Quantifying supply-side climate policies

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Abstract

What are the effects of supply-side climate policies in the oil market? We use global company-level data to estimate the impact of 84 reforms of production taxes between 2000 and 2019 on oil production, exploration, and discoveries. We find that higher taxes primarily reduce companies' exploration expenditures and oil discoveries, and also reduce short-term production of unconventional oil. We then quantify the implications for the oil market using a short- and medium-term dynamic model over the period 2020–2100. Imposing a global climate royalty surcharge of 20 percentage points on oil producers reduces average annual emissions from oil by 5–7 percent in the first five years, and 9–20 percent in the medium term. If only OECD countries adopt this policy, 47–73 percent of the total emission reductions would be offset by increased production in non-OECD countries in the medium term.

Keywords: oil taxation, climate change, supply-side climate policies
JEL codes: E22; H23; L71

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1 Introduction

"A carbon tax on fossil fuel consumption" is economists' traditional response to climate change. Amid insufficient implementation, however, theoretical research has started to make the case for limiting fossil fuel *production* (Harstad, 2012; Asheim *et al.*, 2019). While this idea is gaining traction among policy makers, empirical evidence on the effects of supply-side policies remains limited.[1] This paper addresses this gap by examining three key questions. First, how do oil companies respond to supply-side taxes? Second, what is the effect of these taxes on global CO_2 emissions, given our estimates of individual company responses? Third, what are the distributional effects of the policy across consumers, producers, and governments?

We address these questions using a comprehensive global data set, where we observe oil production, exploration, discoveries, and the estimated extraction costs at the company- and asset-level during the period 2000-2019.[2] Our starting point is the observation that policies incentivizing less oil production are already widespread, as more than sixty countries tax their oil activities with production-based taxes, which are levied on gross production or gross income. Using data on historical petroleum tax reforms across essentially all oil producing countries, we can study the effects of supply-side taxes on oil production, exploration, and discoveries. We employ event studies and a difference-in-differences research design, leveraging the fact that we observe the same companies operating in multiple countries and hence receiving different tax treatments. To quantify the effects at the market level, we combine our estimated supply elasticities with field-level extraction costs, calibrate field-size specific production profiles, and use a range of demand elasticities from the literature. Specifically, we consider the impact of taxes on oil-embedded CO_2-emissions, tax revenue, producer surplus, and consumer surplus.

Our main finding is that companies respond to production-based taxes primarily by reducing oil exploration. A one-percentage-point increase in the tax rate decreases exploration by 2.6%, and

authors gratefully acknowledge support from the Research Council of Norway [Grant no. 331644].

[1] In 2021, a growing group of governments, including Denmark, Greenland, Spain and Ireland, followed earlier moves by Costa Rica, France, Belize and New Zealand to curb or ban new oil and gas exploration licenses. These countries later joined the *Beyond Oil and Gas Alliance*, launched by Denmark and Costa Rica in November 2021, whose core members pledge to halt new licenses for oil and gas and to phase out extraction in line with climate goals (BOGA, 2025). By contrast, the *Net-Zero Producers Forum*, launched in April 2021, brings together Canada, Norway, Qatar, Saudi Arabia, the United States and the United Arab Emirates and focuses on cutting production-related emissions but makes no commitments to restrict production (US DOE, 2021). Beyond these coalitions, individual countries are also considering supply-side tools; for example, Senate Finance Committee Democrats floated a fee on the carbon content of domestic fossil fuel production in 2021 (Axios, 2021). IPCC recognizes the effects of a supply-side coalition as a knowledge gap (IPCC, 2022, WG III Ch. 1, p. 62): "Literature on the potential for supply-side agreements, in which producers agree to restrict the supply of fossil fuels [...] is limited but gaining increasing academic attention".

[2] This study focuses exclusively on the oil market, deliberately abstracting from natural gas. While oil and gas are closely related in production, oil is considerably more important for global emissions, and their distribution and market structures are very different. Natural gas largely depends on semi-connected physical pipeline networks

we estimate an elasticity of exploration with respect to the after-tax oil price of 1.96. By comparing international companies' operations across country borders, we find no evidence that these effects are driven by companies shifting their activity between countries. The decreased exploration also leads to fewer discoveries, and hence a lower future production capacity. For existing wells, we find no effect on aggregate oil production over our sample period, consistent with the insights from Anderson *et al.* (2018) that oil companies flexibly choose when to drill, but that production from existing wells is governed by production constraints. This average, however, hides an important asymmetry. While the null result holds for conventional oil fields, when restricting the sample to unconventional deposits such as shale oil, we find a similar effect of taxes on exploration, and also a production response. Finally, we find no evidence that the extraction costs of new fields are affected by taxes, suggesting that firms, at the margin, do not direct their search to the lowest-cost deposits.

Our estimates of company behavior imply that the existing fiscal taxes constitute an *indirect* climate policy on oil production, which already limits the amount of oil discovered through its effects on exploration. This indirect policy corresponds to an average carbon price of \$32 per ton of CO_2 (tCO_2) at our benchmark oil price of \$65 per barrel.[3] Notably, this figure is an order of magnitude larger than typical demand-side carbon prices.[4] Our quantification suggests that the current production-based taxes already restrict emissions: if all tax rates were to be reduced by one percentage point, the cumulative emissions would increase by 3.2-6.8 gigatons of CO_2 ($GtCO_2$) by the end of the century, where the range reflects demand elasticity of -0.2 to -0.5. This increase is 22-47 percent of today's annual emissions from oil use, relative to maintaining taxes at their present levels. Correspondingly, the global oil price would also be lower.

In addition to highlighting the climate impact of existing oil taxes, our quantification allows us to analyze a hypothetical supply-side policy: a *climate royalty surcharge* levied on oil production. We compare outcomes under the status quo with two hypothetical scenarios: a global tax versus a

for distribution, giving rise to both regional price dynamics and additional layers of political complexities (Gallea *et al.*, 2022). Our data cover more than 98% of the global oil production. Extraction cost refers to the breakeven price at which the net present value of developing a field is zero. By this definition, ignoring all taxes other than a production tax, developing a field is profitable to a company if the after-tax price exceeds the extraction cost. An asset refers to a license, a field or a discovery.

[3]Given a base oil price, focusing on downstream (consumption) emissions and assuming constant CO_2 content, an ad valorem royalty can be recast as an indirect CO_2 tax on downstream emissions (see Prest and Stock, 2023). The average production-weighted royalty in our sample is 21%. Assuming an oil price of \$65/bbl and a CO_2 content of $0.43tCO_2$/bbl (EPA, 2021), we arrive at the CO_2 price as follows: $0.21 \times (\$65/\text{bbl})/(0.43tCO_2/\text{bbl}) \approx \$32/tCO_2$. Note that these figures account only for emissions from oil combustion, excluding emissions from the production process itself (i.e., well-to-refinery greenhouse gas emissions). A true Pigouvian CO_2 tax would also include upstream emissions and differentiate across fields based on their production carbon intensity (Masnadi *et al.*, 2018; Coulomb *et al.*, 2026).

[4]The average demand-side carbon price is currently at \$3.1/tCO_2. This number is a weighted average from the World Bank Carbon Pricing Dashboard, including zeros for unpriced emissions, viewed on January 18, 2022 (World Bank, 2022). The existing demand-side tax initiatives vary between \$0.1–\$137/tCO_2 and 78.5% of global

tax that is adopted only by the OECD countries. We find that, in the short term (first five years), a global climate royalty surcharge of 20 percentage points reduces emissions embedded in oil by 0.7–1.0 $GtCO_2$, which represents a 5-7% reduction. By the end of the century, the effect grows to 1.2–2.6 $GtCO_2$ per year, a 9-20% reduction compared to the baseline without new climate policies. The cumulative effect is 85-161 $GtCO_2$ by the end of the century, or 1.0-2.0 $GtCO_2$ per year on average, corresponding to 7-14% relative to today's emissions from oil. Such coordinated action implicitly allows producers to exert market power, increasing the oil price by $8-14/bbl initially, and by $23-27/bbl by the end of the century. The higher oil price and increased taxes implicitly transfer surplus from consumers and producers to governments.

The climate impact of supply-side policies depends on how broadly they are adopted. When the supply-side climate policy is implemented exclusively by a coalition of OECD countries, the resulting reduction in unconventional supply raises the short-term oil price by $7-11/bbl and by $14-16/bbl toward the end of the century, around half the increase under a global coalition. The higher oil price increases production of unconventional oil in the non-OECD countries, where the policy is not in effect, resulting in an offsetting production increase – or "carbon leakage" – which amounts to 16-37% in the short term. The high oil price also incentivizes more exploration, discoveries, and development of oil fields in the non-OECD, increasing carbon leakage to 58-82% by the end of the century. These ranges correspond to demand elasticities of –0.2 and –0.5, with higher elasticity implying lower leakage rates. The resulting cumulative emission reductions are around two thirds of those under the global tax scenario, amounting to 54-107 $GtCO_2$, or 0.7-1.3 $GtCO_2$ per year, which in turn corresponds to 47-73% of the OECD emission reduction due to production increasing elsewhere. In this scenario, all consumers and producers in the OECD countries lose surplus, and non-OECD producers and governments everywhere gain.

Note that our modeled climate effects may be conservative. Perhaps most importantly, our analysis omits upstream emissions and natural gas. We also abstract from long-term dynamics such as consumers' greater ability to develop substitutes in response to rising prices, as well as strategic behavior by producers. Including these factors could imply that the climate impact of supply-side policy is larger, and that leakage rates are smaller. Finally, our model uses estimates that are based on observed policy changes that may have been perceived as temporary. If the policy were trusted to be permanent, the estimated supply elasticities and leakage rate may be different.

This paper relates to the literature on supply-side climate policy, which consists of both theoretical contributions (Bohm, 1993; Hoel, 1994; Harstad, 2012; Harstad and Liski, 2012; Collier and Venables, 2014; Eichner and Pethig, 2017; Eichner *et al.*, 2023; Harstad and Holtsmark, 2025) and quantitative modeling (Fæhn *et al.*, 2017; Erickson and Lazarus, 2018; Leroux and Spiro,

emissions are not under any CO_2 pricing.

2018; Gerarden *et al.*, 2020; Kruse-Andersen and Sørensen, 2025; Prest, 2022; Prest and Stock, 2023; also Harstad and Holtsmark, 2025), as well as work on oil-market responses to climate policy more broadly (Kellogg, 2024; De Canniere, 2024). The literature has emphasized that unilateral supply-side policies lead to a higher oil price and increased production abroad, and more so the more elastic supply is relative to demand. Our contribution is to offer new evidence on firm-level responses to supply-side policies, and to map those responses into market-level outcomes in a dynamic field-level model. To the best of our knowledge, this study is the first to use quasi-experimental variation to empirically identify the global impacts of supply-side climate policies.

We provide estimates of short-term supply elasticities, when only production from existing fields can adjust, and medium-term supply elasticities, when production from new investments comes online. Our analysis, however, does not account for depletion of low-cost oil reserves in the long term. We find that the average oil supply is relatively inelastic in the short term, consistent with the findings of Güntner (2014), Anderson *et al.* (2018) and Gilje *et al.* (2020). However, limiting climate change depends on cumulative emissions (Rogelj *et al.*, 2018). The relevant elasticity is thus the one we capture by the elasticities of exploration and discoveries. In magnitude, our estimates are somewhat higher than typical elasticities estimated in the literature (Ringlund *et al.*, 2008; Mohn and Osmundsen, 2008; Rao, 2018; Anderson *et al.*, 2018; Newell and Prest, 2019; Brown *et al.*, 2020).[5] This is plausible for two reasons. First, our approach measures elasticity by changes in oil exploration, not only production or development of fields. Second, we use tax-driven variation in prices when estimating elasticities, and show that tax changes are persistent over our sample period.

Our paper also contributes to the small but growing literature on indirect forms of carbon pricing, which influence the relative price of CO_2-emissions although they have another primary objective (see Agnolucci *et al.* 2023; Belfiori and Rezai 2024). Gerlagh *et al.* (2018) and Sen and Vollebergh (2018) study taxes levied for fiscal purposes, Shapiro (2021) study trade tariffs, Hahn and Metcalfe (2021) study energy subsidies to low-income consumers, Preonas (2024) and Asker *et al.* (2024) study market power in coal and oil markets, respectively, and Coulomb *et al.* (2026) study the climate impacts of misallocation in the world oil market through changes in upstream (production) emissions. A central finding of this literature is that the quantitative effects of such indirect policies on emissions can be sizeable, which is also what we document for revenue-motivated oil production taxes.

