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How does the cost of capital affect oil production?*

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Abstract

In the spirit of green finance taxonomies, restricting fossil-fuel producers' access to funds is hoped to help address the climate problem. We develop a project-level model of oil production, calibrate it to the universe of U.S. and Canadian oil projects producible over 2000-2024, and simulate the effects of the cost of capital. Modest increases in this cost are counterproductive, increasing oil production through industry short-termism while reducing project value. Effective costs of capital are unrealistically large, at odds with projects' internal rates of return. At the industry level, a higher cost of capital generates equilibrium adjustments that boost oil profitability.

JEL codes: G1; H20; Q31

Keywords: Oil divestment; Green finance; Short-termism; Unintended policy impact; Internal rates of return

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1 Introduction

Over the past decade, a growing number of investors have committed to ceasing their financing of oil production. These investors are pension funds, banks, and climate-themed asset managers, currently representing about one third of all financial assets under management worldwide (Global Fossil Fuel Divestment Commitments Database, 2025). In the spirit of green finance taxonomies, restricting carbon-resource producers’ access to capital, thereby increasing their cost of capital, is hoped to help address the climate problem. We examine how higher costs of capital affect oil supply and aggregate production.

We focus on real oil production projects, typically involving both upfront development costs and future benefits that depend on the oil price. We consider price-taking producers’ decisions to exploit these projects and examine how the industry’s cost of capital affects these decisions. The cost of capital is the profit-maximizing firms’ opportunity cost of funds, which determines the rate at which their projects’ future cash flows are discounted. Higher costs of capital reduce projects’ net present value (NPV), induce producers to become more short-termist, and generate an equilibrium global price response.

The resource economics literature has long warned that higher discount rates may increase short-run oil production—see, e.g., Long and Sinn (1985), Sinn (2008), van der Ploeg and Withagen (2012), among many others. Interest in this short-termist response to bad future prospects was recently revived by Kellogg’s (2024) study of the anticipated effect of the long-term destruction of oil demand.¹

The financial approach to the climate problem sharply contrasts with economists’ traditional call to price the carbon externality directly. Yet, policymakers and financial regulators have rapidly embraced it as a new paradigm. For example, following the EU-ETS carbon-pricing scheme, the second pillar of the EU climate action is its “green finance taxonomy”—followed by many similar initiatives worldwide—encouraging investors to reallocate financial capital away from climate-harmful activities.

¹For example, anecdotal evidence suggests that the 2022-2023 rise in interest rates—thus in investors’ expected returns—not only pressured oil majors into reducing their long-term investment in project development, but also induced them to prioritize “short-cycle” projects—see *The Economist*, February 6, 2023, available at: <https://www.economist.com/business/2023/02/06/where-on-earth-is-big-oil-spending-its-150bn-profit-bonanza>. This short-termist response is consistent with the fact that oil companies’ profits were higher in 2022-2023 than in the period 2010-2014, despite lower prices.

The finance literature has recently examined the effect of the cost of capital on emissions-generating industries. Pedersen (2026) is the first to point to a theoretical equivalence between carbon pricing and green finance, modeled as an increase in firms’ cost of capital. He shows that, under some conditions, a firm’s augmented discount rate reduces its emissions through investment, in a way identical to the direct effect of a carbon price. Similarly, Chittaro, Piazzesi, Sena, and Schneider (2025) establish an asset market version of the “tax incidence equivalence.” Carbon pricing calls for compensation to firms’ owners by an extra return and, vice versa, investors’ climate concerns amount to imposing a carbon price. Existing attempts to quantify this equivalence rely on calibrated aggregate static production schedules. Pedersen (2026), Chittaro et al. (2025), and Gollier (2025) provide industry-level cost-of-capital benchmarks, indicating the financial returns that investors should forego to provide incentives aligned with climate objectives. For example, Pedersen (2026) suggests that, for the dirtiest industries, a 5 percentage-point (pp) increase in the cost of capital may replicate the effect of a \$50 carbon price.

By contrast, our paper evaluates the effect of the cost of capital on the valuation of real projects generating cash flows over time. Besides the disciplining role of the cost of capital, our framework captures both the short-termist response of the industry to a higher discount rate, and the output market response.

We focus on the U.S. and Canadian oil production industry. Oil accounts for approximately one third of greenhouse gas emissions worldwide and is expected to remain an essential component of the energy mix for decades. At the same time, meeting climate targets implies that a substantial share of currently known and profitable reserves must remain unexploited (McGlade and Ekins, 2015; Welsby, Price, Pye, and Ekins, 2021; Trout et al., 2022)—e.g., about one third of these reserves, should the objective of a two-degree temperature rise be met. For example, unconventional oil such as U.S. shale resources and Canadian oil sands are among the least profitable assets, thus among the most exposed.

Since a persistent increase in the cost of capital is without historical precedent, predicting industry and market responses must rely on economic theory supplemented by calibrated simulations. We model intertemporal oil supply decisions, calibrate our model on the universe of U.S. and Canadian oil production projects, and simulate the dynamic competitive equilibrium for this market segment from 2000 to 2024 under various policies. The specification of our model is guided by facts about

oil extraction projects—see Section 2. In particular, in the model presented in the main text, we define an oil project as a so-called oil “asset,” the level at which production potential is assessed and at which firms commit to the financing, development, and exploitation of a specific geological resource. At this micro (asset) level, production features strong rigidities in general, as recently documented by Ahlvik, Andersen, Hamang, and Harding (2026). Yet these intra-asset rigidities are less strong for shale assets. Thus, in Section 6—with technical details in the appendix—we discuss an extension of our model to a more complex setting in which shale production decisions are made simultaneously at the asset level and at the more granular level of wells within each asset. Our model focuses on producers’ choices about which projects to undertake and when, including rigidities and production constraints.

