Pricing Climate Risks of Energy Investments: A Comparative Case Study

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Climate-related financial risk assessment on energy infrastructure investments

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ABSTRACT

This study assesses climate-related financial risks on energy infrastructure investments. We conduct an asset-level and forward-looking risk assessment on three downstream energy assets: natural gas, coal, and solar photovoltaic power plants. We first identify climate risk factors (physical and transition) that an asset is highly exposed to with its specific asset type, geographic location, time frame, and financing structure and build plausible climate risk scenarios using single or multiple risk factors. We then project an energy asset's cash flow and estimate the asset's probability of default under the built scenarios. We compare the financial impacts of varying climate risk scenarios by analyzing the time and size of the losses due to the given default. We observe climate-related financial risks that are systematic and idiosyncratic: some scenarios affect certain energy assets negatively and others positively, while others negatively affect multiple asset types simultaneously. Our comparative case study results also show that renewable energy investments are likely to be more resilient to climate change than fossil fuel-based energy assets.

1. Introduction

Concern about the adverse impacts of climate change has increased radically over the last decade as the world experiences increases in the severity of weather extremes, much of which can plausibly be attributed to climate change [1]. At the same time, greater availability of high-resolution data and the ability to analyze it have improved the credibility of projections of future climate change, which shows that the impacts of these extremes will worsen as time goes on without aggressive mitigation and adaptation efforts. Moreover, given the complexities of these analyses and deep uncertainties involved, it is also possible, if not likely, that the policy responses themselves will be unanticipated by investors leading to investments that are maladapted to the emerging threats.

The impacts of climate change are already affecting energy infrastructure investments as the energy transition underway is now accelerating dramatically with the global pathway to net-zero emissions. As fossil-fuel electricity generation sources such as coal are gradually being phased out across many parts of the world, fossil reserves [2], companies [3], and physical and financial assets [4,5] are increasingly at risk of becoming stranded assets. Fossil-fuel-based energy infrastructure investments do not reach their planned return on investment leading to possible shutdown and default on the financial obligations required to build them in the first place. The Carbon Tracker Initiative projects that about a third of the fossil-fuel investment planned through 2030 risks failing to deliver adequate returns under the policy actions and market transition to meet the goals of the Paris Climate Change Agreement. On a global economic scale, Mercure et al. [6] estimate the stranding value of fossil fuel assets may cause a US$1–4 trillion loss in global wealth, whose magnitude is comparable to the 2008 global financial crisis. Alongside the rapid phase-out of fossil fuels, natural gas has emerged as a transitional "bridge" fuel providing load-following, flexible electricity generation. With increasing renewable energy incentives such as renewable portfolio standards (RPS) and carbon neutrality or net-zero targets, there is significant momentum for renewable energy development.

Yet, these changes in the values of energy infrastructure assets due to climate risks are not accurately priced [5,7,8]. Previous studies identify that the long-term and non-linear nature of climate risks [9], multiple and often interconnected climate risk factors [10], and dynamic impacts across different assets and contracts [11] pose challenges to assess climate risks in incomparable and quantitative terms. Nordhaus [12] highlights the complex nature of climate risks, whose assessment

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Nomenclature

CAPEX	Capital Expenditures
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture and Storage
CFADS	Cash Flow Available for Debt Service
DCF	Discounted Cash Flow
DSCR	Debt Service Coverage Ratio
EOD	Event of Default
IRR	Internal Rate of Return
ITC	Investment Tax Credit
NPV	Net Present Value
O&M	Operation and Maintenance
OEPX	Operational Costs
PJM	Pennsylvania, New Jersey, and Maryland
PPA	Power Purchase Agreement
PV	Photovoltaic
REC	Renewable Energy Certificates
RPS	Renewable Portfolio Standard
SPV	Special Purpose Vehicle

requires an integrated understanding of the science, economics, and policy of climate change. The social science literature assesses climate risks from a top-down or a bottom-up approach. For the former, we can think of central banks and bank regulators that test responses of key macroeconomic variables (e.g., GDP, interest rate, stock and loan pricing, and BIS ratios) under various climate scenarios and assess their impacts on financial stability [13,14]. They have shown a growing concern of microeconomic heterogeneity for the response of the macroeconomy to aggregate shocks [15], which has led to the latter, bottom-up approach. The need for the bottom-up approach has also emerged from investors' increasing commitments to rebalancing their investment portfolios towards climate-resilient, green assets. Their focus is even more granular, as many investors nowadays have diversified financial assets. Even within the same asset, asset owners can exhibit different financial impacts of climate change depending on which asset class (e.g., debt, bonds, equities) they invest through. In the meantime, however, an individual asset is exposed to systemic risks such as changes in GDP, interest rate, and access to capital. Yet, current climate risk assessment practices lack a systematic perspective [16] or an asset-oriented perspective [17].

The mispricing of climate-related risks may lead to a breach of fiduciary duty of companies, investors, and governments as they fail to consider the long-term implications of stranded assets [18]. The absence of such tools raises concerns for the owners of energy assets who are being forced to review the mix of energy assets in their portfolios and increase capital allocations to renewables. While existing climate risk assessment tools are useful in assessing climate risk exposures of bonds, equities, or corporate lending portfolios, they lack focus on infrastructure assets that are particularly vulnerable to damage from physical and transition risks of climate change. On the other hand, mobilizing investment in climate-resilient infrastructure can also create system-wide opportunities as they can absorb the effects of climate change and expedite the low-carbon transition. Therefore, an integrated framework that can assess relevant climate-related risks and opportunities and how they factor into bankability (i.e., having sufficient profit to secure the required size of a loan at a bank) and profitability of energy infrastructure assets is needed.

In reviewing relevant literature, we acknowledge that not many studies investigate the financial impacts of comprehensive climate risks on an individual asset level. In addition, we also find that empirical studies are limited to recognizing the increasing effects of climate risks, some of which have not existed thus far (e.g., upcoming policies and regulations, new technologies), previously exists but whose impacts are aggravated in isolation or in combination (e.g., simultaneous extreme weather events), or exist but in immaterial threat to infrastructure (e.g., irregular weather fluctuations like extended hot days). But we find a few latest research claims a new space for climate-related financial risk analysis. BIS [19] provides a good overview of conceptual issues related to climate-related financial risk measurement and methodologies, including risk scores, scenario analysis, stress testing, sensitivity analysis, natural capital analysis, and climate value-at-risk. In et al. [11] identify the limitations of extant approaches and newly claim the space that advanced asset-level data can contribute. They develop a new framework to evaluate the bankability of an infrastructure asset by utilizing asset-level data. Still, only a few academic studies apply such a granular (i.e., asset-level) but at the same time comprehensive lens (i.e., multiple climate risks) that provides practical implications to the decision-making process (i.e., projected financial implications).

This study illustrates the usefulness of a newly proposed framework by In et al. [11] for responding to these analytic challenges through its application to a set of representative case studies. We assess climate-related financial risks in three different energy infrastructure investment cases. In the case selection, we focus on downstream energy assets that dominate the U.S. energy supply system today, like natural gas combined-cycle gas turbines (CCGT), coal power plants, as well as rapidly increasing utility-scale solar photovoltaic (PV) investments. In the analysis, we project the combined impact of a range of climate-related risks on the value of the selected investment cases. We use cash flow modeling and scenario analysis methodologies to assess an asset's financial performance, particularly the prospect of repaying its debt, due to climate-related risk in terms of the timing, size, and duration of the economic losses resulting from the default. The main components of the cash flow model are revenue, operating expenses (OPEX), capital expenditures (CAPEX), and financing costs. The cash flow analysis results are used to project debt service coverage ratio (DSCR) and equity internal rate of return (IRR). This study provides evidence-based implications for energy investment portfolio and policy management. We observe climate-related financial risks that are systematic and idiosyncratic: some scenarios affect certain energy assets negatively and others positively, while others negatively affect multiple asset types simultaneously. Our comparative case study results also show that renewable energy investments are likely to be more resilient to climate change than fossil fuel-based energy assets.

We expect this study contributes to elaborating challenges to the asset-level climate risk assessment, which is particularly related to its high level of complexity, and demonstrate a framework to address them. Climate risks, when considered at the asset level, become far more extensive. In the meantime, the list of material risks becomes selective. Often, they can be non-conventional but critical to a specific infrastructure asset, while the asset is less vulnerable to conventional risk factors. Caldecott et al. [20] and Curtin et al. [5] list risk factors more extensively and categorize them into conventional risk categories. By extension, this study uses energy investment cases to demonstrate how different sets of risk factors and scenarios an individual asset faces (by geographical location, time, asset type, operation of the asset, financing structure, etc.) and how to incorporate them into the granular asset valuation practice.

The way of discussing our analysis findings in this regard addresses the limitation of traditional discounted cash flow (DCF) applied at an asset level, whose use of a predefined and constant discount rate limits the practicality of the results it produces. Here, we emphasize the unique aspect of energy infrastructure financing and the value of our assessment. That is, it is highly leveraged, and 70–90% of energy infrastructure assets are financed through debts [11]. Unlike equity investors, who mostly care about the overall IRR of the project, debt investors care about whether they can be paid promised principal and interest every quarter or six months as per the contract term. For debt investors, a higher IRR is preferable but not as important as avoiding any interest period that goes default and unable to repay, as they underwrite more conservatively with a focus on downside protection. These unique aspects of energy infrastructure investment highlight the advantages of computing and utilizing capital cash flow as a means to assess project performance without the need for discounting each cash flow to reach an "intrinsic" asset value. In evaluating project financed assets, therefore, it has long been a market convention to assess a project's DSCR instead of net present value (NPV). DSCR is a metric that evaluates the bankability of a project, and it is calculated as the ratio between cash flow available for debt service (CFADS) and the total debt service in a given period. Therefore, we conduct a DSCR analysis to evaluate the capacity of the project cash flows to meet the debt service obligations throughout the project lifecycle. The enriched contexts from this analysis are suitable for assessing climate risks that are uncertain and complex. Swart et al. [21] discuss that quantitative modeling is legitimate when the system can be specified and the dynamics governing changes are well-known and persistent. However, its power of prediction diminishes when complexity increases and the time horizon of interest is lengthened, which we see highly relevant to climate risks that we are interested in testing. Swart et al. [21] also argue the increased value of qualitative scenario analysis under such circumstances. Qualitative scenario analysis is suitable for addressing concerns of debt and equity holders of infrastructure assets because they have different interests, and debt investors, in particular, are concerned about the security of their facility every single payment period under multiple climate scenarios.

The paper presents the following structure: Section 2 reviews existing climate risk assessment models and tools. Section 3 explains the framework that this study uses to assess asset-level climate-related financial risks and describes the case study design, including case selection criteria and case specifications. Section 4 provides climate risk scenario specifications. Section 5 reports the main results of the three individual case analyses and compares financial impacts due to the varying climate risk scenarios. Section 6 compares three cases and provides implications for energy infrastructure investment decisions and policing makings. Section 7 concludes the paper.

2. Review of literature

We find two strands of research that assess implications of climate risks: research that empirically assesses the economic impacts of climate change and research that estimates financial implications of climate change. While the former research strand is mainly at a macroeconomic level, it is limited in assessing a variety of climate risk factors–especially transition risks [10], offering practical implications at an asset level [11], and thereby providing socio-economic and financial implications at a large-scale [16]. While the latter focuses on applying methodologies to investigate the economic impact at a more granular level (e.g., sector, investment portfolio, asset), most extant studies examine the effect of one single climate risk factor. Since it is highly likely that various climate risks can simultaneously materialize, it is important to assess multiple risks or their interrelated effects. We also find that the criteria and measures of economic impact that previous studies use, while highly reasonable, are inconsistent. In this regard, we see the latest market development for climate risk assessment tools that have benefited from advanced climate data and data analytics to provide risk assessment outputs in financial terms, which we also review later in this section.

The economic literature we refer to empirically investigates the relationship between climate shocks and macroeconomic factors at the country, state, and municipal levels. The impact channels described therein offer good insights into the impacts of climate change on the supply and demand sides of an individual infrastructure asset. For instance, empirical studies show the effects of climate shocks on energy demand [22–24] and energy expenditure [25,26]. Their findings can be used to assess the demand and pricing disruptions in energy infrastructure assets. One other example is empirical studies relating climate shocks to labor productivity [27–29], labor supply [30,31], and labor cost [32]. These findings can provide important implications on the production side of the infrastructure asset as they can affect its operation and maintenance. Yet, extant empirical studies focus on physical risks to the economy, not transition risks or the combined effects of the physical and transition risks [10].

In this regard, the framework recommended by the Task Force on Climate-Related Financial Disclosures (TCFD) has meaningful contributions as it identifies two mainstream climate-related risks as physical and transition [33]. It also provides a consistent framework for investigating the financial implications of climate change. While TCFD recommendations focus on financial implications due to these risks on an organizational level, its risk framework is sufficiently specific to apply it to specifying risks on an infrastructure asset. Climate events such as extreme weather (e.g., extreme heat, extreme precipitation events, cyclones, and hurricanes) and chronic climate change (e.g., temperature increases, rainfall fluctuation) can cause physical impacts to an infrastructure asset [9]. These physical impacts of climate change affect the supply side of an infrastructure asset as they disrupt physical capital (e.g., factories, roads, bridges, machinery), natural resources (e.g., land, in terms of energy infrastructure, oil, coal, natural gas, metals, stone, sand, air, sunlight, soil and water that can be used to make fuel and raw materials for the production of goods), and the workforce (e.g., labor productivity, health and safety threats) [10]. Through these direct channels, physical climate risks can result in financial damage to an infrastructure asset as they cause higher OPEX, CAPEX losses, write-offs and depreciation, and revenue interruptions [34].

