Financing Investment in Electricity*

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Abstract

Meeting rising global electricity demand requires financing large-scale investment in power generation. Despite producing the same electricity output, renewable and fossil fuel plants are financed very differently: renewables typically rely on "project finance" and offtake agreements like Power Purchase Agreements (PPAs) that lock in electricity prices and quantities over the long term. We develop and calibrate an NPV framework that explains these differences by linking production technologies to financing choices under financial frictions. We show how PPAs can help mobilize private funds through a *capital structure channel*. Because renewables have near-zero marginal costs, price certainty under PPAs can significantly reduce cash-flow risk, enabling greater use of bank debt relative to costly equity. This lowers discount rates and increases investment in renewables. In contrast, we show that PPAs are much less attractive for fossil fuel projects with volatile input costs. The framework also highlights a downside of PPAs for renewables: the amplification of macroeconomic shocks, leading to higher investment volatility over the business cycle. We use our framework to explain the slowdown of renewable investment following the 2021-2022 inflationary episode and show that state-dependent investment subsidies indexed to cost shocks can help stabilize private investment.

Keywords: energy investment, renewables, project finance, financial frictions, cost of capital, bank lending, macro-economic risk, inflation

JEL codes: E22; G31; Q42; Q43; Q55

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1 Introduction

Global electricity demand is projected to grow dramatically in the coming years. The rapid growth of the data economy, increasing stakeholder pressure to reduce carbon emissions, and the need to diversify energy sources to reduce dependence on foreign suppliers all make investing in electricity generation capacity a priority in many countries. Technologies like solar, wind, and energy storage have become economically competitive and are now being deployed on an increasingly large scale, offering near-zero marginal costs and carbon emissions once installed. However, these technologies are still widely believed to be "harder to finance" than fossil fuel alternatives. Funding gaps and bottlenecks are frequently cited in media and policy circles as challenges for renewable deployment.[1] As an example, the largest commercial offshore wind power plant in the United States, Vineyard Offshore Wind Farm, was a colossal investment of $2.5 billion that took a decade to develop before it began operating in 2023. Unlocking financing was particularly challenging, as the CEO put it in 2021: "There have been many milestones passed over the last several months... Achieving financial close is the most important."[2]

An important feature of electricity generation is that renewables and fossil fuels typically rely on different financing structures, even though they produce the same homogeneous good. Fossil fuel plants are usually financed by utilities using on-balance sheet vehicles, like bonds. In contrast, renewable energy projects are typically financed through bank loans using a structure known as "project finance", which differs from traditional corporate financing in two key dimensions. First, lenders nearly always require an off-taking agreement as a condition to lend against renewable energy projects. These are long-term contracts where a buyer (usually a utility or large corporate off-taker) agrees to purchase a fixed quantity of electricity generated by the power plant at a pre-negotiated price. In the United States, the most common form of

[1] See e.g., "Bridging the Clean Energy Investment Gap" (OECD, 2024); "Reducing the Cost of Capital" (IEA, 2024).

[2] "Vineyard Wind 1 Becomes the First Commercial Scale Offshore Wind Farm in the US to Achieve Financial Close." Link

off-taking agreement are Power Purchase Agreements (PPAs). For instance, Vineyard Wind secured a 20-year PPA with utilities National Grid, Eversource, and Unitil, selling a fixed quantity of electricity to them at a price of \$0.09/kWh. These types of long-term contracts are rarely required by lenders in other settings. Second, project finance requires setting up a separate off-balance sheet special-purpose investment vehicle (SPV), established solely to own and operate the project. Lenders extend credit to the SPV based only on the specific project's risks and expected cash flows. For example, Vineyard Wind LLC was set up as a standalone company that only owns one asset: the Vineyard Wind project.

In the United States the rise of project finance has gone hand in hand with the rapid growth of renewables and the increasing role of independent power producers (IPPs). Renewable projects are now predominantly developed by IPPs, firms that own generation assets but do not distribute electricity directly to consumers and firms. IPPs are smaller, less regulated, and more dependent on bank financing than the regulated utilities that have been historically dominant (Cicala, 2015; Andonov and Rauh, 2022; Gowrisankaran et al., 2024).

This paper develops an NPV framework of IPP investment in electricity to explain the differential use of project finance and PPAs across technologies. The main innovation is to link the properties of different production *technologies* to *finance*. In the presence of financial frictions, these financing choices can matter for investment outcomes, via their effects on expected returns, risk, and discount rates. We show quantitatively that the project finance structure generally increases investment in renewables primarily through a *capital structure channel*. Because renewables have near-zero marginal costs, PPAs significantly reduce cash-flow risk. This in turn allows greater use of bank debt relative to equity financing, which lowers discount rates and increases investment. However, this financing channel is technology-specific: project finance is much less attractive for fossil fuel projects with volatile input prices. Importantly, we nevertheless show that there can be a downside to PPAs even for renewables: the amplification of macroeconomic risk such as inflation shocks. This occurs because PPA prices are set in the pre-construction phase, which can fix electricity prices to low levels even when macroeconomic shifts lead to cost increases, eroding the post-construction NPV of projects. Thus, project finance and PPAs facilitate financing for renewables, but at the cost of introducing greater investment volatility across the business cycle. While our empirical analysis focuses on the US context and PPAs, the main idea extends to various forms of off-taking agreements used in other parts of the world, including contract-for-difference and feed-in-tariffs.[3]

An important contribution of our framework is to take an investment perspective to the question of renewables development. Although it is well known that from a production perspective, *resource volatility* in wind and solar inputs (i.e. "intermittency") poses key challenges, from an investment perspective this risk is dominated by *electricity price volatility*. Fluctuations in electricity prices are much less predictable over the project's horizon than a renewable plant's electricity production. By fixing electricity prices with committed buyers, investors in renewable projects can be assured of stable and predictable cash flows. Moreover, the risk profile of fossil fuel technologies is fundamentally different from renewables since they rely on tradable inputs (gas), which adds a second layer of volatility on the cost side. As a result, fixing electricity prices alone does not ensure that cash flows become stable for fossil fuels because input costs remain volatile. This is why our framework is set up in terms of net present value (NPV), the canonical way to evaluate investment in finance, rather than in terms of a levelized cost of energy (LCOE).[4] While LCOE measures are widely used to compare the cost of different technologies, they abstract from two key features that are central in our theory: (i) the market prices of electricity and fossil fuel inputs are inherently volatile, and (ii) discount rates are endogenous to risk and capital structure. As we will discuss in depth, these two omitted dimensions are in fact critical to understanding the dynamics of renewable investment.

[3]For instance, renewables investment in Europe often depends on long-term public contracts such as feed-in tariffs (FiTs) and contracts for differences (CfDs). While commonly discussed as subsidy instruments, an important aspect is that they hedge revenue risk (Đukan et al., 2025; Canales and Hirth, 2026).

[4]The LCOE (expressed in \$/kWh) is essentially the discounted cost of electricity generation over a power plant's lifetime.

We nevertheless make two comments on the scope of our framework at the outset. First, we model electricity markets in a stylized way, abstracting from much of the complexities of market structure, regulation, and infrastructure that tend to vary across fragmented regional markets (e.g. Cicala (2015), Gowrisankaran et al. (2024)). While these features are important, they are less central for our question which seeks to explain the widespread use of PPAs for renewables, which is a pervasive feature of IPP investment and bank lending across markets.[5] Our mechanism focuses on electricity price and input cost volatility, which also exists in all electricity markets. Second, we study the value of PPAs for the investing firm and its lenders, abstracting from the details regarding the buyer of electricity that takes the other side of these PPA contracts. We acknowledge that understanding both sides of the PPAs agreement is interesting, especially given the variety of actors involved, from regulated utilities, tech firms, or public entities, having widely different constraints and objectives (Ryan (2021)). That said, this question is beyond the scope of this paper.[6]

The paper proceeds as follows. In the first part of the paper, we present three empirical facts which we use to ground our NPV framework. First, renewable energy sources have a much higher share of capital costs relative to operating costs, implying that more financing has to be provided upfront. Second, electricity produced by renewables has a lower supply elasticity than gas plants, which can flexibly change production to meet shifts in demand. Third, natural gas plants face volatile input costs, whereas renewables have limited input costs. While natural gas input costs are correlated with electricity prices, the correlation is not high enough to completely hedge electricity price volatility. To establish these facts, we compile administrative data and engineering estimates from the Energy Information Administration (EIA), National Renewable Energy Laboratory (NREL), Federal Energy Regulatory Commission (FERC), and the Lawrence Berkeley National Laboratory (LBNL).

Based on these facts, the second part of the paper introduces a simple NPV framework

[5]In some markets regulation essentially prevents the sale of electricity through IPP (Andonov and Rauh, 2022). Our framework naturally does not apply to these settings.

[6]From our vantage point, we take as given that in equilibrium, PPA arrangements will consist of electricity buyers that are acceptable counterparties to the bank or investor that requires PPAs as a condition of financing.

for projects with different technologies. A simple way to think about the NPV of a potential power plant investment is to distinguish between its *internal rate of return* (IRR) and its *discount rate*, often referred to as its (weighted-average) cost of capital (WACC). The IRR is essentially the expected (annualized) rate of return of the project's future profits relative to initial investment.[7] A project's discount rate is its opportunity cost, i.e. the rate of return on the next best comparable project. An investment has a positive NPV as long as its IRR exceeds its discount rate.[8]

In the third part of the paper, we argue that a PPA can increase the NPV of a renewable project, but not for a fossil fuel project. We make this argument in two steps. In the first step, we show that even a fair and permanent PPA significantly reduces the IRR for a gas project (i.e. lower profitability all else equal), but not for a renewable project.[9]. The key point is that electricity prices fluctuate stochastically, while PPAs are modeled as a long-term commitment to sell the plant's expected output at the average expected market price. In this environment, the use of a PPA affects both expected profits and discount rates, but differently based on the underlying technology. The IRR result follows because a significant share of expected profits for a gas plant comes from operational flexibility: adjusting output up and down when the market prices of electricity and gas fluctuate. Namely, the option value of adjusting scale ex-post is ex-ante profitable. A PPA undermines that option value by locking in quantity and price ahead of time. This, however, is not the case for renewables because they have low production flexibility: adjusting output to market prices is technologically difficult, if not nearly impossible without storage. Because of that, a PPA does not reduce expected profits through this channel as it does for more flexible gas plants.

In the second step, we argue that the project finance structure significantly reduces the *discount rate* for a renewable project (i.e. reduced financing costs) but not necessarily for a

[7]Mathematically, the IRR of a project's stream of future cash-flow (including initial investment costs) is the discount rate that makes the project's NPV equal to zero.

[8]As long as projected cash-flows satisfy a regularity condition, which typically holds for energy projects.

[9]Of course, any imperfections in PPA contracts (premium, opportunistic renegotiation, counter-party risk, etc.) would further reduce IRR for obvious reasons across all technologies.

gas project. Although most existing work on energy investment takes discount rates as exogenously given, we explicitly model their determination through the lens of classical theories of financial frictions that lead to a *capital structure channel*.[10] Specifically, in our framework having more debt (i.e. "leverage") and less equity financing lowers the discount rate. Risk-based debt limits imply that cash-flow risk reduces the debt size offered by bank lenders that manage default risk. Additionally, substituting debt with equity is costly as there is an excess risk-adjusted cost of equity financing.[11] Because renewables have near-zero marginal costs, a PPA that locks-in electricity prices and quantities significantly reduces cash-flow risk, which raises debt limits and reduces expensive equity financing. Keeping these projects off-balance sheet is also helpful to make sure that these very safe cash-flows are not mixed with any other risky investments on firms' balance sheets. In contrast, a PPA is detrimental for a gas project's capital structure, for two reasons. First, a PPA only addresses cash-flow risk coming from market volatility on the output side, but leaves market volatility from input prices unaffected. Second, a PPA reduces expected profits, as discussed above, which tightens debt limits and forces the use of more expensive equity financing.

In the fourth part of the paper, we calibrate our framework to show quantitatively how PPAs and the project finance structure specifically foster more investment in renewables. We discipline our parameters by combining micro-data from different sources: (i) market prices for electricity, (ii) capacity and costs across technologies from LCOE estimates, (iii) financial variables, including the cost of debt and equity, as well as debt limits from banks, to match WACC estimates from NREL.[12] In our main calibration, when a typical gas plant adopts a

[10]A natural question is why we start from the vantage point of frictional financial markets. We argue that frictionless theories of finance like Modigliani-Miller or the CAPM are unlikely to explain PPAs because electricity prices and aggregate stock market factors are not correlated in the data. In practice, Modigliani and Miller's famous irrelevance theorem does not hold and the mix of debt and equity financing impacts the project's discount rate.

[11]In Modigliani Miller, this wedge between risk-adjusted debt and equity cost is zero. We do not explicitly model the sources of this wedge. Frictions that have been studied to rationalize a role for capital structure include taxes, agency costs, inefficient bankruptcy or liquidation. Government guarantees can also lead to subsidized debt financing.

[12]NREL refers to estimates produced by the National Renewable Energy Lab of the Department of Energy based on surveys of developers and generators.

PPA, its IRR falls from 5% to less than 3%, while its discount rate stays close to 4.8%. This means that a PPA turns this gas investment project from positive to negative NPV. The opposite happens for a typical solar project. A PPA keeps its IRR unchanged around 4.5%. However, with a PPA, the discount rate of the renewables project falls significantly, from 5% to 3.8%, turning the NPV of the investment positive. This is driven by the capital structure channel, as leverage reacts strongly to the presence of a PPA.

Lastly, in the fifth part of the paper, we nevertheless identify a downside of the project finance structure for renewables: the amplification of macroeconomic risk. We start by showing empirically that there is macroeconomic risk in electricity prices. Fluctuations in electricity prices are strongly correlated with aggregate inflation, which affects the investment cost of building new plants. In addition, we show that PPA prices are closely correlated with current electricity prices, suggesting that shocks to electricity prices are typically perceived as persistent rather than transitory. As a result, although PPAs reduce cash-flow risk post-construction by locking in electricity prices, they shift some of that risk to the pre-construction phase, especially for projects with long development timelines. Unexpected changes in investment costs might turn the NPV negative as construction starts – leading to ex-post abandonment or delay. This mechanism leads to higher investment volatility over the business cycle.

The post-2021 inflation episode was a perfect example: for the first time in recent decades, the cost of building new renewable plants started to *increase* for a number of reasons, including supply chain bottlenecks around the world. Electricity prices also increased significantly at the same time, meaning that without a PPA, rising electricity prices would have mitigated some of these cost increases. However, this channel is shut off with PPAs, since electricity prices are fixed. Furthermore, PPAs are often signed years before construction begins because of the complexity of many renewable projects (offshore wind being the worst case). Because their PPAs locked in low electricity prices, rising costs in the construction phase increased the likelihood that project NPV would be negative ex-post. Offshore wind was hit particularly hard, with roughly $30 billion in investment put on hold or canceled across the United States in spite of generous new subsidies.[13] For this mechanism to exist, we show that there must be a *macro* correlation between investment cost shocks and long-lasting electricity price shocks, which we verify in the data. The resulting capital crunch and the downside of project finance were perhaps hard to anticipate given the decade-long decline in building costs for renewables, something we provide additional evidence for using data on revisions in investment cost forecasts over time.