Each project is characterized by (i) an earliest feasible production date, (ii) fixed development costs, (iii) an operational cost of extraction per barrel, (iv) an exogenous production profile reflecting technological and geological constraints. The key endogenous choice is the initial date, if any, when each asset is tapped. We assume that this choice is made in such a way as to maximize the NPV of the project.² Prices are taken as given by producers; they are endogenously determined in a dynamic competitive market, balancing supply and demand at all times.

Our framework formalizes the three following channels through which the cost of capital affects oil production. First, an extensive-margin supply effect: For given prices, the cost of capital reduces projects’ NPVs, turning some projects unprofitable. Second, an intensive-margin supply effect: The cost of capital decreases the value of future revenues, leading to earlier exploitation of profitable projects. Third, an equilibrium price adjustment effect: Policy-induced production changes at the level of a large industry call for a global oil price adjustment, boosting the profitability of oil projects. Additionally, our model allows us to distinguish the cost of *financial* capital from that of *physical* capital (e.g., pipelines, platforms), whose costs are determined by the price of materials rather than by the cost of funds.

We then calibrate model parameters using production and economic data covering all U.S.

²As a matter of fact, major oil companies require that their projects meet so-called “hurdle” rates of return; profitable projects that don’t meet hurdle rates are sold to other operators taking over production. See, for a recent example, Total Energy’s sale as part of a strategy to focus on more profitable assets (*Reuters*, October 1, 2025, available at <https://www.reuters.com/business/energy/totalenergies-agrees-sell-oil-assets-off-norway-2025-10-01/>). We hold that projects with a positive NPV will be systematically undertaken, either by the initial owner or by a less demanding operator.

and Canadian oil assets, presented in Section 3. We collect, proxy, or estimate the following characteristics: first production year, earliest production year, production path, as well as fixed development and per-barrel operational costs. We consider all oil projects that could have produced after 2000 as candidates for production over the 2000-2024 period.³ We consider production from projects started prior to 2000 as exogenous, to account for short-term rigidities, and we allow for projects unfinished or untapped by 2024 to pay off over a longer horizon.

Main results. We simulate the dynamic competitive equilibrium under alternative costs of capital for 2000-2024.

Increasing the cost of capital has a non-monotonic effect on total production, defined as cumulative lifetime production from projects undertaken during the 2000-2024 period of interest. Starting from a plausible baseline cost of capital, modest increases in line with recently estimated premiums increase oil production slightly. This result is driven by the short-termism effect of higher discount rates on supply decisions, inducing the industry to undertake oil projects before 2024 that it would otherwise have delayed. This is so despite the fact that the cost of capital systematically reduces the NPV of oil projects.

Only unrealistically high premiums of more than 5 pp result in lower oil supply in the long run, because they induce the industry to abandon enough oil projects. Yet, this effect remains weak due to industry short-termism. For example, we compare the effect of the cost of capital to that of a modest \$25 tax per ton of CO₂. To match the tax’s effect on total production, a premium of around 11 pp is required.

Our result may be partly explained by the fact that oil projects are generally very profitable, as reflected by our estimates of project-level internal rates of return (IRR). Yet IRRs do not fully explain our results. Although, by construction, they indicate the effect of the cost of capital on whether a single project is profitable, they do not capture the equilibrium price adjustment generated by an effective cost-of-capital increase at the aggregate level.

Related literature and contribution. Our analysis contributes to the recent finance literature comparing green finance with carbon pricing, seeking to quantify the incentives provided by an

³Our focus on known oil means that we take the oil industry’s “technology” as fixed. In the very long run, technological change may affect the industry’s production capacity, an effect beyond the scope of this analysis.

augmented cost of capital (Pedersen, 2026; Chittaro et al., 2025; Gollier, 2025). We evaluate the effect of the cost of financial capital on firms’ valuation of *real* projects, in isolation from the cost of physical capital inputs. Our framework captures the effects of the cost of capital on intertemporal supply decisions and accounts for the output price equilibrium adjustment that these decisions generate. Our paper is also related to Hartzmark and Shue’s (2023) estimation of the effect of a broad class of shocks to firms’ cost of capital. They document a counterproductive channel of green finance—brown firms’ response to higher costs of capital leads them to increase the emission intensity of their production—and suggest this might be due to short-termist behavior. In the case of oil production, our results align with the short-termism explanation and further indicate that the effect of the cost of capital is non-monotonic: Sufficiently high capital penalties would discipline firms, although this effect is only manifest in the long term.

Like this literature, we leave aside the question of the extent to which oil divestment initiatives have already impacted the oil industry’s cost of capital. Instead, we seek to shed light on the perspective of the financial approach to the climate problem. Recent empirical research finds that markets, driven by climate-concerned investors, already impose a higher cost of capital to emissions-generating firms (Chava, 2014; Hsu, Li, and Tsou, 2023; Gormsen, Huber, and Oh, 2024; Eskildsen, Ibert, Jensen, and Pedersen, 2024) and that the restricted availability of financial resources due to investors’ divestment commitments is material to firms relying on carbon resources (Green and Vallée, 2025). In particular, Eskildsen et al. (2024) estimate that the brownest firms’ cost of capital lies around 50 basis points (bp) above the market average, and that this premium has increased significantly since 2008.

Our framework builds on a recent set of papers modeling and simulating the dynamic equilibrium allocation of oil production based on the same oil data as we use here. This literature studies various sources of inefficiency in the actual allocation of oil—see, e.g., Asker, Collard-Wexler, and De Loecker (2019), Coulomb, Henriët, and Reitzmann (2026), and Asker, Collard-Wexler, De Canniere, De Loecker, and Knittel (2024). Instead, we seek to compare various policies under an unchanged setting featuring realistic economic responses.