On the other hand, government policy (e.g., carbon pricing such as carbon tax and cap-and-trade, environmentally related taxation, government subsidies, and other access to climate finance), technology (e.g., energy efficiency, renewable energy technology, infrastructure development capacities), and consumer preference associated with the transition to a low-carbon economy can cause transition impacts on an infrastructure asset [10]. These transition risks affect the rate and pattern of energy consumption, which can disrupt the volume of outputs and prices of the goods that an infrastructure asset produces. Compared to physical climate risks, the channels that transition climate risks work widely vary, and so as the time taken for these risks to be realized as a cost to an infrastructure asset. It depends on how the economy internalizes the environmental externalities that an asset has generated and will generate. For instance, implementing a carbon tax will directly and immediately increase tax expenses while market demand changes due to consumers' increased awareness of climate challenges will take longer to affect an energy plant's output volume. We also acknowledge some market-oriented instruments that cut through this difference in time horizon. For instance, companies that pledge to net-zero emissions sign more renewable power purchase agreements (PPAs), affecting revenue streams of renewable and fossil-fuel-based revenue power plants [35].

The dynamic nature of financial implications that physical and transition risks bring into an individual asset is worth noting, which can also provide practical implications for investment portfolio management. While it is a macroeconomic level, Ciccarelli and Marotta [10] empirically show that physical risks exert the overall negative impacts on both output and prices, but transition risks exert positive impacts on prices and negative impacts on outputs. When projecting asset-level bankability under climate risk scenarios, In et al. [11] assume that financial risks due to the tail of catastrophic climate change can be managed to some degree by insurance products, but fattening tails will increase insurance premiums, whose pricing depends on insurers' willingness to pay. In the short-run, physical risks directly affect the supply side, while transition risks mainly affect the demand side. In the long run, impact channels become more diverse. For instance, temperature rise can increase energy demand, and the greater funding availability for renewable energy can lower the financing cost of renewable power plants. Yet, to the best of our knowledge, not many studies demonstrate the dynamic financial impacts of multiple climate risk factors throughout the lifetime of an infrastructure asset.

The literature on integrated assessment models (IAMs) and climate change has tried to identify multiple climate risk factors and their scenarios to project economic trajectories for energy sectors [36]. The dynamic integrated model of climate and the economy (DICE) developed by William Nordhaus, for instance, integrates the climate system (e.g., geophysical relationship, carbon cycle, a radiative forcing equation, climate-change equations, and a climate-damage relationship) in the framework of economic growth theory [37]. The damage function, which is a component of this integrated model, calculates the economic costs of climatic change and provides useful implications for policymakers [9,38,39]. Yet, previous IAM-based models are limited in conducting a forward-looking projection of risk outcomes. While findings of empirical analyses of the economic effect of climate change can be useful in estimating the potential economic implications of future climate change, traditional techniques of deterioration and risk modeling based on historical patterns might not be suitable for assessing asset-level risks due to the changing climates that were not considered previously [11,40]. As aforementioned, climate data and risk analysis tools have advanced our ability to project future climate conditions. But how to integrate this advanced information into investment decision-making requires further work. Moreover, the outputs of extant studies are limited in addressing the primary interest of key stakeholders holding debt and equity investment in infrastructure assets. That is, the valuation of investment portfolios and assets, often measured by risk-adjusted return, cash flow, or debt service coverage, under plausible climate scenarios.

Lately, a global market for climate risk management has been developed, addressing the increasing need for climate-related financial risk assessment tools. These market tools benefit from advanced climate data and data analytics, advancing climate risk assessments at a granular level to some degree. Table 1 summarizes our review of existing climate risk assessment tools by highlighting a few as follows. The 2° Investing Initiative and the Principles for Responsible Investment (PRI) recently released the Paris Agreement Capital Transition Assessment (PACTA) tool [41], which examines the composition of an investment portfolio and assesses the overall portfolio alignment with Paris Agreement targets. Its quantitative analysis compares producing metrics such as a forward-looking weighted production (megawatt-hour [MWh], gigajoule [GJ] of oil/gas, tonnes of coal, number of vehicles produced) and carbon intensity, and it offers reliable benchmarks within given sectors, especially in the energy sector. Carbone 4, via the Carbon Impact Analytics tool, provides a bottom-up analysis of climate impacts, aggregated at a portfolio level of sovereign and green bonds as well as stocks and bonds of any listed company. It measures direct and indirect greenhouse gas (GHG) emissions and provides qualitative portfolio-level ratings in each sector. The United Nations Environment Program Finance Initiative (UNEP FI), Oliver Wyman, and a consortium of 16 global banks have developed a. web-tool called Transition Check, which takes a scenario-based approach in assessing climate transition risk exposure of corporate lending portfolios. Its estimates are sector-level expected losses, probabilities of default, and credit rating estimates.

Most climate risk assessment tools assess climate-related financial risks of bonds, equities, or corporate lending portfolios, but not many on infrastructure assets. We find the latest development of ClimateWise developed by the University of Cambridge and Accounting for Sustainability (A4S) shares the view of putting a specific focus on infrastructure. ClimateWise provides two frameworks that analyze climate physical and transition risks on infrastructure assets. Its transition risk framework specifies how the low-carbon transition scenarios can impact costs and revenue drivers of infrastructure assets. While its framework is designed to connect climate-related risks to various valuation models, its current report promotes the use of the DCF to price climate risks [42]. We also find research by Pless et al. [43] that compares NPVs of energy systems with varying energy sources, using DCF and real options analysis. While DCF and NPV analysis can be useful in assessing the profitability of a project over its lifespan, the analysis does not give specific insights into when climate risks can affect an asset's value nor inform about the occurrence of events of default. Limitations also exist to DCF analyses, particularly the use of a single discount rate which is viewed as a major source of uncertainty [11].

Based on our review of literature and market studies, this study aims to assess an asset's ability to meet future financial obligations, especially debt repayment, throughout the financial contract period. We focus on debts because assessing climate risks in the value of debt investments of infrastructure assets is less developed, while debt instruments have historically comprised 70–90% of the total capitalization of infrastructure projects [44]. The probability of default refers to the likelihood that a borrower will fail to repay its debt obligations. It is the most important metric for infrastructure investments because infrastructure assets often have higher levels of leverage than non-infrastructure assets, given less volatile cash flows and the willingness of sponsors of infrastructure projects to accept higher levels of debt [45]. By shedding light on debt investment, this study will make meaningful contributions to climate-related financial risk assessment and management in energy infrastructure. Brealey et al. [46] highlight that the source and form of financing should be reflected in risk management, especially in high leveraged projects. This study focuses on variables that are commonly used by current market investors, namely DSCR and IRR. DSCR analysis is particularly suited to estimate an energy asset's probability of default due to climate risks and the size and time of the losses by the given default.

3. Data and methods

3.1. Risk assessment framework

This study demonstrates how the framework presented by In et al. [11] can be applied to various energy infrastructure assets. While In et al. [11] provide an abridged case study on natural gas to simulate its proposed framework, this study makes a complete analysis and cross-comparison of three energy infrastructure assets covering from fossil fuel to renewable sources. Our assessment is a three-phase approach. Firstly, we select an asset of focus by specifying its energy source (e.g., natural gas, coal, nuclear, wind, solar, etc.), sector (e.g., upstream, midstream, and downstream), asset class (e.g., debt, bonds, equities), geographical location and project period. Following asset selection, the relevant climate risk variables are selected and estimated, mostly based on existing climate science and engineering literature on the performance of energy generation assets. Risks are delineated based on whether they are related to the physical impacts of climate change (i.e., physical risks), correlated to the risks associated with the transition to a lower-carbon economy (i.e., transition risks), or associated with the implementation of new regulations (i.e., regulatory risks). We believe that the impact of changing technologies and levels of sector competitiveness manifests at a more orderly pace and trajectory than regulatory risks, which are likely to have sudden, significant impacts. These variables are utilized to build climate risk scenarios that are important to consider and can potentially impact the specific project's operational performance and financial returns over the asset's lifetime. As part of location- and sector-specific scenario development, our case study of the three energy assets covers four broad categories of climate-related risks: chronic climate change, acute weather events, market and technology transitions, and policy interventions.

Secondly, under each identified risk scenario, we project the combined impact of climate-related risk factors and investigate how the projected impact would affect an energy asset's cash flow. In this process, we project four key cash flow elements throughout the project's investment horizon: revenues, CAPEX, OPEX, and financing costs. These four cash flow elements are connected to the capital structure of the asset specified in the main financial contract and other project-based contracts such as offtake, fuel supply, operation & maintenance

Table 1
Review of climate risk assessment market tools.

Climate Risks	Name	Description	Unit/Level of Analysis	Output Metrics and Analysis
Physical + Transition Risks	**Carbon Delta**	Commercially available fintech tool that quantifies investment risks of publicly-listed companies under climate change scenarios	Equity and corporate bonds at a portfolio level	Climate VaR per security and per scenario, which can be aggregated at a portfolio level
	Environmental Resources Management	Commercially available tool that consists in a top-down portfolio screening and bottom-up asset analysis to evaluate financial opportunities and risks related to the transition to a low-carbon economy	Portfolio and asset class levels	Provides a risk management dashboard to monitor indicators; asset-specific physical climate change risk assessment; and portfolio screening
	ISS Climate	Commercially available tool that offers an impact and risk-oriented scenario analysis at firm, portfolio and sector levels for in eight different scenarios	Equity and fixed income portfolios	Average carbon intensity (historical and forward-looking forecasts); financial impact of physical risks; qualitative portfolio climate target assessment and scoring
	Mercer	Commercially available tool that offers a top-down, asset allocation climate scenario analysis that examines risk/return impacts	Portfolio, sector and asset class levels	Prioritization of risks and opportunities; and potential relative impacts under different scenarios
	Climate MAPS (by Ortec Finance)	Commercially available tool that uses a E3ME macro-economic model to quantify climate risks impacts under different scenarios	Portfolio level	40-years horizon report that includes metrics such as CVaR, expected return, impact on funding ratio, and climate risk factor decomposition
	Artica (by South Pole)	Commercially available tool that performs a top-down portfolio analysis and a deep dive assessment to identify climate risks classified by hazard, vulnerability and exposure	Equity and fixed income at portfolio, sector and company levels	Risk scores and graphics that can be used by investment managers
	Planetrics (by Vivid Economics)	Commercially available tool that uses economic and financial models to estimate the climate risk exposure of financial assets under different scenarios	Equity, corporate and real estate bonds at company level	Asset price value impairment that can be broken down in a granular level; carbon intensity; and temperature alignment analysis
	Entelligent	Commercially available tool that integrates climate scenario analysis and machine learning to reduce portfolio exposure to climate change risks	Equity and publicly-listed stocks at portfolio level	Carbon evaluation; portfolio optimization aligned with ESG goals; measurement of climate risk exposure; ESG product development
	RiskThinking.AI	Commercially available data-driven tool that uses AI to evaluate climate-related financial risks under different scenarios using the CRCS standard	Sector and portfolio levels	Stress-testing that generates a climate-risk adjusted return that values and rates climate-related financial risks
	Climanomics (by the Climate Service)	Commercially available tool that evaluates the impact of climate risks with a catastrophe risk model under specific assets by using climate and socioeconomic data	Portfolio, company and asset class levels	Online report of risks at an asset level that can be scaled-up to company and portfolio levels within a time horizon of 1–80 years
Physical Risks	**Climate Risk Impact Screening - CRIS** (by Carbone 4)	Open-source tool that assesses climate physical risks in portfolios by performing a bottom-up analysis of GHG emissions for different assets	Portfolio level	Reports with benchmarks across sectors for climate-related performance; high risk areas identification; and sector specific investment strategies
	Four Twenty-Seven	Commercially available tool that offers on-demand analytics to assess sensitivities to physical climate impacts at an asset-level for publicly-listed companies and real asset portfolios	Portfolio and asset class levels	Identification of assets/sectors/geographies most at risk; risk mitigation strategies; due diligence for new asset acquisition
	RisQ	Open-source data-driven tool that assesses climate-related financial risk under municipal assets to provide insight to municipal bonds holders	Municipal debt/bonds portfolios	Report with financial "bottom-line" impacts of climate risks
	Trucost Climate Change Physical Risk Analytics (by S&P Global)	Commercially available tool that provides insight of physical climate risks at a company level	Company level	Dataset with the likelihood of impact and potential economic losses of a company under different climate risks scenarios
Transition Risks	**PACTA** (by 2° Investing Initiative)	Open-source tool that analyzes equity and fixed-income climate transition risks for the power, transport and industrial sectors	Corporate lending, equity and corporate bonds portfolios	Report with a 5-years forward-looking of the weighted production of the firms and their carbon intensity; 2-degree and industry peers benchmarks
	ClimateWise (by CSF-Cambridge University)	Open-source framework tool that provides insights about how costs and revenue drivers of infrastructure assets of a portfolio could be impacted by transition to a low-carbon economy	Infrastructure assets at portfolio and asset class levels	Report with key financial metrics (NPV, EBIT) and direct changes in costs and revenue drivers
	Transition Pathway Initiative (by PRI, LSE, Grantham Institute, FTSE Russel)	Open-source tool that provides a bottom-up assessment of GHG emissions of 373 companies and how they prepare for a low-carbon economy by meeting the targets set by international agreements	Sector and asset class levels	Deep dive analyses for industrial sectors that include benchmarking based on emissions intensity
	2 degrees of separation (by Carbon Tracker and PRI)	Open-source tool that analyzes oil and gas firms' exposure to transition risks and how they comply with Paris Agreement targets	Oil and gas companies	Analytical reports that include benchmarking based on CAPEX
	Carbon Impact Analytics - CIA (by Carbone 4)	Open-source tool that assesses climate impacts of portfolios by performing a bottom-up analysis of GHG emissions for different firms	Portfolio level	Identification corporates and sovereigns with high physical risks and the best-in-class corporates or companies with a strong contribution to decarbonization
	Transition Check (by Oliver Wyman and the UNEP FI)	Open-source tool that uses a dozen of climate scenarios to assess transition risk's exposure of banks' lending portfolios	Customers and corporate lending portfolios	Charts and graphics of climate and financial variables within a long-term period broken down by sector and geography