In our calibration, fewer projects would have been abandoned or delayed had their PPAs reflected the new, higher electricity prices. This, however, is not an easy solution since that works against the de-risking of cash flows discussed above. The project finance structure therefore creates a trade-off between the microeconomic benefit of reduced cash-flow risk that increases the average scale of investment and the cost of more exposure to macroeconomic shocks over the business cycle. We show that this issue is not limited to cost shocks but also extends to other macro shocks, like interest rate shocks, as long as they are also correlated with electricity prices.

We conclude by studying a potential policy response: state-dependent investment subsidies. In our calibration, this policy would reduce volatility in renewable energy investment. Indexing the level of investment tax credits (ITC) to construction costs can maintain projects' NPVs and avoid a dry-up of private sector funding in bad macroeconomic times. While perhaps counterintuitive, a stable policy is thus not always the best way to induce stable investment. There are nevertheless challenges to this type of policy: it requires commitment to a clear rule to avoid policy uncertainty and would likely lead to higher fiscal spending.

1.1 Related literature

This paper is at the intersection of energy, finance, and macroeconomics and contributes to three growing strands of literature. We first relate to a large body of work on investment

[13] See e.g., "Cancellations Reduce Expected U.S. Capacity of Offshore Wind Facilities" (EIA, 2024), "Wind Industry in Crisis as Problems Mount" (WSJ, 2023), "The Struggles of the Offshore Wind Industry" (FT, 2023).

in electricity generation and the energy transition, particularly in the industrial organization and macroeconomics literatures (see Kellogg and Reguant (2021) or Fabra and Reguant (2024) for surveys). This includes investment in renewables (Arkolakis and Walsh, 2023; Gonzales et al., 2023; Butters et al., 2025), fossil fuels (Cicala, 2015; Gowrisankaran et al., 2024), their interaction (Abuin, 2024; Adrian et al., 2022), as well as the demand side of electricity markets (Burgess et al., 2025). Much of this literature focuses in particular on the details of utility regulation, vertical integration, or spatial market integration in the presence of externalities. Our contribution comes from our focus on the financing side of investment, including our emphasis on how technology-specific risk and financial frictions drive project discount rates and have thus a large impact on investment dynamics. In this area, we relate most closely to recent work on power purchase agreements, including counterparty risk in PPAs (Ryan (2021) and Fabra and Llobet (2025a)), the role of PPAs in reducing risk (Fabra and Llobet (2025b)) and enabling data centers to use project-finance and expand renewables investment (Heiss et al. (2026)). Relatedly, Reinartz and Schmid (2016), Lin et al. (2021), and Lin et al. (2023) link production flexibility to leverage, liquidity management, and investment for a global sample of utilities. We build on this line of thinking with a novel macro-finance perspective that argues that "de-risking" cash-flows is valuable because of financial frictions and a capital structure channel, a notion that is very important in practice but less well studied in this literature.

Second, we relate to a growing literature on the drivers of green finance, broadly defined; see Giglio et al. (2021) and Hong et al. (2020) for surveys.[14] While many works in this area focus on non-pecuniary preferences of investors for green projects, or financial motives to hedge climate transition risks, our focus is on *technology*-specific risks. In the finance literature, our study relates most closely to Andonov and Rauh (2022) who find a significant change in ownership

[14] Research on corporate finance includes Hartzmark and Shue (2023); Bellon (2021a,b); Bellon and Boualam (2024); Duchin et al. (2022); Shive and Forster (2020); Bai and Wu (2024); Bartram et al. (2022); Feldhütter and Pedersen (2025); De Haas et al. (2025). Research on financial markets includes Giglio et al. (2023); Green and Roth (2021); Baker et al. (2022); Flammer (2021); Pástor et al. (2021); Pedersen (2023); Chittaro et al. (2025); Kumar and Purandaram (2025); Feher et al. (2025).

of new forms of electricity generation in the U.S. away from traditional regulated utilities, including the rise of IPPs in deregulated states and private equity owners. We build on their work by developing a framework of the economics of independent power producers, rather than the regulated utilities that have received more attention in the industrial organization literature. We also complement their focus on equity ownership and regulation by emphasizing the role of debt financing, risk, and financial frictions. We stress the importance of discount rates for investments, in line with recent work by Gormsen and Huber (2025) and Gormsen et al. (2024). Our focus on risks in energy investment is shared with Acharya et al. (2025), Fuchs et al. (2024) and Kellogg (2014), who focus on a real option channel, as well as Hong et al. (2025), who focus on a diversification channel. We add to these works by focusing on power purchase agreements in project finance, emphasizing the role of financial frictions and introducing a capital structure channel. We relate directly to Lanteri and Rampini (2023) and Darmouni and Zhang (2024) who study the effect of limited pledgeability on the transition to clean technologies but abstracts from risk. We also relate to empirical studies of project finance (Green and Vallee, 2025; Sastry et al., 2023; Berg et al., 2024; Garrett and Shive, 2022). We also draw analogies to the literature on blended finance, which considers how public and philanthropic funding can adopt financial structures to "de-risk" projects and crowd in private capital (Flammer et al., 2024). Consistent with this literature, we show how state-dependent government investment subsidies can help to stabilize private investment.

Relatedly, our focus on ring-fencing and capital structure channel for PPAs in energy investment also builds on a large literature in corporate finance regarding hedging and debt capacity, though much of that literature focuses on derivatives contracts provided by large banks to large firms (Stulz, 1996; Leland, 1998; Graham and Rogers, 2002; Campello et al., 2011). While similar in spirit, PPAs are very a different form of risk management that are an integral and pervasive part of the financing of renewables (IRENA 2023). The capital structure channel can also explain why projects are kept off-balance sheet, in the spirit of Leland (2007) argues that keeping safe cash-flows outside the firm allows to raise more debt and increase total value.

Finally, our results on macroeconomic risk connect to a growing body of work studying the links between climate, energy and the macroeconomy; see Bilal and Stock (2025) for a survey. Examples include Barrage (2023), Bakkensen and Barrage (2025), Acemoglu et al. (2023), Barrage (2020), Känzig et al. (2025), Bilal and Känzig (2024), Chittaro et al. (2025), Papoutsi et al., Bistline et al. (2023), and Mehrotra (2024) which focus on other macroeconomic impacts of the transition, such as loss and damage functions, productivity changes, and adaptation. Our main contribution to this literature centers on how the macroeconomic cycle, and in particular inflation spikes, can impede renewable investment through a financing channel. We nevertheless abstract from the macroeconomic link between investment today and future electricity prices that features centrally, for instance, in Arkolakis and Walsh (2023) or Mehrotra (2024).

2 Background on investment in electricity generation

2.1 The changing composition of U.S. power generation

Electricity generation in the United States is undergoing a major transition driven by rising electricity demand, aging infrastructure, and decarbonization goals. Many thermal plants built in the mid-20th century are reaching the end of their operational lifetimes, while electrification in transport and data centers is expanding demand. According to the Department of Energy (DOE)[15] national peak load is projected to rise by nearly 15 percent between 2024 and 2030 and data centers alone will add around 50 GW of continuous load by 2030—roughly equivalent to the entire electricity demand of California. At the same time, a large share of the existing generating fleet, in particular older coal and gas plants, is reaching retirement age, with about 104 gigawatts of generating capacity (roughly 10 percent of the U.S. total) scheduled

[15] *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid* (U.S. Department of Energy, 2025)

to go offline by 2030. Meeting this rising demand will require large-scale investment in new generation capacity.

As shown in Figure 1, virtually all newly installed and planned generating capacity in the United States comes from solar (often paired with battery storage), wind, and gas plants. Solar alone accounts for more than 50% of planned additions through 2027. We therefore focus our analysis on these three technologies – solar, wind, and gas – which together represent nearly the entirety of planned U.S. capacity additions.

Gas and renewables are fundamentally different technologies for producing electricity. Gas plants generate electricity by purchasing and burning gas to drive a turbine and can rapidly adjust output to meet changes in demand. Renewable technologies such as solar photovoltaic and wind power convert available natural resources directly into electricity with near-zero marginal cost but have limited ability to adjust output. These technological differences in (i) input price volatility (ii) operational flexibility are crucial for understanding their respective financing structures. As we show in Section 3, these differences are central to understanding why renewables tend to rely on project finance and PPAs, whereas gas plants are financed more often on-balance sheet.

2.2 Market restructuring and the rise of independent power producers

Over the past decades, the U.S. electricity sector has undergone a structural transformation driven by market restructuring (deregulation) and the accompanying rise of independent power producers (IPPs). Historically, electricity generation, transmission, and distribution were managed by vertically integrated utilities operating under rate-of-return regulation, with limited incentives for efficiency or innovation. The Energy Policy Act of 1992 and FERC Orders 888 and 889 (1996) introduced competition by requiring open access to transmission networks and establishing Independent System Operators (ISOs) to manage wholesale markets. This restructuring separated generation from regulated distribution and enabled IPPs –

firms that own and operate generation assets but do not manage transmission or distribution networks – to compete.

Over the past twenty years, IPPs have displaced regulated utilities as the dominant investors in new generation capacity (Andonov and Rauh, 2022), with their share of total capacity additions increasing to nearly 80 percent by 2024 (see Figure 2). This is true despite IPPs facing regulatory frictions in some regions like the Southeast and part of the West. This aggregate dominance is largely driven by the rise of renewable energy projects, which are overwhelmingly developed and financed by IPPs. IPPs raise capital from private markets typically through project finance structures secured by project-specific cash flows. Unlike traditional utilities, IPPs face market-based pricing and bear investment risk directly.

The rise of IPPs as the primary developers of renewable energy fundamentally changes how investment in electricity generation is financed. This paper examines the economic mechanisms that enable IPPs to raise private capital for renewable projects, with a focus on how long-term PPAs mitigate revenue risk and reduce financing costs but potentially increase exposure to macroeconomic risk. Our focus on the IPP segment complements prior research on regulated utility investment (Gowrisankaran et al., 2024), whose cost-of-service regulatory framework creates fundamentally different financial incentives and risk-return dynamics.

2.3 The role of project finance and power purchase agreements

Power Purchase Agreements (PPAs) are the contractual foundation of project finance in renewable energy. A PPA is a long-term agreement, typically lasting 10 to 25 years, between a power producer and a buyer (usually a utility or large corporate off-taker) that guarantees the sale of electricity at a pre-agreed price. These contracts are almost always signed before construction begins, often several years in advance. In a project finance structure, lenders extend credit solely based on the specific project's risks and future cash flows through a special-purpose company established to own and operate the plant. Lenders typically have either no recourse or only limited recourse to the parent company that develops or sponsors the project (the "sponsor"), meaning they cannot claim the sponsor's capital or assets to repay the debt incurred by the special-purpose vehicle (SPV) that owns and operates the project.

By locking in both a stable price and a creditworthy counterparty, the PPA provides renewable projects with a predictable cash flow stream. This long-term revenue certainty is often seen as a necessary condition for lenders, making renewable energy projects "bankable" (Pombo-Romero et al., 2024; Raikar and Adamson, 2024).[16] Consistent with this view, we show in Figures 3 and 4 that renewables are more likely to rely on project finance and PPAs, in contrast to fossil fuel plants. Renewable projects are more likely to (i) be developed by independent power producers (rather than utilities), (ii) rely on off-balance sheet special purpose vehicles, and (iii) have a PPA in place. The left panel of Figure 3 uses detailed regulatory generator-level data from the EIA to show that over 80% of installed renewable capacity is financed by IPPs.[17] For fossil fuels, the share is below 40%. Consistent with that, the right panel of Figure 3 tracks the share of capacity from generators with "LLC" ("limited liability company") in their name and documents a nearly identical pattern. These LLCs typically represent off-balance sheet special purpose vehicles. Figure 4 complements this evidence by documenting the prevalence of PPAs among renewables. We combine two complementary data sources: utility PPAs, which must be reported to the Federal Energy Regulatory Commission (FERC), and corporate PPAs, typically signed by large technology firms such as Meta, Amazon, and Google, as compiled by Bloomberg New Energy Finance (BNEF). Together, these data show that nearly all renewable projects developed by IPPs operate under a PPA. For fossil fuels, the share is less than 15%. Heiss et al. (2026) show related evidence using plant-level data from the U.S. and emphasize the importance of corporate PPAs for investment in

[16] For simplicity, our baseline framework treats the PPA as an idealized contract that fully fixes the project's sale price. In practice, the dominant structure today is often a virtual PPA (VPPA), a purely financial contract for differences: the project sells electricity into the wholesale market at the local nodal price and separately receives (or pays) the difference between the contracted PPA price and a floating regional hub price (Norton Rose Fulbright, 2020). The hedge is therefore imperfect because the project remains exposed to the difference between hub and nodal prices ("basis risk") which tends to be negatively correlated with output and limits how fully a PPA can stabilize cash flows in practice. Our baseline PPA should therefore be interpreted as a reduced-form benchmark of the de-risking benefit of long-term contracts.

[17] The EIA defines IPPs as limited liability, investor-owned special purpose vehicles that generate electricity for sale to utilities and other off-takers.

renewables.

These patterns also hold globally. The International Renewable Energy Association (IRENA) finds that the vast majority of renewable projects rely on project finance and have limited exposure to electricity prices.[18] For instance, European projects rely on long-term public contracts such as feed-in tariffs (FiTs) and contracts for differences (CfDs). Although these contracts sometimes have an element of subsidy, they also perform a second and equally important function: they hedge revenue risk (Đukan et al., 2025; Canales and Hirth, 2026). The near-ubiquity of offtake agreements across geographies for renewables projects supports our argument that they enhance debt capacity. However, this prevalence poses an empirical challenge: when nearly all U.S. projects have PPAs, empirically estimating their effect on debt capacity becomes difficult. We therefore acknowledge that this link cannot be tested empirically, but our argument is grounded in the institutional fact that lenders require PPAs as a condition of the loan.

2.4 Data

We combine data from a variety of sources on both the financial and real aspects of electricity investment, linking project-level information on investment and financing structures with technical and regulatory characteristics of installed and proposed U.S. power plants. We complement this data with regional monthly wholesale and retail electricity prices, as well as public and corporate PPA prices.

U.S. Energy Information Administration (EIA). We use detailed plant-level data from the *EIA-860* and *EIA-923* surveys, which provide comprehensive information on planned and installed capacity, electricity generation, ownership structure, primary fuel inputs, and operating costs. We also incorporate EIA data on electricity and gas prices, construction costs, as well as utility-level revenue and financial information.

[18] See IRENA, 2023 Renewables Financing Report

Lawrence Berkeley National Laboratory (LBNL). We compile information on power purchase agreements (PPAs) involving utility off-takers from the *Utility-Scale Wind and Solar Markets* reports produced by LBNL. This data includes PPA execution dates, contract duration, prices, technology type, and project location, which we match to EIA plant identifiers where possible.

National Renewable Energy Laboratory (NREL). We draw on detailed estimates of capital expenditure (CAPEX), levelized cost of energy (LCOE), and weighted average cost of capital (WACC) components by technology and over time from NREL's *Annual Technology Baseline (ATB)* and related datasets. This data provides a consistent benchmark for technology cost trends and financing parameters.

IJ Global. We use transaction-level data on energy investment from IJ Global, which primarily covers U.S. energy projects financed through project finance structures. Each record includes information on financial close date, debt and equity composition, lender and sponsor identities, total investment cost, and project technology.