[5]Our finding that investments in oil exploration are sensitive to taxes is in line with research showing that oil exploration is sensitive to the local business climate (Bohn and Deacon, 2000; Cust and Harding, 2020; Arezki *et al.*, 2019; Hamang, 2024).

2 Data

Data on exploration, production and discoveries. Our analysis uses proprietary economic and production data from the UCube database of Rystad Energy, an oil industry consulting and data company. Our study period spans from 2000 to 2019. Figure 1a shows the global coverage of our data including the location of all 49,023 onshore and offshore assets. The dataset has practically full global coverage, as it includes 84 oil-producing countries around the globe that, together, have 98.1% of the global oil production.[6] The data set includes annual information at the asset level, which refers to licenses, fields or discoveries. Fields are classified as either conventional or unconventional, where unconventional hydrocarbons include oil sands, extra heavy oil and tar sand, shale oil (and gas), very tight reservoirs and coalbed methane.

Our data contain information about the amount of oil exploration per company, asset and year. In the case of joint ventures, exploration expenditure is divided between companies following their ownership in a given year. Exploration expenditure includes all costs associated with trying to find and prove hydrocarbons: seismic studies, wildcat wells, appraisal wells, and general engineering costs.[7] We have data on annual oil and gas production at the field level, and in this study we focus specifically on oil production. According to our data, oil production in 2019 amounted to 34,098 million barrels per year, or 93.4 million barrels per day. We aggregate these variables to the company-year-tax regime level.

For discoveries, we observe a cross-section of the total discovered amount of hydrocarbons per field, but not the time variation in when these discoveries are added to existing fields. To capture the timing, we assume that, for each field discovered within our study period, discoveries over time take place in proportion to the exploration capex in different years. We split the discovery sizes per field to company-field-year in proportion to each company's exploration capex.[8] We then aggregate all field-level data to the company-regime-year level, which is the unit of observation in our empirical analysis. We fill in zeros for all companies that are ever active in a given tax regime over our study period.[9]

[6] Our data includes 34,098 MM bbl/year or 93,419 thousand bbl/day oil production in 2019. BP (2020), p. 16, reports an average oil production of 95,192 thousand bbl/day for 2019. This means that our data includes 93,419/95,192 = 98.1% of the global oil production for that year. The dataset includes 49,023 assets, of which 26,740 are fields and 22,283 other assets such as licenses.

[7] Our data also includes information on aggregate non-exploration capital expenditure, which includes many types of expenses, such as investment costs related to development of infrastructure, drilling and completion of wells, as well as modification and maintenance of existing infrastructure. We study that data in the appendix, where the results are shown in Table A.11 and Figure A.9.

[8] In other words, companies may also have positive exploration effort but zero discoveries in a given year, if they drill only dry wells. The timing of exploration expenditure relative to the year of discoveries is shown in Appendix Figure A.2, where we show that roughly 20% of the exploration capex is spent at the year of discovery, around 10% before and the rest after.

[9] All our econometric specifications include company-tax regime fixed effects, which absorb all time-invariant

For each field with discovered oil reserves, we have an estimate of extraction costs from Rystad Energy data.[10] This is a cost assessment rather than actual cost data, and is therefore expected to be a noisy measure of true costs due to a combination of mismeasurement and unobserved cost components. In the Appendix, we compare this cost data with an alternative cost measure, based on the after-tax oil price at the presumed time of field development decisions. Although we observe instances of high-cost fields being developed during periods of low prices as well as low-cost fields being developed during periods of high prices (as expected), we find that, on average, the cost data align well with firms' observed development choices. We calculate the discovery size-weighted average extraction cost at the company-regime-year level.

Oil companies are classified based on the historical operator at the time of drilling. The number of unique companies is 4,274, but the majority of them, 3,610 companies, operate just in one country in our study period, and 325 firms operate in just two countries. On average, these firms are small and together account for approximately one-fourth of all exploration activity in the sample. We categorize these small companies by the number of countries they operate in to use more data and thereby get more statistical power in the main analysis.[11] The implicit assumption we make is that small companies within a given segment respond similarly to year-specific shocks. Other companies are given a unique identifier; out of these 131 operate in three countries, 57 in four countries, and 150 in five countries or more.

Tax data. We use a global data set on oil-related tax changes for 2000-2019. These data are collected from primary sources, Ernst & Young (EY) Corporate Tax guides (2000-2009), EY Oil and Tax Guides (2010-2019) and the Rystad Energy UCube tax database.

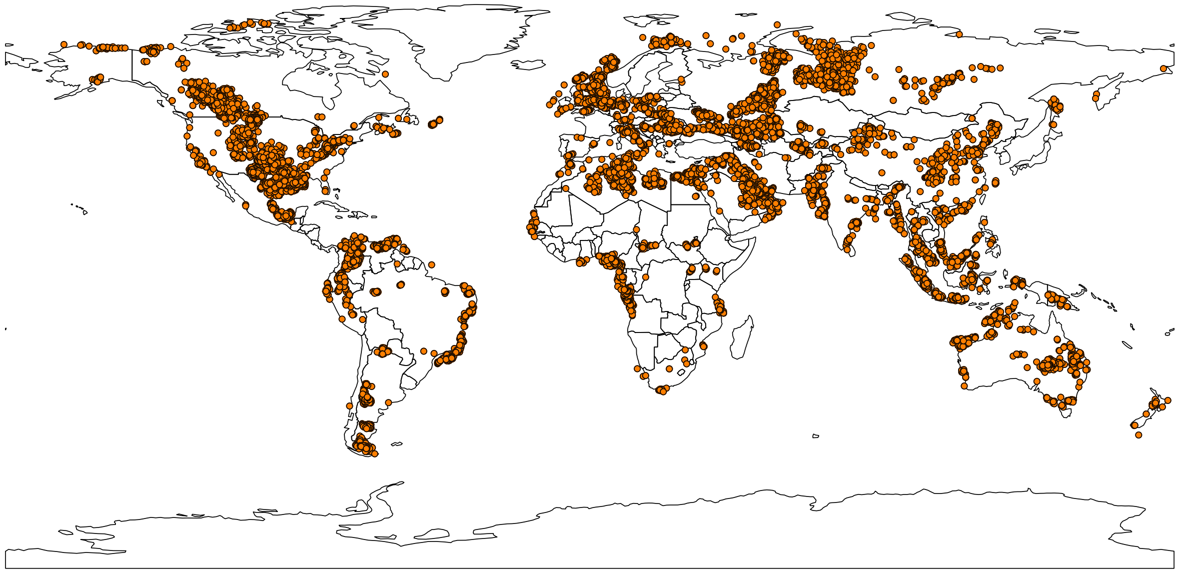
The choice of what taxes to focus on, and how these taxes relate to global climate emissions, is not trivial. The theory on resource taxation has acknowledged that production-based taxes create an incentive to curb exploration and production, while profit-based taxes do not (Lund, 2009; Daniel *et al.*, 2010). The aim of supply-side CO_2-based taxes would be to reduce emissions embedded in produced oil. As noted by Prest and Stock (2023), it is possible to link production-based taxes (r, in % of revenue) and CO_2-based corrective taxes on downstream emissions (τ, in $\$/tCO_2$) by using the carbon content of the fuel (e_{oil}, in tCO_2/bbl) and a base oil price (P_{oil},

characteristics of companies within each regime and effectively exclude firms that are never active in a given regime.

[10] Extraction cost indicates at which (constant) oil price the asset has a net present value equal to zero (NPV) without taxes. For higher oil prices than this, the asset becomes commercially viable. This variable is provided to us by Rystad Energy, and it is based on a real discount rate of 7.5% to calculate the NPV. More information about the data, and how we use it, is found in Appendix A. We use field-level development decisions to build another proxy for extraction costs and cross-verify the Rystad Energy cost data, we show that on average, the two data sets are consistent with each other. Appendix Figure A.1 shows that the distribution of extraction costs has been relatively stable throughout our study period.

[11] Our main specification with company-year and company-tax regime fixed effects only uses variation from companies that drill in at least two regimes in a given year. In Appendix Table A.6 we show that the results are robust to alternative company classifications.

Panel A: Location of assets in our data



Panel B: Production-based tax rates

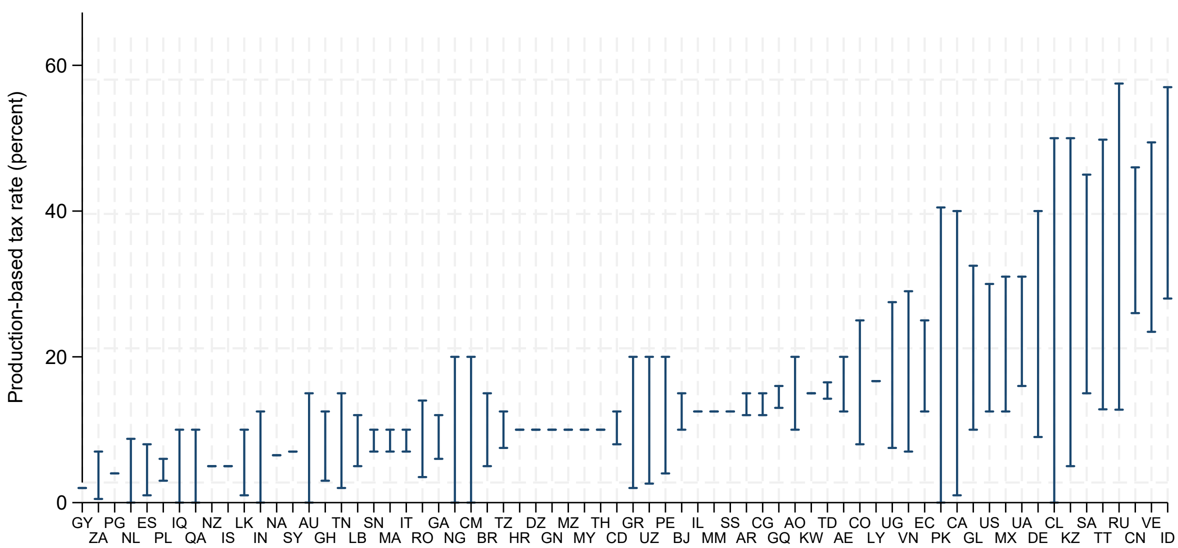


Figure 1: Location of oil producing fields and production tax levels.

Notes: Panel A shows the geocoded locations of all assets in our data. Panel B shows the production-based tax rates on new discoveries in 2019; minimum and maximum taken over onshore and offshore tax regimes. AZ, BH, KH, CY, DK, EG, IR, IE, KE, LA, MR, NO, OM, GB, UY: No production taxes (not shown in the figure); AR, AU, BR, CD, CM, CO, CH, DE, DZ, EC, GA, GH, GL, GN, GQ, GR, GY, HR, IL, IN, IQ, IT, KW, LB, LK, LY, MA, MM, MY, MX, NA, NG, NP, PE, PK, PL, QA, RO, SA, SN, SS, TD, TH, TN, TT, UA, UG, US, ZA: Royalty; BJ, NZ: Royalty ad valorem; IT: Fondo idrocarburi; MX: Over-royalty; EC: Sovereignty margin; TT: Supplemental oil tax; PK: Windfall levy; CL: Special operating agreements; UZ: Subsurface user tax; MY: oil income tax; MZ:Oil production tax; AO: oil production tax; IS, TT: Production levy; VN, CN: Resource tax; CN: Special oil gain levy; AZ: Default PSC regime; ES: Direct tax on the value of the extraction; CA, GL: Gross royalty; ID: Gross-split mechanism; RU, KZ: Mineral extraction tax; RU, NA:Export levy, KZ: Rent tax on exports; CG: Mineral fee. The country codes and other details are found in Appendix D.

in \$/bbl) as: $\tau = rP_{oil}/e_{oil}$. This observation motivates why we study the climate impacts of production-based taxes: they also indirectly work as supply-side climate policies.[12] This group of taxes includes ad valorem taxes levied on gross income (the predominant category), taxes levied on gross production as well as windfall taxes levied on production if the oil price exceeds a certain threshold. In all these categories, costs are neither deductible nor refunded. Figure 1b shows production-based taxes and their ranges in our sample in 2019.