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Table 1 (*continued*)

Climate Risks	Name	Description	Unit/Level of Analysis	Output Metrics and Analysis
	Trucost Carbon Earning at Risk (by S&P Global)	Commercially available tool that assesses companies' exposure to carbon pricing mechanisms and GHG emissions, and their financial performance to provide insights of carbon risks by 2030	Portfolio and company levels	Carbon price risk premium expressed as impact on EBITDA and profit margin
	ClimateWise (by Deloitte)	Commercially available tool that consists in a scenario-based approach to assess climate transition risks of credit portfolios	Banks' lending portfolios	Report and dashboard designed to monitor primary KPI such as benchmarking across sectors and geographies, risk-weighted assets and expected credit losses
	Carbon Transition Assessment - CTA (by Moody's)	Commercially available scoring tool that assesses the carbon transition profile, risk exposure and management response for electric utilities and power generation assets	Asset class level	Weighted score of the different components evaluated; potential risks and opportunities driving changes in revenues and costs

contracts. The key terms in place in the financial and operational contracts allow for the granular estimation of asset-level cash flows.

Finally, we estimate the financial impacts of our selected climate scenarios (i.e., whether, by how much, and when the project's cash flow will change due to the specified scenario). We estimate the asset's probability of financial default due to specific (or a combination of) climate risk factors, assess the size and time of the losses by the given default and calculate the default conditions. To clarify, the main purpose of this analysis is not to determine whether a certain climate risk scenario will happen but rather project whether the asset would default if that risk scenario materialized.

To that extent, we develop combined risk scenarios (i.e., collective risk scenarios) that simulate the occurrence of multiple risk factors in unison, however, with varying levels of severity. In addition to conducting a deterministic analysis in which the financial impacts of a certain severity level (e.g., high, medium, low) are assessed, we conduct a probabilistic analysis through a Monte Carlo simulation approach. Each of the three case studies incorporates a "Probabilistic – Monte Carlo" scenario in addition to the existing evaluations. To develop these probabilistic scenarios, we apply a probability distribution that assigns a probability of occurrence to each collective risk scenario, creates 500 runs of the financial model, and calculates the resulting average. This approach allows investors and users of our risk assessment framework to reflect a blended view of the different collective risk scenarios, adjust the probabilities assigned to each case based on their level of conservatism, assess the resulting cash flows and DSCR metrics, and underwrite their investment accordingly.

Furthermore, the analysis estimates the impact on the value of both debt and equity investments in these cases. We believe that assessing debt risk is particularly important firstly because debt investments expect consistent payments and hence may be less resilient to short-term instability. A few years of weak performance can lead to a default on debt, whereas equity investors are more intrinsically expected and tolerant to short-term volatility. Secondly, debt investments make up a substantial portion of infrastructure financing. Our analysis focuses on risk impacts in the years 2023–40 with the ultimate goal of informing investors and positively influencing near-term debt investment behavior to align with IPCC goals. Through a comparative case study, we can evaluate multiple climate risk scenarios to highlight the variations in resilience across assets in terms of both debt and equity investments.

The outputs of the three case analyses are in the form of the financial metrics that are standard in infrastructure investment due diligence processes. Firstly, we examine a project's DSCR to assess the impact on debt investments' resilience by estimating how many times a project can pay its debt service using the cash flows generated. It is calculated by dividing the CFADS generated in a certain period by the total debt service payments (principal plus interest). Hence, the metric identifies the buffer amount before a default on a loan occurs, and a DSCR below 1.0x indicates an event of default (EOD). In a project financing loan agreement, there are often covenants that may state that any reductions in DSCR below a certain level (1.5x, 2.0x) will trigger an EOD and may pause all the cash distributions to equity holders. Secondly, we examine project IRR to assess the resilience of equity investments. The IRR is calculated as the discount rate that makes the NPV of the project's cash flows project zero. Hence, it implies the annual rate of growth that the investment is expected to generate. DSCR and IRR are the primary drivers of the investment decision and underwrite investments where they view the risk levels are commensurate with the return profile.

3.2. Case study

3.2.1. Asset selection and profile

As our case studies serve to simulate the application of the methodology, we set the most conventional specifications for each asset. As mentioned in the previous section, these specifications include energy source, sector, asset class, geographical location, and project period. We select three utility-scale electricity generation facilities (i.e., downstream energy assets): a new natural gas CCGT, an existing coal power plant, and a new utility-scale solar PV plant. These assets are selected due to their importance in U.S. electricity generation. CCGT and coal power plants dominate U.S. electricity generation today. By 2019, natural gas and coal shared 38.4% and 23.4% of U.S. utility-scale generation, respectively, a production of more than 2551 billion kWh [47]. While solar PV contributed 1.7% in utility-scale generation in 2019, the electricity generation from solar PV ramped up 291% from 2014 to 2019, whereas other renewable sources like wind have increased only by 62% in the same period [48]. In addition, solar PV is expected to become the renewable source with the highest generating capacity additions in the upcoming years as its levelized costs of electricity decrease because of expected technological improvements [49].

We compare across the three assets to show that response to climate-related risks is dynamic and heterogenous, depending on the specific characteristics of each asset. Our analysis focuses only on downstream energy assets, not upstream fossil fuel assets, such as fuel production and transportation. Although fixed-income investments in downstream energy assets are typically perceived as lower-risk investments, it is unclear whether current downstream asset investments adequately price climate-related risks [50]. Moreover, investors perceive that upstream energy assets are exposed to significant climate risk. In any case, upstream energy projects are rarely project financed, and cash flow volatility is expected due to commodity price and production uncertainty [2]. The full list of key assumptions for each case can be found in Table 2.

The first case is a new natural gas CCGT located in Pennsylvania, New Jersey, and Maryland (PJM) power pool. Within the U.S, there is currently a "rush-to-gas," which could mean up to $500 billion in capital investments within the next ten years. Most of these investments are planned in the PJM region, so new power plants replace uneconomic, retiring, and inefficient thermal plants in the Mid-Atlantic and Appalachian states [51]. In PJM alone, 20 GW of new gas capacity is estimated to come online in 2019–22, with an associated $8–10 billion of debt financing [52].

Table 2
Key assumptions for three cases.

(a) Base case key assumptions for the natural gas case study

Plant Assumptions	Value	Unit
Type	Natural Gas CCGT Power Plant	–
Revenue Model	Merchant	–
Location	PJM (Mid-Atlantic)	–
Nameplate Capacity	500	MW
Heat Rate	6.6	Mmbtu per MWh
Combustible Price	$3.00	USD per Mmbtu
CAPEX Assumptions		
Construction Start Date	2020	Start year
Construction Length	3	Years
Construction CAPEX	$1,000,000.00	USD per MW installed (“all-in”)
	$500,000,000.00	USD (total, “all-in”)
Revenue Assumptions		
Capacity Factor	65%	Year 1
Annual Generation	2,847,000	MWh, Year 1
Power Price	$39.80	USD per MWh, Year 1
Fuel Cost & Variable O&M	($22.80)	USD per MWh, Year 1
Spark Spread	$17.00	USD per MWh, Year 1
Capacity Payments	$120.00	USD per MW per day
OPEX Assumptions		
Fixed O&M	$11,000.00	USD per MW per year
Property Tax and Insurance	$7,500,000.00	USD per year
Capital Structure and Debt Assumptions		
Debt Tenor	15	Years
Interest Rate	6.0%	Annual
Debt to Equity Ratio	60/40	–

(b) Base case key assumptions for the coal case study

Plant Assumptions	Value	Unit
Type	Conventional Steam Coal, Supercritical	–
Revenue Model	Merchant	–
Location	Indiana	–
Nameplate Capacity	650	MW
Heat Rate	10.06	MMBtu per MWh
Combustible Price	$1.93	USD per MMBtu
Revenue Assumptions		
Capacity Factor	47.5%	Year 1
Annual Generation	13,897,740	MWh, Year 1
Power Price	$38.84	USD per MWh, Year 1
Fuel Costs & Variable O&M	($23.09)	USD per MWh, Year 1
Spark Spread	$15.75	USD per MWh, Year 1
Capacity Payments	$47.20	USD per MW per day
OPEX Assumptions		
Fixed O&M	$23,000.00	per MW per year
Property Tax and Insurance	$7,840,000	per Year
Capital Structure and Debt Assumptions	**Value**	**Unit**
Net Book Value at 2023	$400,000,000	USD
Refinance Debt Tenor	20	Years
Refinance Interest Rate	5.50%	Annual
Amortization	50%	Debt Principal
Debt to Equity Ratio	55/45	

(c) Base case key assumptions for the solar PV study

Plant Assumptions	Value	Unit
Type	Utility-scale solar PV	–
Revenue Model	PPA	–
Location	California	–
Nameplate Capacity	10	MW
CAPEX Assumptions		
Construction Start Date	2020	Start Date
Construction Length	10	Months
Construction CAPEX	$4,022,271	per MW installed
	$40,227,150	Total pre financing costs
Revenue Assumptions		
Capacity Factor	24%	Year 1
CF degradation	0.5%	Annual
Generation	$21,024	Annual MWh AC, Year 1
PPA price	$37.96	per kWh; base case price; all equity partnership flip
OPEX Assumptions		
Fixed O&M	$22,000	per DC MW per year
Variable O&M	$3.50	per MWh
Capital Structure Leveraged Partnership Flip		
Debt to Equity Ratio	48.8/100	–

(*continued on next page*)

Table 2 (*continued*)

(c) Base case key assumptions for the solar PV study

Plant Assumptions	Value	Unit
Debt Tenor	15	Years
Debt Interest Rate	7.75%	Annual all-in
Tax Investor Equity Share	98%	Of total equity contribution
Project Sponsor Equity Share	2%	Of total equity contribution
Cash sharing ratio – Tax investor	98%	Pre-flip
Cash sharing ratio – Tax investor	10%	Post-flip
Cash sharing ratio – Project Sponsor	2%	Pre-flip
Cash sharing ratio – Project Sponsor	90%	Post-flip
Tax benefit sharing ratio – Tax investor	98%	Pre-flip
Tax benefit sharing ratio – Tax investor	10%	Post-flip
Tax benefit sharing ratio – Project sponsor	2%	Pre-flip
Tax benefit sharing ratio – Project sponsor	90%	Post-flip

For the second case, we study an existing supercritical coal power plant located in Indiana, a state with the second-highest power capacity in coal and the third-largest number of operating coal power plants in 2019 [53]. The midwestern U.S. is one of the regions where coal plants still stably run, and their retirement rate is low [54]. Unlike in the other cases, we analyze this case as refinancing of an existing plant because no new coal power plants have been built in the U.S. since 2015, and their average age is 40 years [53]. Many of these assets are becoming unprofitable as they face increasing policy regulations, requiring them to either reduce their generation or invest in new equipment [55]. However, shutting down of those unprofitable facilities may incur operating losses considering early termination fees and costs associated with fixed-term contracts [56]. This has led coal power merchant generators to deleverage their capital structure to lower indebtedness or refinance their long-term debts [57].

The third case is a new utility-scale solar PV plant located in California, given the state's ambitious climate and renewable energy policy and one of the highest solar resources in the U.S. Through Senate Bill 100, California continues to pave the way as a renewable energy leader, and it has set a goal of supplying all-electric retail sales with renewable and zero-carbon resources to end-use customers by 2045.

3.2.2. *Financing structure*

The financing terms and conditions, including capital structure, can change the values of investments. In general, energy infrastructure assets are financed through equity (shares of ownership), debt (loans), and corporate or project bonds. Project finance is the most frequently used structuring mechanism to finance energy infrastructure projects [58]. In 2019, 35% of global renewable energy asset finance was through project financing [59]. In a project finance structure, aspects such as development, construction, finance, and operation are performed by a special purpose vehicle (SPV), and the project is financed without guarantees from sponsors (i.e., non-recourse), so lenders of the SPV are entirely reliant on the asset and the project cash flows for debt service and principal repayments [60].

For the natural gas CCGT case, project-financed merchant plants in that region typically get financed with 6–7% interest rates and a capital structure of 65% debt and 35% equity [61,62]. We conservatively assume 60% of the construction costs are funded by debt and 40% by equity. In terms of revenue stream, we consider a merchant market model that is more volatile than a contract-based model. In a merchant plant, revenue is generated by bidding in an energy market auction, which determines energy sales prices and capacity payments. On the other hand, a contracted power-purchase agreement provides long-term fixed sales prices and capacity payments [11].