Federal Energy Regulatory Commission (FERC). In addition to the LBNL data, we use regulatory micro-data from FERC's *Electric Quarterly Report (EQR)*. These filings report detailed contractual information for PPAs involving predominantly public utilities, including counterparties, contract capacity, and pricing.

3 Evidence on costs and risk across technologies

Our framework builds on three key facts about the cost and risk profile of electricity generation.

3.1 Differences in upfront investment costs

Renewable plants and fossil fuel plants use different production technologies to generate electricity. One key aspect that impacts the economics of financing is the difference across technologies in the upfront (fixed) capital cost required to build a project, which can be seen in each technology's levelized cost of energy (LCOE). The LCOE (expressed in $/kWh) is essentially the discounted cost of electricity generation over a generator's lifetime.[19] Figure 5 uses data from the EIA to break down the LCOE of renewable versus gas plants into various components. Capital costs account for nearly 80% of the LCOE for renewables, compared with only one-third for gas plants. This is one factor that can make renewables more affected by financing constraints, since more of the costs have to be covered upfront before any operational profit is realized.

3.2 Flexibility of production

A second key technological difference across generation technologies is operational flexibility. Renewable output is largely governed by the availability of wind and solar resources, with storage providing only limited short-run smoothing. By contrast, gas plants can ramp production up or down relatively quickly in response to market conditions (Reinartz and Schmid, 2016; Lin et al., 2023). In electricity market terminology, fossil fuel generation is "dispatchable" while renewables are largely "non-dispatchable". Moreover, renewables with near-zero marginal cost have a near uniform incentive to produce the maximum possible, irrespective of market conditions. In economic terms, this means that gas plants have a higher short-run price elasticity of supply than renewables.

We provide evidence of this difference using regional EIA data. Table 1 reports regressions of monthly ISO-level generation on monthly local wholesale electricity prices separately by technology. We include year and ISO fixed effects and allow for heterogeneity across gas plants by distinguishing between different types of gas generation. Columns (2)-(4) show that gas generation responds strongly to fluctuations in market prices, with the strongest

[19] A key advantage of LCOE is that it accounts for differences in capacity factor across technologies. Capital costs per unit of nameplate capacity are potentially misleading. For instance, a gas plant costs significantly more than a solar plant per unit of nameplate capacity, but the capacity factor of a typical gas plant is often more than twice that of a solar plant. Capital costs per unit of annual output are thus lower for gas, something that the LCOE captures.

response coming from gas "peaker" plants, which operate when demand is highest. By contrast, renewables show no significant response to short-run price movements. Lin et al. (2023) provide similar evidence in a larger global sample. These results are consistent with the view that gas plants are operationally flexible, while renewables are much less able to adjust output in response to market prices.[20]

Two caveats are worth noting. First, regressions of quantities on prices raise the usual simultaneity concern, since prices reflect both supply and demand conditions. Our goal, however, is not to identify a structural supply elasticity for the market as a whole. Rather, we compare the relative responsiveness of different generation technologies facing the same local demand conditions. Since electricity is a homogeneous good within a given market, cross-technology differences in estimated price responsiveness are informative about differences in operational flexibility. Second, one might worry that the price sensitivity of gas generation simply reflects the fact that natural gas input costs are themselves correlated with electricity prices (see Section 3.3), which would impact supply decisions for gas plants specifically and not renewables. However, that concern would, if anything, work against finding a strong positive response of gas output to electricity prices, because higher gas prices raise marginal costs and discourage production. The fact that gas generation still responds strongly and positively to electricity prices therefore reinforces the interpretation that gas plants are much more responsive to short-run price fluctuations than renewable plants.

This difference is central for the rest of the paper. For gas plants, an important share of profits comes from the ability to expand output when margins are high and reduce output when margins are low. For renewable plants, by contrast, output is much less adjustable in the short run, so realized revenues are driven primarily by price fluctuations rather than by active production decisions.

[20] For renewables, the absence of an output response to prices may reflect both a technological constraint and an economic optimum: with near-zero marginal costs, it is nearly always optimal to produce at full capacity whenever prices are positive, so output is effectively determined by resource availability rather than market conditions. For our purposes, the distinction between engineering constraints and profit-maximizing behavior is not central. What matters is that, relative to gas plants, renewable output is less state-contingent, so cash flows depend more directly on market prices than on active production decisions.

3.3 Input price volatility

Renewables produce electricity from freely available natural resources. In contrast, gas plants must first purchase gas (in their input market) to produce and sell electricity (in their output market). Using regional price data, we find that the price of gas is volatile and that this market volatility is not offset by electricity prices (Table 2).

To understand this, it is useful to start with a formula for the profits of a stylized gas plant. Its operating profit margin is the difference between the price of one unit of electricity and the cost of producing it, say $p_t - c_t$. Focusing on fossil fuel costs c_t, the cost of producing one unit of electricity is the product of two terms: (i) the price of gas, and (ii) the efficiency of the plant, i.e. how many units of gas it takes to produce one unit of electricity (this is also known as the plant's "heat rate"). Defined this way, the margin $p_t - c_t$ is commonly referred to as the "spark spread" in the industry. The variance of this spark spread is a key component of cash-flow risk for a gas plant. When the spark spread increases, a plant is more profitable. When it decreases, profitability decreases. For illustration, Figure 6 plots electricity prices and gas costs for seven regional U.S. electricity markets. The gap between the two, the spark spread, clearly fluctuates over time in all markets.

We empirically decompose the variance of the spark spread in different U.S. electricity markets using regional gas and electricity prices from the EIA. Note that there are three terms behind this variance:

$$Var[p_t - c_t] = Var[p_t] + Var[c_t] - 2Cov[p_t, c_t]$$

The first term is the variance of electricity prices. Both gas and renewable plants are exposed to this variation in output prices. The last two terms are specific to gas plants. The second term captures the volatility of the price of gas, which everything else equal makes gas plants cash-flow more risky. However, the third term importantly captures the fact that electricity and gas prices are, to some extent, correlated. This correlation between input and output prices creates a potential for hedging electricity prices that is unique to gas plants. Because the second and third terms go in opposite directions, it is an empirical question how the presence of input market volatility affects the risk of gas plants overall.

Table 2 presents the results. Row 7 and 8 in the third panel show that there is substantial volatility in both electricity and gas prices. Interestingly, row 9 shows that the spark spread is also highly volatile. The standard deviation of the spark spread (row 6) is roughly twice its mean (row 3), while for both electricity prices and gas costs the ratio is less than one (row3/row1, row5/row2). As a result, the variance of the spark spread is in fact not much lower than the variance of electricity prices. Electricity and gas prices on average have a positive correlation coefficient of 0.54 (row 12) due to the fact that gas plants are often the marginal source of power in many markets.[21] However, this correlation is not large enough to offset the volatility in electricity prices. If the correlation was very high, the volatility of the spark spread would be significantly smaller than the volatility of electricity prices.

This has important implications. Gas plants are not "naturally" hedged even if the price of their inputs correlates with their output price. This means that their cash-flows are substantially volatile absent any risk management measures. Moreover, gas projects face market volatility from both the output and input side. This is in contrast to renewables which, due to their near-zero marginal cost, only face market volatility from the output side. Removing electricity price volatility only would still leave substantial volatility for a gas plant. Row 10 shows that the variance of fuel cost is on average still a third of the spark spread variance. The key difference is that renewables face revenue risk only, whereas gas plants face both revenue risk and input-cost risk.

[21] The implied correlation coefficient can be computed with the following formula: $\rho_{p,c} = \frac{Var[p_t]+Var[c_t]-Var[p_t-c_t]}{2\sqrt{Var[p_t]Var[c_t]}}$.

4 An NPV framework of financing investment in electricity

4.1 Overview

We provide a framework to understand the financing of investment in electricity generation. The framework builds on the previous empirical evidence to explain why the project finance structure arises and what its implications for investment dynamics are. Our baseline model is purposely stylized to make the point as transparently as possible. In particular, we abstract from much of the complexities of market structure, regulation, and infrastructure that tend to vary across fragmented regional markets. Note that, for instance, in a few markets regulation heavily penalizes IPPs: our baseline model naturally does not apply as such to these settings. More generally, there are many potential extensions that could be incorporated, and we list a few below.

We take a net present value (NPV) approach to investment decisions. An investment should be undertaken when its NPV is positive. Conceptually, it is useful to break down a project's NPV into two components: its *internal rate of return* (IRR) and its *discount rate* (often referred to as its (weighted-average) cost of capital, or WACC). The IRR is essentially the expected (annualized) rate of return of the project's future profits relative to initial investment.[22] A project's discount rate is its opportunity cost, i.e. the rate of return on the next best comparable project. The investment has a positive NPV as long as its IRR exceeds its discount rate:[23]

$$NPV > 0 \iff IRR > \text{discount rate}$$

This section develops a stylized perpetuity model of energy investment that nests both renewable and fossil fuel technologies. The framework is designed to map the three facts in Section

[22]Mathematically, the IRR of a project's stream of future cash-flow (including initial investment costs) is the discount rate that makes the project's NPV equal to zero.

[23]As long as projected cash-flows satisfy a regularity condition, which typically holds in the context of energy projects.

3 into a small set of objects: capital intensity into upfront investment cost i, operational flexibility into ξ, input-cost risk into c_t, macroeconomic exposure into the aggregate state s_t, and long-run contracting into the PPA. We first focus on cash-flow risk (once operations have started), while a later section will introduce macro-economic risk (before construction is undertaken).

4.2 Operating profits and IRR

Consider a power plant that produces electricity in perpetuity. The plant has a maximum nameplate capacity K. (Scaled) operating profits in year t are given by $\pi_t/K = q_t/K \times (p_t - c_t)$. These profits are stochastic, determined by the following three quantities. p_t is the market price of electricity, which determines revenues. c_t is the plant's operating costs, which for simplicity only include variable costs. The difference $p_t - c_t$ is the plant's (operating) profit margin. q_t/K is the plant's capacity factor, defined as the ratio of its electricity output to its nameplate capacity. Formally, each is determined by its own equation:

$$p_t = \bar{p} + a_p s_t + e_{p,t}$$

$$c_t = \bar{c} + a_c s_t + e_{c,t}$$

$$q_t/K = \theta + \xi(p_t - c_t - (\bar{p} - \bar{c}))$$

The first equation assumes that electricity prices p_t stochastically fluctuate around their expected value $\bar{p}$. Electricity prices are affected by an aggregate shock s_t representing the state of the economy that can affect other variables, as well as an idiosyncratic shock. Similarly, c_t the cost of operating the plant fluctuates around its expected value $\bar{c}$, subject to potentially both aggregate and idiosyncratic shocks. Finally, the plant capacity factor is on average equal to θ, but might adjust depending on the parameter ξ that reflects the price elasticity of supply. Output will go up or down depending on whether profit margins are unexpectedly high or unexpectedly low.[24]

While both renewables and fossil fuel plants face the same stochastic electricity price, the parameters underlying their cost and output are different. In terms of costs, a renewable plant has near-zero, a-cyclical production cost, implying that both the average variable cost $\bar{c}$ and the loading a_c on the aggregate state are low. On the other hand, gas plants have to purchase fuel to produce electricity, so $\bar{c}$ is substantially higher. The price of gas might also be cyclical, which would impact the value of the loading a_c. The two technologies also diverge in terms of capacity factor. Importantly, gas plants are technologically more flexible; the parameter ξ is positive. For renewables, the parameter ξ is much smaller, often close to zero. The baseline capacity factor θ is also typically higher for modern gas plants than renewables.

The IRR of the project is determined by the flow of expected operating profits $E[\pi_t/K]$ as well as investment costs (CAPEX) i (in \$ per unit of nameplate capacity K). For ease of illustration, in this section we provide a closed-form formula for a stylized perpetual plant that produces every period:[25]

$$IRR = \frac{E[\pi_t/K]}{i}$$

The calibration below incorporates additional realistic features, including capital depreciation, corporate tax, fixed operational costs, or interconnection costs. This section also abstracts away from the arrival of news about cost shocks, but that is the subject of Section 6.

4.3 Financing and discount rates

Although much of the existing work on energy investment takes discount rates as given, foundational finance theories emphasize that they are endogenous to risk and capital structure.

[24]This linear supply function can be micro-founded with a production function with quadratic adjustment costs. Assume that the plant maximizes $q_t p_t - c(q_t)$, where $c(q_t) = c_0 + c_t q_t + \frac{1}{2\xi}(q_t - \bar{q})^2$. The first order condition implies that $q_t = \theta + \xi(p_t - c_t - (\bar{p} - \bar{c}))$ as above, where $\theta := \bar{q} + \xi(\bar{p} - \bar{c})$.

[25]Mathematically, the IRR solves $\sum_t E[\pi_t/K]/(1+IRR)^t - i = 0$, which simplifies to our expression thanks to the perpetuity formula. The current formula assumes no subsidies. Adding production tax credits s^q and investment tax credits s^i leads to $IRR = \frac{E[\pi_t/K]+s^q}{i(1-s^i)}$

4.3.1 Frictionless benchmark

Classical frictionless theories such as Modigliani-Miller imply that a project's discount rate is entirely driven by a single variable: its systematic risk. Systematic risk, sometimes called aggregate or market risk, is measured by the project β ("beta") which is simply defined as the regression coefficient between the project's risky returns and aggregate stock market returns. Other forms of risk do not require risk compensation because they are diversifiable and thus do not create risk at the portfolio level. Note that this logic extends to richer "factor models" beyond the CAPM that have been proposed in the past decades. However, the fourth fact above shows that electricity prices are at best weakly correlated with the main stock market factors. The presence of a PPA is thus unlikely to dramatically change the systematic risk of a project. For ease of exposition, we therefore generally abstract from this qualitatively weak channel.[26]

4.3.2 Financial frictions

Absent financial frictions, the famous Modigliani and Miller's irrelevance theorem shows that discount rates are independent of capital structure. In other words, how the project is financed, i.e. the mix of debt and equity financing, does not impact the value of the project. However, it is well understood that in practice financial frictions exist and are a first-order driver of investment decisions. Frictions that have been studied to rationalize a role for capital structure include agency costs, inefficient bankruptcy and liquidation, and taxes (see Graham and Leary (2011) for a survey). In line with classical finance research, we model the financial side such that having more debt (i.e. "leverage") and less equity financing lowers the discount rate. Our framework consists of two components. First, there are risk-based debt limits. Second, substituting debt with equity is costly: there is an excess (risk-adjusted) cost of equity financing.

[26]That does not mean that systematic risk or that CAPM betas do not matter for discount rates and corporate investment in general. Only that these forces are unlikely to be significantly affected by a PPA.

Risk-based debt limits: We emphasize the idea that lower cash-flow risk (including "diversifiable" risk) facilitates debt financing. This is in line with how debt sizing is done in practice for project finance, consistent with the idea that low-risk is necessary to make the project "bankable."[27] Annual operating profits (scaled by capacity) are random as above, with $\pi_t/K \sim F$. Debt contracts are perpetual (to match perpetual cash-flows), paying a coupon rate r^D on face value D. The annual debt service is thus $r^D D$. Default occurs if $\pi_t/K < r^D D/K$.