The average production-weighted tax rate over all countries is 21%. Assuming a reference oil price of P_{oil} = \$65/bbl and a carbon content of oil at 0.43 tCO_2/bbl we arrive at a global indirect CO_2 price of \$32/tCO_2. This average number, however, masks substantial heterogeneity across countries. Moreover, these figures do not include production subsidies (\$15bn/year, Jewell *et al.* 2018), which are small compared to consumption subsidies (\$324bn/year, Jewell *et al.* 2018) and production taxes (\$464bn/year, this study).[13] We cover questions related to endogeneity of tax reforms, including the potential leverage of simultaneous events, in Section 5.

Our unit of observation is the *tax-regime–company–year* level. As countries often set different taxes for onshore and offshore areas, we define a *tax regime* to be a unique combination of a country and an onshore or offshore area. When tax reforms change a range of taxes, our main specification uses the median change in tax rates. This is a potential source of measurement error, which we explore in Section 5 by analyzing the changes in lower and higher bounds of each tax reform. We identify altogether 54 production tax increases and 30 decreases. In our raw data, the average increase is 5.2 percentage points and the average decrease is 5.3 percentage points. The analysis aggregates multiple tax reforms within a calendar year and treats them as a single reform. More details on the tax data are found in Online Appendix D. Out of the 167 tax regimes in our sample, 96 had no tax changes over the study period.

Our study focuses on the effects of production taxes. Hence, we do not estimate the impacts of reforms in other tax instruments such as profit taxes, regular corporate income taxes, pricing of CO_2-emissions at the source (such as the EU ETS), and expenses related to obtaining exploration or drilling rights (auctions, area or license fees). We also leave out changes in expenses related to any local (land owner, municipality- or state-level) contracts or taxes, or field- or firm-level variation in government take that is more likely to be endogenous. As long as reforms of these taxes are not correlated with production tax reforms, they do not bias our estimations. In the quantification, we aim to keep track of profit-based taxes as they are important when considering

[12] A positive production-tax is a part of the optimal taxation when resource rent taxation is not feasible, see (Daubanes and Lasserre, 2023). In Figure A.3 we show that, on average, countries with high production tend to have higher production tax rates. Note that the similarity between production taxes and carbon taxes only holds for downstream (combustion) emissions: A tax levied on upstream (production) emissions would affect fields very differently depending on their emission intensities, see Masnadi *et al.* (2018) and Coulomb *et al.* (2026).

[13] We have roughly 34,000 MMbbl oil produced per year, the average production-weighted tax rate is 21% and the benchmark oil price is \$65/bbl. This gives 34 bn bbl/year $\times$ 0.21 $\times$ \$65/bbl=\$464 bn/year in production tax revenue.

the split of surplus between the producing companies and governments. Profit-based taxes include oil rent taxes, as well as windfall taxes and other taxes levied on profits from oil extraction. Deduction rules of profit-based taxes, such as the time profile of deductions, interest or uplifts paid on delayed deductions vary across tax regimes.[14] For simplicity, in Section 6 we assume that costs are either fully deductible or directly refunded in the profit tax category.

3 Empirical approach

Our difference-in-differences strategy compares a company's operations in a tax regime before and after a production tax change to the same company's activities in other tax regimes over the same period. We estimate variations of the following linear regression model:

$$\ln(Y_{ijt}) = \beta Tax_{jt} + \gamma_{ij} + \gamma_{it} + \gamma_{rt} + \epsilon_{ijt} \tag{1}$$

The main dependent variable, Y_{ijt}, is (the logarithmic transformation) of exploration expenditure, oil production, discovered reserves or discovery-weighted extraction cost by company i in tax regime j and year t. Tax_{jt} denotes production tax rates (in percentage points, between 0 and 100), where taxes vary by the location of the asset (onshore or offshore), the country, and the year. Our coefficient of interest is β, the average treatment effect (on the treated) of the production tax rate on the different outcome variables. Details of the taxes may differ, and we estimate the treatment effect of a representative tax reform.

To study the timing of our treatment effect, we estimate event study specifications, letting the policy impact, β_τ, vary with event-time:

$$\ln(Y_{ijt}) = \sum_{\tau \neq -1} \beta_\tau I_{j\tau} + \gamma_{ij} + \gamma_{it} + \gamma_{rt} + \epsilon_{ijt} \tag{2}$$

$I_{j\tau}$ is either an indicator variable for each tax reform or an indicator scaled by the tax rate and τ indexes years relative to the tax reform in regime j. Some countries undergo multiple tax reforms, and the estimation treats each reform in a country separately, with its own pre- and post-reform outcomes. When multiple reforms occur within the same tax-regime–year, they are aggregated and treated as a single reform.

Equations (1) and (2) include a set of fixed effects. Company $\times$ tax regime fixed effects (γ_{ij})

[14] In an earlier version of this paper we showed that the results are robust to including profit-taxes. The design of profit taxes varies in terms of, for example, their rules for the timing of deductions, which costs are deductible, what other taxes can be deducted from them and whether deductions can be refunded in cash. Metcalf (2018) and Ahlvik and Harding (2025) demonstrate that the details can have a large impact on the distortion of profit-based taxes. For this reason, we do not attempt to empirically estimate their effects but instead focus on production taxes.

capture any time-invariant unobserved factors, such as a company's home bias or other characteristics of a certain country or company. Company × year fixed effects (γ_{it}) control for unobservable time-varying characteristics at the company-level, such as company-specific technology, geological competence or expectations regarding the future oil price. Region × year fixed effects (γ_{rt}) control for global or region-specific shocks and trends, such as the global oil price or changing economic conditions, where the regions are Europe, Africa, Asia–Oceania, North America and South America.

In some cases, companies have zero activity, such as no exploration, in a given tax regime and year. To account for both the intensive margin (increased activity within a given regime) and the extensive margin (firms entering or exiting a given tax regime), we also estimate a Poisson model, expressing the average treatment effect in levels as a percentage of the baseline mean:

$$\ln \mathbb{E}[Y_{ijt}] = \beta_{Pois} Tax_{jt} + \gamma_{ij} + \gamma_{it} + \gamma_{rt} \tag{3}$$

Unlike the log-transformed OLS specification, this model accounts for zeros in the dependent variable. This is most important for discoveries, with a considerable share of zeros for years in which a firm does not discover new resources in a given tax regime.

Taxes influence firm decisions by altering the prices they effectively face. Accordingly, we use the after-tax oil price to inform our quantification in Section 6, and present estimates based on this variable, defined as $(1 - Tax_{jt}/100) \times OilPrice_t$. To isolate the variation in prices driven by the tax reforms, we instrument the after-tax oil price with production-based taxes in a two-stage least squares estimation (2SLS):[15]

$$\ln(Y_{ijt}) = \beta_p AfterTaxPrice_{jt} + \gamma_{ij} + \gamma_{it} + \gamma_{rt} + \epsilon_{ijt} \tag{4}$$

$$AfterTaxPrice_{jt} = \alpha Tax_{jt} + \gamma'_{ij} + \gamma'_{it} + \gamma'_{rt} + \epsilon'_{ijt} \tag{5}$$

Equations (4) and (5) represent the second-stage and the first-stage, respectively, and they effectively scale the tax-rate semi-elasticity from equation (1) with the effect of the tax rate on the after-tax oil price: $\beta_p = \beta/\alpha$. The exclusion restriction is that production taxes influence Y_{ijt} only through the after-tax oil price. We also run a specification where we instead use the log of the after-tax oil price, where β_p can be interpreted as the elasticity.

[15] Our quantification in Section 6 uses field-level data scaled by the intensive-margin treatment effect, allowing firms to respond to after-tax prices rather than to tax rates. Therefore, we treat the models in (4)-(5) as our preferred specifications. This is in line with our finding that firms respond on the intensive margin: OLS specification (1) and Poisson estimations (3) give similar results, and in Appendix Table A.5 we find no effect on extensive margin responses, indicating that the results are robust to including zeros in the analysis.

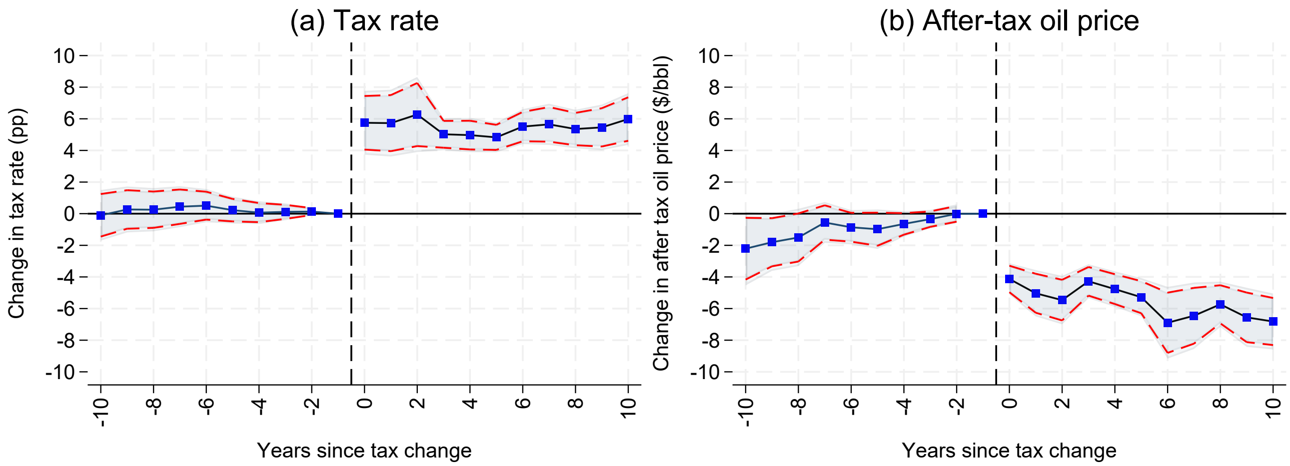


Figure 2: Impact of tax reforms on (a) production-based tax rates and (b) after-tax prices

Notes: These event study graphs are based on estimation of equation (2), using an indicator for tax increases (=1) or tax decreases (=-1) and allowing the coefficients on the indicator variable to vary with event time. Dependent variable is (a) the tax rate in percentage points or (b) after-tax oil price in $/bbl. Time zero denotes the time when a country undergoes a tax reform. The graph is readjusted such that the coefficient for year -1 equals zero and other coefficients can be interpreted as changes relative to that year. All figures use company-tax regime, region-year and company-year fixed effects. Connected dots show yearly values, red dashed lines show 90% confidence intervals and gray area shows 95% confidence interval. Standard errors are two-way clustered by company and country.

4 Empirical results

Event study: Tax levels. As a first step, Figure 2 presents the impact of an average production tax reform at time zero on (a) production-based tax rates and (b) after-tax oil prices. Figure 2a illustrates that an average production tax reform is 5-6 percentage points in magnitude. Tax reforms lead to a sustained change in the tax rates, and countries do not seem to systematically repeal their earlier reforms during our sample period.[16]

Before the tax-reforms, we see no systematic difference between the control and treatment groups, suggesting that omitted factors or reverse causality are not driving the tax reforms. Figure 2b shows the associated impact on the after-tax oil price. Again, as expected, there is a swift effect at the time the tax change is implemented. An average tax reform reduces the after-tax oil price by about $4-7/bbl. These results combined indicate that a one-percentage point increase in production taxes decreases after-tax oil prices by slightly less than $1/bbl on average.

Event study: Exploration, production, discoveries, and extraction costs. Figure 3 presents the impact of a one percentage point change in production taxes on exploration (Figure 3a), production (Figure 3b), discoveries (Figure 3c) and extraction costs of discovered deposits

[16]Oil taxes may be revised after the end of our sample period. If firms believe that a tax change will be repealed, our estimates may differ from the effects of a permanent tax policy (see discussion in Section 6.4).

