is to be found in the scientific literature that shows that temperature increase is proportional to cumulative carbon emissions at a given time horizon, and independent of the carbon emissions pathways (Allen et al., 2009; Matthews et al., 2009; Meinshausen et al., 2009; Gillett et al., 2013). Our social cost of carbon is thus consistent with a temperature target, corresponding to a carbon budget. However, climate damages are already materializing. These damages appear earlier if emissions happen earlier. It is not only the ultimate total amount of GHG that we emit in the atmosphere that matters but also the time path of the accumulation. In addition, for secondary drivers of climate change with shorter half-life than CO_2, such as methane, the emission pathway matters for temperature increase. For both reasons, emissions that occur now may have a higher social cost, in present value, than future emissions. In a robustness check, we assume that the social cost of carbon (SCC) increases at a rate lower than the discount rate, thus the discounted value of the SCC decreases through time: the timing of pollution then matters and, all things given equal, cleaner resources should be used earlier on. We assume that the current SCC increases at a rate of 1.5%, which gives an annual rate of

[28] In our benchmark specification and across these robustness checks, we use an exogenous value of the social cost of carbon (SCC) i.e. we do not model the feedback emissions reduction in the oil industry could have on the value of the SCC. To determine the potential impact of endogenizing the SCC on our results, we proceed as follows. We utilize the DICE-2016 model (DICE2016R, Matlab implementation by Derek Lemoine, available at https://github.com/dlemoine1/DICE-2016R-Matlab). We begin by adjusting the damage coefficient to set the SCC at \$200/tCO2 in 2020 (2010 dollars in DICE). After establishing this baseline, we account for the reduction in emissions due to supply recomposition by subtracting 11.00 $GtCO_2$ (gains from past supply recomposition) from the emission totals prior to 2018 and distributing a further 9.30 $GtCO_2$ reduction (gains from future supply recomposition) across future periods within DICE by modifying exogenous emissions (such as emissions from land use). We then recalculate the entire model to find the new SCC, which shows a reduction by \$4 in SCC in 2020, translating to a 2% change in the SCC. Given these results and other robustness checks that show that emission reductions are minimally impacted by variations in the SCC within the range of \$50–\$400/tCO2eq, we conclude that making the SCC responsive to emission reductions in the oil sector would have a negligible impact on our findings.

Figure 3: Gains from supply recomposition as a function of the social cost of carbon.



Notes: This figure displays the emission reductions (in $GtCO_2eq$) in the two counterfactuals, *Optimum* (gap between red and green dots) and *Clean future* (green dots), for different values of the social cost of carbon (in 2018 US dollars). See the main text and the notes to Tables 2 and 4 for the description of counterfactuals and the baselines to which they are compared.

variation of the discounted SCC of -1.5% given our 3% discount rate: this corresponds to the dynamics of the discounted SCC in DICE 2016-R3 model when the target is set to keep the global temperature increase below 2°C.[29] Results are displayed in Panel (1) of Appendix Table G1.[30]

Overall, emission reductions from combined past and future supply recompositions do not change much: they amount to 19.32 $GtCO_2eq$ (= 10.88+8.44) when the discounted SCC decreases at a rate of 1.5%, against 19.41 $GtCO_2eq$ (= 10.27 + 9.14) when the discounted SCC is constant. Yet, as the discounted SCC decreases, past carbon misallocation matters more, and the distribution through time of emission reduction is modified: relatively more emission reduction (as a percentage of cumulative emission reduction in the counterfactual) occurs earlier in time when the discounted SCC decreases than when it is constant (see Appendix Figure G5). Furthermore, as the time-varying discounted SCC also impacts the valuation of environmental gains for a given emission pathway and as early emissions cost

[29] In DICE 2016-R3 Model (Nordhaus, 2019), the current social cost of carbon increases from 225 ($2018) in 2015 to 749 ($2018) in 2050 in a scenario that strictly keeps the global temperature increase below 2°C, this corresponds to an annual rate of increase of 3.5%. Since the default discount rate in DICE is 5%, this gives an annual variation of the discounted SCC of -1.5%.

[30] We then consider that the current SCC is constant (Panel 2) or increases at a rate of 2% (Panel 3).

more, past supply recomposition generates more gains than future supply recomposition.

7.2 Other sensitivity analysis

Our sensitivity analysis covers changes in carbon intensity estimates, private costs measures, availability of resource for extraction, extraction capacity constraints, and imperfect substitution between oil crudes. Appendix Tables G2–G7 provide detail on our sensitivity analysis.