The project can borrow from a set of competitive lenders. Assume lenders target a probability of default, say α.[28] This corresponds to an interest rate r^D, which includes a risk premium for default risk. Setting a target for default risk is equivalent to setting a risk-based borrowing limit:

$$P(\text{default}) \leq \alpha \iff P(\pi_t/K < r^D D/K) \leq \alpha \iff D/K \leq F^{-1}(\alpha)/r^D$$

This can be re-written more intuitively if we first note that $F^{-1}(\alpha)$ is the α percentile of operating profits, $\pi_t^\alpha/K := F^{-1}(\alpha)$. To isolate the effect of risk, we define the borrowing limit Λ relative to average profits $\bar{\pi}_t/K$:

$$D/K \leq \underbrace{\Lambda}_{:=\frac{\pi_t^\alpha/K}{\bar{\pi}_t/K}} \frac{\bar{\pi}_t/K}{r^D} \tag{1}$$

Intuitively, projects with lower cash-flow risk can borrow more. For the same target default probability α and the same average profits, safer projects have a higher α percentile of profits, implying a higher debt limit Λ. This gives a natural channel for any "de-risking" of cash-flows to boost leverage and reduce the project's discount rate. An interpretation of the debt limit Λ that is consistent with practice is in terms of target interest coverage ratio. This ratio is

[27] See for instance Chapter 4 in Raikar, Santosh, and Seabron Adamson. Renewable Energy Finance: Theory and Practice. London, England: Academic Press, 2020. Print.

[28] This is consistent with how lending is done in practice, but per se this is not a deviation from MM. The deviation from MM will come from an excess cost of equity financing.

defined as operating profits over debt service, i.e. $\pi/r^D D$. Using a similar logic to the model above, bankers typically target coverage ratios to be maintained relative to expected operating profits. In our framework, the target coverage ratio is simply $1/\Lambda$. A lower coverage ratio implies more debt financing.[29]

A natural micro-foundation for risk-based debt limits is that in practice banks have incentives to keep the risk of their loans in check. Both regulation (e.g. risk-based capital requirements) as well as market discipline (e.g. the risk of deposit withdrawals) induce banks to make relatively safe loans. If loans are securitized, a good credit rating is also important to maximize the demand from institutional investors.

WACC and leverage: The amount of debt financing ("leverage") matters for the project's discount rate in the presence of financial frictions. The key force is the existence of an "excess cost of equity". The discount rate follows the classical weighted average formula:

$$WACC = \underbrace{r^D}_{\text{cost of debt}} + \underbrace{(1-l)}_{\text{leverage}} \underbrace{(r^E - r^D)}_{\text{excess cost of equity}}$$

In a Modigliani-Miller world, the excess cost of equity increases with leverage in a way that exactly cancels out: $r^E - r^D$ is proportional to $1/(1-l)$ so that the overall WACC is unaffected by leverage. We deviate from this perfect benchmark by assuming that equity financing is excessively costly and that the WACC declines with leverage. This is a common feature in macro-finance models that often assume a convex cost of (outside) equity issuance, or assume this cost is infinite. A reduction in leverage has thus a strong effect on increasing discount rates.

We do not explicitly micro-found the wedge. One possibility perfectly consistent with our focus on bank debt above is the existence of government guarantees and deposit insurance. These public backstops make bank debt "cheap" relative to alternative forms of financing.

[29] Note that the main force is quantity rationing, in line with practice. The interest rate r^D does not change with debt size D and is not very sensitive to the project's characteristics. Debt size D is where most of the action is: it adjusts to keep default risk (and thus interest rates) constant.

Other well-known possibilities include a tax advantage of debt or asymmetric information. In principle, our main conclusions are not driven by exactly which forces are behind this wedge. We parametrize the discount rate in the following way. We follow this approach and assume that some underlying frictions imply an excess cost of equity of $r^E - r^D = \chi_e$. Parameter χ_e can be interpreted as the excess cost of equity for a fully equity-financed (unlevered) project. The WACC formula thus reduces to:

$$WACC = r^D + (1 - l)\chi_e$$

For tractability, we proxy leverage by $l = \frac{D/K}{i}$, the share of investment cost covered by debt financing.[30]

5 The value of project finance

5.1 Power Purchase Agreements (PPAs)

We model Power Purchase Agreements (PPAs) as long-term contracts to sell electricity at a pre-agreed price. To isolate the role of cash-flow risk, the baseline framework focuses on *fair and permanent* PPAs. In other words, a PPA is modeled as a commitment to sell the plant's expected output at the average expected market price, so that $p_t^* = \bar{p}$ and $q_t/K = \theta$ for all future periods t. Recall that, absent a PPA, the equations determining electricity prices p_t and output per unit of capital q_t/K are,

$$p_t = \bar{p} + a_p s_t + e_{p,t}$$

$$q_t/K = \theta + \xi(p_t - c_t - (\bar{p} - \bar{c}))$$

[30]If the project's NPV is small, this is close to leverage in terms of market value.

In this setting, a PPA has two effects. First, it removes all revenue risk from fluctuations in electricity prices. Second, it eliminates production flexibility, i.e. $\xi^{PPA} \approx 0$. In this sense, the main role of a PPA in the model is to "de-risk" revenues.

We make two comments on our modeling choice. First, we abstract from any contractual imperfections in PPA contracts (opportunistic renegotiation, counter-party risk, etc.). Clearly, these have negative effects on investment that are well understood Fabra and Llobet (2025a,b); Ryan (2021). We also ignore basis risk in PPA pricing.[31] Our contribution is to point out a novel financing channel, and to illustrate that as clearly as possible we show that even fair and permanent PPAs can have pros and cons. Second, we take the existence of these PPAs as given and study their effect on investment, i.e. we do not model the supply side of PPAs.[32] This important question is beyond the scope of this paper.

5.2 Effect on internal rate of return

The first main result is that even a fair and permanent PPA significantly reduces the internal rate of return (IRR) for a fossil fuel project, but not for a renewable project. The key distinction between the two technologies is the degree to which output can be adjusted in response to realized market conditions. To see this, note that expected profits without a PPA can be decomposed as follows:

$$E_{noPPA}[\pi_t/K] = \underbrace{E[q_t/K]}_{\text{av. production}} \underbrace{E[p_t - c_t]}_{\text{av. margin}} + \underbrace{Cov(q_t/K, p_t - c_t)}_{\text{option value from flexible production}} = \theta(\bar{p} - \bar{c}) + \xi Var[p_t - c_t]$$

When production is inflexible ($\xi \approx 0$) expected profits depend only on average prices and costs. In that case, replacing a stochastic market price with a fair fixed-price contract has no

[31] See Section 5.5. In reality, most current PPAs are financially settled at a regional hub, while the project sells its electricity at the local nodal price. The hedge is therefore imperfect, because the project remains exposed to basis risk, i.e. the gap between nodal and hub prices. Since basis risk introduces additional cash-flow volatility, accounting for it would imply less complete de-risking than in our benchmark. Our baseline PPA should thus be interpreted as a benchmark of the de-risking role of long-term contracts, rather than as a literal description of current market practice.

[32] Firms taking the other side of a PPA include a variety of actors, such as regulated utilities, tech firms, or public entities, all having widely different constraints and objectives.

first-order effect on expected profits. A PPA changes the distribution of profits, but not their mean. For an inflexible plant, the IRR effect of a PPA is therefore small or zero.

When production is flexible ($\xi > 0$), by contrast, expected profits (1st moment) depend on variance of profits (2nd moment). Intuitively, this comes from the option value of adjusting output ex-post: increasing production when electricity prices are high relative to costs, and reducing output when margins are low. The option value of adjusting production is ex-ante valuable and its value increases with the volatility of electricity and gas prices.

By contrast, under a PPA, expected profits simplify to:

$$E_{PPA}[\pi_t/K] = \theta(\bar{p} - \bar{c})$$

For a plant with meaningful production flexibility, these expected profits are strictly lower $E_{PPA}[\pi_t/K] = \theta(\bar{p} - \bar{c}) < E_{noPPA}[\pi_t/K]$. This is because even a fair and permanent PPA eliminates this option value by locking in a fixed price and quantity. This implies that the IRR *declines* for any project for which a significant share of profits is expected to come from operational flexibility.[33]

This logic does not apply to renewables, because they have little short-run operational flexibility: with near-zero marginal costs, it is nearly always optimal to produce at full capacity whenever prices are positive, so output is effectively determined by resource availability rather than market conditions. Because of that, a PPA does not reduce expected profits through this channel like it does for flexible gas plants. When $\xi \approx 0$, $E_{PPA}[\pi_t/K] = E_{noPPA}[\pi_t/K]$.

The implication is that the IRR effect of PPAs is heterogeneous across technologies. For renewables, PPAs can de-risk revenue streams without meaningfully reducing expected profits. For gas plants, PPAs can lower expected profits by eliminating the option value associated with flexible production. It follows that the potential of a PPA to increase NPV and investment

[33] Note that there is also some heterogeneity within gas plants in this dimension. Newer, more efficient generators are dispatched more often, while older less efficient "peaker" plants are dispatched less frequently have more volatile output. In some markets, gas plants also receive capacity payments independent of output. However, the rise of inelastic and intermittent renewable sources has increased the value of production flexibility for gas plants.

for renewables operates through a *discount rate channel*, which we turn to next.

5.3 Effect on discount rate

We now turn to the second channel through which a PPA affects project value: the discount rate. Unlike the IRR channel discussed previously, this effect works through financing conditions rather than expected operating profits. A PPA can raise NPV even when it leaves expected profits unchanged, because de-risking cash flows expands debt capacity, thereby reducing reliance on costly equity and hence lowering the cost of capital. We argue that this *capital structure* channel is of first-order importance for renewable projects, but not necessarily for fossil fuel projects.

In our framework the main benefit of de-risking cash-flows through PPAs is that it relaxes financing constraints: lower cash-flow risk endogenously increases debt limits and reduces the project's weighted average cost of capital.

For renewables, a PPA clearly reduces the volatility of profits. Without a PPA, profit variance is driven by fluctuations in electricity prices and, to a lesser extent, operating costs:

$$Var_{noPPA}[\pi_t/K] = \theta^2 \underbrace{var[p_t - c_t]}_{\text{variance of margins}} = \theta^2(\underbrace{a_p^2 var[s_t] + var[e_t^p]}_{\text{electricity price risk}} + \underbrace{var[e_t^c]}_{\text{cost risk}})$$

By contrast, with a PPA, the sale price is fixed in advance, so most of the revenue risk disappears except the remaining variance from operating cost shocks:

$$Var_{PPA}[\pi_t/K] = \theta^2 var[e_t^c]$$

Since renewables have very small variable costs, this term is also small in absolute terms. The variance reduction is therefore large, both in magnitude and relative to total risk.[34]

[34] The idea still applies even in the presence of production shocks from renewables due to random variation in natural conditions. The baseline framework can be easily extended to incorporate such shocks. Assume that the plant's capacity factor is given by $q_t/K = \theta + e_t^q$, with e_t^q independent from other random variables. Then $Var_{noPPA}[\pi_t/K] = (\theta^2 + var[e_t^q])var[p_t - c_t] + var[e_t^q](\bar{p} - \bar{c})$. With a PPA, the variance drops to

To understand why this matters for financing, recall the expression for debt limits:

$$D/K \leq \underbrace{\Lambda}_{:=\frac{\pi_t^\alpha/K}{\bar{\pi}_t/K}} \frac{\bar{\pi}_t/K}{r^D}$$

For renewables, a PPA raises this debt limit by increasing Λ. By reducing profit volatility, it improves the ratio of downside to average profits, $\pi_t^\alpha/\bar{\pi}_t$, so the project's cash flows in bad states become larger relative to it's mean cash flows. Since lenders care about repayment precisely in those downside states, the project can sustain more debt. At the same time, as shown above, expected profits are largely unaffected for renewables. Together, these two forces increase leverage, reduce reliance on expensive equity financing, and lower the discount rate.

This capital structure channel is reminiscent of the corporate finance evidence that hedging can increase debt capacity, although that literature focuses on derivatives contracts signed between big banks and big firms (Stulz, 1996; Leland, 1998; Graham and Rogers, 2002; Campello et al., 2011). PPAs are a different form of risk management that is an integral and pervasive part of the financing of renewables (IRENA 2023). The capital structure channel can also explain why projects are kept off-balance sheet. Leland (2007) argues that keeping safe cash-flows outside the firm allows to raise more debt and increase total value.

This capital structure channel is less straightforward for fossil fuel plants. On the one hand, a PPA still provides some de-risking, but much less than for renewables. This is because a gas plant faces market volatility not only in electricity prices on the output side, but also in fuel costs on the input side. As the third of our initial facts shows, removing output price volatility alone still leaves substantial variance in operating margins. In other words, a PPA would lead to an increase in the factor Λ but by less than for renewables. In addition, as Section 5.1 shows, a PPA may reduce expected profits for a flexible gas plant by eliminating the option value of adjusting output to realized margins. The overall effect on leverage, and

$Var_{PPA}[\pi_t/K] = (\theta^2 + var[e_t^q])var[e_t^c] + var[e_t^q](\bar{p} - \bar{c})$. This is still significantly smaller as well as being small in absolute value since production shocks average over the entire year in a relatively predictable way.

hence on the discount rate, is therefore ambiguous.

This logic is consistent with industry practice. Bankers explicitly report setting lower debt limits for projects without a PPA, and that the effect is technology-specific. Data from Norton Rose Fulbright illustrate this point. For renewables, a PPA increases the factor Λ by almost 25 percentage points (from about 55% to 80%). For gas plants, a PPA increases this factor by less than 10 percentage points (from 69% to 76%). We use these numbers in the calibration below to discipline the debt part of our framework.[35]

Moreover, a further issue for gas plants is that their expected profits decline under a PPA, as shown above. This endogenously reduces debt limits by making default on a large loan more likely. If that profitability effect is large enough, it can dominate de-risking effect. In that case, a PPA can actually reduce leverage and increase the use of expensive equity financing. For these reasons, it is ambiguous whether the project-finance structure lowers discount rates for fossil fuel technologies.

5.4 Calibration

We take our NPV framework to the data to assess the quantitative impact of the mechanisms described above. Relative to the baseline framework of the previous section, we add a number of additional features to make the calibration more realistic: finite project lifetime, fixed operational and maintenance (O &M) costs, initial interconnection costs, and corporate taxation, including a depreciation and interest rate tax shield. We discipline the parameters by combining micro-data from different sources. Table 4 summarizes the parameter values. Most of the parameters are externally calibrated. Whenever possible, we use data representative of a typical U.S. solar and gas project over the 2016-2019 period. Data on capacity factors and electricity prices come from the EIA. Detailed technology-specific costs come from NREL and include variable operating costs, fixed O&M costs, and upfront capital costs. We also use cost

[35] In practice, bankers often speak of coverage ratio (which map directly to debt limits): *"For contracted wind, expect a coverage ratio of 1.3 to 1.4 times P50 revenue. For a merchant wind project, the coverage ratio is more like 1.8 to 2.0 times P50 revenue. For fully-contracted solar, expect a coverage ratio of 1.25 times P50. Merchant solar is 1.75 times P50 and 1.4 times P99."* Source: Norton Rose Fulbright (2024): link.

of debt and interconnection cost assumptions from NREL. Debt limits are calibrated using target coverage ratios across technologies with and without PPA from Norton Rose Fulbright. For solar, we also account for various subsidies in a simple form by assuming an investment tax credit and a small value of Renewable Energy Credits.[36] We use simple values for the corporate tax rate and plants' lifetime. Finally, two parameters are externally calibrated. The first is the excess cost of equity χ_e. We calibrate its value to 5% to match the cost of equity from NREL. The second is the option value of flexibility ξVar for gas plants. We calibrate it to match the leverage ratios for gas plants reported by NREL.