In the spirit of Anderson, Kellogg, and Salant’s (2018) critique—recently substantiated by Ahlvik et al. (2026)—we depart from Hotelling’s (1931) conventional model of nonrenewable resource management: Instead of imposing tight constraints on oil production flows like Asker et

al. (2019) and Coulomb et al. (2026), we consider that micro-level oil production trajectories are determined, focusing the analysis on producers’ decisions whether and when they start oil projects. We also consider the peculiarity of shale oil by extending our model to a more granular and sophisticated definition of an oil project, allowing more flexibility in the production of shale resources.

Finally, our paper extends the study of supply-side climate policies initiated by Harstad (2012)—see also, e.g., Asheim et al. (2019) and Ahlvik et al. (2026)—to the analysis of financial penalties.

2 Model

Facts about oil projects. We use data from the Rystad Energy UCube Database (Rystad, hereafter), one of the most comprehensive datasets of oil assets. Rystad provides information on U.S. and Canadian oil projects,⁴ for conventional oil, at the level of oil fields and their extensions, and, for shale oil, at the level of groups of wells within a field. These units are called “assets” in Rystad data, defined so as to approximate the level at which projects’ potential is assessed, and development and exploitation decisions are made (Rystad Energy, 2014). In the model presented in the main text, we will use the terms asset and project interchangeably.⁵

Our model’s specification and calibration are guided by the following facts about oil extraction projects.

(i) *Delayed developments.* Once an asset is discovered, it may be developed and exploited as soon as possible thereafter, or its development may be delayed until prices and financing conditions warrant exploitation (Arezki, Ramey, and Sheng, 2017). Most oil projects undertaken in the U.S. and Canada over 2000-2024 started to produce with a delay of several years with respect to the earliest possible year of production that we estimate based on assets’ discovery year and type of oil—see Appendix B.1. 75% of these projects start with a delay of less than 19 years.

(ii) *Projects’ continuous production.* Once an asset is developed and production starts, exploitation is typically continuous, producing oil in each period until depletion.⁶—see Appendix B.2, showing that estimated continuous trajectories explain most of yearly asset production changes. Asset-level

⁴For these countries, Rystad data is widely regarded as providing near-complete coverage of commercially relevant oil assets. See A.1 for more details.

⁵The extension presented in Section 6 will redefine a shale project as more granular groups of wells than in the original data.

⁶Exceptions are related to unanticipated shocks (e.g., COVID-19 crisis), which our calibration of demand will ignore.

production is governed both by wells' production and by the opening of additional wells, if any. Well-level production is known to be determined by physical factors (Anderson et al., 2018). The sequence of wells' drilling within an asset may be explained by pre-determined capacity constraints (e.g., transportation infrastructure), and by competition for pressure across wells (Kellogg, 2014). *(iii) Conventional (shale) oil projects' production rigidity (flexibility).* For conventional resources, asset-level production is inelastic. Shale assets offer greater flexibility than conventional ones (Ahlvik et al., 2026), allowing production to be determined by drilling wells (or groups of wells) within each asset.

Our baseline model abstracts from this flexibility, but we verify in the extension presented in Section 6 that our main results are unchanged when we redefine a shale project as a more—around ten times more—granular level than original assets.

Oil supply. Our modeling of oil supply is based on price-takers' project-level decisions.

The oil industry consists of many projects indexed by $i \in \mathcal{I} = \{0, 1, \dots, I\}$ that may produce oil at a set of dates $\mathcal{T} = \{0, 1, \dots, T\}$. Each project i may only start producing after its earliest feasible production date $\bar{t}^i$, exogenous. A project's first production, at (endogenous) date $\tau^i (\geq \bar{t}^i)$, generates a fixed development cost $C_F^i > 0$. The production cost per barrel extracted—inclusive of quality- and location-discounts—is $c_V^i > 0$. The amount of recoverable reserves from project i is $\bar{R}_0^i > 0$.

Each project's recoverable oil reserves $\bar{R}_0^i$ are produced through a path of exogenous production flows:

$$q_t^i = q_t^i(\tau^i) \equiv \begin{cases} 0 & \text{if } t < \tau^i \\ \min(\bar{q}^i(t - \tau^i), R_t^i) & \text{if } t \geq \tau^i \end{cases},$$

where $\bar{q}^i(t - \tau^i)$ is an exogenous function of time since first production and $R_t^i \equiv \bar{R}_0^i - \sum_{s \leq t} q_s^i$ is the remaining amount of oil to be recovered from the project.

For a given price trajectory $(p_t)_{t \in \mathcal{T}}$, a given cost of capital r , and an income tax rate θ , the industry's problem is to choose first production dates τ^i , one for each project i should it be tapped,

such that:

$$\forall i \in \mathcal{I}, \max_{\tau^i \in \mathcal{T} \cup \infty} NPV^i(\tau^i) \equiv (1 - \theta) \left(\sum_{\mathcal{T}} (p_t - c_V^i) q_t^i(\tau^i) \left(\frac{1}{1+r} \right)^t - C_F^i \left(\frac{1}{1+r} \right)^{\tau^i} \right), \quad (1)$$

where $\tau^i = \infty$ denotes the decision not to exploit an asset at all, which occurs when the maximum NPV is nonpositive ($NPV^i(\infty) = 0$). The choice of projects' NPV-maximizing start dates $(\tau^{i*})_{i \in \mathcal{I}}$ determines all projects' production $q_t^i(\tau^{i*})$, hence aggregate supplied quantities $Q_t \equiv \sum_{\mathcal{I}} q_t^i$, for all dates $t \in \mathcal{T}$.