Carbon intensities (Appendix Tables G2 and G3) We first consider the possibility that flaring efficiency,—the percentage of natural gas that ends up being totally combusted into CO_2—, may be different than the value of 95% used in the OPGEE model and we use instead values of 91% or 98% to cover the range of estimates found in the literature (Ozumba and Okoro, 2000; Chambers, 2003; Johnson, 2008; Caulton et al., 2014; Gvakharia et al., 2017; Masnadi et al., 2018; Zavala-Araiza et al., 2021; IEA, 2022; Plant et al., 2022). We then change the measure of the flaring-to-oil ratio: we swap our regional-FOR measure for a field-specific measure in both the baseline and the counterfactuals (see the spatial matching procedure described in Appendix A.2). We then consider the possibility that flaring can be fully or partially (50%) reduced together with supply recomposition at no cost, or that methane emissions can be halved with supply recomposition at no cost coherent with recent estimation on methane abatement (IEA, 2021a; Clausing et al., 2023). In another robustness check, we scale up by a constant factor (either 1.5 or 2) venting and fugitive emissions per barrel in both the counterfactuals and the baseline to capture the possible underestimation of VF emissions in OPGEE. We then allow carbon intensity to vary with field depletion building on evidence by Masnadi and Brandt (2017). In another robustness check, we take into account that some gas is often lifted together with oil and may be sold on the market, displacing gas production elsewhere. The OPGEE model was run with the Co-Product Displacement approach (CPD), in which gas sold from an oil field produces emission credits that are deducted from the field's total CO_2eq emissions.[31] Finally, we check that our main results are robust to changes in emission scopes, more precisely to either dropping the part of emissions related to refining, or to adding downstream emissions to midstream and upstream emissions.

Private extraction costs (Appendix Table G4) We first use a finer measure of the private-cost sensitivity to depletion and approximate the relationship between cumulative

[31] The rationale here is that producing a similar amount of gas elsewhere would have emitted Greenhouse Gases. Carbon intensities using the CPD approach are similar to the main figures (Appendix Figure B1). In addition, we have checked that oil-supply recomposition would have had a negligible impact on the natural gas market with a small increase of 0.6% of the global natural gas supply (coming from gas and oil fields) over the 1992–2018 period.

private extraction costs and depletion by a piece-wise linear function with two breakpoints instead of one. Then, we use an average cost measure that ignores the cost sensitivity to depletion. We then recalculate average costs excluding all productions and costs before the optimization starting date (year 1992). We then use the Levelized cost of energy (LCOE). We further consider extraction costs that vary from year to year which allows us to account for changes in extraction inputs' costs. Finally, using our benchmark cost measure, we reduce the discount rate used to construct counterfactual supplies and value private gains, from 3% to 1.5%, which lowers the overall gains from the *Optimum* counterfactual, via smaller economic gains.

Resource availability (Appendix Table G5) First, we treat fields' discoveries over the 1992–2018 period as exogenous surprises. We then change our resource availability constraint and simply assume that extraction cannot start before the first production year recorded by Rystad. This robustness check allows to account for the fact that extraction from a field might be constrained by technologies' availability even after the field discovery. We then relax the resource availability constraint, and assume that all resources discovered after 1992 were available starting in 1992. This change reflects the situation in which resource exploration is sufficiently efficient to respond (at no cost) to the society needs and make resources discovered after 1992 immediately available when needed. Though our reserves' estimates are aligned with estimates or proven reserves from the literature (BP, 2019; IEA, 2019; OPEC, 2019; BGR, 2020; EIA, 2021), in a robustness check, we verify the robustness of our findings to a 10%-reduction and a 25%-reduction of each field's initial reserves.

Extraction capacities (Appendix Table G6) First, we drop the constraint associated to (5): a field capacity is strictly declining from the beginning of the field life, the extraction rate is below 5% of current reserves, or below the historical maximal extraction-to-current-reserves ratio if the latter is larger. Second, we consider the case where the extractive capacities are constant (we drop the constraint associated to (6)): the extraction rate is below 2.5% of 1970 reserves, or below the historical maximal extraction rate if the latter is larger. Then, we assume that extraction capacities are 1.5 times larger than benchmark extraction capacities. Finally, we assume that extraction capacities are 1.5 times larger only for OPEC countries to account for the fact that OPEC have actually spare capacities.