We find that the project finance structure increases investment in renewables but not in gas projects. Figure 9a shows the effect of a PPA for a gas project. The x-axis measures the share of revenues contracted under a PPA, from zero (no PPA) to one (full contracting). Two patterns emerge. First, as the gas plant adopts a PPA, its IRR falls significantly, from 5% to below 3%. This is consistent with the theoretical prediction above: a large share of the project's IRR is driven by the option value to adjust production. Second, its discount rate does not fall and in fact rises modestly from 4.8% to 5.3%. As a result, a PPA moves the gas project from positive to negative NPV.

The reason the discount rate does not fall is the capital structure channel. Although a PPA increases the factor Λ by a small amount, it also reduces expected profits enough that overall debt limits fall. This forces the project to rely more heavily on equity financing, which pushes the discount rate upward. This shows why project finance is typically not the optimal financing structure for a flexible gas project.

The opposite pattern emerges for a solar project, as shown in Figure 9b. A PPA keeps its IRR unchanged around 4.5%. This is because there is no option value in production. The discount rate, however, falls significantly, from 5% to 3.8%. In this case, it is the discount rate

[36] We abstract from the working of tax equity markets and assume that tax credits can be realized immediately to fund the project. On tax equity and banks, see also Garrett and Shive (2022). The actual tax credit received by solar projects during this period was typically close to 30%. We use a higher value to capture other forms of subsidies (like accelerated depreciation) without modeling them in detail. The price of REC varies widely across states and over time. The value of \$2/MWh is very conservative for states with RPS mandates but a bit higher than market with only voluntary RECs (EPA).

channel that turns the project's NPV positive. Quantitatively, a PPA substantially relaxes debt limits and increases leverage. This illustrates how the project finance structure facilitates financing for renewables specifically.

5.5 Additional implications

Project finance for gas projects. The logic above helps to rationalize why project finance is less common for gas in practice. It also helps to understand why, when project finance is used, it typically takes a different form than for renewables. Given the (risky) cost structure and longer life span of a gas plant, risk mitigation rarely takes the form of PPAs commonly used for renewables. Instead, it relies on forms of risk management that are more common in traditional corporate finance. The first is the use of financial hedging through derivative contracts with financial institutions. The two most common instruments are heat rate call options and revenue puts. The goal of both instruments is to limit the risk that profits dip too low and debt becomes unsustainable. However, in practice frictions tend to lead to imperfect risk-sharing. Financial institutions with expertise in derivatives, such as dealer banks, face their own constraint and frictions which impede their ability to provide perfect hedging for the risks faced by gas plants. This can create trouble for the project finance structure that is so reliant on debt. The bankruptcy of the Panda Temple gas plant was a heavily publicized recent example of how derivatives were not enough to mitigate cash-flow risk in the face of market volatility.[37] A second form of risk management is frequent debt refinancing and re-contracting. Although a gas plant itself can last for decades, the maturity of debt and other contracts is typically much shorter. These loans must be frequently refinanced, sometimes with a change in ownership. Financial contracts also must be renewed frequently to reflect new conditions in electricity and gas markets. This is in contrast with renewables that typically have longer contract maturities. These differences are in line with technological differences: operating a gas plant is fundamentally more risky.

[37]"Panda Temple bankruptcy could chill new gas plant buildout in ERCOT market", May 15th 2017, Utility Drive. Source.

Levelized cost of energy. Measures of the levelized cost of energy (LCOE) are widely used to compare the cost of different technologies. One potentially under-appreciated aspect of these measures is that they implicitly depend on the discount rate. Everything else equal, a lower discount rate leads to a lower LCOE. A natural implications that the project finance structure helps keep LCOE low through a lower discount rate. This "hidden" discount rate effect is especially large for renewables with higher initial investment cost. To see this more precisely, in a simple perpetual model the LCOE (absent subsidies) is given by the following closed-form expression:

$$LCOE \approx \bar{c} + \frac{f}{\theta} + r\frac{i}{\theta}$$

The first two terms capture operational costs: $\bar{c}$ is the average marginal cost and f is fixed O&M costs, with θ being the capacity factor. Investment costs are reflected in the last term: i is the investment cost per unit of capacity. Importantly, this cost is multiplied by the discount rate r. A lower discount rate reduces LCOE and especially so for technologies with a high ratio of investment cost to output i/θ like renewables. More generally, the discount rate is key for innovations that reduce investment cost i to translate into lower LCOEs.

Figure 10 shows that in our main calibration the LCOE for renewables would be 20% higher without PPAs. This large effect is entirely driven by the capital structure channel. To size the effect of the channel more intuitively, the middle bar shows that the effect is as large as an investment tax credit of 25%, which is close to the current baseline value for the United States. This suggests that, quantitatively, this financing effect is as potent as existing fiscal policy instruments.

Firm entry. A natural implication of our capital structure channel is that project finance is more valuable when financial frictions are stronger (i.e. higher excess cost of equity χ_e). Project finance can thus naturally help fuel entry of new, smaller firms in electricity markets. Andonov and Rauh (2022) document such a shift, with the entry of new investors particularly pronounced for renewables.

However, we caution against the interpretation that lenders only require PPAs from highly creditworthy off-takers because renewables firms are smaller or riskier. We offer two key pieces of evidence. First, project finance structures are used across the board for renewables projects, regardless of the age or size of the equity sponsor, some of whom are very large developers or traditional utilities. For example, Iberdrola is the equity sponsor of the Vineyard Winds project, a Spanish utility company with a $100 billion balance sheet that has existed since 1992. Despite this, Vineyard Winds still relied on a PPA and project finance structure. More generally, the International Renewable Energy Association (IRENA), an inter-governmental organization, finds that worldwide, 88% of utility-scale renewables projects are financed using project finance, and that nearly all projects required some form of price guarantees, with full exposure to wholesale prices being rare.[38] The capital structure channel seems to be relevant across different settings.

Long-term storage and market volatility. Our framework also suggests a complementarity between investment in renewables and innovations that can lower market volatility. For instance, the development of long-term storage technologies has the potential to reduce swings in electricity prices by absorbing shocks to demand or supply. Even though current storage technologies have cycles measured in hours, efforts are directed towards developing storage systems with significantly longer horizons. Our capital structure channel implies that the advent of such technologies could in principle significantly facilitate investment in renewables by lowering the need for PPAs to raise debt financing.

PPAs settlement and basis risk. Our baseline framework treats PPAs as fully eliminating electricity price risk at the project level, consistent with an idealized fixed price contract at the point of generation (a so-called bus-bar contract). In practice, the dominant structure in the corporate PPA market today is a hub-settled virtual PPA (VPPA), under which developers remain exposed to basis risk (the difference between the hub price and the project's local nodal price). Because node prices fall relative to hub prices precisely when local renewable output is high (due to congestion and the depression of local prices), basis risk is

[38]See IRENA, 2023 Renewables Financing Report.

negatively correlated with output and therefore reduces expected cash flows beyond what a simple price-variance calculation would suggest. This additional friction implies that a larger share of VPPAs and wider basis risk dampen the capital structure channel.

6 Macroeconomic risk and project finance

6.1 Cost shocks and macroeconomic correlation

An important finding is that project finance is not all upside, even for renewables. We identify a novel downside of PPAs: the amplification of macroeconomic shocks. While a PPA reduces risk in operating cash-flows, it leads to more exposure to cost shocks. For this mechanism to operate, two empirical conditions must hold: (i) there must be a (macro) correlation between electricity prices and investment/financing costs, and (ii) shocks to electricity prices must be relatively long-lasting. We document each fact in turn, and then use them to discipline a simple amplification model.

Macroeconomic risk in electricity prices. We first show that there is meaningful macroeconomic risk in electricity prices. Table 3 uses EIA data to examine correlations between monthly wholesale electricity prices, factor returns, and macro variables. There is a strong correlation between electricity prices and aggregate core inflation. This is natural but not mechanical, since core inflation excludes energy prices. For completeness, we show this relationship is robust to controlling for short-term and long-term interest rates, which also move contemporaneously given the desire of the central bank to fight inflation. Finally, electricity prices are largely uncorrelated with aggregate stock returns using a range of traditional and production-based asset pricing factors. This last point is itself important for the rest of the paper: the lack of correlation with aggregate equity factors implies that the case for PPAs cannot rest on a CAPM-style systematic-risk channel, but must instead come from financial frictions, as developed in earlier sections.

The strong positive correlation with core inflation also suggests that when electricity prices are high, the cost of building new plants is high too. We provide direct evidence of this link using CAPEX forecast data from NREL. Figure 7 shows that capital costs jumped significantly after 2022 for all types of technologies. After many years of continuous decline, the cost of building plants increased during this inflationary episode, in line with the sharp rise in the price of capital goods due to supply chain bottlenecks and higher production costs (Darmouni and Sutherland, 2024). In magnitude, the shift was comparable to between five and ten years of "learning by doing" cost reduction for renewables, and even more for gas. The size and abruptness of the shift also indicates that this macro shock was largely unexpected.

PPA prices track electricity prices. The amplification mechanism also relies on shocks to electricity prices being relatively persistent. A temporary shock would only marginally affect the NPV of a long-lived project and would be largely smoothed out in PPA prices set ex-ante; only a long-lasting shock makes the wedge between fixed PPA revenues and current marginal-cost-driven construction prices economically meaningful. We document this persistence using PPA price data. We construct PPA price indices for wind and solar by combining price data from LevelTen Energy on corporate PPAs with data from the Berkeley Lab on utility PPAs. Figure 8 plots these indices alongside average retail and wholesale electricity prices. PPA prices rose by roughly the same amount for wind and solar over the sample, and this increase closely tracks the rise in electricity prices: both move by approximately \$30 per MWh. (There is, of course, a difference in levels, since PPAs do not include factors such as transmission and distribution costs.) Because PPAs have a typical horizon of 10 to 25 years, their price level should reflect average expected electricity prices over that horizon: a long-lasting shock would move PPA prices, whereas a transitory shock would not. The tight comovement between PPA and retail prices therefore indicates that shocks to electricity prices are perceived as long-lasting, at least during this episode.

Together, these two facts pin down the macroeconomic assumptions of the amplification model that follows. The joint movement of inflation, electricity prices, and construction costs corresponds to assumptions $a > 0$ and $b > 0$ below: when the macroeconomic state s rises, both expected electricity prices and investment costs rise. The persistence of electricity-price shocks justifies treating s as a long-lived state variable that meaningfully shifts the present value of future revenues, rather than a transient blip that PPA pricing already smooths through. The inflationary surge of 2022 (when electricity prices and construction costs both jumped upward and have remained elevated) is a good example of exactly the kind of shock the model is designed to capture.

The key point is that a PPA makes it more likely that a project is abandoned ex-post in reaction to bad news. To illustrate this in a clear way, we extend a simplified version of the framework above to account for macroeconomic risk. Section IA.2 in the Internet Appendix develops a more complete framework. Consider a renewable plant with unit capacity and unit capacity factor, with no operational costs and no depreciation. The expected annual future electricity price is p, construction costs i, and the discount rate is r. The project NPV is positive if:

$$p/r - i > 0 \iff p > ri$$

Importantly, these variables are random, but also correlated. There is an aggregate variable s that captures the state of the macroeconomic cycle. At the start of development, s is unknown with $E[s] = 0$. At the time of construction, the developer learns s. Expected future electricity prices are given by $p = \bar{p} + as$. Importantly, investment costs also vary with the state s, with $ri = \bar{ri} + bs$. Consistent with the empirical evidence presented above, assume that a and b are both positive: when inflation is high, electricity prices and construction costs are high.[39]

[39]Interest rates can also be high due to the endogenous central bank response to inflation.

6.2 Abandoning investment ex-post

Assume that ex-ante the project is profitable, i.e. $\bar{p} > \bar{ri}$. However, even in that case, the project might be "underwater" by the time construction starts. Absent a PPA, the project is not abandoned if the (interim) NPV is positive:

$$p/r - i > 0 \iff \bar{p} - \bar{ri} > (b-a)s$$

The larger the difference $b - a$, the more likely the project is to be abandoned. The key point is that *ceteris paribus* a PPA makes it more likely that a project is abandoned ex-post. This is because with a PPA the electricity price is set at development, without the knowledge of s. In this case, $a \approx 0$, and the project is abandoned if $\bar{p} - \bar{ri} < bs$, which makes investment more sensitive to the cycle s.

We make three comments on the mechanism. First, a PPA acts as an *amplification* mechanism: investment is still sensitive to the news absent a PPA, a PPA simply increases that sensitivity. Second, it requires a *long-lasting shock* to electricity prices. A temporary shock would only marginally affect the NPV of a long-lived project, and ex-ante PPA prices are not distorted ex-post. Third, there must be a *macro correlation between electricity prices and investment costs.* If not (i.e. $b \approx 0$), a PPA would actually help stabilize investment by removing the variation in electricity prices.

Intuitively, think of a high realization of s, like in 2022. Building a plant is now significantly more expensive. But electricity prices are also higher for the foreseeable future. If the PPA price could be reset, fewer projects would be abandoned.[40] The problem is exacerbated the longer the development time of the project, since this is when PPA prices are typically locked-in. This increase in "development risk" in the face of the macroeconomic cycle is consistent with the recent collapse of offshore wind investment in the United States. Rising input costs and fixed PPA prices rendered many projects unprofitable despite generous subsidies, leading

[40] Here for simplicity we ignore the previous force that a PPA reduces r.

to about \$30 billion in cancellations and delays.[41]

Our simple framework captures this mechanism quantitatively. Figure 11 shows the evolution of the internal rate of return (IRR) for the calibrated solar project subject to a large cost shock. We assume that at $T = 6$, both electricity prices and construction costs permanently increase by 40%. The solid red line illustrates the case where a PPA is in place: the IRR falls by over 2.5 percentage points, dropping below the discount rate. As a result, the NPV becomes negative, creating incentives to abandon or delay the project. This occurs because construction costs rise while the PPA price remains fixed at its pre-shock level. The dashed red line shows the counterfactual in which the PPA price adjusts ex-post to reflect the cost shock. In that case, a higher PPA price leads to higher revenue that balances most of the increase in investment cost. The IRR falls but remains above the discount rate.

Note that there is no easy solution. First, renegotiating a fixed PPA ex-post is difficult as these contracts are meant to induce long-term commitments. Second, the alternative of writing state-contingent PPAs for which the price resets at the time of construction has an important drawback. It creates cash-flow risk for initial investors and works against the "de-risking" value of PPAs emphasized in the previous section. Note also that this issue is not restricted to cost shocks, but also extends to interest rate shocks correlated with electricity prices. This lengthens the list of potential macro variables to index PPA prices to, making efficient state-contingent PPAs complex instruments that might be less appealing to lenders. The project finance structure thus creates an inherent trade-off between the average scale of investment and its volatility throughout the cycle.