For the coal power plant case, capital structure is mainly driven by the market that the asset serves and its technological capacity. Debt capacity in a utility-owned plant depends on the technology in a regulated market, while debt capacity in a merchant market is based on market risk. Average returns of a regulated utility and its asset depend on the rate base, pre-defined by regulators [63]. A coal power plant is considered a baseload power asset and is perceived as less risky because of its proven technology and ability to generate electricity at a steady rate. Thus, debt capacity tends to be higher than in other assets. For our case study, we assume a coal power plant in a merchant market which will typically have a capital structure of 55% debt and 45% equity following a refinancing [63].

Regarding the solar PV case, project finance structures have been used in the California market to optimize the benefits from federal tax credits and the Modified Accelerated Cost Recovery System (MACRS), a method of accelerated depreciation of the asset's value. Through this method, asset value can be fully depreciated within five years, therefore reducing tax liability and accelerating the rate of return on investment. A significant driver of the early growth in solar PV was the Investment Tax Credit (ITC). Tax credits are reductions in income taxes that a company would otherwise pay to the federal government. Solar developers tend to be smaller companies with little tax liability to benefit from the tax benefits associated with solar investments in the U.S [64]. Therefore, the ITC encouraged the involvement of large institutional players and corporates – with large "tax equity appetites" such as JPMorgan, Goldman Sachs, and Google – in solar energy partnership flip transactions that freed up capital for developers. Tax credits led to the creation of tax-equity financing structures such as partnership flips, sale-leasebacks, and inverted leases.

In this solar case study, we use a leveraged partnership flip model, where the project company is financed by a combination of the project sponsor and tax investor equity and debt (as back-leverage by the project sponsor). Through this structure, tax equity investors can optimize solar by 26% ITC (ITC level in 2020) and five-year accelerated depreciation. In such financing structures, the allocation of cash must be separated from that of tax benefits [64]. A flip in the project's ownership structure typically occurs once a previously agreed equity investor target IRR has been reached. The project sponsor receives the majority of the distributable cash, whereas the tax equity investor gets the majority of the tax benefits. The tax equity investor immediately obtains 99% of the ITC and the majority of the taxable losses/gains pre-flip in ownership. In post-flip, the project sponsor then receives the majority of the taxable losses/gains once the tax benefits from the ITC and accelerated depreciation have mostly expired. For solar PV projects, revenues are mainly driven by electricity sales from PPAs between a utility or corporate off-taker and the solar project developer and Renewable Energy Certificates (RECs).

4. Analysis

4.1. *Climate-related risk factors*

We identify climate-related risk factors that are likely to occur in each case and, if so, might impact the investment valuation. Some risk factors are common across the three case studies (such as increased temperatures, increased frequency of extreme weather events, renewable energy technology advancement, and cost decline), while others are asset-specific (such as the ITC phase-down for solar PV projects). We refer to existing literature and market studies to build plausible climate scenarios and estimate their impacts on a project's cash flow. Table 3 summarizes the main identified climate risk variables across the natural gas, coal, and solar cases. Using these variables, we build climate risk scenarios that simulate single or combined risk factors.

4.1.1. Physical risks

4.1.1.1. Water-related risks. Water scarcity can result in the curtailment of thermal plants, such as the natural gas CCGT plant in our case study if adequate cooling water is unavailable [65,66]. A thermal plant uses a "once-through" cooling system, which intakes surface water and discharges warmer water, or a "closed-loop" system, which reuses water for cooling. The former is predominantly exposed to water scarcity risks, while the latter is only vulnerable to extreme water temperature increases. The once-through cooling systems are present in roughly 30% of natural gas CCGT plants in the U.S., and recently built natural gas CCGT plants are mostly built with closed-loop water cooling systems to reduce the exposure to water scarcity risks [67]. Our case study uses a natural gas plant with a once-through cooling water system and assumes that water scarcity risk will decrease its annual capacity factor by 1.5% per annum [68]. We assume a coal plant is more vulnerable to water temperature rise because superficial water sources, which most coal plants use for cooling, can reduce plant efficiency. Using the estimates from Henry and Pratson [68] and Makky and Kalash [69] under the 1 °C of climate warming condition, we assume water temperature increase will reduce a coal power plant's capacity factor by 0.12% per annum.

As climate change is likely to exacerbate prolonged water scarcity resulting in drought in California [70], it is important to consider the risk of dust accumulation on solar panels caused by the lack of rainfall. The accumulation of dust on solar panels (i.e., soiling) causes panel efficiency to decrease by around 0.2% per day if panels are not cleaned or washed out by the rain [71,72]. Kimber et al. [72] find that the daily efficiency loss of 0.2% without rainfall results in annual energy generation losses between 1.5 and 6.2% depending on the location, with losses of 4.5–5% for the Los Angeles or Central Valley areas. We price the risk of increased drought and soiling as 5% reductions per annum in annual electricity generation and a 10% increase per annum in operation and maintenance (O&M) costs.

4.1.1.2. Air temperature increase. Increased air temperatures can reduce power plant efficiency, resulting in lower generation for solar PV [73–75] and increased fuel usage for natural gas CCGT [76]. For the natural gas CCGT case, we consider increases in turbine heat rate and fuel usage caused by increased air temperatures. We derive estimates based on [76] work, leading us to conservatively project a 0.15% increase per annum of OPEX due to increased fuel usage associated with 0.1 °C ambient temperature increase. While utility-scale solar PV plants in California indeed experience seasonal capacity reductions due to increased air temperature, it remains challenging to precisely estimate capacity reductions due to this cause [77]. Instead, we examine solar manufacturers' panel specifications. Solar panel efficiencies are typically rated at 25 °C [78]. A typical solar panel temperature coefficient, the percentage decrease in power output per degree of temperature increase, is around 0.4% per 1 °C [78,79]. Using these estimates, we find that temperatures of 40 °C would, for example, result in a power output drop of 6%. Using California Energy Commission's extreme heat modeling tool [80], we estimate 40 extreme heat days in the 2050 summertime, defined as days in a year when daily maximum temperature is above the extreme heat threshold of 103.9 °F or 40 °C. Thus, we assume a 6% decrease in power output over 40 days during the summer for solar PV plants in California.

On the contrary, in a coal power plant case, the temperature rise may otherwise increase plant efficiency, depending on the plant's cooling system [68,81]. A plant with a closed-loop cooling system tends to exhibit a positive correlation with air temperature. For every 1 °C increase in ambient air temperature, its net efficiency increases 0.004%, which means that it requires 3.5 fewer tons of coal to maintain constant power output. Conversely, in a plant with an open-loop cooling system, an increase of 1 °C in air temperature reduces the plant efficiency by 0.007% [81]. Since a closed-loop cooling system is commonly installed for coal power plants in Indiana, we assumed that increases in air temperatures lead to efficiency increases of 0.004%. Furthermore, we developed our scenario very conservatively by assuming 1 °C temperature rise every year, leading to these efficiency impacts taking place annually.

4.1.1.3. Extreme weather events. Acute, extreme weather events can affect all power plant types and result in sudden plant downtime or repair expenses. Yet, the likelihood of extreme weather events on a single plant remains low [66]. Risks due to these extreme weather events may have already been priced in the financial contract structure. That is, the insurance sector and broader financial system increasingly bear the "tail risk" of increased frequency of extreme weather events. We thus model the increased risk of extreme weather as a 15% increase per annum in insurance costs throughout the asset's operational life based on an expert interview [82]. As the highest risks are not concentrated in a single region, in our natural gas and coal cases, we chose not to distinguish plant insurance costs by U.S. region [11]. For a coal power plant, the premium needed for the insurance coverage might be higher than for a natural gas plant because of the trend of insurers exiting from the coal business [83]. However, little information is available to know the usual premium paid by coal power plant owners. Therefore, for our coal risk scenario, we consider an insurance cost increase of 16% per annum, which is a premium of 1% in addition to the annual escalation of the natural gas CCGT insurance.

For the solar PV case, we test the impact of a severe hailstorm event. While property risk insurance of solar PV projects typically covers visible and obvious damage from hailstorms [84], it usually does not cover performance losses due to hailstorms causing no visible damage but microcracking the panels. Using data from the National Oceanic and Atmospheric Administration on hailstorm incidence from 1955 to 2018 and the Stanford DeepSolar Project on the number of solar installations per county, we find that areas of high hailstorm incidence are likely to coincide with areas with high numbers of solar installations [85]. Notably, in Fresno, San Bernardino, and San Diego counties, there have

Table 3
Climate risk variables, grouped by risk categories.

	Case 1: Natural Gas CCGT in PJM	Case 2: Coal Power in Indiana	Case 3: Solar PV in California
Physical risks			
Water-related	●	●	●
Air temperature increase	●	●	●
Extreme weather	●	●	●
Transition risks			
Competitive RE tech	●	●	
Flexible fuel supply contracts		●	
Curtailment			●
PPA price reduction			●
Regulatory risks			
Carbon pricing	●	●	
Mandatory CCS	●	●	
ITC Phase down			●

been 60, 54, and 37 large hailstorm incidents and 199, 369, and 627 utility-scale solar PV plants, respectively. Hailstorms can result in visible fracturing of the panel plate cover as well as form "microcracks" in the photoactive material [86]. Muehleisen et al. [86], studying hailstorm damage to solar panels in Austria, have found that exposure to large hailstones (with a diameter up to 40 mm) resulted in 10–20% power losses before panel replacement. We assume that once a severe hailstorm affects a solar project, insurance costs would increase 1.5x post-incident.

4.1.2. Transition risks

4.1.2.1. Renewable energy cost decrease. Renewable energy cost reduction and technology advancement have been drastic since 2010 [87]. Rocky Mountain Institute [51] projects that the cost of new-build renewable energy portfolios may become cheaper than operating portfolios of efficient natural gas generation. Advanced energy storage technology has also reduced renewable energy costs [88,89] and is upending the convention that baseload fossil-fuel generation is needed to solve intermittency challenges associated with renewable electricity generation [90]. Competition with renewables has already resulted in lowering capacity factors for fossil fuel power plants, a trend observed and expected to progress across almost all independent system operators (ISOs) and regional transmission organizations (RTOs) [91]. Due to the auction-based competitive bidding nature of wholesale electricity markets in the U.S. and low bids submitted by renewable energy generators, renewable energy cost reduction also results in an overall electricity market price decrease. Using renewable energy cost projections from the Rocky Mountain Institute [51], we develop falling electricity prices to input our natural gas and coal financial models. High, Medium, and Low-risk electricity prices scenarios are developed, accounting for uncertainty and variability in future wholesale prices.

In addition to competition with increasingly inexpensive renewable generation, coal plants face competition with natural gas power plants following the shale gas revolution in the U.S, which has driven down gas prices. As a result, the average capacity coal plant factor dropped from 67.1% in 2010 to 47.5% in 2019 [92]. Based on the reported capacity factors, we calculate the average annual reduction rate as about 2.17% and the compound annual reduction rate as about 3.76%. Thus, we assume a fixed annual reduction in coal plant capacity factor of 4% (high-risk estimate), 2% (medium risk estimate), and 1% (low-risk estimate).

Falling renewable energy costs have led to tremendous growth and increased competitiveness in the solar industry over the past decade. However, falling costs can also be viewed as a risk for utility-scale project developers and investors, given that revenues in solar-PV projects are entirely linked to fixed-term, fixed-price power purchase agreements (PPAs), which are required to receive competitive financing for solar projects. In our solar PV case study, we consider risks related to the decrease in PPA prices, another recent trend observed in the U.S. solar industry. Bolinger et al. [93] have shown that PPA prices in California have steadily decreased in the past decade from >100$/MWh to 20–30$/MWh in 2019 (prices in real 2018 $). For our analysis, we chose to model the impact of a 20% decrease in PPA prices.

4.1.2.2. Flexible fuel supply contracts. Fuel costs dominate about 50%–60% of the variable O&M costs of a coal power plant [94]. To minimize risks from fuel price fluctuations, a coal power generator typically uses a long-term fuel supply contract at a fixed price, such as a take-or-pay contract [95]. Under this fixed contract, a generator needs to keep receiving fuel or pay the contracted cost even if they do not need it. Due to the increased availability and use of alternative energy sources in the electricity market, coal power plants have ramped down their electricity generation, reducing their capacity factor and fuel use. As an alternative to these fixed-term contracts, a generator may reduce the length of fuel supply contracts and use a spot market [96]. For our coal case study, we consider three scenarios with variable fuel supply contract terms once a reduction of 1% in capacity factor per annum occurs: a 20-year-long fixed fuel supply contract, a 5-year-long fixed fuel supply contract, and a spot-rate market contract.

4.1.2.3. Increased renewables curtailment. As California moves towards integrating more renewables into its electricity system, the utility-scale solar business model will face increasing curtailment risks. For instance, 80% of California curtailments in January and February 2017 were solar projects [97]. Curtailment of solar-generated electricity occurs due to the lack of temporal alignment between abundant solar electricity generation (in the middle of the day) and periods of high electricity demand (mornings and evenings). High curtailment levels typically occur in the Spring, when hydropower electricity generation is particularly high and electricity demand low compared to Winter or Summer [98]. March 2020 has seen up to 10.7% of solar generation curtailed [99]. We assume solar curtailment as a 10% decrease in electricity generation per year, reflecting our view that curtailment rates are likely to increase in the future with higher solar penetration levels.