Proposition 1 (Aggregate supply monotonicity). *Suppose that the cost of capital r is fixed and let $\delta_t \equiv (1+r)^{-t}$ denote the corresponding discount factor. Let $Q_t(p)$ denote date- t aggregate supply as a function of the price path $p \equiv (p_t)_{t \in \mathcal{T}}$. For any two price paths p and p' ,*

$$\sum_{t \in \mathcal{T}} \delta_t (p'_t - p_t) (Q_t(p') - Q_t(p)) \geq 0. \quad (2)$$

This property is analogous to the standard formulation of the law of supply with many commodities (Mas-Colell, Whinston, and Green, 1995, Chapter 5), where barrels of oil supplied at different dates are treated as different commodities and discounted prices are the relevant commodity prices—a proof is presented in Appendix C.

No such supply property holds for the cost of capital.⁷ Yet, our modeling captures that oil supply responds to the cost of capital through two margins. At the extensive margin, producers decide whether to launch profitable oil projects and abandon unprofitable ones; at the intensive margin, they decide whether to start profitable projects earlier or later.⁸

Demand and dynamic equilibrium. Assuming that the demand for oil at each date is given by $D_t(p_t)$, strictly downward sloping, we define a competitive equilibrium as a sequence of prices and aggregate quantities $(p_t, Q_t)_{t \in \mathcal{T}}$ such that, $\forall t \in \mathcal{T}$, (i) $Q_t = D_t(p_t)$, and (ii) $Q_t = \sum_{i \in \mathcal{I}} q_t^i(\tau^{i*})$.

Proposition 2 (Uniqueness of aggregate quantities in the dynamic equilibrium). *In the dynamic competitive equilibrium, the sequence of prices and aggregate quantities $(p_t, Q_t)_{t \in \mathcal{T}}$ is*

⁷Moreover, in our model, a price instrument such as a per-barrel tax cannot generally be mimicked by an increase in the cost of capital, even if the increase varies over time.

⁸Appendix C.2 presents a simple graphical example illustrating the intensive- and extensive-margin effects through which the cost of capital affects supply.

unique.

The uniqueness of aggregate equilibrium quantities, perhaps surprising given the model’s cost structure, results both from the law of supply and from the monotonicity of demand⁹—a proof is presented in Appendix C.

3 Data and calibration

Our objective is to capture U.S. and Canadian oil production potential over the historical period 2000-2024. We relegate technical details of our calibration to Appendix D.

Population of assets. To calibrate our model, we use detailed production and cost information from Rystad’s universe of U.S. and Canadian oil assets producing since 1970 or expected to produce in the future.¹⁰

Exogenous versus endogenous production. For projects started but unfinished by 2000 (3,717 assets), we consider their post-2000 annual production as an exogenous part of oil supply in order to capture observed asset-level production rigidities.

All other assets (9,770 assets) are considered candidates for post-2000 endogenous production. We estimate or proxy their characteristics—earliest production year, production trajectory, and development and operational costs—using Rystad asset-level production and cost data on oil discovery, production, and costs.

Earliest production year. Following Asker et al. (2019) and Coulomb et al. (2026), we proxy the earliest production year given oil-type-specific irreducible development delays. Only assets with earliest production years before 2024 will be considered for production during the historical period 2000-2024 (6,550 assets). Assets with earliest production dates after 2024 are incorporated through the buffer period described next.

⁹In a nutshell, the proof goes as follows. Demand strict monotonicity implies

$$\sum_{t \in T} \delta_t (p'_t - p_t) (D_t(p'_t) - D_t(p_t)) < 0. \quad (3)$$

It follows that two different price paths p and p' cannot both satisfy (2) and (3), hence the uniqueness.

¹⁰Rystad’s information on assets in U.S. and Canada regions is considered of the highest quality (Asker et al., 2019; Rystad Energy, 2016).

Post-2025 “buffer” period. In order to take into account that projects may be started years after their earliest production year, the simulated model includes an additional 20-year “buffer” period (2025-2044), allowing the industry to start projects with a delay, in competition with projects with earliest production years between 2025 and 2044.

Assets’ estimated production trajectory. We model the trajectory of annual outputs of endogenously started assets as a discrete Weibull distribution over time, and we estimate its parameters at the asset level based on historical production data and Rystad’s projections.

Fixed and operational costs. Following Coulomb et al. (2026), in line with Rystad Energy (2016)’s suggestions, we treat pre-production investment expenditures (well and facility capital expenditures) as a stream of development costs. We allow for different development-cost structures across conventional and shale assets: Conventional projects incur substantial multi-year facility investment, whereas shale projects’ development involves primarily well-level capital expenditures.

We estimate each asset’s per-barrel cost of production as the levelized cost of extraction (LCOE) for all categories of variable production and operating costs. Additionally, we estimate asset discounts as price differentials relative to the WTI benchmark¹¹ based on basins and types of assets, and we incorporate them in assets’ variable costs. Finally, we proxy the U.S. and Canadian oil income tax system as a 25% tax on projects’ NPV.

Demand for U.S. and Canadian oil. We treat demand explicitly as a residual demand, net of rest-of-the-world supply, and assume that both the global demand for oil and foreign supply are iso-elastic, except for Saudi’s production that we treat as a fixed component. Following Kellogg (2024), we assume that the elasticity of global demand is 0.5. We set the supply elasticity to 0.4, a value that is roughly two to three times larger than the short-run oil supply elasticities reported in the recent literature, reflecting the longer adjustment horizon considered in our model.¹²

Demand is calibrated to match average price incentives over 2000-2024 while abstracting from year-to-year fluctuations so as to focus our simulations on policies’ intertemporal effects generated

¹¹Oil assets often sell output at a discount due to differences in oil type, quality, and access to transportation infrastructure. For example, Canadian oil-sands resources sell at a high discount with respect to the WTI benchmark.

¹²Our main results are robust to changes both in elasticity assumptions—see Section 6—and in the level of the demand.

by policies. We first calibrate global demand and foreign supply of years 2000 and 2024 based on observed quantities and prices, and obtain their counterparts in other years by linear interpolation (2001-2023) and extrapolation (2025-2044). Then, we adjust the entire stream of relative demand functions so that our baseline simulation approaches the observed 2000-2024 average price.