Note finally that it is plausible that this macro-risk was under-appreciated by developers and investors. Solar took off around 2014 amid historically low levels of inflation and interest rates. Moreover, construction costs for renewables have been falling every year at an accelerating pace. It is thus possible that the sudden turn taken by the macro-monetary cycle

[41] See e.g., "Cancellations Reduce Expected U.S. Capacity of Offshore Wind Facilities" (EIA, 2024), "Wind Industry in Crisis as Problems Mount" (WSJ, 2023), "The Struggles of the Offshore Wind Industry" (FT, 2023).

in 2022 was largely unexpected. In fact, there is evidence of this from CAPEX and WACC forecasts from NREL. Figure 7 shows that CAPEX forecasts discretely jump up post-2022. Figure IA.1 in the Internet Appendix shows the same for WACC. This is consistent with a large surprise. There was thus potential for neglected risk in contract design. Recall that if the belief was that there was no macro-risk in construction costs ($b \approx 0$), then a PPA creates no additional risk. In fact, a constant PPA *reduces* volatility by insulating investment from shocks to electricity prices. But that ended up being the opposite of how it played out in 2022. This reinforces one of the key messages of this paper: the need to carefully account for macro-correlations to understand the dynamics of electricity investment.

6.3 State-contingent subsidies

In this last section, we explore potential policy tools to address this volatility in renewable investment. Even though the point holds more generally for alternative policy instruments, we focus on investment subsidies, like investment tax-credits (ITC), because of their simplicity and prevalence. We show that state-dependent subsidies indexed on aggregate costs are natural tools in this setting.

Figure 12 illustrates this result in our calibration. In the baseline, ITC is constant throughout and equal to 40%. The baseline IRR and WACC in solid red and solid blue are the same as in the previous Figure 11. The NPV turns negative at $T = 6$ after the cost shock. The dashed red line shows the impact of state-contingent subsidies on the project IRR. In that counterfactual, the ITC is contingent on realized aggregate construction costs. Instead of being constant at 40%, it is equal to 25% when construction costs are low but increases to 45% when they become high. In that case, the dynamics of IRR are very different: it is stable and constantly above the discount rate (in this example by a small margin). That ensures that the NPV remains positive over the cycle and there are no incentives to abandon the project ex-post. This is achieved by re-distributing the subsidies across the states of the world where they help the most. Relative to the constant subsidies policy, in good times the IRR is lower but still above the discount rate. In bad times, the IRR is significantly higher and just above the discount rate, triggering investment.

State-contingent policy can help avoid a dry-up of private sector funding in bad economic times. Commitment to a constant policy is thus not always the best way to induce stable investment. Designing energy and climate policy around macro-shocks is a natural implication of our framework.[42] There are nevertheless challenges to this type of policy. It requires commitment to a clear rule; otherwise it can generate substantial policy uncertainty which would hurt investment instead of stimulating it. It can also lead to higher fiscal spending.

7 Conclusion and policy implications

This paper aims to understand investment in electricity by linking technology and finance. It argues that the widespread adoption of project finance and offtake agreements like Power Purchase Agreements (PPAs) is a direct consequence of the unique risk properties of renewable energy technologies. The core mechanism enabling renewable investment operates through a capital structure channel: PPAs significantly de-risk cash flows, which in the presence of financial frictions reduces discount rates by relaxing debt limits. In contrast, power purchase agreements are much less attractive for fossil fuel projects with volatile input prices. However, even for renewables this beneficial financing structure creates an inherent trade-off. By locking in long-term prices, project finance amplifies exposure to macroeconomic risk—especially inflation in construction costs—thereby increasing investment volatility. The post-2021 slowdown in renewable investment illustrates this broader vulnerability to macroeconomic shocks.

Our perspectives centers on the importance of risk management and hedging in determining how renewables are financed, which has implications for optimal policy across technologies and over the business cycle. We show that state-contingent subsidies can help address the challenge with fixed PPAs while preserving their hedging benefits for lenders. We look forward to future

[42] There is perhaps a connection with the modern conduct of monetary policy: state-contingent interest rate policy often aims to counteract macro-shocks in order to achieve a long-term inflation target.

work on how to design optimal policy for supporting renewables development that addresses frictions on the financing side.

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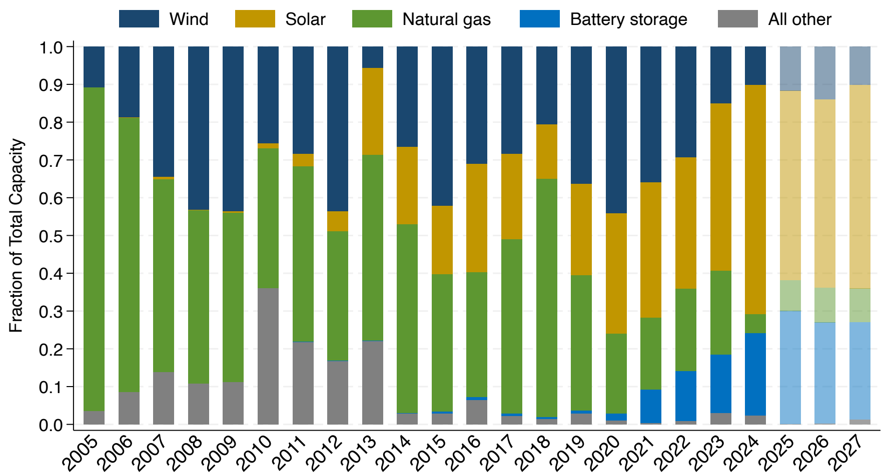
Tables and Figures

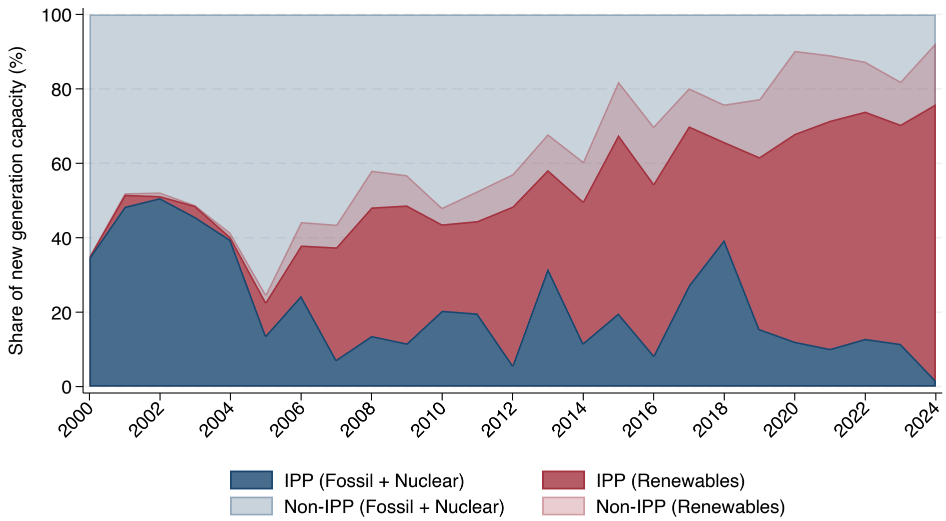
Figures

Figure 1: Share of new U.S. electricity generation capacity additions by technology



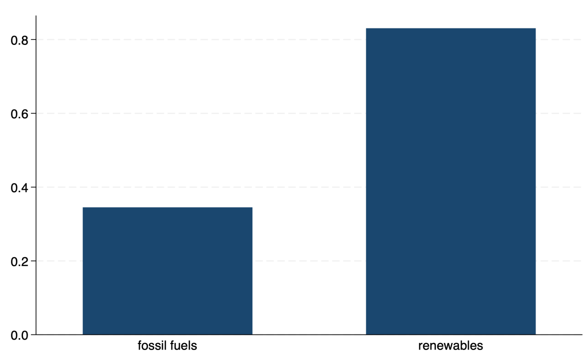
Notes: This figure shows the annual share of new U.S. utility-scale electricity generation capacity additions by technology from 2005 to 2027. Data for 2025–2027 reflect planned (proposed) projects. Data from the U.S. Energy Information Administration (EIA).

Figure 2: Share of new generation capacity financed by IPPs

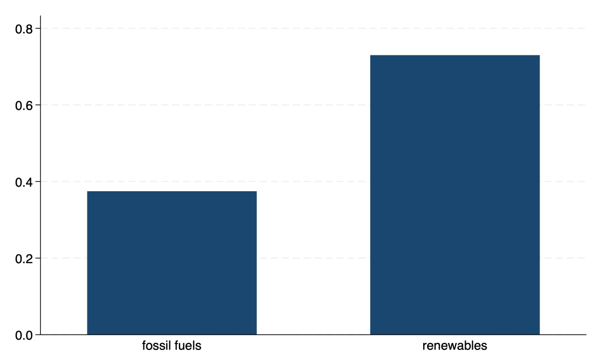


Notes: This figure shows the annual share of new U.S. utility-scale electricity generation capacity additions financed by independent power producers (IPPs) and non-IPPs, by technology and fuel type, from 2000 to 2024. Data from the U.S. Energy Information Administration (EIA).

Figure 3: Comparison of installed generation capacity financed by IPPs and LLCs.



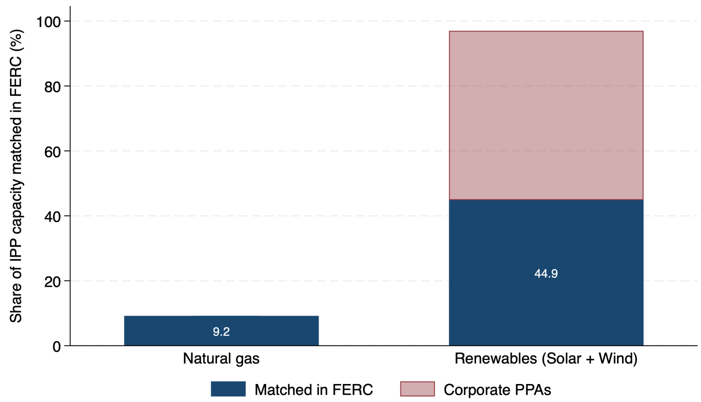
(a) Independent Power Producers (IPPs)



(b) Limited Liability Companies (LLCs)

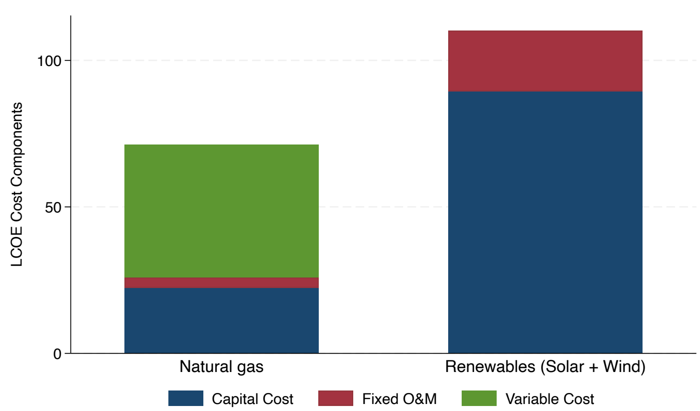
Notes: The figure reports the shares of installed generation capacity in 2024 financed by Independent Power Producers (IPPs) and Limited Liability Companies (LLCs), respectively. Each panel shows the share of capacity (in MW) aggregated into fossil fuels (natural gas, coal and petroleum) and renewables (solar and wind). Nuclear and other renewables are excluded. Data from the U.S. Energy Information Administration (EIA).

Figure 4: Share of IPP capacity that can be matched to regulatory filings of utility PPAs



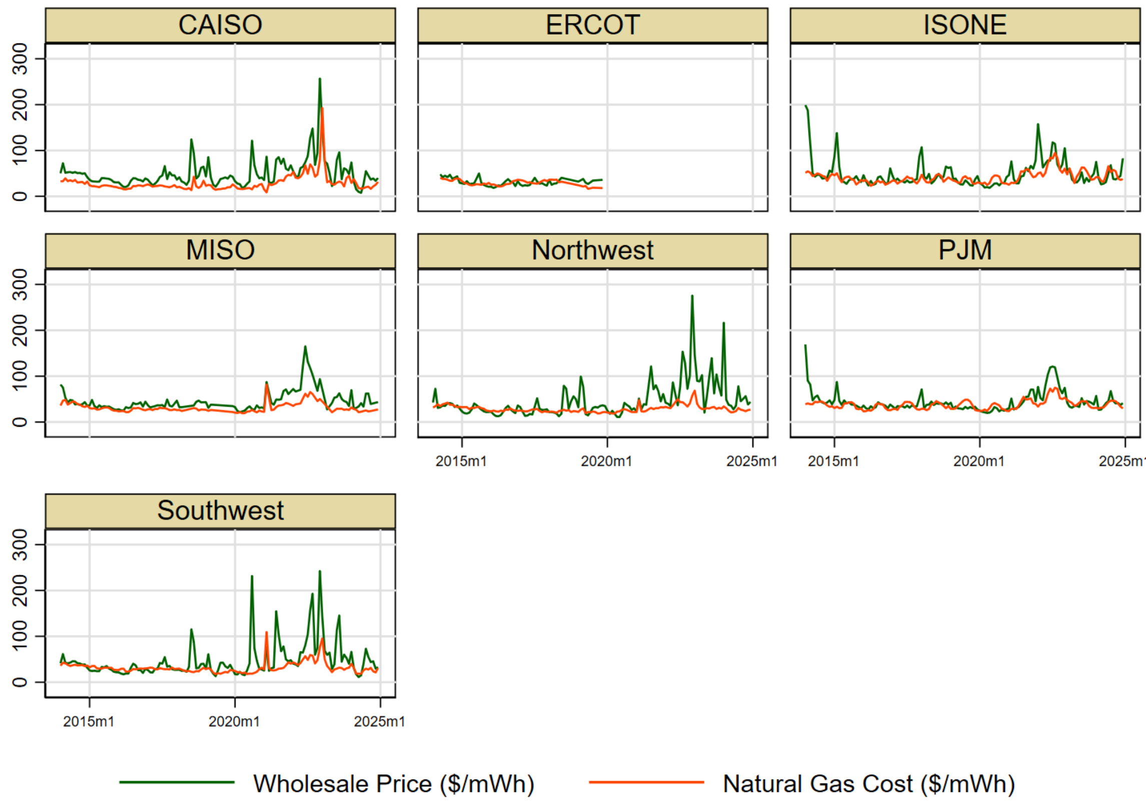
Notes: This figure shows the share of independent power producer (IPP) capacity for natural gas and renewables (onshore wind, offshore wind, and solar) reported in the *EIA-860* data that can be matched to utility power purchase agreements (PPAs) in the Federal Energy Regulatory Commission (FERC) database. The sample includes plants operable since 2015 and excludes ERCOT, which is outside FERC jurisdiction. The blue bars represent the fraction of IPP capacity matched to FERC-filed *utility* PPAs, while the red bars indicate *corporate* renewable PPAs reported by Bloomberg New Energy Finance (BNEF) since 2015.