4.1.3. Regulatory risks

Interventions by policy at the international, national, or state levels can vary widely, ranging from RPS, production and investment tax credits, carbon neutrality targets, carbon pricing, or mandated carbon capture and storage (CCS). Policy implementations can result in climate policy "shocks" following significant events such as different political trajectories, climate-related financial disclosure requirements, or important scientific discoveries [100].

4.1.3.1. Carbon pricing. In our natural gas and coal cases, we assume carbon prices will be implemented as per the Carbon Pricing Leadership Coalition [101] projections. We envision that the initial market response to carbon price implementation would be passing through some of the carbon pricing expenses to consumers via higher electricity rates. We assume that the price will be applied at a rate of $30/ton of CO2 starting in 2025. At the same time, electricity prices will increase to absorb 25–50% of carbon price expenses for the natural gas case and 75–90% for the coal case.

4.1.3.2. Carbon capture and storage installation. We also consider CCS installation, which can be mandated by policy requirements or taken as pre-emptive mitigation against carbon price implementation. CAPEX and OPEX of CCS retrofits or installation on new-built plants vary widely depending on the plant type. Cost estimates for implementing this technology are higher when CCS is installed in coal power plants than when installing natural gas plants [102]. In our natural gas case, we assume the CCS installation will cost $200–400 million CAPEX for the new-built plant and $15/ton of CO2 variable O&M costs each year. We also assume a 5% decrease in capacity factors vs. pre-CCS levels due to parasitic losses. In the coal case, we assume CCS retrofit on an existing plant will cost $340–500 million and $13/ton of CO2 variable O&M. Also, there will be a decrease in capacity factor due to parasitic losses set at 5% [103].

4.1.3.3. Solar investment tax credit phase-down. Established with the Energy Policy Act of 2005, ITC has been a critical driver of the U.S. solar industry development. ITC has been extended several times, but it is set to step down in the next few years. The ITC stepdown is likely to decrease the tax equity interest that has helped catapult the solar industry over the past decade. However, this might be offset by the increasing number of states setting clean energy standards (or setting more ambitious standards like California). In our solar PV case study, we consider an ITC decrease from 30% to 10% and its complete phase-down (in the high-risk scenario).

4.2. Climate risk scenarios

We build baseline "no risk" scenarios based on inputs shown in Table 2. In the natural gas case in PJM territory, an attractive post-tax equity IRR of 14% is achieved, and a healthy DSCR of 2.0x is maintained throughout the debt term, reflecting the financial attractiveness of natural gas projects in this region. In the solar PV case in California, we reach a 10.5% after-tax IRR in year 8 and determine the PPA price that is sufficient to achieve this IRR. In the coal case in Indiana, because we model out a deleveraging scenario for the asset, the revenues are used to pay down debt, and the post-tax equity IRR is lower than in the other cases, with a value of 8.03%. However, DSCR remains above 2.0x, except for the first three years of the period, which is from 1.79x - 1.93x.

Our scenario analysis estimates the impacts of a single climate-related risk factor and combined impacts from multiple risk factors on a project's cash flow (see Table 4 for complete scenario assumptions). We estimate the impact through the DSCR for the natural gas, coal, and solar PV case studies, with the addition of IRR sensitivities for both tax equity investors and project sponsors in the solar PV case study.

As aforementioned, some climate risks are likely to co-occur. We combine some risk scenarios and test their impacts. In the natural gas and coal cases, we look at combinations of physical (water scarcity, increasing water temperature, increasing air temperatures, and extreme weather events) and technology (decreasing renewable costs) risks using "High," "Medium," and "Low-risk" scenarios. For the combined physical risk scenarios for natural gas, water scarcity was only included in an additional High-risk scenario, as we consider this risk only occurs if a plant has a closed-loop cooling water system design. In the coal case, the water temperature risk is included in all combined physical risk scenarios. In the solar PV case, we study the combination of all physical risks (extreme heat, droughts, and acute hailstorm events) as well as transition risks (increasing renewables curtailment and falling PPA prices) and regulatory risks (ITC phase-down) combined, with "High," "Medium," and "Low-risk" scenarios. Our approach to simulating these risk impacts on energy investments was first to determine the impact of physical risks and transition risks occurring individually, then in unison through the combined risk scenarios. The regulatory risks were simulated separately from these risks for the natural gas and coal scenarios. This approach allowed us to isolate the impact of physical and transition risks from regulatory risks as we determined the varying levels of vulnerability to different types of climate-related risks. For the solar PV case, the risks were simulated following physical, transition, and regulatory risks.

In building climate risk scenarios, we assume how specific (or specific combinations of) risk factors can affect the four components of cash flow. Revenues can be negatively impacted by a decrease in capacity factor, resulting in a drop in electricity generation or lower electricity sale price. In natural gas CCGT and coal plants, capacity factor drops can result from water scarcity (natural gas) or increasing water temperatures (coal), forcing curtailment of the plant. In solar PV plants, extreme heat, dust accumulation, and curtailment result in lower capacity factors. Renewable energy cost reductions resulting in overall lower electricity market prices also decrease revenues for fossil-fuel generators such as natural gas CCGT and coal power plants, having a more pronounced impact in the latter due to the decrease in capacity factor due to the lower use of the plant over time. Increases in expenses can arise from increases in fixed O&M costs (e.g., plant insurance or solar panel cleaning) or variable O&M costs (e.g., fuel usage, carbon price set in fuel supply contracts). The addition of CCS facilities to natural gas CCGT or coal plants also results in higher fuel usage, parasitic electricity load from the CO_2 capture and compression units, and additional fixed O&M costs and CAPEX. CAPEX assumptions remain the same in all scenarios for solar PV cases, apart from the CCS scenarios in the natural gas and coal.

Table 4
Summary of climate risk scenarios.

(a) Climate Scenarios for the natural gas case study

Scenario name	Risk level	Estimated impacts on cash flow
Water Scarcity	High	−1.5% p.a. capacity factor
Air temperature	High	+0.15% p.a. fuel usage
Extreme weather	High	+15% p.a. insurance premium
Low-cost renewables	High	$35/MWh flat 2030+ electricity sales price
All factors	High	−1.5% p.a. capacity factor +0.15% p.a. fuel usage +15% p.a. insurance premium $35/MWh flat 2030+ electricity sales price
All factors excl. water (H)	High	+0.15% p.a. fuel usage +15% p.a. insurance premium $35/MWh flat 2030+ electricity sales price
All factors excl. water (M)	Medium	+0.10% p.a. fuel usage +10% p.a. insurance premium $40/MWh flat 2030+ electricity sales price
All factors excl. water (L)	Low	+0.08% p.a. fuel usage +5% p.a. insurance premium $42/MWh flat 2030+ electricity sales price
Carbon Pricing 2C Scenario (H)	High	$30/ton carbon price starting 2025 Electricity sale price increases to absorb 25% of carbon price
Carbon Pricing 2C Scenario (L)	Low	$30/ton carbon price starting 2025 Electricity sale price increases to absorb 50% of carbon price
CCS Facility Scenario (H)	High	$200 mm CapEx and $18/ton variable O&M −5% Capacity factor due to parasitic losses
CCS Facility Scenario (L)	Low	$400 mm CapEx and $18/ton variable O&M −5% Capacity factor due to parasitic losses

(b) Climate Scenarios for the coal case study

Scenario name	Risk level	Estimated impacts on cash flow
Water Scarcity	High	−0.12% p.a. capacity factor
Air temperature	High	−0.004% p.a. heat rate
Extreme weather	High	+16% p.a. insurance premium
Low-cost renewables	High	$30/MWh flat 2030+ electricity sales price −4% p.a. capacity factor
Fuel supply contract	High	−1% p.a. capacity factor
All factors (H)	High	−4.12% p.a. capacity factor −0.004% p.a. heat rate +16% p.a. insurance premium $30/MWh flat 2030+ electricity sales price, −2% p.a. capacity factor
All factors (M)	Medium	−2.08% p.a. capacity factor −0.002% p.a. heat rate +11% p.a. insurance premium $40/MWh flat 2030+ electricity sales price, −1% p.a. capacity factor
All factors (L)	Low	−1.06% p.a. capacity factor −0.001% p.a. heat rate +6% p.a. insurance premium $42/MWh flat 2030+ electricity sales price, −0.5% p.a. capacity factor
Carbon Pricing 2C Scenario (H)	High	$30/ton carbon price starting 2025 Electricity sale price increases to absorb 75% of carbon price
Carbon Pricing 2C Scenario (L)	Low	$30/ton carbon price starting 2025 Electricity sale price increases to absorb 90% of carbon price
CCS Facility Scenario (H)	High	$340 mm CapEx and $13/ton variable O&M −5% Capacity factor due to parasitic losses
CCS Facility Scenario (L)	Low	$500 mm CapEx and $13/ton variable O&M −5% Capacity factor due to parasitic losses

(c) Climate Scenarios for the solar PV study

Scenario name	Risk level	Estimated impacts on cash flow
Extreme heat	High	−6% power output over 40 summer days

(*continued on next page*)

Table 4 (*continued*)

(c) Climate Scenarios for the solar PV study

Scenario name	Risk level	Estimated impacts on cash flow
Drought and dust accumulation	High	−5% power output p.a. +10% p.a. O&M costs
Hailstorm	High	−20% power output until panel replacement 1.5× insurance premiums post incident
All physical risks combined	High	−6% power output over 40 summer days −6% power output p.a. +10% p.a. O&M costs −20% power output until panel replacement 1.5× insurance premiums post incident
Renewables curtailment	Medium	−10% p.a. power output
Changes in PPA prices	Medium	−20% PPA prices
ITC Phase down	Medium	ITC reduction from 30% to 10%
All transition + regulatory risks combined (H)	High	−15% p.a. power output −25% PPA prices No ITC. Change in financing structure
All transition + regulatory risks combined (M)	Medium	−10% p.a. power output −20% PPA prices ITC reduction from 30% to 10%
All transition + regulatory risks combined (L)	Low	−5% p.a. power output −15% PPA prices ITC reduction from 30% to 22%

5. Results on three cases

5.1. Natural gas CCGT in the PJM power pool

As aforementioned, we model a new-build 500 MW CCGT plant in the PJM Power Pool. Our analysis assumes a 60% debt and 40% equity capital structure to finance the project's $500 million capital cost. The base case incorporates an average merchant electricity sales price of $39.80/MWh, escalating with inflation. The asset uses the energy sales and capacity revenues to pay operational expenses, debt service payments, taxes, and cash flow to equity.

Our scenarios analysis shows that none of the physical risk scenarios, when they occur in isolation, leads to an EOD (i.e., the project's DSCR goes below 1.0x; we can alternatively assume stricter conditions for an EOD, for instance, 1.5x project DSCR.). It is the transition risk scenario associated with renewable energy cost reductions that cause the project to default. This scenario incorporates a ceiling on the energy sales price due to the increasing competition from low-marginal cost renewables in wholesale markets. As other expenses continue to rise, the cash flow margins of the project compress, and the asset becomes unable to service its debt obligations starting in 2034 (see Fig. 1 (a)).

When simulating the impacts of risks occurring in unison, the asset goes into default in both of the "Collective - High Risk" scenarios, with and without water-related risks, and has a very small buffer even in the "Collective - Medium Risk" scenario (see Fig. 1 (b)). This means that if the combined risk impacts on key operational metrics take place at the more severe levels, the asset can go into default as early as 2030. This result is sensible since the combined occurrence of risk scenarios simulates a capacity factor reduction, insurance premium increase, heat rate increase, and an energy sales price ceiling, which shows the severe financial damage combined climate-related risks can cause for the asset. Furthermore, in the probabilistic scenario where a probability distribution is assigned to the occurrence of different collective risk scenarios, the asset is also expected to default in 2037. The probabilistic scenario reflects a blended view of the different collective risk scenarios by using a Monte Carlo simulation of 500 model runs, where each run shows a scenario based on the assigned probability distribution shown in Table 5.

Fig. 2 shows our simulation of regulatory risk scenarios. We find that carbon price implementation causes the earliest default for the asset amongst all risk scenarios. This is due to the large emissions cost associated with every unit of electricity generation based on the per-ton carbon prices outlined by the Carbon Pricing Leadership Coalition for price trajectories limiting warming to 1.5 °C or 2 °C [101]. Even though the CCGT plant is more efficient and has a lower heat rate compared to other fossil fuel-powered generators, its level of emissions is still sufficient to lead to default. There were two mechanisms simulated within the carbon pricing scenario, assuming different levels of market absorption for the cost increase at the generation level. Even when assuming that 50% of the increased generation costs can be passed through and recovered from buyers, the asset is expected to default in 2032 (see "Carbon Pricing (50% Market Absorption)" in Fig. 2). These results collectively show that although the CCGT plant demonstrates resilience to physical risks occurring in an isolated manner, it is vulnerable to transition and regulatory risks, as well as vulnerable to scenarios where physical risks happen collectively.