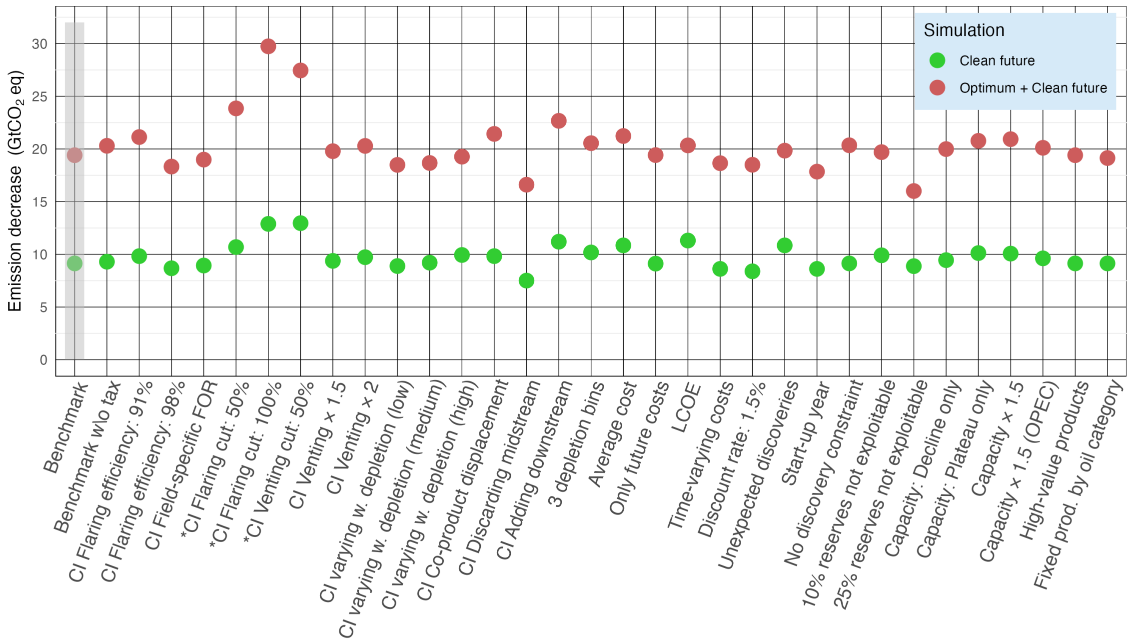
Imperfect substitution between oils (Appendix Table G7) First, we impose that the annual productions of each of the three high-value petroleum products (gasoline, diesel, jet fuel) cannot be smaller than their observed values while fixing product slates of each crude. Second, we split oil into two categories: the first consists of only light and regular oil, the second of all other types of oil resources. We constrain the past annual production of each of these two categories in the counterfactual to be the same as in the observed.

Summary Overall, our results are robust to these changes as apparent from Figure 4. Across all robustness checks presented in this section, optimal emission reductions over the 1992–2018 period lie between 7.13 (when 25% of reserves are not recoverable) and 16.85 GtCO_2eq (when flaring emissions are reduced to zero[32]). Future emission reductions from optimal supply recomposition lay between 7.34 (when the current social cost is constant) and 12.96 GtCO_2eq (when venting emissions are halved[33]).

[32] These gains come from supply recomposition and flaring reduction. Yet, the gains from supply recomposition alone are reduced to 5.59 GtCO_2eq when assuming a simultaneous 100%-decrease in flaring at no cost in the counterfactual supply only.

[33] These gains come from supply recomposition and venting reduction. Yet, the gains from future supply recomposition alone are reduced to 8.42 GtCO_2eq when assuming a simultaneous 50%-decrease in venting at no cost in the optimal future alone.

Figure 4: Gains from supply recomposition: other sensitivity analysis.



Notes: This figure displays the emission reductions (in $GtCO_2eq$) in the two counterfactuals, *Optimum* (gap between red and green dots) and *Clean future* (green dots), for each robustness check presented in Section 7. See the main text and Appendix Tables G2–G7 for a description of robustness checks. See the main text and the notes to Tables 2 and 4 for the description of counterfactuals and the baseline to which they are compared. Private costs are computed inclusive of production taxes to construct counterfactual supplies. *For "Flaring cut: 50%", "Flaring cut: 100%" and "Venting cut: 50%", environmental gains represent the combined gains that come from supply recomposition and flaring or venting cuts in counterfactual supplies. The gains from supply recomposition alone are reduced when assuming a simultaneous decrease in CI in the counterfactual supply only: gains from supply recomposition in the past account for 7.33 $GtCO_2eq$ and 5.59 $GtCO_2eq$ in the case of a 50%- and 100%-decrease in flaring at no cost, respectively. Gains from supply recomposition in the future account for 7.63 $GtCO_2eq$ and 6.80 $GtCO_2eq$ for future supply in the case of a 50%- and 100%-decrease in flaring at no cost, respectively. Gains from supply recomposition in the past account for 9.56 $GtCO_2eq$ in the case of a 50%-decrease in venting at no cost. Gains from supply recomposition in the future account for 8.42 $GtCO_2eq$ for future supply in the case of a 50%-decrease in venting at no cost. For "No discovery constraint", "Fixed production by Oil category" and "High-value products", emission reduction from the *Clean future* does not change compared to the benchmark.