Figure 5: Breakdown of LCOE across technologies



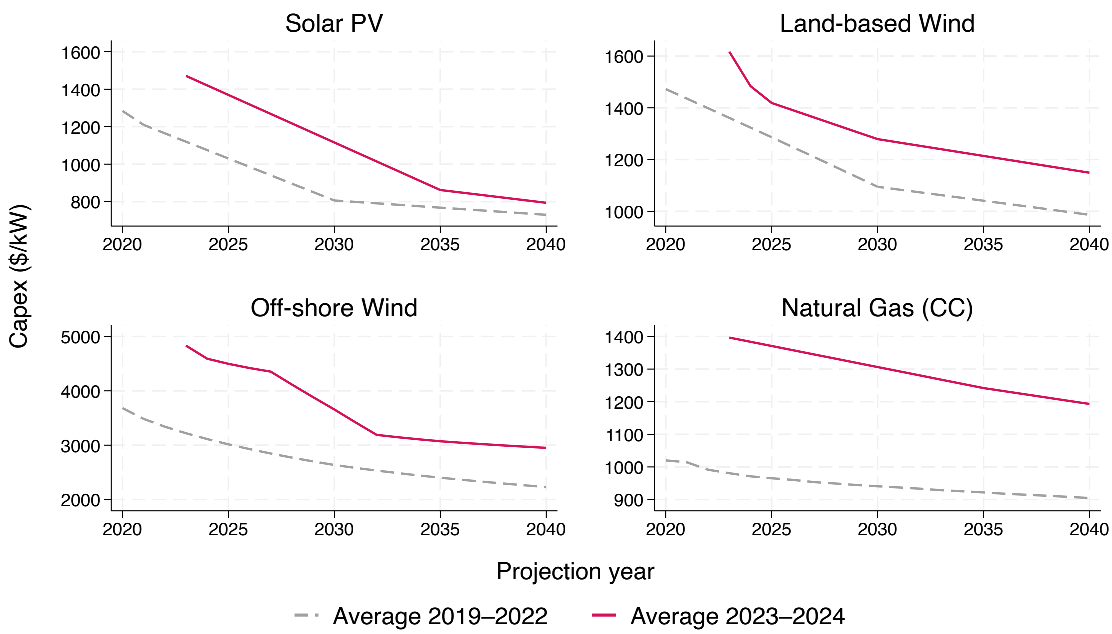
Notes: The figure shows the decomposition of the levelized cost of electricity (LCOE) into capital, fixed operation and maintenance (O&M), and variable cost components for natural gas and renewable technologies. Renewable technologies include onshore and offshore wind and solar. The height of each bar represents the average total LCOE, and segments indicate the relative contribution of each cost component. Data from the U.S. Energy Information Administration (EIA), covering annual estimates from 2014 to 2023.

Figure 6: Wholesale prices and natural gas input costs by ISO



Notes: This figure shows average wholesale price and natural gas by ISO. Wholesale prices are obtained from the EIA, and natural gas costs are calculated as the product of the EIA's citygate gas price and an assumed heat rate of 7000 BTU/kWh.

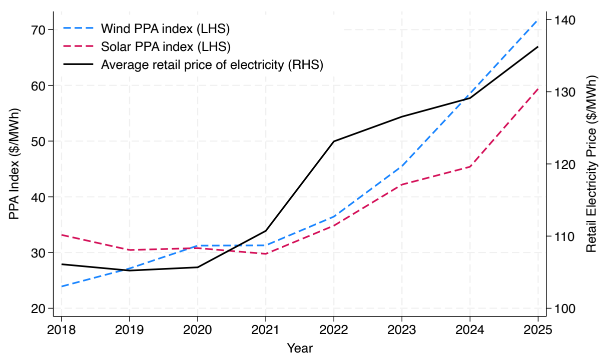
Figure 7: CAPEX forecasts over time across technologies



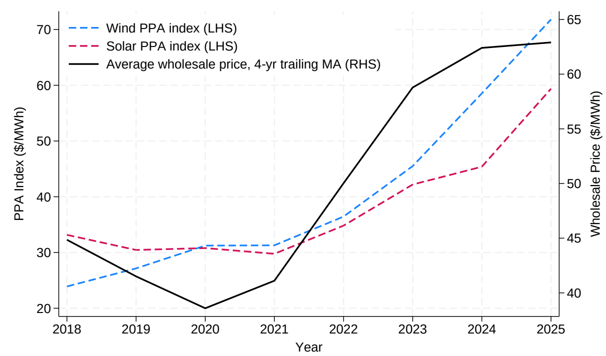
Notes: This figure shows capital expenditure projections for different generation technologies over time from the National Renewable Energy Laboratory (NREL) Annual Technology Baseline (ATB) *Reference* scenario. The red line shows the average projections from the 2023–2024 ATB editions and the grey dashed line shows the average projections from the 2019–2022 ATB editions. For each technology, we use the representative plant configuration as defined by NREL.

Figure 8: PPA versus retail and wholesale electricity prices

(a) Retail electricity price

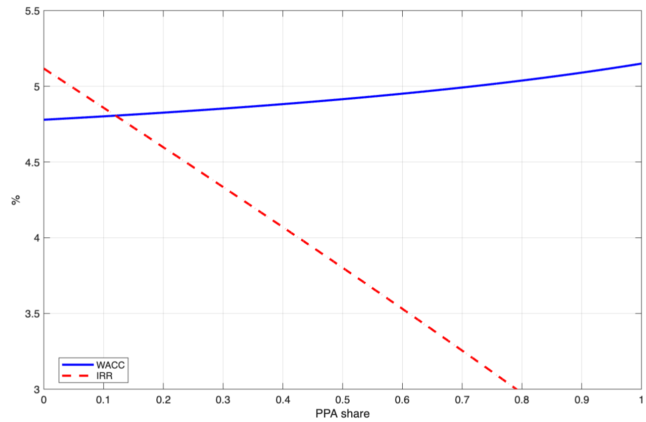


(b) Wholesale electricity price

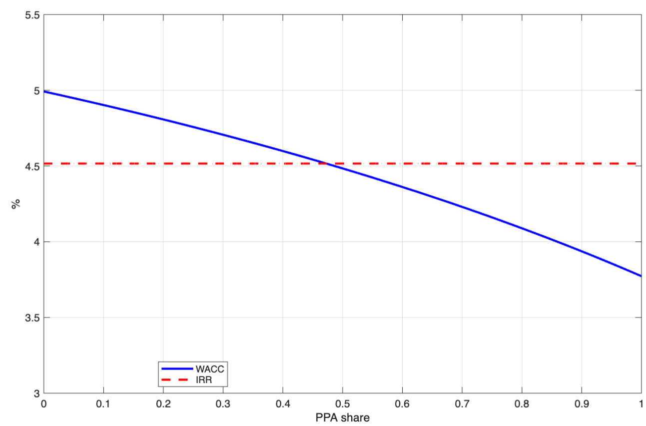


Notes: This figure compares solar and wind PPA price indices (left axis) with average U.S. electricity prices (right axis). Panel (a) uses the average retail electricity price; panel (b) uses the average wholesale electricity price expressed as a 4-year trailing moving average to smooth short-run volatility (notably the 2022 natural gas spike). Separate indices for wind and solar are constructed as an annual equal-weighted average of the LevelTen Energy (corporate) PPA price index and annual averages of utility PPA prices collected by the Berkeley Lab. LevelTen indices reflect the 25th percentile of observed U.S. PPA prices, capturing the most competitive market offers. Retail and wholesale price series are from the U.S. Energy Information Administration (EIA). Wholesale prices reflect a weighted-average of major trading hubs. The sample covers 2018Q3 to 2024Q3. All series are expressed in nominal dollars per MWh.

Figure 9: Model-implied effect of power purchase agreements (PPA) on IRRs and cost of capital for different technologies.



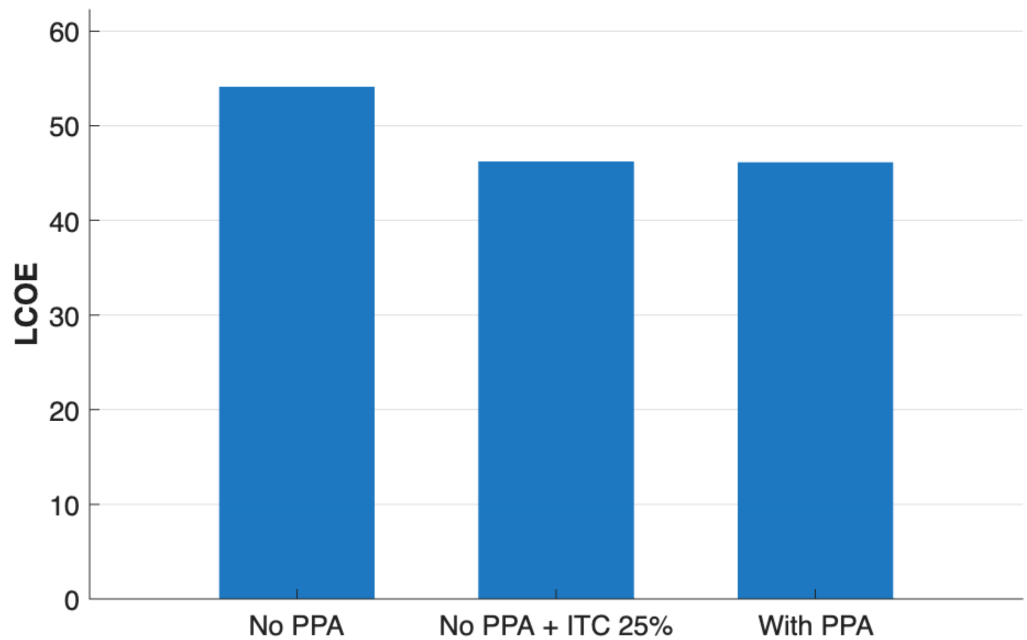
(a) Gas



(b) Solar

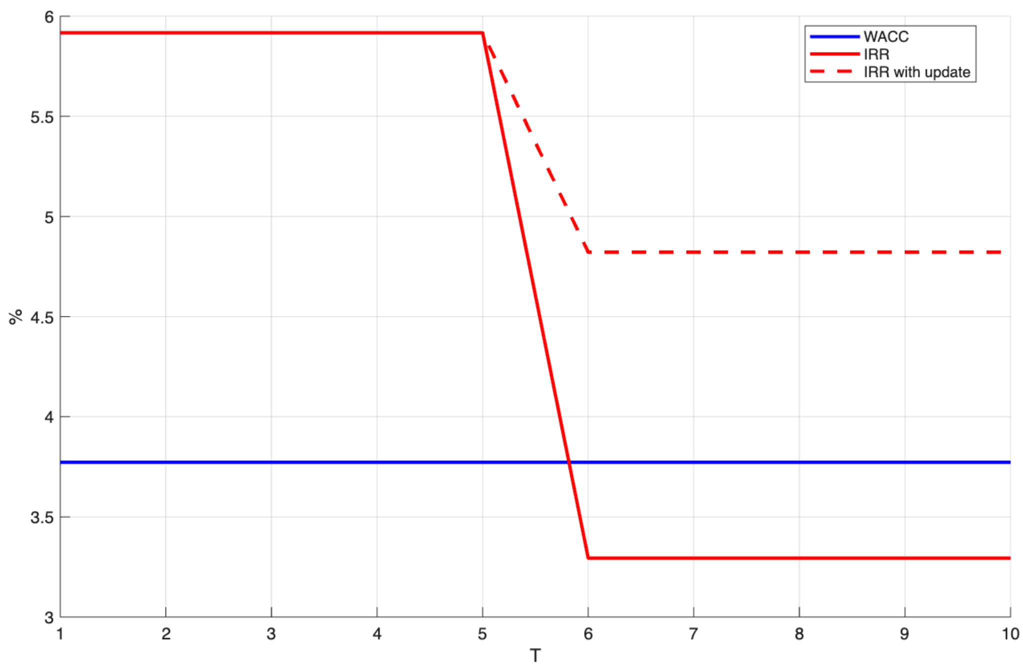
Notes: This figures shows the model-implied effect of the usage of PPAs on the IRR of a gas project (Panel A) and a solar project (Panel B). The x-axis is the share of the project revenues contracted under a PPA. The y-axis is the model-implied internal rate of return (IRR), a measure of profitability, or the weighted average cost of capital (WACC), a measure of financing costs, for different projects. The details of the parameter calibration and model as are discussed in the text.

Figure 10: LCOE and PPA



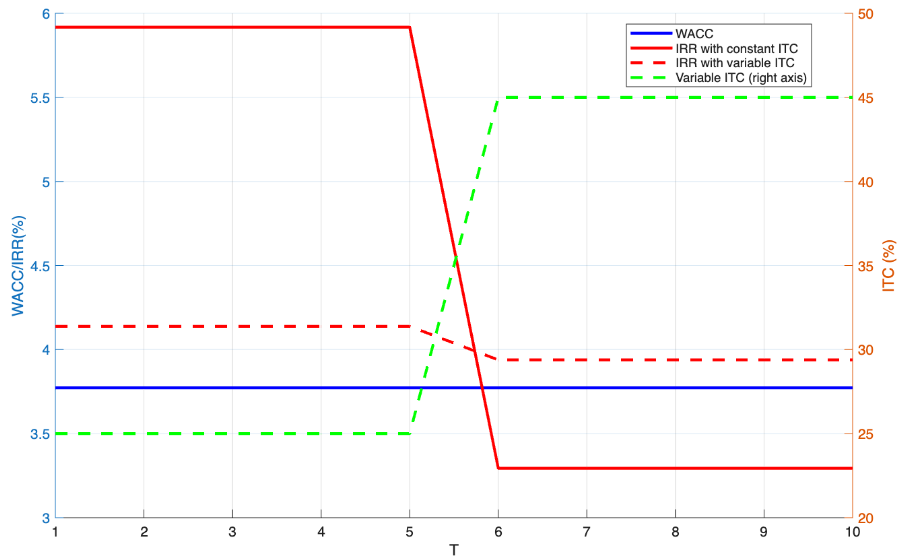
Notes: This figure shows the model-implied the levelized cost of energy (LCOE) for a solar project under three scenarios. The LCOE is defined as the constant electricity price such that the NPV of the project is zero. The left bar assumes no PPA and no investment tax credit (ITC), the middle bar assumes no PPA and an ITC of 30%, and the right bar assumes a PPA and no ITC. The details of the parameter calibration and model as are discussed in the text.

Figure 11: Model implied effects of a cost shock on project IRRs and cost of capital



Notes: This figure show the model-implied dynamics of the internal rate of return (IRR) of a renewable project around a cost shock at $T = 6$. The x-axis indexes time periods. The y-axis is the model-implied internal rate of return (IRR), a measure of profitability, or the weighted average cost of capital (WACC), a measure of financing costs, for different projects. The solid red line assume a PPA price that is constant over time. The dashed red line assumes a PPA prices that increases at $T = 6$ by the same amount as the cost shock. The details of the parameter calibration and model as are discussed in the text.

Figure 12: Model-implied effect of time-varying subsidies on project IRRs and cost of capital.



Notes: This figure show the impact of time-varying subsidies in our baseline model on a renewable project. There is a cost shock at $T = 6$. The x-axis indexes time periods. The y-axis is the model-implied internal rate of return (IRR), a measure of profitability, or the weighted average cost of capital (WACC), a measure of financing costs, for different projects. The solid red line assume an investment tax credit that is constant over time at 30%. The dashed red line assumes an investment tax credit that is 25% before the cost shock and 42% after. The dashed green line shows the value of the investment tax credit over time. The details of the parameter calibration and model as are discussed in the text.