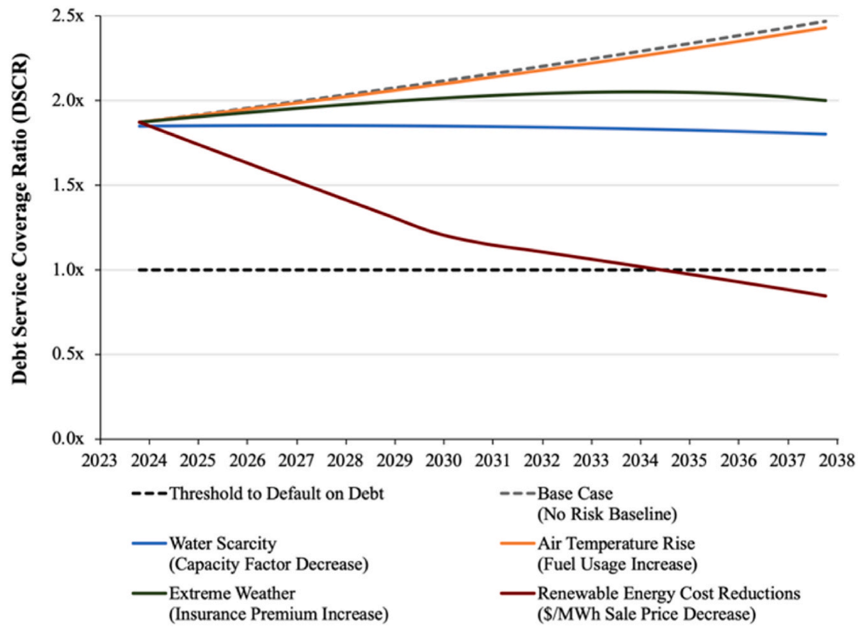
5.2. Coal Refinancing in Indiana

We study the refinancing of an existing 650 MW coal power plant located in Indiana. The project capital structure is 55% debt and 45% equity, and its remaining net book value (i.e., the loan to be refinanced) is $400 million. We assume a refinance of the debt starting in 2023 to extend the length of the debt maturity with a more competitive interest rate. The total repayment period is assumed as 20 years with an interest rate of 5.5%. The base case scenario considers an average merchant electricity sales price of $38.84/MWh, which escalates with inflation. The asset revenues from energy and capacity sales are used to pay operating expenses, debt service, taxes, and cash flows to equity. We assume the debt principal will be amortized 50% during the repayment period to keep the DSCR above 1.0x.

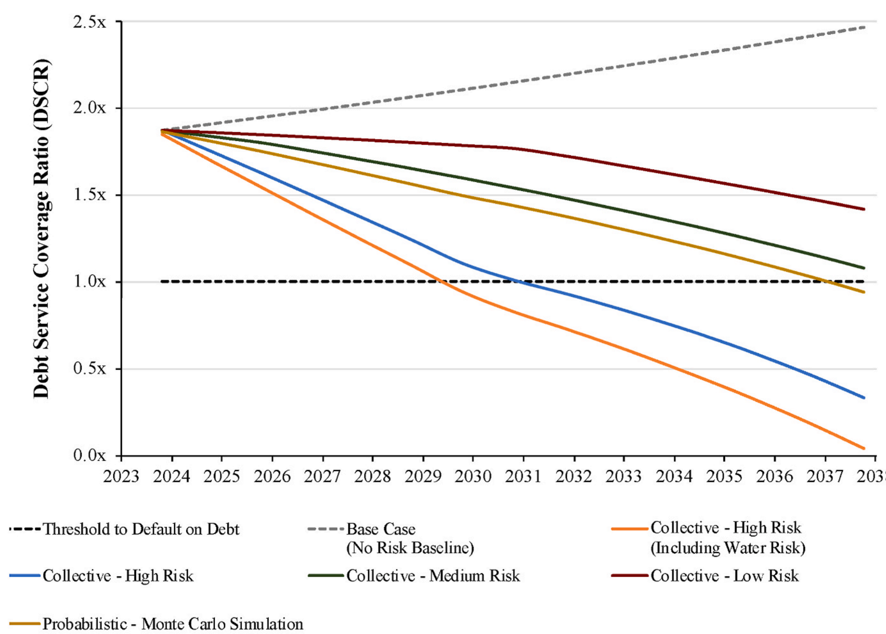
When comparing the effects on physical and transition risks in isolation, the project is more likely to go into default under two scenarios: when the cost of energy decreases due to generation from renewables and when the insurance premium increases due to the occurrence of extreme weather events (see Fig. 3 (a)). Under the former scenario, the project goes into an EOD after 2025 and defaults by 2030. The reduction of the energy market prices in this scenario negatively impacts the revenues for the coal power plant. This is worsened due to a decrease in the plant's capacity factor caused by a higher penetration of other energy sources. Under the latter scenario, the project goes into an EOD in 2037, ramping down quickly after that period. While we also test a scenario with water temperature rise, its impact on the DSCR is small. Air temperature rise causes a positive impact to a small degree, yet DSCR remains the same as the base case in the long term.

When simulating the impacts of risks occurring in unison, the asset goes into an EOD in the High and Medium-risk scenarios, but the timing of default varies. The project DSCR drops under 1.0x in 2026 and 2029 for the High and Medium-risk scenarios, respectively (see Fig. 3 (b)). This means that if these climate risk impacts occur together as simulated in the combined risk scenarios, depending on their severity, the impact will cause the coal power plant to go into default earlier. Under a probabilistic scenario where a probability distribution is assigned to the occurrence of the collective risks, the DSCR has a similar trend to the collective medium risk scenario, falling in default after 2033. This probabilistic scenario reflects a joined view of the collective risk scenarios by using a similar Monte Carlo simulation as the one used for the Natural Gas CCGT case by assigning a probability distribution as shown in Table 6.

As regulatory risk scenarios, we consider implementing carbon pricing at $30/ton CO_2 starting in 2025, and electricity sales price increases to absorb 90% and 75% of the carbon price. We find that the financial impacts of carbon pricing are more prominent in the coal



(a) DSCR projection under physical and transition risk scenarios in isolation



(b) DSCR projection under combined risk scenarios

Fig. 1. DSCR Projection on the Natural Gas CCGT in PJM Case.
Fig. 1-(a) shows DSCR projection under physical and transition risk scenarios in isolation. Fig. 1-(b) shows DSCR projection under combined risk scenarios considered in high, medium, and low-risk levels.

power plant case than the natural gas power plant case. This is mainly because coal combustion generates carbon emissions about 2x higher than combustion of natural gas [42]. Regulatory risks for carbon pricing in the coal case consider a "pass-through" of these price increments to customers. Our analysis shows that at least 90% of the carbon price should be levied on consumers to avoid default during the debt term. A pass-through below 90% would cause DSCR to go below 1.0x since the first-year carbon price starts being implemented, as it can be seen in Fig. 4 with a 75% of customer market absorption of these additional charges.

Fig. 4 (b) simulates three scenarios: the project has a 20-year, 5-year, and spot-rate fuel supply contract when a reduction in capacity factor occurs. We find that the DSCR curve becomes negative when the project has a 20-year fixed fuel supply contract, while project DSCR moves

Table 5
Probability distribution for the occurrence of collective risk scenarios - natural gas CCGT in PJM case.

Scenario Name	Probability of Occurrence
Collective - High Risk (Incl. Water Risk)	15%
Collective - High Risk	15%
Collective - Medium Risk	40%
Collective - Low Risk	30%

upward in the other two cases. This is because a fixed fuel supply contract makes the coal power plant keep paying the same amount of coal despite its fuel usage decreases. Despite the lower revenues, the project should pay the fixed fuel expenses. In case the fuel supply depends on the spot market, although the cost of fuel may change as per commodity market trends, the amount needed can be sized according to the amount the plant requires to operate, and therefore, fuel expenses can be paid along with the revenues.

We also test the scenarios of CCS facility installations to avoid emission charges. We consider the additional CAPEX and OPEX needed to install CCS facilities to be offset by tax credits provided by Section 45Q. For our scenario with a CAPEX of $340 million, the project's revenue becomes lower than added operating expenses once the tax credit benefits end, making the coal plant go into default. These metrics are worse if the CAPEX is $500 million, in which the project becomes financially unfeasible. Therefore, CCS retrofits as an alternative might become only attractive if upfront CAPEX requirements and parasitic loads decrease.

5.3. Utility-scale solar photovoltaic in California

We considered two financing structures for our solar project: (1) a leveraged partnership flip with a tax investor and sponsor leverage and (2) a traditional debt and equity finance structure with no flip in ownership, which is used only in the scenario with a complete rollback of the ITC. Given that utility-scale photovoltaic projects are typically financed with a leveraged tax equity partnership flip structure, we study tax investor IRRs in addition to DSCR as our variables of interest. We also study the variations in PPA prices required to meet target after-tax returns of 10.5% by year 8, which is a key analysis performed in the industry to assess the economic feasibility under different electricity sales prices. PPAs ensure long-term electricity sales at a given price and are therefore key to determining a project's returns. The base case calculated PPA price is $29.56/MWh in the leveraged partnership flip model. Our financial analysis was performed by adapting the NREL System Advisor Model (SAM) Power Purchase Agreement financial model to incorporate our scenario analysis capabilities [104].

In our solar PV case, we find that transition and regulatory risks (Fig. 5 (b)) appear to have a stronger financial impact than physical risks (Fig. 5 (a)) on DSCR and tax investor IRR. We identify that a project default can occur only in the transition and regulatory risk scenarios, where default is defined as the DSCR dropping below 1.0x, as represented by the dotted black line in Fig. 5 (b). We acknowledge that, depending on the project's risk profile, higher DSCR covenants can also be set in debt contracts to ensure the cash flow buffers to pay debt service are higher. As shown in Fig. 5 (b), a DSCR below 1.0x is observed in the scenarios combining all transition and regulatory risks (at "Collective – High Risk" and "Collective – Medium Risk" levels, as defined in our scenarios). In the "Collective – Medium Risk" scenario, which combines all transition and regulatory risks, the ITC reduces from 30% to 10%, curtailment of renewables results in a 10% yearly decrease in generation, and PPA prices fall by 20%. As a consequence, the project goes into default early on in the project's lifetime (Year 1 and Years 1–5), years when the benefits from the ITC are applied. In the "Collective – High Risk" scenario, DSCRs remain below 1.0x throughout the debt tenor. This result indicates that the project does not generate enough positive cash flow to meet its debt service obligations in any debt tenor years, demonstrating the severity of a scenario where all transition and regulatory risks happen collectively. The "Probabilistic - Monte Carlo Simulation on Combined Scenarios" scenario (risk occurrence probabilities shown in Table 7 represents the average results from 500 probabilistic financial model runs. Results from this Monte Carlo approach suggest that the project goes into default, similarly to in the Medium and High Collective Risk scenarios. Results in Fig. 5 (b) also show the strong impact of decreasing PPA prices, highlighting the importance of PPA price as a revenue and key project economics driver ("Low PPA prices" scenario).

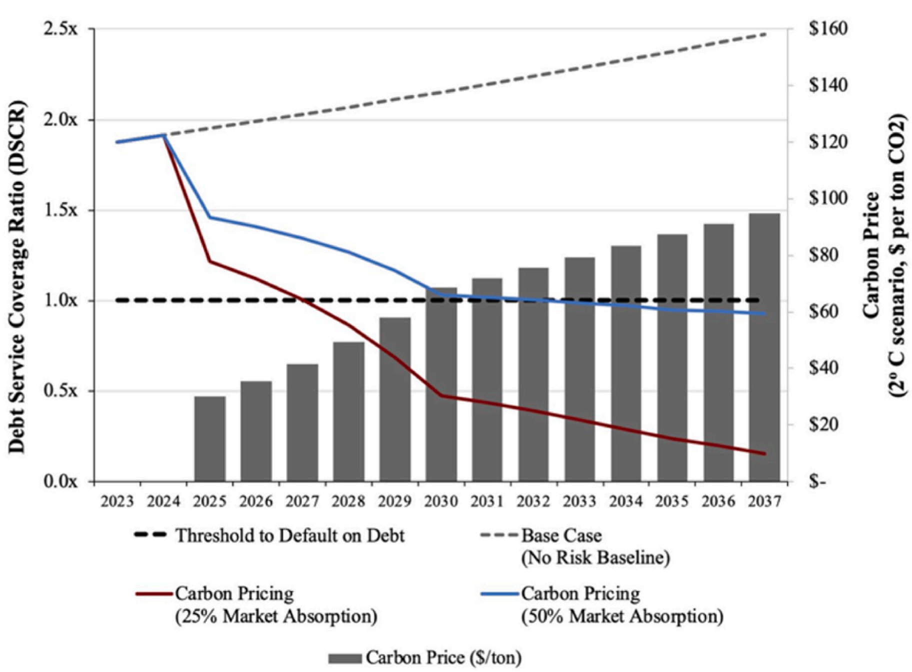
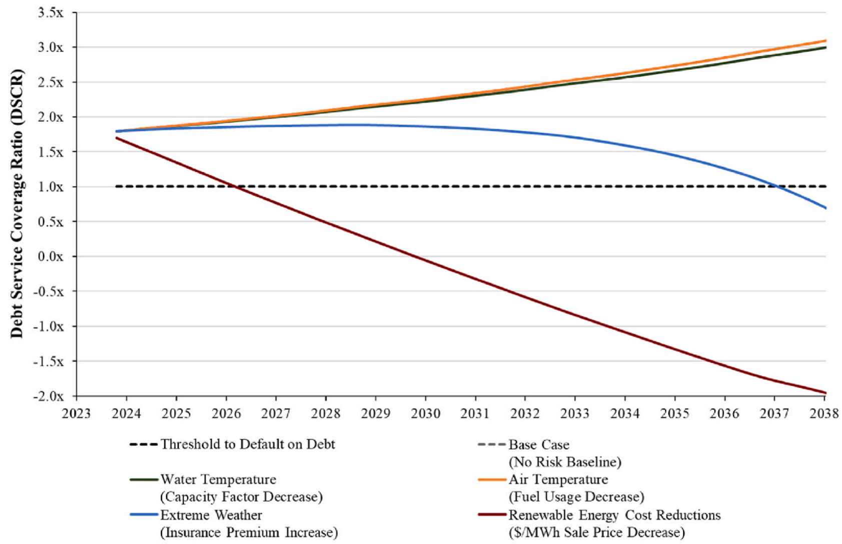
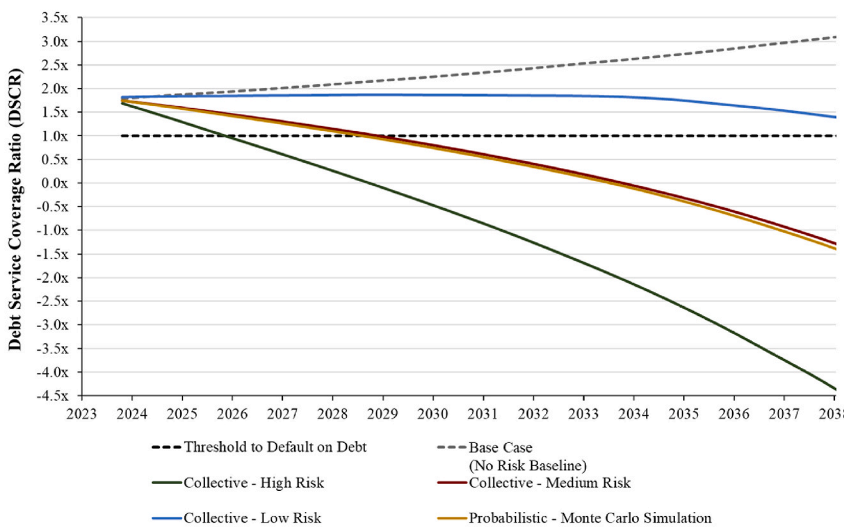


