This paper presents a framework for pricing the climate resilience of an energy infrastructure project through assessing the value of its required debt and equity investments. Integrating climate scenarios into an asset valuation model provides useful and specific insights for risk management, but there is a lack of academic and market tools that effectively address this need. The critical barrier is that climate-related risks (physical and transition) are typically indirect variables in the cash flow calculation, and they should be computed based on the direct variables such as revenue, capital expenditures (CAPEX), operating expenses (OPEX), and financing costs. The implementation of this framework shows how to delineate climate-related risks that are asset-specific and transforms them into financial risks. Using cash flow simulation and scenario analysis, it estimates an energy infrastructure asset’s probability of default due to climate-related risks and the size and timing of the losses for any given default. To demonstrate the framework's application, we simulate the price climate-related risks of a utility-scale electricity generation facility (i.e., a downstream energy asset) powered by natural gas.

Highlights:

- The framework consists of three parts. First, it identifies the climate risks that an individual energy project would be exposed to under a multitude of feasible climate risk scenarios and economic trajectories
- Second, it prices the identified climate risks at the level of the individual energy project’s cashflows by downscaling and translating climate risk information
- Third, it calculates the probability of default and identifies the largest potential gains and losses due to the identified climate risks for an individual project

Keywords: climate risk management, stranded assets, project finance, cash flow simulation, scenario analysis, energy investment

Word Count: 11,842
Introduction

The impacts of climate change are no longer hypothetical distant phenomena, and climate change is already creating physical and transitional risks for investments and businesses. The world is paying more for natural disasters, and recent extreme weather events have driven up uninsured losses [1, 2]. The Paris Agreement’s climate mitigation target requires a massive scale-up of investments in renewable energy technologies and a phase-out of investments in fossil-fuel-based plants [3, 4, 5]. As a result, asset owners are being forced to review the mix of energy assets in their portfolios.

Energy infrastructure is an asset class that makes “climate resilience” interesting to think about as it poses major challenges and opens up large opportunities for its developers, owners, operators, and investors. Building, operating, and financing environmentally-friendly and climate-resilient infrastructure assets can deliver not only positive environmental externalities but also a monetary value and good stewardship of available financial capital. The Carbon Tracker Initiative (2018) [6] assesses that 42% of global coal plants are already unprofitable as of 2018, and, by 2040, 72% of global coal investments are at risk of becoming unprofitable due to a combination of falling renewable energy costs, carbon pricing, and air pollution regulations. It implies the potential to create stranded assets and destroy significant shareholder value while complying with climate change and greenhouse gas (GHG) emissions regulation scenarios. Caldecott (2018) [7] and Mercure et al. (2018) [8] demonstrate that the value of stranded energy assets is not being fully reflected in the value of investors’ portfolios.

Ultimately, managers should understand how their energy infrastructure assets could be financially impacted by physical and transitional risks and adapt their businesses and portfolio management strategies appropriately. Yet, the large-scale and long-term nature of energy infrastructure makes doing so uniquely challenging and significant. Energy infrastructure investments usually have time horizons that span multiple decades, making climate-related risks crucial to consider in the lifetime of the asset [9]. It is particularly difficult to assess the resilience and sustainability of an infrastructure asset due to the inherent ex post facto nature of sustainability, where today’s investments can only be judged as sustainable far from the future realities [10]. To translate climate risk evaluation into business decisions (the former is inherently long-term while the latter is short-term, in relative terms), there needs to be a framework for assessing the resilience of an infrastructure asset.
The time horizon difference becomes more prominent in highly leveraged financing schemes such as project finance, which are the most commonly used structure to finance energy infrastructure assets [11, 12]. IEA (2020) [13] reports that fossil fuel transactions are highly leveraged over 80% debt, and renewable energy assets also show a strong tendency to reduce capital costs and employ greater leverage from banks. In principle, project finance is a non- or limited-recourse financial structure where project debt and equity used to finance the project are paid back from the cash flow generated by the project (typically, a special purpose vehicle (SPV)). In general, 70-80% of energy infrastructure assets are financed through debts, while 20-30% are equity [14, 15]. Despite the prevalent share of the debt investors in energy infrastructure financing, however, specific interests of debt investors have been undermined in climate risk assessment. The interests of debt holders are even shorter than equity holders because the former is fixed to the contracted term and whether the asset can generate sufficient cash flow to repay the principals and interests due every pay period, mostly quarter, semi-annual or annual.