Tables

Table 1: Flexibility of electricity generation across technologies

	ln(net generation)						
	Baseload	Gas Baseload	Gas Mid	Gas Peaker	Other Renewables	Solar	Wind
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
ln(wholesale price)	0.146**	0.269*	0.271**	0.707***	-0.0843	0.0165	-0.0624
	(0.0397)	(0.132)	(0.107)	(0.166)	(0.0592)	(0.136)	(0.0498)
Constant	15.22***	14.47***	13.14***	10.90***	14.83***	12.22***	14.24***
	(0.147)	(0.487)	(0.396)	(0.613)	(0.218)	(0.500)	(0.184)
Observations	757	757	757	757	757	757	757
Adjusted R^2	0.976	0.863	0.719	0.904	0.960	0.873	0.914
IsoFE	Y	Y	Y	Y	Y	Y	Y
YearFE	Y	Y	Y	Y	Y	Y	Y

Notes: The dependent variable is the natural logarithm of monthly net electricity generation by technology and ISO. The explanatory variable is the natural logarithm of the average monthly wholesale electricity price in the same ISO. Columns report separate regressions for baseload generation (coal and nuclear), natural gas generation disaggregated by operational role (baseload, mid-merit, and peaker), other renewables (biomass, hydro, and geothermal), utility-scale solar, and wind. All regressions include ISO and year fixed effects. Standard errors, clustered at the ISO level, are reported in parentheses. The sample covers the contiguous United States from 2000 to 2024. * $p < 0.10$, ** $p < 0.05$, *** $p < 0.01$.

Table 2: Summary Statistics of Electricity Prices and Natural Gas Costs by ISO

Statistic	ISO Region							
	CAISO	ERCOT	ISONE	MISO	Northwest	PJM	Southwest	Average
Mean:								
(1) Wholesale price (p_t)	49.76	31.21	49.42	45.69	46.53	44.28	47.02	44.84
(2) Natural Gas Cost (c_t)	28.71	29.81	41.61	31.06	28.64	37.59	31.69	32.73
(3) Spark spread ($p_t - c_t$)	21.05	1.40	7.81	14.64	17.89	6.69	15.33	12.11
SD:								
(4) Wholesale price	31.05	7.70	30.37	23.28	38.47	22.29	38.65	27.40
(5) Natural Gas Cost	19.01	5.88	12.86	10.29	7.66	10.02	12.59	11.19
(6) Spark spread mwh	24.55	8.36	26.52	16.43	34.56	18.30	34.52	23.32
Variance:								
(7) Wholesale price	963.96	59.29	922.23	541.73	1480.12	497.02	1493.50	851.12
(8) Natural Gas Cost	361.44	34.57	165.51	105.87	58.72	100.39	158.54	140.72
(9) Spark Spread	602.53	69.85	703.06	269.95	1194.42	334.83	1191.76	623.77
(10) Variance ratio	0.60	0.49	0.24	0.39	0.05	0.30	0.13	0.31
(11) cov(p_t, c_t)	361.44	12.01	192.34	188.82	172.21	131.29	230.14	184.04
(12) Implied correlation(p_t, c_t)	0.61	0.27	0.49	0.79	0.58	0.59	0.47	0.54

Notes: This table reports summary statistics for the mean, standard deviation (SD) and variance for the wholesale electricity price p_t (\$/mWh), natural gas input cos c_t (\$/mWh), and spark spread which is the wholesale price minus the natural gas cost ($p_t - c_t$). We calculate these summary statistics by ISO region. The variance ratio in row 10 is defined as the $Var(c_t)/Var(p_t - c_t)$. The implied correlation in row 12 can be obtained as: $\rho_{p,c} = \frac{Var[p_t]+Var[c_t]-Var[p_t-c_t]}{2\times\sqrt{Var[p_t]Var[c_t]}}$. Wholesale electricity prices are obtained from the EIA and natural gas prices refer to citygate prices, also obtained from the EIA. Data spans 2014-2024.

Table 3: Wholesale electricity prices and macroeconomic variables

	Wholesale Electricity Price (YOY %)						
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
Core CPI (YoY %)	12.26***					12.01***	
	(3.877)					(4.044)	
Core PCE (YOY %)		20.81***					20.91***
		(4.244)					(4.545)
Excess Market Return			-0.252	-0.195		-0.0244	0.0831
			(0.782)	(0.822)		(0.739)	(0.701)
SMB			-1.370	-1.379		-1.283	-1.171
			(1.177)	(1.184)		(1.248)	(1.150)
HML			1.575	1.142		1.140	0.643
			(1.546)	(1.951)		(1.564)	(1.477)
RMW				-0.209		-0.910	-1.190
				(1.913)		(1.823)	(1.670)
CMA				1.233		1.102	0.890
				(2.511)		(3.614)	(3.601)
Investment Factor					1.967	-1.780	-1.551
					(2.805)	(4.407)	(4.208)
Constant	-14.92	-27.52**	20.82*	20.69*	19.65*	-13.67	-28.00**
	(13.47)	(11.66)	(11.30)	(11.37)	(11.32)	(13.85)	(12.04)
N	276	276	276	276	276	276	276
adj. R^2	0.063	0.148	0.002	-0.004	0.002	0.048	0.133
controls	Y	Y	Y	Y	Y	Y	Y

Notes: This table reports regressions of the year-over-year percentage change in wholesale electricity prices on key macroeconomic indicators. The dependent variable is the annualized growth rate of volume-weighted average U.S. wholesale electricity prices. Explanatory variables include core CPI inflation (YoY %), core PCE inflation (YoY %), Fama-French 3-factor and 5-factor monthly returns, and the investment theme factor return from Jensen et al. (2023). Control variables for the 10-year Treasury yield and the federal funds rate are included where indicated. Each column presents a separate regression with the variables indicated. Heteroskedasticity-robust standard errors are reported in parentheses. The sample period is from 2000 to 2024. * $p < 0.10$, ** $p < 0.05$, *** $p < 0.01$.

Table 4: Model Calibration Parameters: Solar vs. Natural Gas (2016–2019)

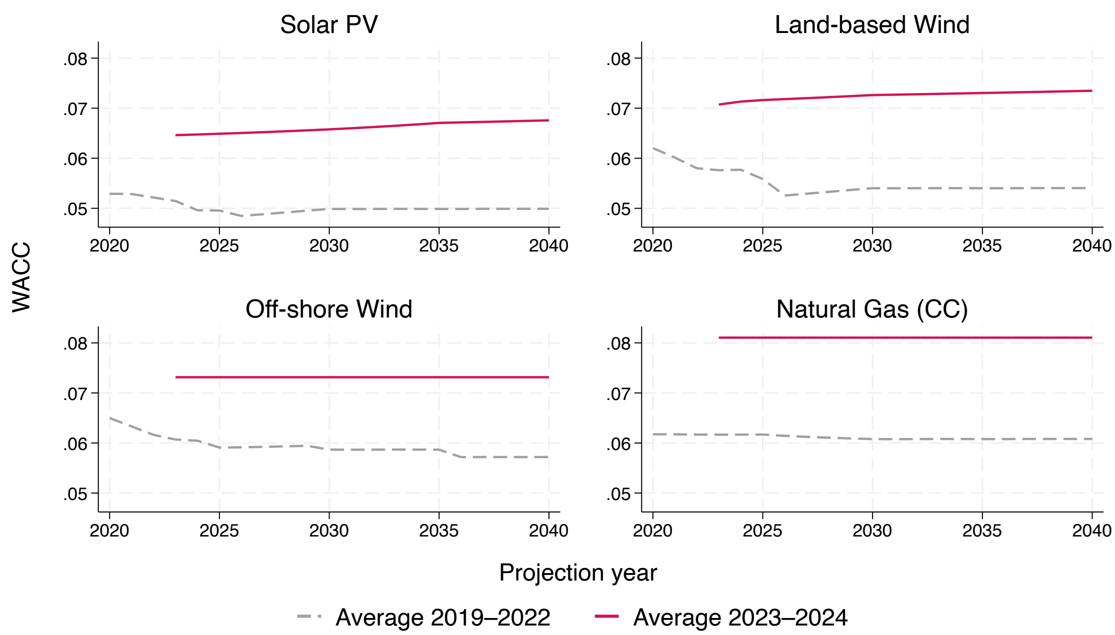
Panel A: Externally calibrated parameters				
Symbol	**Definition**	**Source**	**Value (Solar)**	**Value (Gas)**
θ	Av. capacity factor	EIA, 2016–2019 av.	25.00%	54.80%
$\bar{p}$	Av. electricity price	EIA, 2016–2019 av.	$35.9/MWh	$35.9/MWh
$\bar{c}$	Av. variable costs	NREL, 2016–2019 av.	$0/MWh	$22.75/MWh
f	Fixed O&M costs	NREL, 2016–2019 av.	$19,000/MW-yr	$26,000/MW-yr
i	Upfront capital costs	NREL, 2016–2019 av.	$1,470/kW	$1,030/kW
int	Interconnection costs	NREL, 2016–2019 av.	$100/kW	$100/kW
r_D	Cost of debt	NREL, 2016–2019 av.	3.85%	3.85%
Λ_{PPA}	Debt limit with PPA	Norton Rose Fulbright	80%	77%
Λ_{noPPA}	Debt limit without PPA	Norton Rose Fulbright	57%	45%
τ	Corporate tax rate	Tax code	21%	21%
s	Investment tax credit	Tax code	40%	N/A
REC	Renewable energy credit	EPA	$2/MWh	N/A
T	Plant lifetime	Norton Rose Fullbright	30 years	100 years
Panel B: Internally calibrated parameters				
Symbol	**Definition**	**Source**	**Target moment**	**Parmeter value**
χ_e	Excess cost of equity	NREL, 2016-19 av	9% cost of equity	5%
ξVar	Option value of flexibility (gas)	NREL, 2016-19 av	65% leverage (gas)	36000$/MW-yr

Note: This table summarizes the parameters values used to calibrate the model.

INTERNET APPENDIX

IA.1 Additional figures

Figure IA.1: WACC forecast over time across technologies



Notes: This figure shows cost of capital projections for different generation technologies over time from the National Renewable Energy Laboratory (NREL) Annual Technology Baseline (ATB) *Reference* scenario. The red line shows the average projections from the 2023–2024 ATB editions and the grey dashed line shows the average projections from the 2019–2022 ATB editions. For each technology, we use the representative plant configuration as defined by NREL.

IA.2 Full model of macro-risk

Persistence of shocks: This mechanism exists if there is persistence in electricity prices and input costs. Assume that the aggregate shock s_t displays some level of persistence:

$$s_t = \rho s_{t-1} + e_{s,t}$$

with $\rho < 1$ and $Var[e_{s,t}] = \sigma_s^2$. The long-run (unconditional) mean of s_t is 0, but $E[s_t|s_0] = \rho^t s_0$. If the current state is $s_0 = 0$, $E[s_t|s_0] = 0 \quad \forall t$. However, the variance increases with the time horizon: $Var[s_t|s_0] = \sigma_s^2 \frac{1-\rho^{2t}}{1-\rho^2}$.

Project development and construction: Assume that at $t = 0$ the project PPA is signed (if any). Construction is done at $t = \tau$ at the unit cost i_τ and operations start the following year. The parameter τ captures the development time (permitting, studies, etc.) that can vary across technologies (for instance longer for wind than solar). The depreciation rate of capacity K is δ. For simplicity, we first consider a project with fixed capacity factor θ. What is the (per-unit) NPV of the project when construction starts at $t = \tau$?

$$NPV_\tau/K = \sum_{n=1}^{\infty} \frac{(1-\delta)^{n-1}\theta E[p_{\tau+n} - c_{\tau+n}|s_\tau]}{(1+r)^n} - i_\tau$$

To capture macro variation, we assume that investment costs are pro-cyclical: $i_\tau = \bar{i} + a^i s_\tau$. Because of persistence, high cost today implies higher electricity prices in the future. This is a natural hedge that is undermined by a PPA. Formally, $E[p_{\tau+n} - c_{\tau+n}|s_\tau] = \rho^n s_\tau$. The NPV at $t = \tau$ simplifies to:

$$NPV_\tau/K = \underbrace{\frac{\theta(\bar{p} - \bar{c})}{r+\delta} - \bar{i}}_{\text{baseline NPV}} + \underbrace{\left[\frac{\rho(a_p - a_c)\theta}{r + 1 - \rho(1-\delta)} - a^i\right] s_\tau}_{\text{macro risk}}$$

There is now risk that comes from the loading on s_τ (the state of the world when construction starts).[43] The variance of the NPV is given by:

$$\left[\frac{\rho(a_p - a_c)\theta}{r + 1 - \rho(1-\delta)} - a^i\right]^2 Var[s_\tau | s_0]$$

The beta with the aggregate state s_τ is similarly given by: $\left[\frac{\rho(a_p - a_c)\theta}{r+1-\rho(1-\delta)} - a^i\right]$.

Everything else equal, a PPA ($a^p = 0$) increases macro risk as long as $a^i > 0$. (Here were are ignoring that a PPA might change r.) However, if macro variation in investment costs are ignored ($\hat{a}^i \approx 0$), then a PPA can actually reduce risk through the usual operational cash-flow channel (as long as a_c is low enough).

Macro risk also increases with development horizon τ, since $Var[s_\tau] = \sigma_s^2 \frac{1-\rho^{2\tau}}{1-\rho^2}$ and $\rho < 1$.

The same force exists when production is flexible (i.e. ξ is not necessarily zero). In this case the (per-unit) NPV is given by:

$$NPV_\tau / K = \underbrace{\frac{\theta(\bar{p} - \bar{c}) + \xi \mathcal{V}}{r + \delta} - \bar{i}}_{\text{baseline NPV}} + \underbrace{\left[\frac{\rho(a_p - a_c)(\theta + \xi(\bar{p} - \bar{c}))}{r + 1 - \rho(1-\delta)} - a^i\right] s_\tau}_{\text{macro risk}}$$

where $\mathcal{V}$ captures the variance of future profit margins, with $\mathcal{V} \approx \sigma_p^2 + \sigma_c^2 + (a_p - a_c)\sigma_s^2/(1-\rho^2)$.[44] The previous insight that setting $\xi = 0$ hurts baseline NPV is also visible here.

What if there is time-to-build? This is straightforward to include. If it takes $\tau' \geq 1$ periods to build, the effect weakens. Intuitively, if it took forever to build, electricity prices would drift back to their long-run level and would be uncorrelated with construction costs irrespective of PPA. That means that the downside of PPA does not come from time-to-build but from "time-to-develop".

Formally,

$$NPV_\tau / K = \underbrace{\frac{\theta(\bar{p} - \bar{c}) + \xi \mathcal{V}}{r + \delta} - \bar{i}}_{\text{baseline NPV}} + \underbrace{\left[\frac{\rho^{\tau'}(a_p - a_c)(\theta + \xi(\bar{p} - \bar{c}))}{r + 1 - \rho(1-\delta)} - a^i\right] s_\tau}_{\text{macro risk}}$$

[43] The expected NPV is close to the baseline as long as $s_0 \approx 0$.

[44] This ignores a small correction for increasing variance of s_t over time. The exact last term is $(a_p - a_c)\sigma_s^2/(1-\rho^2)[1 - \rho^2(r+\delta)/(r+1-\rho(1-\delta))]$.

As $\tau' \to \infty$, the first term of macro risk vanishes and cyclicality only comes from investment costs.