Post-buffer-period prospects. We take into account that production of assets started before, but unfinished by, 2044 generates revenues and operational costs after 2045. We assume that production continuing beyond 2044 receives the 2044 equilibrium price.

4 Simulations of the effects of the cost of capital

Using the calibrated model, we solve for the dynamic competitive equilibrium of the U.S. and Canadian oil market over 2000-2024.¹³ For given policy parameters, the obtained equilibrium establishes the price trajectory, the start dates of all projects and, therefore, U.S. and Canada’s aggregate oil production over time.

Baseline simulation. As a baseline assumption, we set the cost of capital to 4% in real terms, a middle-of-the-road parameter choice between the 3% and 5% discount rates of, respectively, Coulomb et al. (2026) and Asker et al. (2019), consistent with Damodaran’s (2026) estimate for the U.S. oil production industry.¹⁴

As a result of our demand calibration, the baseline simulation matches the average WTI price over the 2000-2024 period. In addition, it generates an average development delay of 10 years. Since the observed average development delay among assets brought into production between 2000 and 2024 is 13 years, the model likely understates the scope for advancing production.¹⁵

Augmented costs of capital. We consider various augmented costs of capital resulting from a range of premiums, from realistic rates—4.5% is in line with the 50-basis-point premium estimated by Eskildsen et al. (2024)—up to unrealistic rates higher than 15%.

¹³We present the details of our algorithm in Appendix E.3.

¹⁴In Section 6, we discuss how alternative choices modify our results.

¹⁵For more details on the baseline simulated price trajectory and on the development delays that it generates, see Appendix E.

Figure 1 shows the simulated production (upper panel) and associated price path (lower panel) under the 4% baseline cost of capital, as well as under relatively modest premiums (50 bp and 2 pp). Both premiums increase production relative to the baseline throughout 2000-2024.

This outcome, perhaps counterintuitive, may be explained as follows. On the one hand, oil assets' NPVs are negatively impacted by the cost of capital. As the cost of capital increases, systematically fewer assets are tapped in total, i.e., over the entire 2025-2044 horizon. On the other hand, firms limit this impact by advancing the dates on which they begin exploiting their assets. In other words, the rise in the cost of capital makes the industry more short-termist, inducing it to exploit available oil projects earlier than it would do otherwise. For modest capital premiums, these two effects translate into a greater total production of projects started over the historical 2000-2024 period of interest. For example, the effect of a 2-pp premium is driven entirely by industry short-termism, with projects' start years brought forward by 3.7 years on average. If the start dates of projects initiated over 2000-2024 were held fixed at their baseline levels, their total production would be unchanged, as all projects would remain profitable despite the premium.¹⁶

As the cost of capital is augmented further, it effectively reduces total oil production by making oil projects unprofitable. Yet, because they exacerbate short-termism, even high capital costs yield only modest reductions in total oil production: For example, Figure 1 shows the effect of a high cost of capital (approximately 15%) that induces the same total production as would a carbon tax of \$25 per ton of CO₂; we explain how we consider this tax shortly below. Moreover, even though the 15% rate discourages as much oil as the tax, its short-termism effect translates into increased production in the first part of the horizon.¹⁷

Carbon-price benchmark. To assess the effect of the augmented cost of capital, we consider the effect of a carbon price of \$25 per ton of CO₂—in 2024 real terms, constant in present value—the cost of capital being held unchanged at its baseline level. For simplicity, we assume that all assets are equally emission-intensive, generating lifetime emissions of 0.544 tCO₂ per barrel, in line with Asker et al. (2024). In contrast with an increase in the cost of capital, a carbon tax introduces a wedge between producer and consumer prices, unambiguously lowering incentives to produce.

¹⁶We are grateful to Charlotte De Cannière for suggesting the decomposition of the premium's effect into industry short-termism, NPV destruction, and equilibrium price adjustment. See Appendix E.6.

¹⁷Its negative effect on total emissions is mainly due to the fewer projects continuing production after 2024.

The resulting wedge—\$13.6 per barrel in 2024—depresses the producer price at all years, inducing lower quantities produced throughout and reducing total production from 2000-2024 assets by 13.56 billion barrels.

Summary. Figure 2 shows how the cost of capital affects total production from projects undertaken over 2000-2024. Modest yet realistic increases in the oil industry’s cost of capital lead to greater oil production. Augmented costs of capital become effective in discouraging production relative to its baseline level only when these rates exceed 10%. At this cost, a sufficient number of oil projects become unprofitable, which dominates the short-termism effect of higher discount rates. Yet, the effect of the cost of capital is relatively weak: A cost of capital as unrealistically high as 15%—a premium of 11 percentage points—would barely have the same effect on total production as a modest \$25 carbon tax. Additional simulations show that achieving the same effect as a \$50 carbon price would require increasing the cost of capital to 24%.

5 Why oil projects’ IRRs do not inform the effect of the cost of capital

Oil companies often characterize the profitability of extraction projects by their internal rates of return (IRRs), directly comparable to their cost of capital.¹⁸ Analysts’ and academic specialists’ estimates of oil IRRs are generally high—e.g., around 35% for U.S. tight oil according to Rystad, based on its 2024 price assumption.¹⁹ High returns to exploiting oil extraction projects *partly* explain why a high cost of capital is required to significantly discourage oil production. Yet, they don’t fully explain our results.

Conventional IRRs assume fixed—often constant in corporate assessments—producer prices. This assumption fits well with the perspective of price-taking operators of economically “small” projects underlying our model. Because they assume fixed prices, conventional IRRs indicate the effect of increasing the cost of capital on a single project’s profitability. However, IRRs fail to capture the effect of the cost of capital when it is augmented at an aggregate level at which

¹⁸IRRs are defined as the cost of capital that turns a project’s NPV nonpositive.