It is difficult to estimate the exact timing and severity of the physical impacts of climate change, and its economic and social consequences are very complex [16]. Investors who can mobilize investment capital to build new renewable energy infrastructure assets and transform existing fossil-fuel assets realize this as a significant barrier to the energy transition. Hence, this study aims to address the outstanding concerns of financial stakeholders to integrate climate-related considerations in their decision-making process for energy infrastructure investments. The currently available economic models and market tools do not fully address the concerns of investors. As aforementioned, debt investors need more specific projections of a project’s cash flow to ensure the project is bankable. In turn, the successful arrangement of debt financing is the central concern of equity investors, who usually develop and own the asset. Only very recently, the undermined interests of project finance have been revealed on the global community by a very few initiatives such as the Paris Agreement Capital Transition Assessment (PACTA) by the 2° Investing Initiative with backing from UN Principles for Responsible Investment (PRI) [17].

This study presents an integrated framework for pricing the climate resilience of energy infrastructure assets comprehensively. The proposed framework can project the financial impacts of adverse climate scenarios with a focus on the value of energy infrastructure assets, measured by debt service coverage ratio (DSCR) and internal rate of return (IRR). The framework integrates climate data from multiple sources and scenarios into a project-finance based valuation model (i.e.,
cash flow analysis), and estimates an asset’s financial default risks resulting from specific climate-related risk scenarios. We note that the framework does not provide one single metric to show the probability of the default throughout the asset’s entire lifetime. Instead, it assesses DSCR at each pay period. Through this new approach, investors are not only able to calculate a probability of default but are also able to assess the size and time of the losses resulting from the given default. We also demonstrate the use of this framework through its assessment of a natural gas combined cycle gas turbine (CCGT) investment in the Pennsylvania, New Jersey and Maryland (PJM) power pool.

This study builds upon the literature that has identified climate risk factors and their scenarios to project economic trajectories for fossil fuel/renewable energy sectors produced. Integrated Assessment Models (IAMs) and IAM-based models (e.g., integrated global system modeling [IGSM], dynamic integrated climate change [DICE] model, cost-benefit [CB] IAMs, detailed process [DP] IAMs) look at multiple climate risks associated with the economy [18]. These models attempt to provide a holistic assessment of climate risks at a macroeconomic level. Yet, there exists a continued need to evaluate the asset-level risks borne due to the changing climate and associated risks. There is a critical need for a framework that can perform scenario analysis. Most macro/environmental integrated assessment models are developed for a specific purpose other than financial risk analyses and, as such, are not yet suitable for performing the type of scenario analysis appropriate for financial risk evaluation. Moreover, while a few extant economic models enable users to simulate multiple climate scenarios and estimate overall impacts to an economy, they do not assess the financial value of an asset.

On the other hand, IAMs can provide critical socio-economic inputs to these financial analyses. Without these inputs, such analyses the financial methods would have no way to consider the wide range of demographic, economic, behavioral, technological, and regulatory conditions within which risky climate vulnerable investments must be made. It is hoped that the framework proposed in this paper can help stimulate IAM development and scenarios based on them to better provide these critical inputs. At the same time, the financial climate risk analysis community can provide better ways to represent the quantities of investment funds necessary to make transitions to very low greenhouse gas futures without much consideration of required financing costs across regions, sectors and technologies. Here we use generalizations drawn from ranges of societal demographic, economic, behavioral and technological conditions from available IAM scenario
IAM simulations to illustrate their potential to inform project and asset specific climate financial risk assessments employing some traditional financial risk assessment methods.