8 Conclusions

In exploring a supply-side approach to carbon emission mitigation in the oil industry, this paper argues for the substantial environmental benefits of prioritizing lower-carbon intensity deposits. Emission gains from past and future supply recomposition are economically significant as compared to global Greenhouse gas emissions or to the remaining global carbon budget, or if translated into environmental costs. They represent about a third of all anthropic GHG emissions in 2019 and about 4.4% in our conservative approach (6.5% when flaring eradication is also implemented, and even more allowing for additional mitigation options such as venting cuts) of the remaining all-sector carbon budget of the net-zero emission in 2050 pathway (IEA, 2021b), estimated at 460 $GtCO_2$. The cost of past and future carbon misallocation is evaluated at \$4.06 trillion using a social cost of carbon of \$200/tCO_2eq.

Our approach that consists in optimizing the supply structure, without changing the aggregate supply level, contrasts with current policies that mostly aim to reduce aggregate oil consumption and supply. These policies are necessary given the scale of emissions to abate to reach carbon neutrality in 2050, and a mix of supply-side and demand-side constraints can ensure an effective decrease in global use despite the existence of free riders, as advocated in Asheim et al. (2019). Yet, they significantly reduce consumer surplus, as the low price-elasticity of transport demand is compounded by the scarcity of clean substitutes for oil in this sector. Reducing the demand size from the *Announced Pledges Scenario* to net-zero in 2050 would save 44.2 $GtCO_2$eq in the upstream and midstream industry, and around 220 $GtCO_2$eq if downstream emissions are also taken into account. Supply recomposition over the 1992–2060 thus represents around 10% (and 15% when gas flaring abatement is eradicated in addition to supply recomposition) of the effort needed to "close the ambition gap" in oil consumption.

We have shown that recomposing supply while constraining the changes in some countries' productions in the past still leaves large potential gains from supply recomposition. Similarly, we find that countries' aggregate supplies tend to be similar in the optimal future supply and in the alternative cost-effective future supply. This partly alleviates political-feasibility concerns regarding changes in deposit-level supplies.

Which policy instruments should be used to attain the recommended deposit-level supplies? A tax in the past chosen over a relatively-large range would have led to emission reductions in the past of the same order. A modest tax could also generate significant emission reductions in the future. The existence of relatively low-carbon emitting resources that are also cheap to extract implies that even a small tax in the \$50–100 range leads to significant emission reductions. However, an effective tax might actually be larger than the true carbon price to account for the ability of oil producers to sacrifice some rent and absorb part of the tax (Heal and Schlenker, 2019). The reaction of OPEC to a global carbon tax is of particular importance to assess its effectiveness. Carbon pricing may raise opposition: for instance, some countries may refuse to implement carbon pricing in order to carry on extracting dirty domestic resources. The current state of carbon pricing initiatives indeed shows that major oil producers are still not properly pricing oil emissions (World Bank 2020). Consumer countries from a 'Green' coalition could set border carbon adjustments (McLure, 2014) or simply ban imports of high-carbon oil barrels from non-cooperative countries. Attempts from consumer countries such as the initial draft of the EU's Fuel Quality Directive or the California Low Carbon Fuel Standard should be promoted.

To durably prevent any country from consuming dirty oil, the 'Green' coalition could also buy deposits in a supply-side policy *à la* Harstad (2012). Taking this approach, can we find a simple rule to lower emissions as in the optimal supply? Buying all of the deposits of bitumen, extra-heavy or heavy oils, and deposits in the top 21% of the flaring-to-oil ratio distribution in 1992 to prevent their exploitation, and then extracting the other deposits in a cost-effective way without any further pollution consideration would have generated the same emission reduction as over the optimal path (about 20.30 $GtCO_2eq$ over the 1992–2060 period). This is, however, significantly costlier than the optimal policy, as it reduces the associated private economic gains by \$4.81 trillion as compared to the unconstrained optimal supply path, corresponding to an additional cost of \$236 per avoided ton of CO_2eq.

Reducing the oil industry's carbon footprint draws parallels with successful past policies, like the US's desulfurization of coal under the 1990 Acid Rain Program. This program introduced a cap-and-trade system to cut SO_2 emissions from fossil fuel-fired units, achieving significant emission reductions at low cost and without detriment to power generation (Stavins et al., 2012). Notably, switching to low-sulfur coal accounted for about half of the total mitigation in the early years of the system (Burtraw, 2000), directly relating to the oil supply recomposition advocated in this paper. Additionally, SO_2 abatement through installing scrubbers for SO_2 mirrors potential reductions in the oil sector's carbon intensity, for example, by minimizing gas flaring and methane leaks. Our analysis indicates that such within-field reductions could increase future emission reductions by up to 41%, though the cost of these technological measures in each field is complex to assess.

9 Data Availability Statement

Some of the data underlying this article were provided by Rystad under permission and cannot be shared publicly. The remaining data and the code used in this research are available on Zenodo at https://dx.doi.org/10.5281/zenodo.13759560.

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