¹⁹See *Rystad Energy News*, October 1, 2024, available at <https://www.rystadenergy.com/news/upstream-breakeven-shale-oil-inflation>. See also, Erickson, Down, Lazarus, and Koplow (2017).

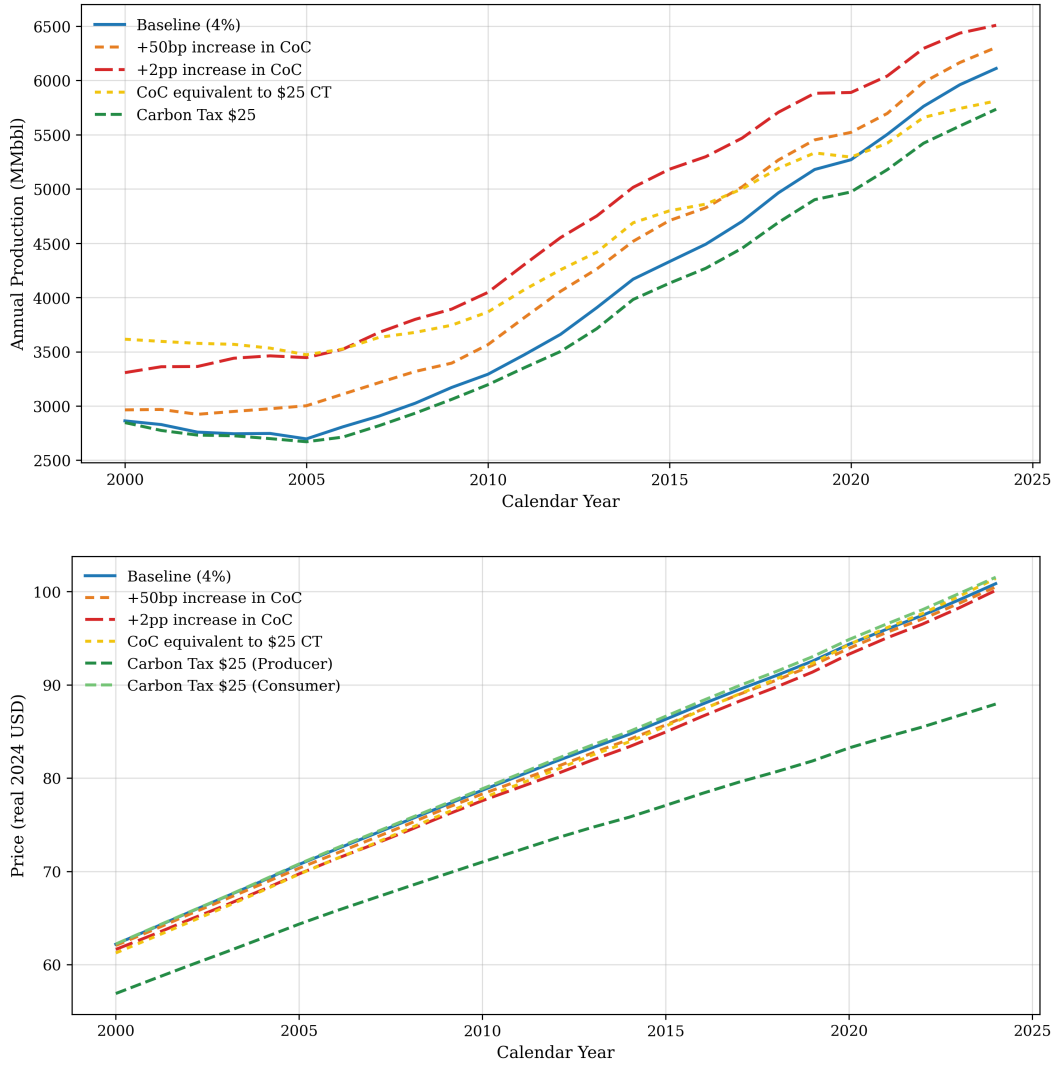


Figure 1: Oil production and price trajectories, the cost of capital and carbon pricing, 2000-2024.

Notes: The upper panel shows oil production trajectories under alternative policy scenarios. The blue solid curve represents the baseline scenario with a 4% cost of capital (CoC). The orange medium-dashed and red long-dashed curves represent the outcomes of 50-bp and 2-pp premiums, respectively. The yellow short-dashed curve represents the CoC-equivalent policy scenario, calibrated so as to discourage the same total production over assets' lifetimes—i.e., including projects' post-2024 continued production—as the \$25 carbon tax does. The green dashed curve represents a carbon pricing scenario with a \$25 carbon tax (in 2024 \$, constant in present value) under the 4% baseline cost of capital. Annual production is measured in million barrels. The lower panel plots price trajectories under the same policy scenarios. For the carbon-pricing scenario, the dark-green dashed curve shows the producer price, while the light-green dashed one shows the consumer price. The carbon tax creates a wedge between the two. Prices are expressed in 2024 USD.