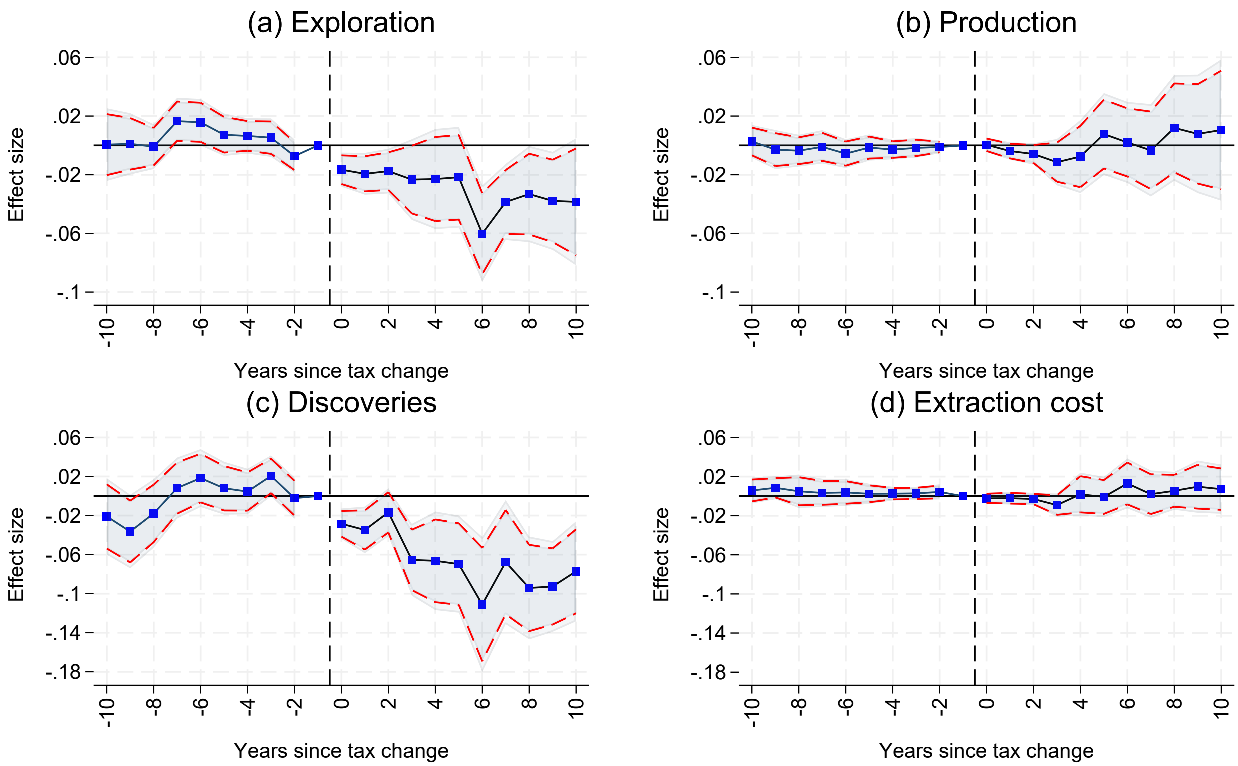


Figure 3: Estimated impact of production tax changes on (a) exploration, (b) production, (c) discoveries and (d) extraction costs for 1pp change in production taxes

Notes: Graphs show coefficients on year-since-tax-reform indicators from regressions corresponding to the specification of equation (2), where each reform is normalized to represent one percentage point increase in production taxes. We take the logarithmic transformation of each dependent variable. All effects are shown in relation to year -1. All figures use company-tax regime, region-year and company-year fixed effects. Connected dots show yearly values, red dashed lines show 90% confidence interval and gray area shows 95% confidence intervals. Standard errors are two-way clustered by company and country.

(Figure 3d) based on equation (2). The lack of statistically significant pre-treatment effects lends support to the parallel trends assumption in our difference-in-differences strategy.[17] Moreover, we see no evidence of anticipation effects right before the tax changes.

Figures 3a and 3c show that both exploration and discoveries respond to tax reforms. The effect is statistically significant immediately after the reform, but its magnitude increases over time. The delayed responses are consistent with the time lags related to licensing, seismic data acquisition, analyses and drilling preparations, which are typical in the exploration industry. For example, Łucki and Szkutnik (1990) report an average time lag of 1.2-5.4 years between seismic prospecting and exploration drilling and Hendricks and Porter (1996) report an average time lag of 1.6 years between license acquisition and exploration drilling in the United States. Ahlvik and

[17] Our approach, relying on two-way fixed effects and staggered implementation of reforms, may be biased if treatment effects are heterogeneous or dynamic (see Goodman-Bacon, 2021). In Section 5, we show that our results are robust also when previously treated units do not act as comparisons for later treated units. This approach is illustrated in the appendix event study Figure A.7.

Harding (2025) used Norwegian data and a single tax reform to show that licensing responded with a one-year delay, and drilling responded with a three-to-five year delay. These reported time lags are consistent with the gradually increasing effect in our event study. The effect for exploration is approximately -0.04 after ten years, indicating roughly a 4% reduction in annual exploration, and is somewhat larger for discoveries. Figures 3b and 3d show null results on both oil production and extraction costs; the coefficients are close to zero and statistically indistinguishable from zero throughout the period.

Effects on exploration. Table 1 presents our main results, both for the direct effect of taxes, and for the more decision-relevant effects of the after-tax oil price, on oil exploration, production, discoveries and extraction cost of discovered deposits. Columns 1-4 show the reduced-form results for a change in tax rate–ranging from 0 to 100, such that a one-unit increase corresponds to a one percentage-point increase–on exploration which are based on estimating equation (1). The three first columns introduce fixed effects one-by-one as indicated in the bottom rows of the table. Increased tax rates have a negative effect on exploration (panel A), consistent across all columns. Our preferred estimate in column 3 shows that a one percentage-point increase in production taxes reduces exploration by, on average, 2.6% over the study period.[18] As the event study in Figure 3 suggests, the effect becomes more pronounced over time. Column 4 splits the effects into short-term (first five years) and the horizon spanning from six to twenty years (the end of our sample period), and finds that the effect is 2.2% in the first five years and grows to 4.1% over the subsequent years.

Sometimes firms are not actively carrying out exploration in a given tax regime. To account for zeros, columns 5–6 estimate the Poisson model. The results are consistent but somewhat less precisely estimated. Poisson regression estimates a coefficient of -0.0148, which translates to a 1.5% decrease over the study period and a parameter -0.0518 translating to a 5.1% decrease beyond five years. The observed consistency between OLS and Poisson estimates suggests that the findings are not driven by inactive firms with zero exploration.[19]

We estimate the after-tax price semi-elasticity and after-tax price elasticity in columns 7–8 using the 2SLS estimation procedure in equations (4)-(5). Column 7 shows an estimated semi-elasticity of 0.037 using the after-tax price in levels, indicating that 1$/bbl increase in the after-tax price increases exploration by 3.8%. Column 8 shows an estimated elasticity of 1.96 using the after-

[18]The estimated effects in equations (1) and (3), denoted by β and β_{Pois}, are semi elasticities, meaning that a one-percentage-point increase in tax rates leads to $(e^{\beta} - 1) \times 100\%$ change in the dependent variable.

[19]Table A.5 shows the results for various intensive and extensive margin responses, as theory suggests that taxes can differently impact the two margins; see, e.g., Devereux and Griffith (2003). We find no effect on extensive margin, defined as firm entry to a given tax regime. Most effects are driven by companies changing activity within assets (e.g., fields), but we find some evidence that companies change the number of discovered assets they operate in.

tax price in logs, meaning that a 1% increase in the after-tax oil price increases exploration by 2.0%. These elasticities are somewhat larger than the respective elasticity estimates presented in the earlier literature. One reason may be that we use variation stemming from tax changes, not variation in market prices.[20]

Effects on production. We find small and statistically insignificant coefficients on taxes in our production regressions, across all specifications in Table 1 Panel B within our sample period. In Table 2 we unpack the null effect on production by studying subsamples of the data. Motivated by the earlier literature arguing that existing oil production is largely unresponsive to price and tax changes because adjustment costs for already-producing wells are high (Güntner, 2014; Anderson *et al.*, 2018; Gilje *et al.*, 2020), we focus on the production responses of older wells discovered before the first tax reform in our sample. We split the data and run separate analyses for conventional (columns 1-4) and unconventional (columns 5-8) fields separately.[21] Our findings confirm that tax reforms do not change production from existing conventional fields. However, unconventional production is found to be tax-sensitive as we find a statistically significant intensive margin response. These results align with Bjørnland *et al.* (2021) who find that production from unconventional reservoirs is more price-sensitive than production from conventional reservoirs.

Effects on discoveries. As noted, a higher after-tax price increases companies' exploration efforts, which is their primary behavioral margin. However, this does not necessarily imply that increased exploration leads to more discoveries, for instance, if higher taxes reduce the discovery rate. For this reason, we also examine whether tax reforms affect the quantity of resources discovered in Panel C of Table 1. We estimate similar and significant effects across all specifications. A one-percentage point increase in tax rates decreases discovered oil amounts by about 4.3%. As for exploration, also this effect is more pronounced beyond the short-run and grows to 8.9% as we consider time periods beyond the first five years. Results from the Poisson regression suggest similar patterns, indicating that the inclusion of zeros – companies with no discoveries in a given tax regime and year – is not driving the results. The price elasticity reveals that one $/bbl increase in the after-tax oil price increases discoveries by 6.4%. These results provide robust evidence that increased exploration leads to more discoveries; if anything, the effect is somewhat stronger on discoveries than on exploration. However, because discovery size is a random outcome of explo-

[20] We compare our results with those presented in the literature in Appendix Table A.2. A set of papers have observed that tax changes have stronger impacts than price changes in other contexts: Li *et al.* (2014); Rivers and Schaufele (2015); Antweiler and Gulati (2016); Andersson (2019); Basaglia *et al.* (2023); Köppl and Schratzenstaller (2023); Mideksa (2024). A potential explanation in our case is that the tax reforms are persistent within the time-span of our sample (see Figure 2).

[21] Table A.8 shows the results for the split between conventional and unconventional fields for other variables. We find somewhat larger exploration and discovery effects for unconventional fields, although the small number of observations increases standard errors substantially.

Table 1: Effects of tax reforms on exploration, production and discoveries.

	Tax elasticity						Oil price elasticity	
	Tax rate (pp)	Tax rate (pp)	Tax rate (pp)	Tax rate (pp)	Tax rate (pp)	Tax rate (pp)	After-tax oil price ($/bbl)	log($/bbl)
	OLS	OLS	OLS	OLS	Poisson	Poisson	2SLS	2SLS
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Panel A: Impact on exploration								
Treatment effect	-0.0261***	-0.0278***	-0.0261***		-0.0148*		0.0371***	1.9649***
	(0.0059)	(0.0063)	(0.0065)		(0.0088)		(0.0096)	(0.4921)
...1 to 5 years				-0.0221***		-0.0077		
				(0.0069)		(0.0101)		
...over 6 years				-0.0410***		-0.0518***		
				(0.0108)		(0.0124)		
N	41,919	41,919	41,042	41,042	62,282	62,282	41,042	41,042
Panel B: Impact on production								
Treatment effect	-0.0028	-0.0011	-0.0015		0.0021		0.0021	0.1111
	(0.0061)	(0.0083)	(0.0069)		(0.0042)		(0.0100)	(0.5221)
...1 to 5 years				-0.0056		-0.0021		
				(0.0040)		(0.0041)		
...over 6 years				0.0107		0.0078		
				(0.0173)		(0.0104)		
N	23,897	23,897	22,288	22,288	32,485	32,485	22,288	22,288
Panel C: Impact on discoveries								
Treatment effect	-0.0374***	-0.0469***	-0.0440***		-0.0717***		0.0623***	3.2809***
	(0.0108)	(0.0125)	(0.0129)		(0.0212)		(0.0168)	(0.9829)
...1 to 5 years				-0.0331***		-0.0372*		
				(0.0109)		(0.0199)		
...over 6 years				-0.0927***		-0.1169***		
				(0.0212)		(0.0235)		
N	19,727	19,727	17,890	17,890	27,329	27,329	17,890	17,890
Panel D: Impact on discovered fields' extraction costs								
Treatment effect	-0.0006	-0.0015	-0.0038		-0.0079		0.0047	0.2743
	(0.0053)	(0.0053)	(0.0062)		(0.0058)		(0.0079)	(0.4543)
...1 to 5 years				-0.0059		-0.0096*		
				(0.0053)		(0.0051)		
...over 6 years				0.0046		-0.0004		
				(0.0118)		(0.0102)		
N	14,095	14,095	12,283	12,283	12,382	12,382	12,283	12,283
Company-tax regime FEs	x	x	x	x	x	x	x	x
Year FEs	x							
Region-year FEs		x	x	x	x	x	x	x
Company-year FEs			x	x	x	x	x	x

Notes: This table reports regression coefficients from 32 separate regressions, 8 per panel. The dependent variable is exploration capex (Panel A), oil production (Panel B), discovered resources (Panel C), and oil extraction cost (Panel D). Treatment is the production tax rate in levels between 0-100 (columns 1-6), After Tax Price ($/bbl) in levels (column 7) or logs (column 8). Columns 1-4 estimate OLS in equation (1) with logarithmic transformation of the dependent variable. Columns 5-6 show Poisson regression results based on (3). Columns 4 and 6 show the effects on taxes separately for years 1-5 and for years 6-20. Columns 7-8 show the second-stage results of the 2SLS in equations (4)-(5). The first stage in equation (5) is -0.6988*** (0.0699) (F-value 100.1) in column 7 and -0.0132*** (0.0003) (F-value 1601.7) in column 8. Fixed effects as indicated in the bottom rows. Standard errors in parentheses are two-way clustered by company and country. * p<.10, ** for p<.05, and *** for p<.01.