The research gap being addressed is in this paper is the need to provide financial analyses of climate vulnerable investments at the project or infrastructure level for those involved in those decisions as well as a basis or point of comparison for such calculations at higher levels of aggregation. A wide range of financial stakeholders now engaged in assessing and managing investments for financial disclosure, risk assessment and risk management have great interest in information at this level. This ranges from companies making their own investment, to institutions who provide financing for climate vulnerable projects and infrastructure investments, to those providing insurance to these stakeholders. Moreover, at the level of asset or risk portfolio management in financial institutions, or even for those charged with monitoring financial stability at central or international banks, these projections provide crucial cross checks on - or foundational elements of - portfolio analyses based on more aggregate data and analyses.

We note the above limitations in the pricing of climate risks associated with the value of the related financial contracts. To the best of our knowledge, none of the extant literature prices climate risks based on the value of an “individual asset,” particularly the value of its required debt and equity investments. Assessing asset-level cash flows is challenging because the spectrum of cash flow projections varies widely depending on asset profile, regional circumstances, market awareness, and financial contracts, all of which need to be considered while the availability of the data required to do so is limited. Traditional discounted cash flow (DCF) is at an asset-level, but its use of predefined and constant discount rate limits the practicality of findings. To address this shortcoming, Pless et al. (2016) [24] combine DCF and real option analyses to assess and compare the net present value (NPV) of energy systems of varying energy sources. Yet, NPV analysis does not provide specific insights into how climate risks can affect an asset’s value during its lifetime. As aforementioned, assessing a project’s debt service coverage at each pay period instead of the lump sum cash flow for the lifetime is more critical for highly leveraged energy infrastructure projects. In evaluating project financed assets, it has long been a market convention to assess a project’s DSCR instead of 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 DSCR analysis to evaluate the capacity of the project cash flows to meet the debt service obligations throughout the project lifecycle [11].

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This study is the first in a research series that price climate-related risks at an asset level. In the subsequent study, In et al. (2021) [25] provide an in-depth, comparative case study on three downstream energy assets powered by natural gas, coal, and solar. The natural gas CCGT case herein is the abridged version of the full case study from the subsequent study. The proposed framework is meant to support managers in pricing and managing the climate-related financial risks of their energy infrastructure investments. Managers can simulate the value of an asset’s debt and equity investments based on the asset’s climate-related risks under possible climate transition-risk scenarios and economic trajectories. The types of energy assets considered can span different fuel and energy sources, from coal to natural gas to solar. By extension, the framework is flexible enough to be tailored to various types of infrastructure assets. This study provides an added value over existing climate risk assessment tools by providing the basis for new, climate-enhanced financial pricing models that are downscaled to focus on the cash flow level. This asset-level climate risk assessment approach considers the geographic location of the asset and its specific country’s economic and energy market conditions, the projects’ asset-level financial characteristics and capital structure (e.g., loans, bonds, equity), as well as the investors’ investment appetites for fossil fuel/renewable energy sectors. Using this framework, managers can calculate the probability of default, assess the largest potential gains/losses at the individual project level, and bring a sophisticated climate lens into traditional financial risk metrics such as DSCR and IRR.

The remainder of this paper is organized as follows: Section 2 reviews the extant climate risk assessment tools and lays out aspects to consider when assessing the climate resilience of energy infrastructure assets. Section 3 presents a framework that assesses material financial impacts from climate change and a low-carbon transition on energy infrastructure investments. Section 4 demonstrates an application of the proposed framework by assessing climate-related financial risks of a natural gas CCGT investment in the PJM power pool. Section 5 concludes with an agenda for further research.

2 Review of Climate Risk Assessment Methods and Practices

2.1 Climate-Related Risks
Climate events are projected to have a broad variety of impacts on societies and ecosystems combined with other environmental, economic, and political stresses, which adds to the complexity [26, 27]. The Task Force on Climate-related Financial Disclosures (TCFD) specifies risks related
to the physical impacts of climate change, and risks associated with the transition to a low-carbon economy [16]. Physical could be caused by chronic climate change resulting in water scarcity or precipitation increase, surface water temperature increase, ambient air temperature increase, as well as increased frequency of acute extreme weather events. Physical risks can directly damage an asset’s operation and productivity or indirectly cause supply chain disruptions, thereby influencing revenue and expenditures of assets. Hong et al. (2019) [28], for instance, demonstrate that global temperature rise, risks of drought, discounting effects of food stock prices, and thereby profits of food companies are connected to one another. As weather-related economic losses have increased, households and companies have become more reliant on insurance. However, such an increase in weather-related insurance claims brings financial burdens to households and companies who must pay higher insurance premia [29].