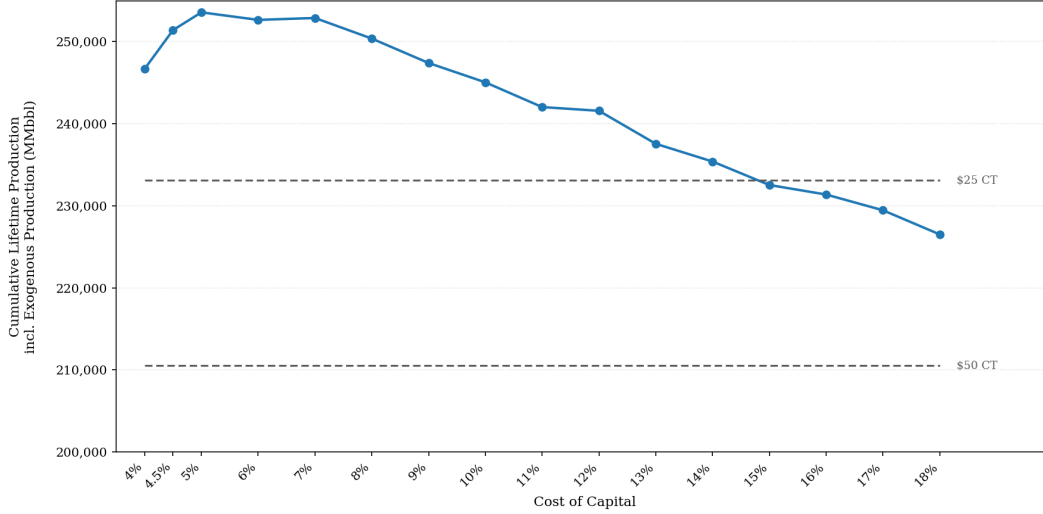


Figure 2: Total oil production and the cost of capital.

Notes: The figure plots total oil production (in million barrels) under a range of costs of capital. Total production is defined as the cumulative lifetime production from projects undertaken during the 2000-2024 period of interest. For this figure, production from exogenous assets is also included. The blue curve connects simulated pairs of total production and cost of capital. The grey-dashed horizontal lines indicate the total production that \$25 and \$50 carbon prices would induce. Comparison between the blue curve and the \$25-level grey curve suggests that a cost of capital of around 15% induces the same total production as would a \$25 carbon tax.

production affects prices. In our simulations, for example, a cost of capital of 15% reduces U.S. and Canadian long-run oil production by 5.5%, calling for an adjustment in the equilibrium global price because demand for U.S. and Canadian oil is relatively inelastic.

To illustrate the discrepancy between real projects' IRRs and the effect of the cost of capital,²⁰ we calculate the IRRs of all oil projects considered for production over 2000-2024 in our simulations, based on fixed baseline market conditions, in line with the conventional practice. These rates range from 4%, our baseline cost of capital, to more than 100%. The median IRR is 55.24%, consistent with existing estimates of the high profitability of oil projects. Appendix E.7 shows the full distribution of IRRs over producible assets' reserves. Figure 3 reports the baseline IRRs of the least profitable projects only, namely those that are abandoned when the cost of capital is increased to achieve the same reduction in oil production as a \$25 carbon tax. The intersection with the baseline IRR curve incorrectly suggests that a cost of capital of 10% would be sufficient to meet this objective, whereas our analysis shows that a rate of around 15% is required.

²⁰For a theoretical illustration of this discrepancy and of the effect of the cost of capital on the oil price, Appendix C.4 presents a simple example of an economically "large" project, i.e., sufficiently large that its abandonment calls for an equilibrium price spike. Its IRR must be adjusted accordingly.

To reconcile oil IRRs with the effect of the cost of capital at the industry level, one should adjust their calculations to account for price equilibrium adjustments driven by the cost of capital (beyond re-optimized drilling dates). The blue curve in Figure 3 shows how the IRRs of the least profitable oil projects change when they are recalculated under the equilibrium price trajectory associated with the nearly 15% cost of capital that reduces oil production by the same amount as a \$25 carbon tax. These adjusted IRRs are consistent with the effect of the cost of capital, confirming that if the latter were increased above 15%, the abandonment of oil projects with lower IRRs would reduce total oil production by about the same amount as a \$25 carbon tax.

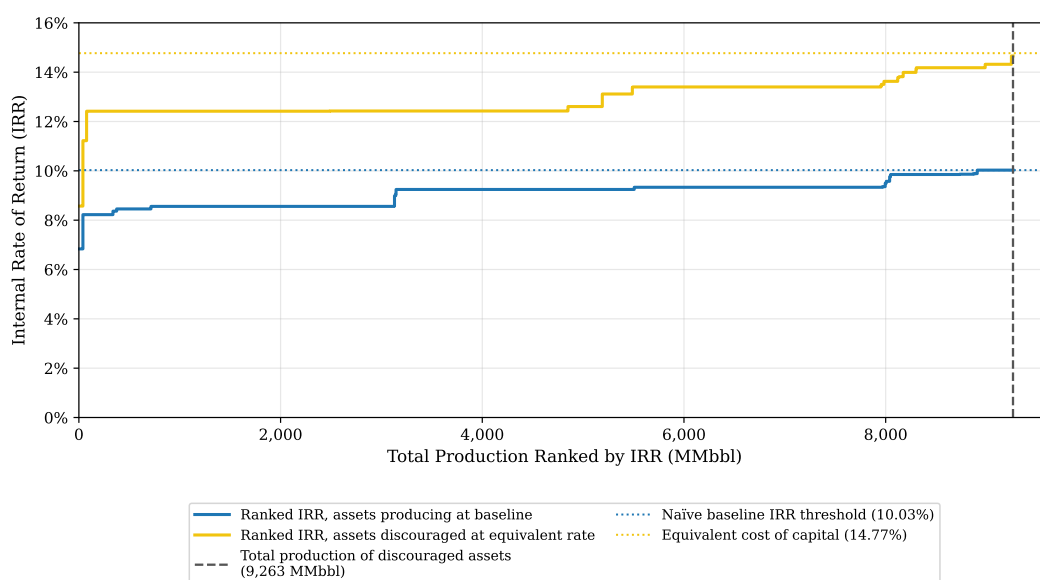


Figure 3: Assets' IRRs, cost of capital, and discouraged oil production.