Fig. 2. DSCR projection with carbon pricing on the natural gas CCGT in PJM case.
Fig. 2 **shows DSCR projection under carbon price implementation scenarios, considering a variation in market absorption levels.**



(a) DSCR projection under physical and transition risk scenarios in isolation



(b) DSCR projection under combined risk scenarios

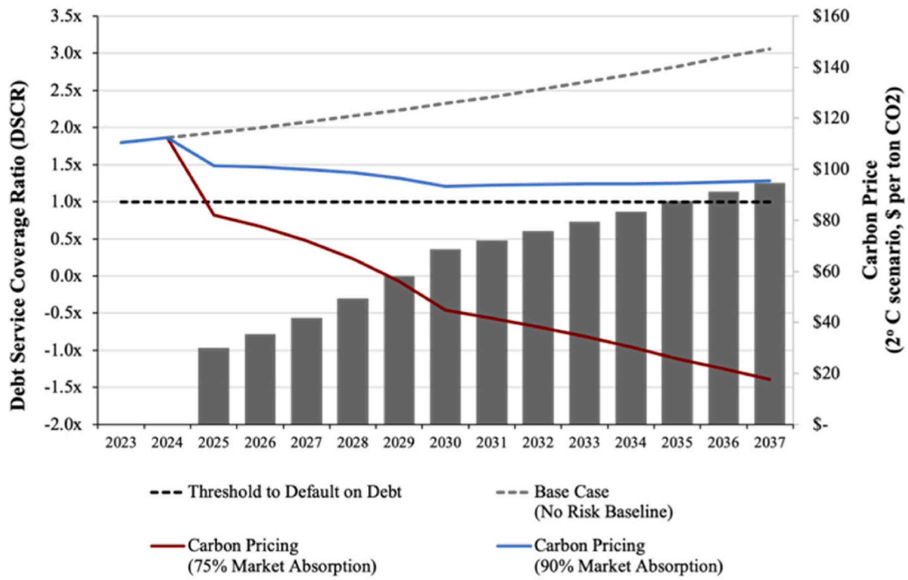
Fig. 3. DSCR Projects on the Coal Refinancing in Indiana Case.
Fig. 3-(a) shows DSCR projection under physical and transition risk scenarios in isolation. Fig. 3-(b) shows DSCR projection under combined risk scenarios considered in high, medium, and low-risk levels.

Table 6
Probability distribution for the occurrence of collective risk scenarios - coal refinancing in Indiana case.

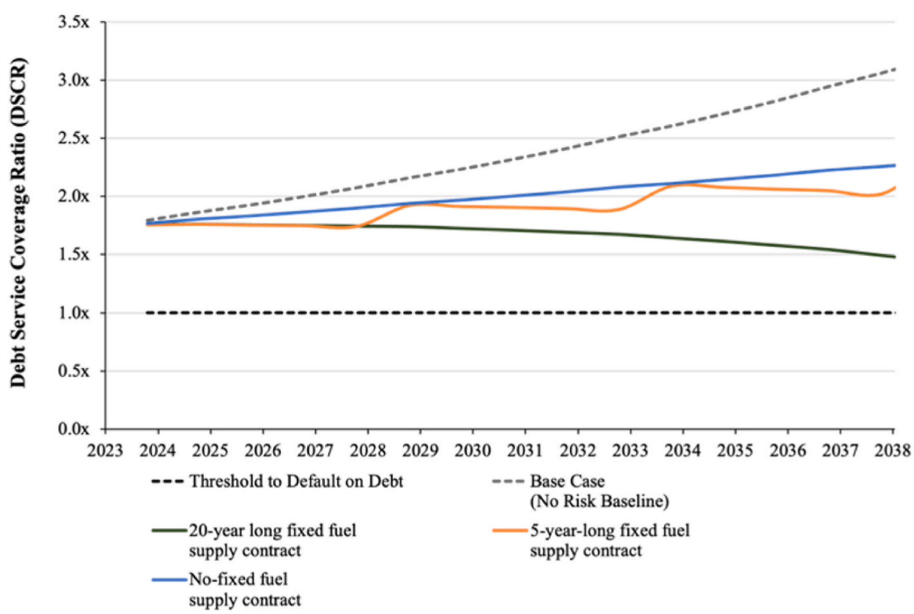
Scenario Name	Probability of Occurrence
Collective - High Risk	30%
Collective - Medium Risk	40%
Collective - Low Risk	30%

When analyzing the impacts of physical risks on DSCR (Fig. 5 (a)), we find that an acute extreme weather event can significantly decrease the DSCR in a given period but does not result in a default. This dramatic drop in DSCR following an extreme weather event (if not covered by insurance) is explained by the material revenue decrease associated with damages from the hailstorm event impacting electricity generation capability. Therefore, we note that although physical risks do not result in default, whether they happen in isolation or collectively, compared to transition and regulatory risks, acute physical risks can have a much more sudden impact on DSCR. Taking a probabilistic approach also does not show a risk of default under the physical risks considered, with lower DSCR impacts modeled in the probabilistic Monte Carlo approach compared to the combined all physical risks scenario or hailstorm scenario.

Another key metric to analyze in an equity partnership flip model is the equity returns to the tax investor. Fig. 6 shows after-tax cumulative IRR under physical (Fig. 6 (a)) as well as transition and regulatory risk scenarios (Fig. 6 (b)). As in the DSCR analysis, we immediately note how the impact of physical risks on investor returns is limited compared to the impacts of physical and regulatory risks. Target returns of 10.5% are met in the scenarios considering extreme heat and acute hailstorm



(a) DSCR projection under carbon price implementation scenarios

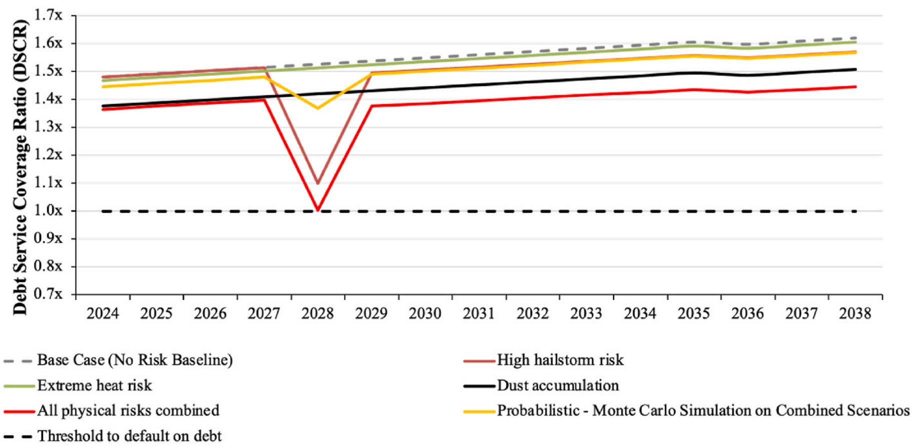


(b) DSCR projection under different lengths on fuel supply contracts

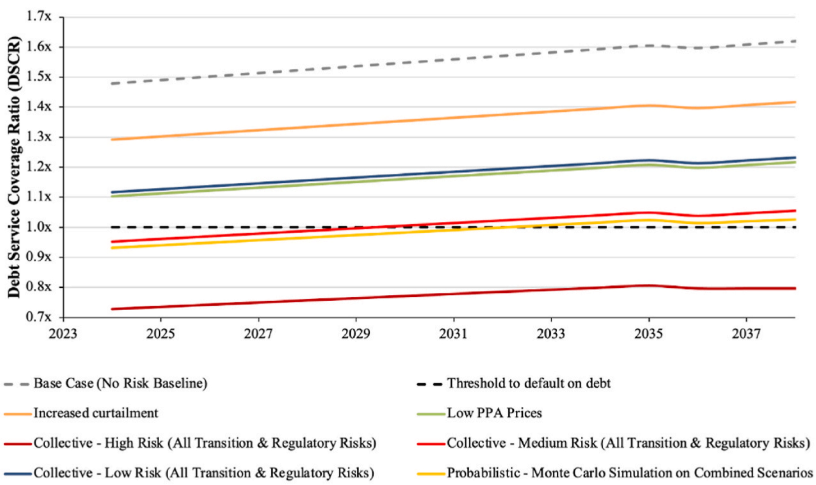
Fig. 4. DSCR Projection with Carbon Pricing and Fuel Supply Contract on the Coal Refinancing in Indiana Case.
Fig. 4-(a) shows DSCR projection under carbon price implementation scenarios, considering a variation in market absorption levels. Fig. 4-(b) shows DSCR projection under different lengths on fuel supply contracts in case a reduction of 1% of the capacity factor occurs.

events when studying these risk variables individually. However, we observe that these physical risk scenarios cause a delay in when the target return is reached. Compared to a 10.5% return achieved in year 8 in the Base Case scenario, target returns are met in years 9 and 14 in extreme heat and hailstorm scenarios. Furthermore, in the scenarios considering increased dust accumulation and the combination of all physical risks, the target return is not reached in the 2024–2038 period. In the probabilistic Monte Carlo physical risks scenario, target returns of 10.5% are met, in line with the Base Case and Extreme Heat scenarios.

On the other hand, in the transition and regulatory risk scenarios (Fig. 6 (b)), target equity returns are not met throughout the operational period in the modeled scenarios (including the probabilistic Monte Carlo simulation on collective scenarios), highlighting the severity of these risks to solar investments We identify that to mitigate the impacts of transition and regulatory risks and meet target returns in these scenarios, PPA prices would have to increase. For example, in the "Increased Curtailment" and "Collective – Low Risk" scenarios, PPA prices would have to increase from $29.56/MWh in the Base Case to



(a) DSCR projection under physical risk scenarios



(b) DSCR projection under transition and regulatory risk scenarios

Fig. 5. DSCR Projection on the Utility-scale Solar PV in California Case.
Fig. 5-(a) shows DSCR projection under physical risk scenarios. The "Probabilistic - Monte Carlo Simulation on Combined Scenarios" run includes all physical risks (extreme heat, hailstorm and dust). Fig. 5-(b) shows DSCR projection under transition and regulatory risk scenarios, both in isolation and combination. The combined risk scenarios considered in high, medium, and low-risk levels. The "Probabilistic - Monte Carlo Simulation on Combined Scenarios" run includes all combined high, medium and low-risk level scenarios.

Table 7
Probability distribution for the occurrence of collective risk scenarios - utility-scale solar PV in California case.

Scenario Name		Probability of Occurrence
Transition and regulatory risks analysis	Collective – High Risk	30%
	Collective – Medium Risk	40%
	Collective – Low Risk	30%
Physical risks analysis	High hailstorm risk	30%
	Extreme heat risk	40%
	Dust accumulation	30%

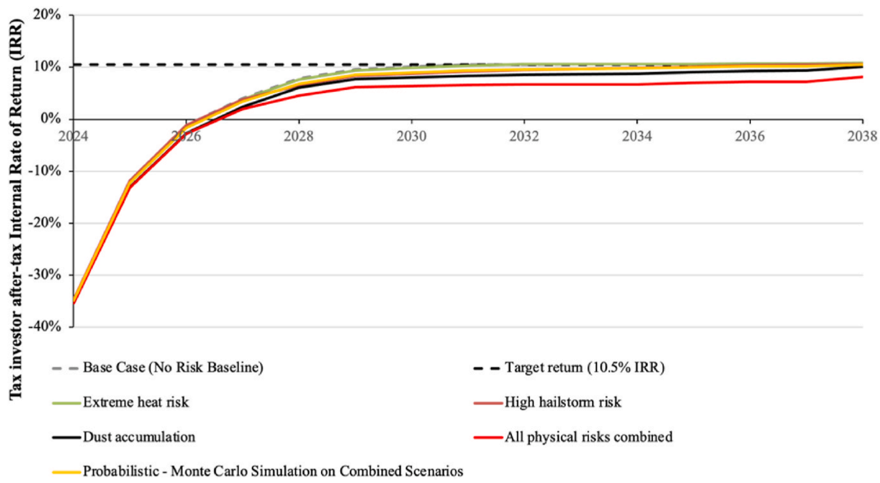
\$36.94/MWh and \$39.46/MWh, respectively, to meet the 10.5% target tax investor return in year 8.