Transition risks are mainly driven by technology and regulatory changes, and they also impart financial effects, damage to reputation and image, or political consequences [30]. Market shifts in supply, demand, and price can manifest from technological and regulatory risks, although the mechanism varies. One example of the technology impact is how changing grid dynamics (i.e., more distributed and intermittent resources) have increased the demand for energy storage and impacted energy market behavior by requiring more flexible operation of ‘baseload’ fossil fuel plants [31]. Transition risks may result from the adjustment of asset prices towards a low-carbon economy, based on the increased awareness since the Paris Agreement [22, 32]. Battiston et al. (2017) [19], Monasterolo et al. (2018) [20] and Huxham et al. (2019) [21] shift the focus from physical risks to transition risks. De Greiff et al. (2018) [22] provide complementary tests focused on the pricing of short-term transition risks, rather than physical risks, to assess the pricing and term structure of environmental risk in syndicated loans. However, projecting, measuring, or pricing transition risks is very difficult because the transition is inherently slow in progress, and it is unknown how the world will evolve into a low-carbon economy [33].

Asset owners put critical attention on regulatory risks than on other transition risks. Krueger et al. (2020) [34] and Seltzer et al. (2020) [35] discuss that regulatory risks are different from other transition risks because regulatory risks have already been materialized financially, and these risks can suddenly affect a majority of investors very quickly. TCFD (2017) [16] includes policy interventions to offset transition risks, such as carbon pricing, shifting energy use toward renewable energy over fossil fuels, adopting energy-efficiency solutions, encouraging greater
water efficiency measures, and promoting more sustainable land-use practices. A considerable amount of climate-related risks has not yet financially materialized but is increasingly likely to be materialized. Others, such as BIS, add liability risks, which can be caused by the increased compensation paid to economic agents affected by the physical or transition risks from climate change [32, 36].

2.2 Climate Risk Assessment Models

Asset owners and managers need to consider how their climate-related risks and opportunities may evolve and their potential implications under different conditions [16]. According to the Financial Stability Institute (FSI)’s survey of eighteen insurance authorities, stress testing and scenario analysis are two prevalent methods utilized by insurers to assess climate risk exposures [37]. In this study, we mainly use scenario analysis because climate-related risks may occur simultaneously or sequentially within a structure of interlinked social, ecological, and technical systems [38]. Scenario analyses can assess single or multiple climate-related risks and the interaction of those risks in a more complex manner. Climate scenarios often make use of climate projections (e.g., descriptions of the modeled response of the climate system to scenarios of GHG and aerosol concentrations) by using model outputs and combining them with observed climate data. Entities such as the Intergovernmental Panel on Climate Change (IPCC), International Energy Agency (IEA), and Environmental Protection Agency (EPA) have developed global climate scenarios to form the basis of climate risk assessment. These scenarios aim to create plausible representations of future climate by integrating data from multiple disciplines and different resource use cases, such as various global energy use or land-use scenarios. Their underlying methodologies are based on the theoretical foundation laid out by IAMs.

IAMs aim to integrate knowledge from two or more domains into a single climate-risk assessment framework [39, 18]. IAMs in the climate and energy sector combine the domains of climate science and economics. They are often theoretical and possess varying levels of complexity. DICE is a type of IAM developed by William Nordhaus for research in the economics