Table 2: The effect on production from pre-existing unconventional and conventional fields

	Conventional production				Unconventional production			
	OLS	Poisson	OLS (extensive)	2SLS	OLS	Poisson	OLS (extensive)	2SLS
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Tax rate (pp)	0.0018	0.0052	-0.0015		-0.0641***	0.0178	-0.0007	
	(0.0067)	(0.0042)	(0.0014)		(0.0190)	(0.0910)	(0.0035)	
After-tax price ($/bbl)				-0.0026				0.0753***
				(0.0093)				(0.0220)
N	21,555	30,543	41,040	21,555	863	1,627	3,380	863
Dependent variable	log y	y	1(y>0)	log y	log y	y	1(y>0)	log y

Notes: The table presents 8 separate regressions estimating the effect of taxes (columns 1-3, 5-7) or after tax price (columns 4 and 8) on oil production, where the dependent variable is transformed as indicated on the bottom row. The sample is restricted to fields where discovery year is before the first tax change in a country, or year 2010 (mean year of first tax reforms) in countries with no tax changes. All specifications use company-regime, region-year and company-year fixed effects. Standard errors two-way clustered by company and country are in parentheses. * p<.10, ** for p<.05, and *** for p<.01.

ration expenditure, the estimated effect has a larger standard error than the effect on exploration activity and the 95 percent confidence intervals overlap in most specifications.

Effects on extraction costs. We do not find robust evidence that tax changes have an impact on the extraction cost of newly discovered deposits (Table 1, Panel D), independent of the time horizon. This suggests that a higher tax neither makes companies search for new deposits with low production cost (a statistically significant negative coefficient), nor that companies respond to a tax increase by finding high-cost deposits (a statistically significant positive coefficient).

5 Robustness

Identifying the effects of national tax policies on the behavior of internationally integrated oil-producing companies is a challenging task. In this section we aim to address what we think are the four most important empirical challenges in our setting: (i) spillovers between treated and control units, (ii) staggered difference-in-differences design, (iii) that tax changes may be endogenous, and (iv) measurement error in tax rates.

Spillovers. Our main results rely on the Stable Unit Treatment Value Assumption (SUTVA). The assumption would be violated if a change in production taxes within one tax regime influenced the company's exploration or production activities in other regimes. The net present value of an asset depends directly on its own tax rates, and therefore, under frictionless markets, we would not expect spillovers to arise. However, if markets are not perfect, the effect is ambiguous. On the one hand, a tax reducing reform may shift activity or fixed factors (e.g., drilling rigs or workers) from other locations, thereby decreasing investment there. In that case, SUTVA violations would bias our results upward. On the other hand, a lower tax rate elsewhere can increase free cash and increase exploration expenditure in other locations.[22] In this case, SUTVA violations would bias our results down.

Our data include multinational oil companies with operations spanning multiple jurisdictions, providing us with an opportunity to test for potential spillovers within companies. The results are presented in Table 3. Columns 1 and 2 present the response of companies' exploration expenditure to the tax rate in the country where the investments occur, as well as to the companies' exploration-weighted average tax rate abroad. As expected, we find that own tax rate has an impact on exploration in the same regime, confirming the main results of Table 1.[23] The average tax rate abroad does not have a statistically significant direct impact on drilling in a given country. Columns 3 and 4 show results using data for only small companies that operate in two countries or fewer. For these companies we expect the spillovers to be the largest. Even for this group, we find no evidence of activity-shifting, although the null result is not precisely identified due to low statistical power. To be sure that SUTVA violations among these small companies are not biasing our results, we run the analysis without them in columns 5 and 6. We find that the main effect remains robust, thereby indicating no evidence that activity shifting within companies poses a threat to our identification.[24]

Staggered difference-in-differences. Recent econometric literature on staggered difference-in-difference design has identified a potential bias in two-way fixed effects models when treatment effects are heterogeneous or dynamic (Sun and Abraham, 2021; Callaway and Sant'Anna, 2021; Goodman-Bacon, 2021). In Column 1 of Table 4, we follow the approach of Cengiz *et al.* (2019) and run a stacked regression. We create 18 cohort-specific datasets, one for each treatment year, which include tax changes in that cohort and use never-treated countries as controls (see also Roth *et al.* 2023 and Baker *et al.* 2025). The results in Table 1 remain robust: we find significant effects on exploration and discoveries, and no impact on production or extraction costs. The stacked event study graph in Appendix Figure A.7 shows no signs of pre-trends and confirms our findings.

[22] Some studies have found some evidence of liquidity constraints or financing frictions in the oil and gas industry, see, e.g., Black *et al.* (2018), Gilje *et al.* (2020) and Ahlvik and Harding (2025).

[23] Note that, unlike our main analysis, the analysis in Table 3 uses company-tax regime and region-year, but not company-year, fixed-effects. The analysis includes all data, and makes no aggregation to company-segments for companies operating in one country. Therefore the results of column 1 is the same as column 2 of Table A.6.

[24] A tax change in one country can affect production and exploration elsewhere through changes in global oil prices. The year fixed effects included in our estimations effectively hold the oil price constant. Thus, our estimates are *net* of any leakage effects. Section 6 aims to quantify this leakage through a market-level analysis.

Table 3: Testing for activity shifting within companies: exploration

	All companies		Companies operating in 2 countries or fewer		Companies operating in 3 countries or more	
	(1)	(2)	(3)	(4)	(5)	(6)
Tax rate (pp)	-0.0202***	-0.0243***	-0.0164**	-0.0157	-0.0262***	-0.0263***
	(0.0063)	(0.0059)	(0.0080)	(0.0110)	(0.0070)	(0.0070)
Company's tax rate		-0.0040		-0.0003		-0.0050
abroad (pp)		(0.0061)		(0.0120)		(0.0059)
N	82,322	44,836	44,706	7,238	37,616	37,598

Notes: The six separate regressions use company-level data and make no aggregation to company-segments for companies operating in one or two countries. Columns 1-2 use all data, columns 3-4 use only data for companies operating in 1 or 2, columns 5-6 use companies operating in 3 countries or more. The dependent variable is log of exploration capex in tax regime i. Explanatory variable *Tax rate* is the production tax rate (between 0-100) in the same country, i. Variable *Company's tax rate abroad* is the company's exploration-weighted average tax rate (between 0-100) in all other countries than i. All specifications include company-regime and region-year fixed effects. Standard errors two-way clustered by company and country are in parentheses. * p<.10, ** for p<.05, and *** for p<.01.

Endogenous tax changes. Our main identification strategy assumes that tax changes are exogenous, which implies that the error term ϵ_{ijt} in equation (1) is uncorrelated with Tax_{jt}, conditional on the included fixed effects. This assumption could be violated if tax changes were caused by shifts in companies' oil activities (reverse causality), or if there is an unobserved factor not captured by the fixed effects that correlates with both Tax_{jt} and the outcome Y_{ijt} (omitted variable bias). The event study of Figure 3 indicates that pre-trends are parallel, supporting the assumption of exogenous tax changes. This is further supplemented by Appendix Figure A.4, where we find no significant evidence for correlation between tax reforms and observable variables related to the oil sector or macroeconomic indicators. We thus cannot reject the exogeneity of tax reforms for the sample period.

We further explore the possibility that tax reforms and our estimates may be driven by large incumbent companies with the power to influence the government's decision. Table 4 splits the sample along three dimensions proxying for companies' lobbying power: private companies, which arguably have weaker ties to the government than public companies (column 2); small companies, which arguably have less lobbying power than large ones (column 3); and companies without existing production in the country and therefore weaker incentives to lobby (column 4). We find similar effects in all three sub-samples. The exception may be discoveries, where we estimate somewhat smaller coefficient for companies without pre-existing production in the country in question. Given that this difference is less pronounced for exploration, it may also be caused by these new companies having limited geological knowledge of the area. Finally, we exclude countries that belong to OPEC (column 5), where tax rates may be used to influence global oil prices, and find that the results remain robust.

Measurement error in tax changes. Our global analysis requires a way to standardize the tax systems, which we do by capturing production taxes by a simple tax rate. Unavoidably, we lose some nuances with this standardization. First, as Figure 1b shows, tax systems sometimes encompass a range of tax rates, and the same applies to tax reforms. In the main analysis, we approximate the magnitude of tax reforms by the change in the median tax rate. It could be that the effective tax rate is instead closer to either the lower or the higher end of the range. Table 4 (columns 6-7) repeats the analysis using instead the lower and higher ends of the tax changes. The results remain very close to those in our main analysis presented in Table 1 in that we find statistically significant effects for exploration and discoveries with coefficients similar in size to those in our main analysis.

Second, production taxes can differ along some other dimensions, for example, the tax rates

Table 4: Effects of taxes on exploration, production and discoveries, robustness

	(1) Stacked regression	(2) Private ownership	(3) Small company	(4) No existing production	(5) Non-OPEC	(6) Reform, low-end	(7) Reform high-end
Panel A: Impact on exploration							
Tax rate (pp)	-0.0294***	-0.0242***	-0.0353***	-0.0191**	-0.0228***	-0.0224***	-0.0198***
	(0.0078)	(0.0072)	(0.0075)	(0.0092)	(0.0064)	(0.0077)	(0.0050)
N	422,440	36,492	8,624	29,503	34,446	41,042	41,042
Panel B: Impact on production							
Tax rate (pp)	-0.0048	-0.0032	0.0027	-	0.0016	0.0015	-0.0030
	(0.0073)	(0.0062)	(0.0062)		(0.0077)	(0.0079)	(0.0044)
N	227,240	18,669	4,452	-	18,036	22,288	22,288
Panel C: Impact on discoveries							
Tax rate (pp)	-0.0578***	-0.0519***	-0.0782***	-0.0281	-0.0389***	-0.0485***	-0.0259***
	(0.0145)	(0.0150)	(0.0202)	(0.0203)	(0.0124)	(0.0134)	(0.0087)
N	172,928	15,676	3,837	10,665	14,771	17,890	17,890
Panel D: Impact on discovered fields' extraction costs							
Tax rate (pp)	-0.0032	-0.0025	-0.0053	0.0040	-0.0089	0.0015	-0.0037
	(0.0064)	(0.0060)	(0.0039)	(0.0089)	(0.0060)	(0.0059)	(0.0041)
N	128,020	10,799	2,849	7,372	9,653	12,283	12,283

Notes: The table reports coefficients from 28 separate regressions, 7 per panel. All specifications use company-region fixed effects. Column 1 uses region-year-indicator and company-year-indicator fixed effects, columns 2-7 use region-year and company-year fixed effects. Column 2 drops national oil companies (NOCs and INOCs), 3 uses companies drilling in one, two or three countries only, 4 uses companies without existing oil or gas production in the country before the reform (note that production response cannot be estimated for this group), 5 uses non-OPEC members only. The variable tax rate is the median production-based tax rate in columns 1-5, low-end in 6 and high-end in 7. Standard errors two-way clustered by company and country are in parentheses. * p<.10, ** for p<.05, and *** for p<.01.

sometimes depend on the level of production, the size of deposits, or the oil price. Moreover, some production taxes are deductible in corporate income taxes or other tax bases, while others are not. We examine various tax systems in Appendix Table A.12 and demonstrate that our results are robust to excluding specific types of production taxes.