Overall, studying IRR and DSCR, we identify that solar PV plants tend to be more vulnerable to transition and regulatory risks than physical risks. However, although acute weather events may not result in a project default, it is important to note the severe and sudden impact these scenarios can have on DSCR.

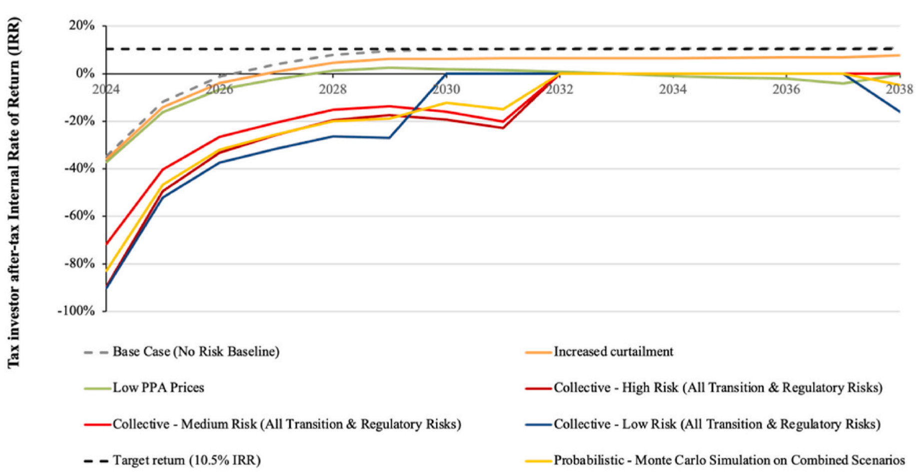
6. Discussion

Out of the full range of 12 climate risks identified in our risk assessment framework, this study covers four of them that seem most important for evaluating the risk of the three energy infrastructure case studies: incremental (chronic) climate change, acute weather events, market transitions, and policy interventions. This analysis produces several insights regarding climate-related energy infrastructure investment risk assessments and management.

First, within the range of scenarios we tested in our comparative case studies, we find that financial impacts due to transition risks are likely to be larger than those due to physical risks in all three cases. The selected physical risks exclude risks due to extremely low-probability and high-impact events because we assume those force majeure risks are transferred from the debt contract holders to other relevant stakeholders through the structure of the financing of the projects. As per our desire to focus on the value of debt and equity investments in infrastructure assets, we consider the financial impacts directly imposed on the debt and equity holders. Our natural gas and coal power plants both go into default under scenarios considering renewable energy cost reduction and the associated energy sales price decreases in wholesale markets, which we identify as a transition risk. In contrast, these assets are more resilient to physical risk scenarios when these scenarios are considered



(a) IRR projection under physical risk scenarios



(b) IRR projection under transition and regulatory risk scenarios

Fig. 6. IRR Projection on the Utility-scale Solar PV in California Case.
Fig. 6-(a) shows after-tax tax investor cumulative IRR projection under physical risk scenarios, evaluated in isolation and combination. Fig. 6-(b) shows after-tax tax investor cumulative IRR projection under transition and regulatory risk scenarios, evaluated in isolation and combination. We assume the asset is financed through a leveraged partnership flip model.

individually. Similarly, the IRR of the solar plant in a leveraged partnership flip financing structure drops to below zero in both the ITC phase down and low PPA price scenarios, which mainly represent transition risks. On the other hand, the project IRR is much less impacted by physical risks even when they occur in a combined manner. This analysis reveals a similarity across all three case studies and suggests that investors strongly consider potential risks associated with transitioning to a lower-carbon economy in their investment decisions. Previously, Battiston et al. [3] also concluded that transition risks might pose a more significant risk to infrastructure investments than physical risks. Our analysis provides additional evidence for that conclusion.

Secondly, our analysis demonstrates that one climate-related event may affect certain energy assets negatively and other assets positively, which has important portfolio-level implications. For instance, the risk of increasing air temperatures increases fuel usage by natural gas plants but decreases it for coal plants, affecting total fuel cost expenditures in opposite directions. Furthermore, increases in extreme heat events also negatively affect solar PV plants due to resulting decreases in panel efficiency. Hence, there is a benefit to a diversification of energy assets. The resilience of a portfolio of generation assets will be greater if it consists of assets with varying directional (i.e., preferably negatively correlated) impacts from climate-related risks. Therefore, this comparative asset-level analysis identifies the importance of portfolio-level risk assessment and management: the negative financial impacts on some assets from climate-related risks may be muted by positive impacts for other assets within the portfolio. Furthermore, this study demonstrates the ability to granularly determine implications for portfolio-level resilience through a bottoms-up analysis consisting of asset-level risk assessments. It is also important to consider the magnitude of the risk impacts on different assets in addition to the direction of the impacts. The savings in fuel usage attained by the coal plant in the increasing air temperature scenario is minimal compared to the substantial comparative vulnerability a coal plant may possess, highlighting the need for holistic risk assessments across asset classes.

Thirdly, our analysis shows that risk scenarios can affect multiple asset types negatively simultaneously, which may indicate a larger vulnerability for the asset portfolio or energy system, and ultimately even the stability of the global financial system as a whole. If there are defaults across multiple energy asset types simultaneously due to climate-related risk, even diversified energy portfolios may be impacted. For instance, renewable energy cost reductions and increased competition from renewable energy are transition risk scenario that makes both natural gas and coal plants default. The cost reductions achieved by increased research, development, and investment into renewable energy can be identified as a mitigation measure for further climate risks, as these efforts aim to make renewable energy more prevalent, displacing fossil fuel-based generation and reducing GHG emissions. Andersson-Sköld et al. [105] state that a strategy to reduce one climate-related risk can impact other climate-related risks in potentially positive or negative ways, emphasizing the importance of comparative case studies for climate risk assessments. To that extent, the cost reductions achieved in wind and solar energy may, in some cases, be a detriment for these renewable resources. The reduced wind and solar equipment costs allow renewable energy developers to cut costs and create substantial competition, with competing developers bidding to sell the electricity generated at prices as low as possible. The competition creates downward pressure on the PPA prices that the developers are willing to accept as they bid lower, intending to win the contract. However, as identified in our solar case study, reduced PPA prices pose a fundamental risk to solar PV investments, causing the project to earn less revenue for each unit of generation, thereby damaging project economics. Therefore, if PPA prices become too low, not only do natural gas and coal plants face the risk of default, but renewable energy assets will also be affected. Hence, our study demonstrates the importance of cross-asset risk assessment as it identifies the large-scale impact certain risk scenarios can have through simultaneous impacts on several energy asset types.

Finally, our analysis demonstrates that renewable energy investments are likely to be more resilient to climate change than fossil fuel-based energy assets. In our solar PV case study, there is no default when any of the physical risk scenarios are evaluated individually, and target returns are reached by the tax equity investor in all physical risk scenarios, although realized over a more extended period. Furthermore, regulatory risks such as lower PPA prices and increased curtailment cause reductions in solar PV target returns but generally do not result in defaults. In contrast, investments in natural gas and coal plants can both default under all transition and regulatory risks. Furthermore, the natural gas plant defaults are more likely in the high combined physical risks scenario, and the coal plant defaults are more likely under the medium and high combined physical risk scenarios, as well as under the extreme weather scenario. This comparative analysis indicates that renewable energy investments are more resilient to climate-related risks and can hence provide stronger investment opportunities, in addition to reducing environmental impacts. It is also important to note that our results indicate that the order of the resilience to climate change risks amongst the three assets corresponds to their emissions profiles. The coal plant has the highest vulnerability to climate-related risks, followed by the natural gas CCGT plant and then the solar plant. This outcome makes sense since the regulatory risk scenarios simulate the implementation of measures that penalize carbon emissions, and hence, the impacts on the individual plant investments were larger for plants with higher emissions. Our analysis provides evidence that emissions levels are correlated with the climate-related vulnerability of an asset since there is a larger likelihood of losses resulting from increased expenditures due to the implementation of climate change-mitigating regulations. This is a critical observation that can catalyze more deployment of capital into renewable energy investments, which provides valuable ESG benefits and more robust climate resilience profiles, which is a paramount concern for assets with multi-decade investment horizons. As investors anticipate additional regulatory actions driven by climate change that favor clean energy technologies, renewable energy investments are poised to provide even stronger investment returns, and the climate resilience gap between fossil fuel-based assets and renewable energy may further widen.

7. Conclusions

The low-carbon and clean energy transition are becoming a mainstream concern of asset owners. We have seen increasing climate change threats, and related transitions are increasingly posing a new set of risks and opportunities to energy infrastructure assets from the last decade. Energy infrastructure asset owners may lose value under a disordered transition to a low-carbon economy. Nonetheless, the concept of stranded assets has been perceived as a largely hypothetical and far-off concern. Asset owners and managers still do not see the urgency of this stranded asset issue not because their assets are indeed climate-resilient but because they are not adequately re-valued under the rapidly changing environment. As a result, many of them incorrectly perceive climate change's implications to be long-term and not necessarily relevant to decisions made today.

In this regard, this study examines financial risks driven by an asset's resilience to climate change and transition. These financial risks will readjust the value of debt and equity investments. We prioritize debts in energy investments because they are typically highly leveraged, and debt takes 70–90% of the asset value. Moreover, as debt investments expect regular, consistent payments, they may be less resilient to short-term instability. A few years of weak performance can lead to a default, whereas equity investors more intrinsically expect short-term volatility. Secondly, debt investments make up a substantial portion of infrastructure financing. Therefore, by using the framework developed by In et al. [11], we integrate multiple climate risk scenarios and data to highlight the variations in resilience across assets in debt and equity investments. Using cash flow modeling and scenario analysis, we estimate the selected asset's financial default risks exposed to specific climate-related risk scenarios. Our novel approach goes beyond assessing the lumpsum loss in value due to a default and provides the ability to evaluate the size and time of the losses by the given default.

We argue that a bottom-up approach can effectively drive changes to investment and business as usual. For instance, Asian Development Bank [106] highlights the effectiveness of this approach in bridging the gap between theoretical analyses of climate change impacts and the planning decisions made by city authorities and utility managers. The individual stakeholders would change their behaviors more promptly if they could specify impacts on their assets that might be caused by climate change, how these affect asset and portfolio valuation and what they can do now to prepare for them. A granular level climate risk assessment of energy investments can help companies consider the risks and opportunities associated with various energy sources and make informed decisions.

Project-level cash flows are highly dependent on the asset's profile and capital structure, financial contracts, market awareness, and regional circumstances. All of these factors need to be considered, and because related publicly available data is limited, developing projections of asset-level cash flows and risk estimates is challenging. Some crucial characteristics of climate and financial risks are the: (1) nonlinearity of climate impacts, (2) complexity and interconnected nature of relations and risk in the financial network, and (3) uncertainty of climate policy introduction. For instance, climate data at the asset or regional level has been highly challenging to capture and access – a situation recently starting to improve through advanced technologies focused on the issue. The good news is that data and service providers enhanced the reliability of risk assessment. Also, financing conditions and terms at the individual energy project level (e.g., leverage, margin, tenor, and other special financing conditions) are proprietary and hence kept private. This calls for collaborative work to access and leverage those asset-level data.

Understanding the dynamics of investors' decisions under uncertainty with energy projects and assessing the climate-related financial risks associated with different investment strategies would not be possible by only referring to discipline-based approaches. Applied interdisciplinary research and cross-fertilization among knowledge domains (i.e., climate science, computer science, policy, socioeconomics, and financial economics) are critical. By exploiting synergies across these domains, we expect this study to yield evidence-based information for decision-makers, delivering results that various stakeholders can utilize. This is crucial to scale up investments in renewable energy to achieve climate targets and minimize the risk of carbon-stranded assets.

Credit author statement

Soh Young In: Conceptualization, methodology, software, validation, investigation, writing - original draft preparation, writing - review and editing, visualization, supervision, project administration, funding acquisition **Berk Manav:** methodology, software, validation, formal analysis, data curation,.; writing - original draft preparation, visualization, funding acquisition **Clothilde M.A. Venereau:** formal analysis, data curation, writing - original draft preparation, visualization **Luis Enrique Cruz R.:** formal analysis, data curation, writing - original draft preparation, visualization **John P. Weyant:** Conceptualization, methodology, writing - original draft preparation, writing - review and editing, supervision. All authors have read and agreed to the published version of the manuscript.

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Declaration of competing interest

The authors declare the following financial interests/personal relationships which may be considered as potential competing interests: Soh Young In reports financial support was provided by Stanford Center for Integrated Facility Engineering (CIFE).

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