Notes: The figure ranks assets by internal rates of return (IRRs) from low to high and plots their associated total oil production. Total production is defined as the cumulative lifetime production of assets that start production between 2000 and 2024, including production after 2024. The blue solid step curve ranks the IRRs of the assets that produce during 2000-2024 in the baseline scenario, calculated using baseline production start dates and prices. The yellow solid step curve ranks the IRRs of the assets producing during 2000-2024 baseline scenario but abandoned under the 14.77% cost-of-capital scenario. This cost of capital generates the same total production as would a carbon tax of \$25 per ton of CO₂. For each discouraged asset, IRR is evaluated at the feasible production year that maximizes its NPV under the 14.77% cost of capital. The gray dashed vertical line shows the total production of abandoned assets. The blue dotted horizontal line reports the naive baseline IRR cutoff obtained by applying this production quantity as the target reduction to the baseline IRR ranking. The yellow dotted horizontal line shows the 14.77% cost of capital.

6 Robustness: Sensitivity and shale-production flexibility

We assess the robustness of our results to alternative assumptions about demand elasticities, the baseline cost of capital, and shale production flexibility. Technical details are provided in Appendices G and F.

Changes in the price sensitivity of demand. We vary the elasticity of both price-sensitive components of residual demand—the global oil demand and the supply from the rest of the world—by $\pm 10\%$.

Our main conclusions are unaffected by these changes. In particular, the effect of the cost of capital remains non-monotonic, with total oil production peaking at a cost-of-capital premium of approximately 1-2 pp. Moreover, the cost of capital remains a relatively weak instrument compared with carbon pricing.

As demand for U.S. and Canadian oil becomes more responsive, the effect of an increase in the cost of capital becomes stronger. However, the effectiveness of carbon pricing also increases. As a result, their relative effectiveness changes little. The cost of capital equivalent to a \$25 carbon tax remains close to 15%.

Changes in baseline cost of capital. In line with Damodaran’s (2026) (nominal) estimate of 6%, we have set our baseline cost of capital to 4%, between the 3% and 5% discount rates adopted respectively by Coulomb et al. (2026) and Asker et al. (2019). We explore the implications of using these two alternative values.

A change in the baseline cost of capital is not equivalent to an offsetting adjustment in the cost-of-capital premium. In particular, its effects cannot be inferred simply by shifting the curve in Figure 2 to the left or right. In addition to its direct impact on the net present value of oil projects, the baseline cost of capital also affects our calibration of development and operating costs. As a result, changes to the baseline cost of capital affect both project valuations and the model’s underlying calibration.

Using baseline capital costs of 3% or 5% leaves our qualitative conclusions unchanged. As expected, however, a higher (lower) baseline cost of capital requires a lower (higher) premium to achieve a given production-reduction objective.

Well-level production decisions within shale assets. For simplicity, the model presented in the main text assumes that asset-level production is rigid both for conventional and for shale oil projects. However, Ahlvik et al.’s (2026) empirical analysis reveals that production is less rigid in shale assets than in their conventional counterparts. We examine how this flexibility affects our results by redefining shale oil production decisions to finer production units. Unlike conventional fields, shale assets are developed through the sequential completion of wells, allowing producers to adjust drilling activity more flexibly in response to market conditions.

We capture this intra-asset flexibility with a two-stage structure. First, within each shale asset, production decisions are made at the well-batch level, where a batch is defined as the group of wells completed in the same asset-year. A batch is, on average, 10 times smaller than a shale asset in production volume. Second, the resulting set of producing well batches should jointly cover the development cost required to initiate production at the level of their asset. Building on the asset-level calibration approach, we use Rystad’s technical parameters to construct well-level production trajectories for shale assets and evaluate production timing for well batches. Batch-level production decisions depend both on well capital expenditures required for drilling and completion, and on the per-barrel variable cost, defined in a manner similar to the asset-level analysis. Appendix G presents the calibration in detail.

The results are qualitatively the same as the asset-level analysis. In particular, modest increases in the cost of capital, such as 50-bp and 2-pp premiums, lead to greater production throughout 2000-2024 due to changes in production timing.

Yet, the additional intra-shale-asset decision margin alters the cost of capital’s effectiveness relative to the asset-level model. This is because this margin allows producers to abandon uneconomic batches of wells, thereby increasing the internal rate of return of the assets they belong to. By contrast, the intra-asset margin makes production more responsive to carbon pricing; among assets producing during 2000-2024, total production falls by 6.7% under a \$25 carbon tax, compared with 5.5% in the asset-level specification. As a result, the cost of capital with the same effect as a \$25 carbon tax lies around 30%, rather than 15% according to the main asset-level analysis.

7 Conclusion

Oil divestment is emblematic of the financial approach to climate policy. It is hoped to raise the cost of capital of oil projects, thereby discouraging carbon extraction. We show that the cost of capital affects both the valuation of real projects and the timing of their implementation. Strikingly, for the range of green premiums documented empirically, restricting the oil industry’s access to capital can be counterproductive, boosting oil production through industry short-termism for up to 25 years.

Overall, our findings suggest that capital penalties have only limited potential to discourage oil production. Oil projects are highly profitable, as reflected by their estimated IRRs. This partly explains why only very large increases in the cost of capital are environmentally effective. Moreover, effective capital penalties raise oil prices, increasing the profitability of remaining projects and partly offsetting their intended effect. Over 2000-2024, discouraging oil production would have required investors to forego premiums exceeding 5 percentage points.

Green finance, however, encompasses more than divestment. Focusing on the oil sector abstracts from the possibility that capital is redirected toward competing energy sources, thereby reducing oil demand. Extending our framework to study green investment is a natural avenue for future research. Nor do we examine investor engagement or shareholder activism as potentially more effective alternatives to divestment (Broccardo, Hart, and Zingales, 2022), which may encourage firms to adopt a more long-term perspective (Gollier and Pouget, 2022). If industry short-termism weakens the disciplining effect of divestment, understanding its interaction with engagement and shareholder activism becomes a natural direction for future research.

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