6 Quantification

In this section, we quantify the aggregate effects of supply-side climate policies on oil market outcomes. We build a quantitative dynamic model, focusing on field-by-field aggregation of annual global production and the associated market-clearing equilibrium oil price, solved annually. Emissions map directly to the CO_2 content of the produced oil. We analyze tax incidence by examining changes in producer surplus, consumer surplus, and tax revenue. The key elements of the model are introduced below, with full details provided in Appendix C.

The policy is an increase in production-based taxes, and we call the additional tax a "climate royalty surcharge" following Prest and Stock (2023). In our baseline scenario, all taxes remain at their 2019 levels. In the global scenario in Section 6.3, we introduce a global permanent climate royalty surcharge on existing production and new discoveries. The surcharge is levied on top of the existing taxes. In the OECD scenario in Section 6.4, we introduce the surcharge only in a coalition consisting of all OECD countries.

6.1 Principal mechanisms in the quantitative model

The model features standard mechanisms emphasized in the theoretical literature on supply-side climate policies. A climate royalty surcharge unleashes the following principal events:

(A) In the short term, the production of unconventional oil falls, shifting the supply curve to the left. This increases the oil price. The more elastic the demand is with respect to the price, the larger is the drop in quantity and the lower is the increase in the price.

(B) Further, despite the price increase, incentives to develop fields into the production phase are weakened, decreasing the number of newly discovered fields that ultimately start producing.[25]

(C) Finally, investments in oil exploration fall, leading to fewer new oil discoveries and lower oil production over time.

[25] Note that, in the case of a tax *decrease*, the field development response would potentially be stronger than for a tax increase (the focus of our paper), due to the stock of already discovered fields that initially are marginally unprofitable, depending on the size of this stock. However, in our quantification, the relevance of this asymmetry turns out to be less important, partly also due to the counteracting mechanism of the zero-lower-bound restriction on tax rates: Some countries already have so low production taxes that they will quickly reach zero tax rates.

(D) In the medium term, reduced oil production, due to the mechanisms described in points (B) and (C), lead to an even higher oil price, over and above the mechanism in (A). This further dampens the effect of the supply-side climate policy.

(E) If only a subset of countries forms a coalition and introduces a climate royalty surcharge, there will be a leakage of production to non-coalition countries. An immediate cut in unconventional production by the coalition will raise the oil price, as noted in point (A) above. The degree of short-term leakage will depend on the capacity of non-coalition countries to ramp up their production of unconventional oil. The leakage will increase over time, as non-coalition producers will develop new production, according to points (B)-(D) above.

6.2 Overview of the quantitative model

Demand. We model global oil demand using an affine demand curve, set to be constant over time and calibrated to match the initial oil price of \$65/bbl, roughly the average over our sample period (2000-2019), and initial production of 34.1 billion bbl/year.[26] We base the demand elasticities (at the initial point) on the existing literature and simply assume two alternative functions, one with relatively high elasticity (-0.5) and one with relatively low elasticity (-0.2). We do not allow this range, or the level of demand, to change over time.[27] Our intention is not to take a stance on what the price elasticity of oil demand is, but rather study the implications of our results using a range of demand elasticities. Note that the demand elasticity is likely higher in the long term, as consumers have time to adjust their investments and develop new substitutes. Thus, the upper bound in our analysis may be interpreted as a longer-term elasticity.

Supply. We build the oil supply bottom-up from the 26,740 fields observed in our data:

Production profile: In the model, the production flow for a given producing field is assumed to follow a typical path over the field's life-cycle. We find this path by calibrating a piece-wise function across all fields in our data, using the initial discovery size, remaining reserves, and discovery year.

[26] Our scenario is one where the world fails to implement demand-side policies that would reduce oil demand. The assumption is roughly consistent with the IEA scenarios: The Stated Policies scenario predicts a 17% increase in the oil supply and the Announced Pledges scenario predicts a 14 % decrease by year 2050 compared to 2020-level (IEA, 2021). Unlike isoelastic demand functions, affine demand avoids producing non-trivial quantities demanded at very high prices, where alternative fuels become competitive.

[27] Our choice of baseline-range of elasticities follows Prest (2022). Consistent with this range, Hamilton (2009), for example, points to a demand elasticity for crude oil of -0.31 found by Dahl (1993) and -0.21 found by Cooper (2003). At the higher end of demand elasticities in the literature, Balke and Brown (2018) find a mean demand elasticity of -0.51 and Uria Martinez *et al.* (2018) report an average demand elasticity from -0.61 for new oil price maxima (where we disregard end-use price elasticities which are mechanically and systematically biased relative to the crude oil elasticity, as explained in Hamilton, 2009.) It should be noted that long-term demand elasticities can be much larger, in line with findings for electricity (Deryugina *et al.*, 2020; Buchsbaum, 2023), because more time allows consumers to find substitutes and ways to economize on the usage. At the lower end, IMF (2011) and Arezki *et al.* (2017) suggest estimates between -0.07 and -0.09.

This calibrated profile follows a piece-wise process characterized by an initial period with no production, a reserve-specific production plateau followed by an exponential decline, taking into account that larger deposits have longer life-cycles.[28] The sum of field-level production gives us total production at any point in time.

Production response: The model's short-term oil supply elasticity follows from our estimated production elasticities. In line with our empirical findings, we assume that production from existing conventional fields is insensitive to tax changes: conventional production increases only through increased development and exploration of fields. However, unconventional production responds to prices according to the estimated after-tax price semi-elasticities from Table 2 (column 8).

Exploration and discovery responses: Each year, oil companies make new discoveries, adding to the stock of undeveloped fields. In the model, exploration and discoveries depend on the after-tax oil price according to the estimated semi-elasticity from Table 1 (Panel A, column 7). We assume that firms respond to contemporaneous after-tax prices rather than to anticipated future prices, and that the responses are identical for exploration and discoveries. Naturally, we cannot observe the extraction costs or other characteristics of future discoveries. Based on our finding that extraction costs of discoveries are invariant to taxes (Table 1, Panel D), we assume that the volume and cost distribution of new discoveries will mirror those observed under the same tax regime from 2000 to 2019.

Field development and undeveloped fields: Fields are developed and ultimately start producing if their extraction cost is below the after-tax oil price. Hence, not all new discoveries are taken to the production stage. We refer to these as undeveloped fields. In our model, a field remains undeveloped if the extraction costs exceed the after-tax oil price. These undeveloped fields may be developed later if the oil price increases.

Market-clearing and outcomes. Aggregate global oil supply is the sum of production from all fields in a given year. The oil market clears every period, such that the oil supply from all operating fields equals oil demand at the associated global equilibrium price.[29]

Emissions: We calculate CO_2 emissions embedded in oil production using a CO_2 content of 0.43 tCO_2/bbl (EPA, 2021). This calculation is conservative, as it does not include emissions from natural gas and emissions directly related to production.

Distributional consequences. Both tax changes and the price responses affect the incidence of the tax. We define periodic consumer surplus (CS) conventionally as the area between demand

[28]The same functional form is used by Arezki *et al.* (2017) and Ahlvik and Harding (2025). Prest (2022) uses a similar approach but a different functional form for the production profile. Appendix C describes our approach in detail, including the functional form, the data and approximation method. Although individual fields do not follow this profile exactly, the average production follows the functional form well as shown in Appendix Figure A.14.

[29]We use the oil price and consumption in 2019 as the initial values in the model. For baseline development of prices and quantities, see Figure A.16.

curve and the oil price.[30] Producer surplus (PS) is calculated for each field as the difference between the equilibrium oil price and extraction cost times production, minus exploration expenditure and the sum of paid taxes.[31] We allocate producer surplus to the country where drilling and production take place, not to the country where the oil company has its headquarter. Total oil tax revenue consists of all taxes, the existing taxes and the additional climate royalty surcharges.

Timing. In our model, the *short term* corresponds to the period during which only production from existing unconventional fields is allowed to respond to tax reforms (1–5 years). The *medium term* refers to the remaining years, when production from new investments comes online (6–80 years). This paper does not analyze the *long term*, during which major technological changes and resource depletion may occur (beyond 80 years).[32]

6.3 Policy analysis 1: Global supply-side climate policy

We begin by considering a global climate royalty surcharge, on top of any existing taxes and levied on all oil production. The tax is introduced permanently in 2020, and we simulate the effect on the oil market over the period 2020-2100. All effects are relative to a baseline scenario with existing taxes but with no climate royalty surcharge.

Figure 4 illustrates the global oil price and production when the climate royalty surcharge is set at 20 percentage points. The immediate contraction in unconventional oil production due to the tax increase reduces oil supply by 1,500-2,300 million bbl per year, where the range represents different demand elasticities. This corresponds to 5-7% of global oil production in the baseline case of no climate royalty surcharge. The inward shift in global oil supply leads to a short-term increase in the oil price of \$8-14/bbl. In the medium term, the effects on quantity and price increase because the taxes both reduce the development of marginal fields and reduce oil exploration and new discoveries. However, the gradual increase in the oil price dampens the effects. By 2100, the oil price increase is \$23-27/bbl and the oil production reduction amounts to 2,800-6,000 million bbl per year. The latter corresponds to 9-20% lower production and emissions than without the climate royalty surcharge. The medium-term increase in the global oil price roughly equals a

[30] Note that the global oil demand is affected by (i) non-uniform demand-side climate policies (Ramstein *et al.*, 2019) and (ii) subsidies on oil consumption that remain large (Coady *et al.*, 2017, 2019). Demand therefore deviates from the consumers' pre-tax willingness to pay, and our definition of consumer surplus should therefore be interpreted with caution.

[31] In the quantification, we consider both production taxes and profit-based taxes; further details are provided in Appendix D. Although we assume that profit taxes do not influence producers' behavior, they may be significant for the distribution of rents. Note that the effect of existing and new taxes (that are in % of revenue) on after-tax oil prices depends on the equilibrium pre-tax price. Consequently, an increase in oil prices also influences the revenue generated from existing taxes.

[32] In the long term, oil demand may be more elastic because it takes time to substitute away from oil. Oil supply may be less elastic due to economic depletion of reserves, as low-cost reserves may have been depleted and higher-cost reserves must be used next. A more elastic demand and less elastic supply would reduce the leakage rate in the long term.

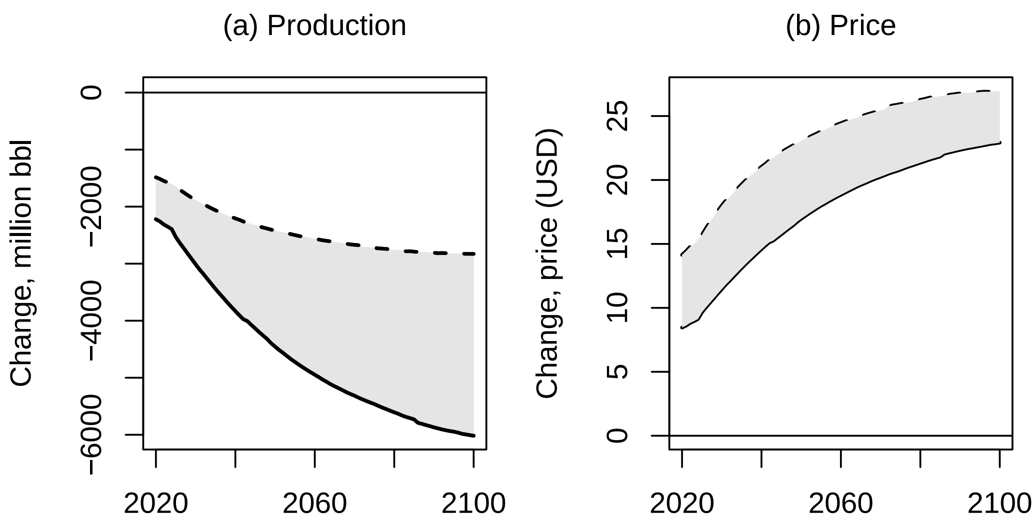


Figure 4: Dynamic effects of the global 20 percentage point climate royalty surcharge

Notes: The figure shows the effect of a 20 percentage point climate royalty surcharge on yearly development of (a) oil production and (b) oil prices relative to the benchmark of no tax change. The solid line represents high demand elasticity (-0.5) and the dashed line represents low demand elasticity (-0.2).

global carbon price of \$53-63/tCO_2 levied on oil consumers.[33]

Average annual emissions fall in response to a climate royalty surcharge, as shown in Figure 5a for different levels of tax changes. A 20 percentage point increase in the tax rate decreases the cumulative emissions over the period 2020-2100 by 85-161 GtCO_2, or 1.0-2.0 GtCO_2 per year on average. For comparison, this decrease amounts to 17-32% of the remaining carbon budget for 1.5°C degree warming or 7-14% of the carbon budget for 2°C degree warming.[34] In contrast, if all production tax rates were to be reduced by one percentage point, the cumulative emissions would increase by 3.2-6.8 GtCO_2, which corresponds to 22-47% of today's annual global CO_2 emissions from oil.

The tax incidence in the form of changes in annual average consumer surplus, tax revenue, and producer surplus is presented in Figure 5, panels (b)-(d). A higher climate royalty surcharge reduces consumer surplus, as it triggers an increase in the oil price, reaching around a loss of

[33]In this calculation, we use (\$23/bbl)/(0.43tCO_2/bbl)≈\$53/tCO_2 and (\$27/bbl)/(0.43tCO_2/bbl)≈\$63/tCO_2.

[34]The estimated remaining carbon budget from the beginning of 2020 for limiting warming to 1.5°C with a 50% likelihood is 500 GtCO_2 and for 2°C (67% likelihood) this is 1150 GtCO_2; see Lee *et al.* (2023). Recall that our results are the lower bound for the global emission reduction, because we only focus on emissions embedded in the produced oil (using emission factor of 0.43 tCO_2/bbl; EPA, 2021). We do not include emissions in natural gas and emissions from production. Direct emissions from oil production and refining are considered to be covered by the other policies, such as local carbon taxes and emissions trading schemes, and they are not considered in this paper. The direct emissions vary substantially, from 3.3 g CO_2eq./MJ in Denmark to 20.3 g CO_2eq./MJ in Algeria, see Masnadi *et al.* (2018). Moreover, we do not take into account that oil may displace other fossil fuels.

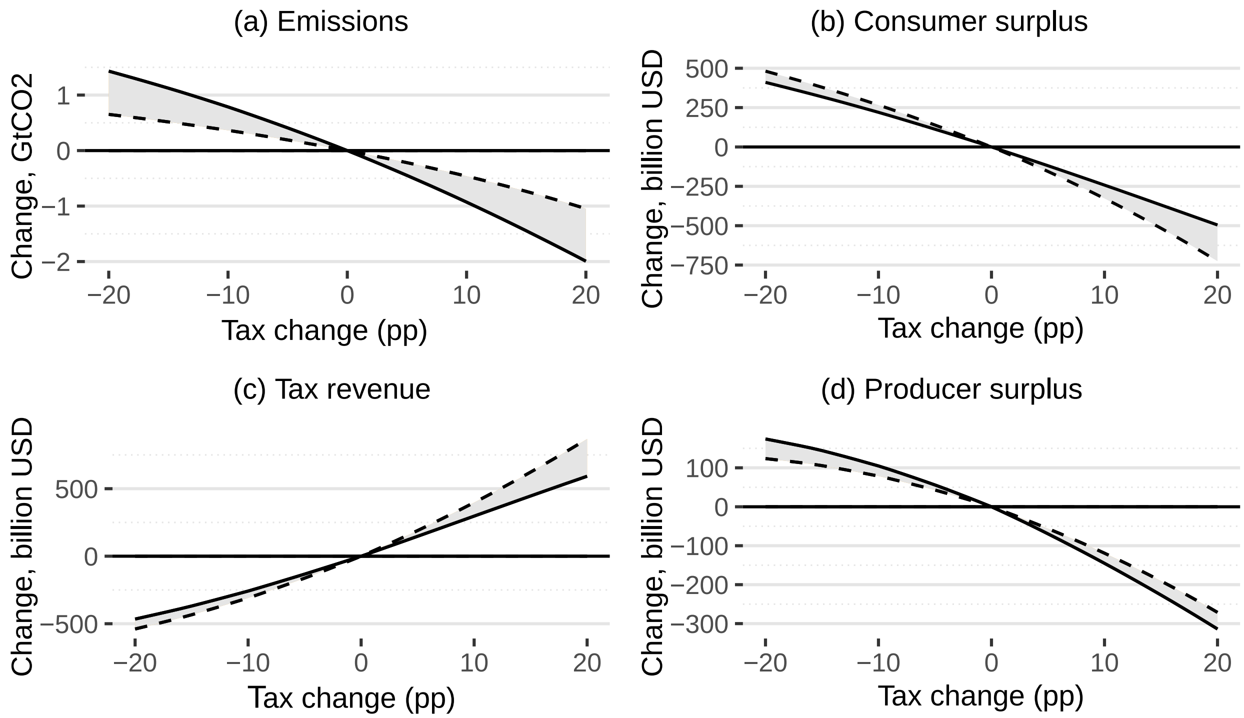


Figure 5: Annual average effects of a global supply-side climate policy

Notes: The figure shows the changes in average annual (Panel a) cumulative emissions, (Panel b) consumer surplus, (Panel c) tax revenue, (Panel d) producer surplus relative to the scenario where tax levels are kept unchanged (x-axis equal to zero). On the y-axis, the figure shows annual average (undiscounted) values over the time period 2020-2100. At the left of the x-axis, current taxes are reduced by the indicated percentage points, or by the existing tax if it is less than what is indicated, since the minimum possible tax rate is zero. At the right of the x-axis, a global royalty surcharge is added to the existing taxes as indicated. The solid line represents high demand elasticity (-0.5) and the dashed line represents low demand elasticity (-0.2). Appendix Figure A.17 shows that, even after accounting for uncertainty in supply elasticities, uncertainty in demand elasticity drives most of the overall variability in the results.

\$500-\$730 annually for a 20 percent royalty. Producer surplus also decreases by \$270-\$310 billion per year, although the effect is dampened by the higher oil price.[35] Governments in oil producing countries, and in principle their respective citizens, are the main beneficiaries of the introduction of a climate royalty surcharge. A 20 percentage point tax rate increase raises the tax revenue by \$590-870 billion globally per year during our study period. There are two reasons for the strong effects on the tax revenue. First, there is a mechanical effect, as governments tax new fields and the existing, relatively inelastic production. Second, the higher oil price increases tax revenue even further, and the supply-side climate policy essentially turns the producing countries into an

[35] Tax incidence in the static market can be calculated by the use of demand and supply elasticities, ϵ_d and ϵ_s, and the formula $\frac{\epsilon_d}{\epsilon_s - \epsilon_d}$. Our numerical model captures real-world aspects that complicate the calculation. For example, supply is inelastic in the short term but becomes elastic in the medium term, producer surplus includes revenues and costs occurring at different periods, and oil price changes also affect the tax revenue collected from already existing production- and profit-taxes.

oil market monopoly.[36] This higher oil price increases revenue from the existing and new taxes. Intuitively, higher oil prices increase profits and revenue, which are split between companies and governments according to existing taxes.

For a 20 percentage point climate royalty surcharge, summing the net present value of consumer surplus, tax revenue, and producer surplus indicates a direct economic loss of $130 to $220 billion per year under low and high demand elasticity in our study period, or $1,000 billion and $1,400 billion in net present value. The policy would break even for a constant social cost of carbon of $72-$84/tCO_2.[37] For a global policy, the standard tax incidence argument indicates that same aggregate outcome can be reached either by demand or supply-side climate policies. However, the distributional impacts of the two policies are different depending on who gets to collect the tax revenue, governments in oil producing countries or those in oil consuming countries, as well as on how they interact with existing taxes.

6.4 Policy analysis 2: OECD-wide supply-side climate policy

To analyze the impacts of a climate royalty surcharge with imperfect global coverage, we study a scenario where the policy is adopted by a supply-side coalition consisting of OECD countries only.[38] This coalition accounts for 30 percent of the current oil production and 49 percent of global exploration expenditures in year 2019. The surcharge is again added on top of any existing taxes and levied on all oil production.

Figure 6 shows the impact on production and prices for a climate royalty surcharge of 20 percentage points adopted by the coalition. The coalition immediately reduces its production of unconventional oil, which leads to a $7-11/bbl increase in the global oil price. The non-coalition countries react to the higher price by increasing their unconventional oil production. This short-term leakage is limited, however, as OECD countries hold a larger share of the unconventional production. Around 63-84% of the OECD reduction turns into a global reduction in the short term (first five years), implying a leakage rate of 16-37%. The flip side is that the price increase is only slightly lower than under the global scenario in Section 6.3. The higher price leads to more exploration and more production by the non-OECD countries over time. By 2050, the reduction in annual production is 5,000 million bbl in OECD countries and the increase in non-OECD countries

[36] The link between market power and conservation of resources was already recognized and discussed by Hotelling (1931) in his seminal article. The demand-side climate policies would have an opposite effect, turning oil importers into a monopsony in the oil market (Liski and Tahvonen, 2004).

[37] We calculate the social cost of carbon (SCC) at which emission reduction equals the net present value of consumer surplus (CS), producer surplus (PS), and tax revenue (Tax) as $CS + PS + Tax = \sum_{t=0}^{80} \frac{SCC}{(1+r)^t} e_t$ where e_t is the annual emission reduction and $r = 7.5\%$ is used for discounting.

[38] OECD countries with oil drilling or production in our sample are: Australia, Canada, Chile, Germany, Denmark, Spain, United Kingdom, Greece, Ireland, Israel, Iceland, Italy, Mexico, Netherlands, Norway, New Zealand, Poland and United States

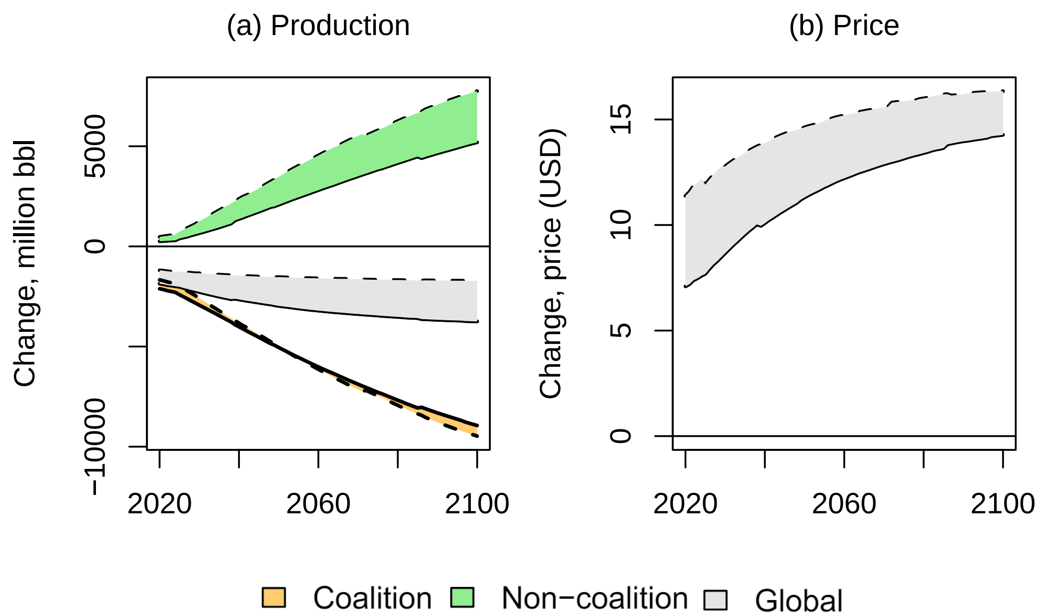


Figure 6: Dynamic effects of the OECD-wide 20 percentage point climate royalty surcharge

Notes: The figure shows the effect of a 20 percentage-point climate royalty surcharge on yearly development of (a) oil production and (b) oil prices relative to the benchmark of no tax change. The solid line represents high demand elasticity (-0.5) and the dashed line represents low demand elasticity (-0.2).

is 2,100-3,500 million bbl, reflecting a leakage rate of 41-70%.

By year 2100, the coalition has reduced annual production by 9,000-9,400 million bbl, while non-members have increased theirs by 5,200-7,800 million bbl. This adds up to a net reduction of 1,700-3,700 million bbl. These numbers imply that the leakage rate in year 2100 is 58-82%. Notably, the medium-term reduction by the coalition exceeds the total reduction observed under the global scenario. This outcome is driven by the higher oil price in the global scenario compared to the coalition scenario: \$23–27/bbl versus \$14–16/bbl in year 2100. Accordingly, the dampening of the surcharge effect by higher prices is weaker in the coalition scenario. Intuitively, a price-taking coalition would see only a quantity effect, whereas a monopolist would face a downward-sloping demand curve. Our OECD coalition is somewhere between these two cases.

Leakage rates should be interpreted in light of the key assumptions embedded in the model. First, the demand elasticity is likely to be higher in the long term, as consumers have time to adopt clean investments and develop substitutes. In the long term, beyond the horizon of our study and with the emergence of new technologies, the demand elasticity may exceed the upper bound considered in our analysis. Second, both estimates and modeled effects may depend on the perceived permanence of tax changes. In our model we assume that the climate royalty surcharge is permanent. If, in reality, the production tax reforms were perceived as temporary, our empirical estimates are likely smaller than the true elasticities corresponding to a permanent tax change. Consequently, our model simulation understates the leakage rate that would arise if non-OECD producers trusted the tax change to be permanent. Conversely, if non-OECD producers expect the tax changes not to be permanent, but to apply over a sufficiently long window, they may behave strategically by accelerating resource extraction at the expense of their future production possibilities. Such front-loaded extraction could dampen their medium-run supply response, causing our model to overstate the leakage rate in the medium run. Third, our analysis does not consider the long term, when the low-cost oil resources may be depleted. Last, we have assumed that the current distribution of unconventional oil discoveries will prevail; if non-OECD countries start discovering more unconventional oil in the future, their supply response will increase, but the price response would be more modest.

Figure 7 shows the average annual emission reduction and distributional impacts for varying rates of the OECD climate royalty surcharge. By adopting a 20 percentage points surcharge, the coalition reduces its cumulative emissions over the period 2020-2100 by 202-204 $GtCO_2$, equivalent to an average annual reduction of 2.5 $GtCO_2$, as shown in Figure 7a. The net cumulative effect on global emissions is 54-107 $GtCO_2$, or 0.7-1.3 $GtCO_2$ per year on average, implying an average leakage rate of 47-73%. The global effects of OECD supply reduction amount to approximately two thirds of the impact observed under a global policy.

The increased production by non-OECD countries as a response to the policy has implications for the cost incidence. The average annual consumer surplus, shown in Figure 7, panel (b), is monotonically decreasing in the tax rate as the oil price increases. The tax revenue, shown in Figure 7, panel (c), increases for the coalition through the direct impact of higher tax rates and indirectly through higher oil price. However, reduced oil production cuts into tax revenue, causing revenue to plateau at higher tax rates. Tax revenue increases also in non-OECD countries solely due to higher oil prices. These countries benefit from the OECD supply reductions, much like a competitive fringe benefits when a monopoly restricts output. As presented in Figure 7, panel (d), a higher tax rate by the OECD lowers their own producer surplus, while higher prices increase producer surplus in non-OECD countries. The sum of these two terms is slightly negative overall.

Consider an OECD-wide climate royalty surcharge of 20 percentage points. The sum of changes in consumer surplus, tax revenue, and producer surplus results in average annual global losses of \$120 billion and \$170 billion under low and high demand elasticity, respectively. Expressed in net present value terms, these numbers represent total economic losses of \$1,000 billion and \$1,300 billion. This policy would break even for a constant social cost of carbon of \$88-124/tCO_2 (see footnote 37). These costs are higher than under a global policy due to misallocation of emission reduction efforts globally: OECD takes strong action while non-OECD countries leave low-cost abatement opportunities unused. This comparison between global and OECD-wide coalitions

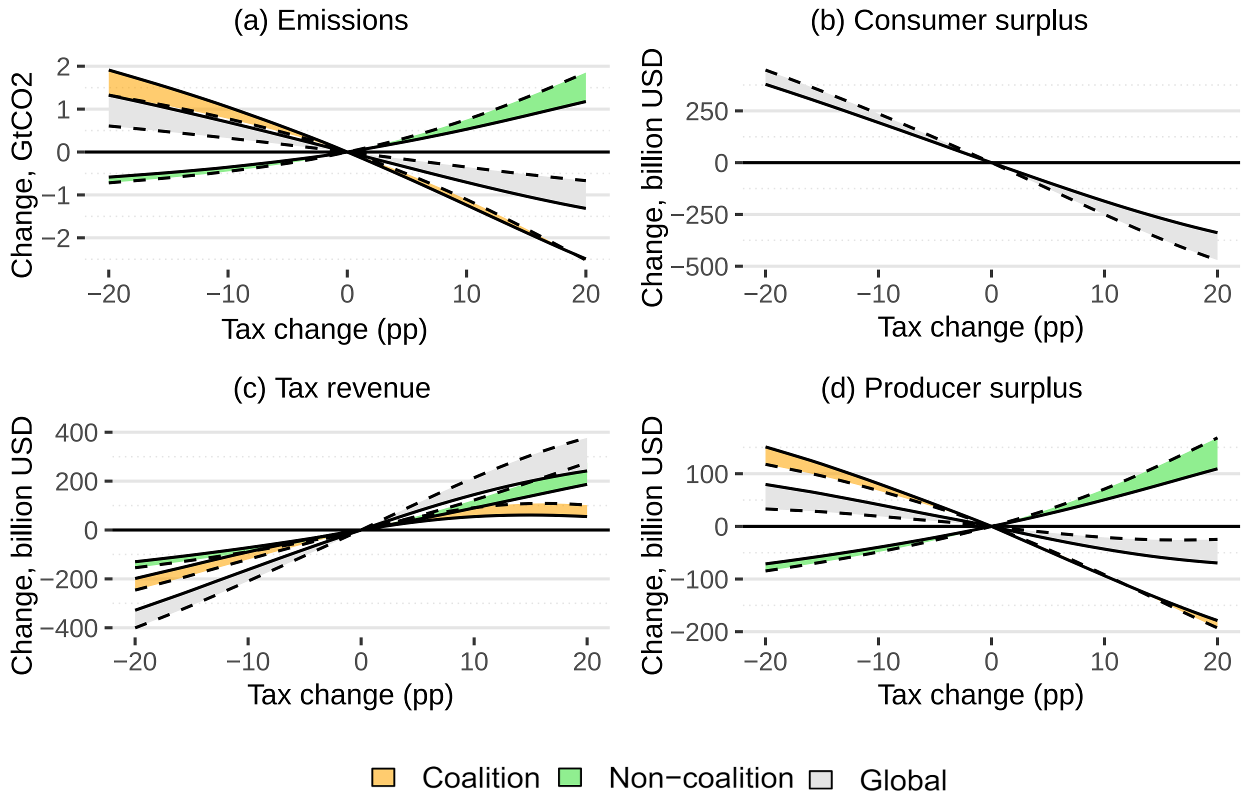


Figure 7: Average annual effects of an OECD-wide supply-side climate policy

Notes: The figure shows the changes in average annual (Panel a) cumulative emissions, (Panel b) consumer surplus, (Panel c) tax revenue, (Panel d) producer surplus relative to the scenario where tax levels are kept unchanged (x-axis equal to zero). Green line is rest of the world, orange line is coalition, and gray area is the net effect. On the y-axis, the figure shows average annual (undiscounted) values over the time period 2020-2100. At the left of the x-axis, current taxes are reduced by the indicated percentage points, or by the existing tax if it is less than what is indicated, since the minimum possible tax rate is zero. At the right of the x-axis, a global royalty surcharge is added to the existing taxes as indicated. The solid line represents high demand elasticity (-0.5) and the dashed line represents low demand elasticity (-0.2).

thus reveals that supply-side climate policy loses some, though not all, of its effectiveness when implemented solely by OECD countries. However, the burden falls disproportionately on OECD producers because less of the taxes can be passed on to the consumer price.

7 Conclusions

For the Paris Agreement to successfully reduce emissions and limit global warming, the current view is that large amounts of oil need to be left in the ground (McGlade and Ekins, 2015; Welsby *et al.*, 2021; Pellegrini *et al.*, 2024). Corrective prices on oil production offer a promising theoretical opportunity to achieve this objective. We study the effectiveness and incidence of supply-side policies by the use of historical reforms of production-based oil taxes.

We emphasize three findings. First, oil companies respond to higher production-based taxes primarily by reducing exploration, which leads to fewer new reserves and hence lower future production capacity. We find no effect on oil production from existing conventional oil fields, but estimate a short-term production response from unconventional fields.

Second, supply-side climate policies have potential to reduce emissions. A hypothetical 20 percentage point climate royalty surcharge levied on all oil production globally would reduce emissions from oil by 5-7 percent in the first five years and by 9-20 percent by the end of the century, where the range reflects low (-0.2) and high (-0.5) demand elasticity. The cumulative global emissions would fall by 85-161 $GtCO_2$ by year 2100, equivalent to 17-32% of the carbon budget consistent with 1.5°C warming. Around two-thirds of the cost would be borne by consumers, one-third by producers, while governments would increase their total tax revenues from oil. Supply-side climate policies may meet resistance from consumers and producers, depending on how the tax revenue is used.

Third, if the supply-side policy is instead implemented by a coalition of OECD countries only, 47-73 percent of the cumulative cuts are replaced by countries outside of the coalition due to a higher oil price. The leakage is smaller in the short term, 16-37 percent, and gradually increases over time to 58-82 percent by year 2100, for high and low demand elasticity, respectively. Despite the leakage, the policy reduces cumulative emissions by 54-107 $GtCO_2$, around two thirds of the emission reduction in the global scenario, and more than the initial shares of the coalition in terms of oil production and exploration. The cost of the policy falls on global consumers and oil producing companies operating in the coalition countries, while companies in non-member countries and all governments of oil-producing countries benefit.

These results are likely conservative because: (i) we account only for downstream emissions from oil, excluding natural gas and upstream emissions; (ii) we abstract from long-term dynamics such as consumers' greater ability to adjust and develop substitutes; and (iii) our empirical estimates are based on observed policy changes that firms may perceive as temporary. Accounting for these factors, the climate impact of supply-side policies would probably be larger.

Our approach offers new insights into the design of optimal supply-side policies. Taxation is a market-based approach and therefore a cost-efficient alternative to reduce carbon emissions embedded in oil, compared to command-and-control policies such as governments licensing selected oil projects.[39] Upstream (production) and midstream (transportation and refining) emissions would break down the cost-efficiency as a Pigouvian tax would treat fields differently and allocate more production to cleaner fields (see Coulomb *et al.*, 2026), but these emissions can also be

[39] There may be other valid reasons to rule out certain areas from oil production, such as local biodiversity concerns.

handled by other policy instruments.[40] The optimal supply-side tax rate would be linked to the social cost of carbon, which is increasing over time (Golosov *et al.*, 2014; Van den Bijgaart *et al.*, 2016; Barrage and Nordhaus, 2024). There are several aspects of supply-side climate policies that we believe represent promising avenues for future research. These include whether supply-side policies should be managed primarily through taxes or tradable production permits, how to design these policies to achieve coalition stability, the potential political and social reception of such policies, and strategies to prevent carbon leakage.

Data availability statement. The data used in this article were provided by Rystad Energy under license and cannot be shared publicly. Researchers may obtain access directly from Rystad Energy by purchasing an appropriate license (details at https://www.rystadenergy.com/client-portal). All code to reproduce the results (conditional on data access) is archived at https://doi.org/10.5281/zenodo.18377302.

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[40] For instance, the EU Emissions Trading System covers emissions from oil and gas production and refineries, and many countries have CO_2-based taxes to price emissions from transportation.

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