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1 Liability risks may be borne due to insufficient disclosure of information by a company or entity regarding its exposure to climate-related risks. If a business were to then suffer financial losses caused by climate-related risks, such as flooding and weather events, or regulatory penalties, such as those due to emissions, its investors might make claims against the business. Furthermore, entities who suffer from climate-related impacts overall might make claims against the polluting companies who they argue are responsible [29]. These liability risks pose significant challenges not only to businesses but also to the insurers of these companies. The framework in this study does not include liability risk considerations as it focuses on value at risks that cannot directly infer potential tail events.
of climate change, often referred to as an aggregated CB IAM. It is a globally aggregated model that can assess the impacts of climate change and different policy approaches on macro-level economic and scientific outcomes. Based on the perspective of neoclassical economic growth theory, this model deals with the trade-off between foregone consumption for making investment in (human) capital and technology and its benefit in the future. The DICE model includes the natural capital of the climate system as an additional kind of capital stock, assessing how devoting output to emissions reduction and reducing consumption in the present can prevent economically harmful climate change and thereby increase consumption possibilities in the future. CB IAMs are powerful tools to inform climate policy, for instance, through simulating the impacts of various carbon pricing schemes on carbon emissions levels, economic growth, and observed temperature changes. CB IAMs provide a more aggregated representation of climate change mitigation costs and aggregate impacts by sector and region into a single economic metric. The main motivation for developing CB IAMs has been to use them to implement cost-benefit analysis to identify “optimal” climate policies, but they have also been used to calculate the costs and benefits associated with policies for which marginal costs and marginal benefits are not equal. These models do not provide any detail on either energy system changes or in changes in output from individual sectors in individual world regions resulting from climate change.

The second type of IAM, referred to as a detailed process (DP) IAMs [18], is more spatially and sectorally disaggregated. These models consider a broader range of climate change impact metrics (e.g., climate goals, development goals, equity goals, etc.) and can also be used to project the impacts (including costs) of achieving these objectives on world regions. The DP IAMs provide more information than the CB IAMs on the physical impacts and economic costs of climate change and the benefits of GHG emissions mitigation. This has two important implications. First, similar to the aggregation and calibration required on the mitigation side of the CB IAMs, the more complex DP IAMs can also provide projections of the economic costs net of endogenous adaptation to climate change for key sectors (e.g., agriculture) by region. These estimates can then be aggregated for use in the CB IAMs. Since most climate impacts take place at the watershed, agricultural growing region, ecological zone, city, or similar level, this additional degree of geographical disaggregation is essential for improving the validity of the damage functions used in the aggregate CB IAMs. Second, the additional information on both the physical and economic impacts of climate change may be vitally important to decision-makers in some regions and sectors.

Electronic copy available at: https://ssrn.com/abstract=3736415
Not surprisingly, it is this class of more detailed IAMs that have been used to develop the scenarios used by the IPCC in its assessment reports.

Although current models enable to assess climate scenarios and the associated risks, their analysis remains macro. This can be a critical bottleneck for the frameworks, scenarios, and measures by IPCC, IEA, and EPA: they do not provide the actionable financial metrics to alter investment decisions. Many macroeconomic models are formulated at a systems level and thus are somewhat limited in informing investors about their value at risk (VaR). One can compute the VaR associated with climate shocks using outputs from IAMs, in which aggregate financial losses are derived top-down in terms of estimated GDP (gross domestic product) losses due to physical risks resulting from climate change [19]. NGSF (2019) [40] points out that macroeconomic models may not accurately predict the economic and financial impact of climate change, which further hinders immediate actions from mitigating and adapting to climate change. The models may not assess and price the financial risks of owning polluting assets vs. green assets. Silva (2019) [32] states that future research should advance and develop models and measures of climate-related risks applied to individual assets. It would allow investors to make informed decisions and help society become more resilient, drawing much-needed investment towards greener assets.

2.3 Climate-related Financial Risks
Climate risk assessment studies have evolved to measuring a country, company, portfolio’s exposure to climate-related risks and quantifying their financial impacts in the form of standard financial risk metrics. Some studies use portfolio analysis, which assesses how much a portfolio is exposed to climate risks and estimates its VaR under different climate scenarios. Monasterolo et al. (2017) [23] develop two indices, namely “GHG holding” and “GHG exposure,” which are designed to identify the exposure and contribution of single investors’ portfolios to climate transition risks. Battiston et al. (2017) [19] conduct portfolio-level climate risk analysis assessing the VaR and distributions of losses suffered by a bank based on its amount of equity holdings in fossil fuel vs. renewables-based utilities and sectors. While the portfolio analysis can provide a standard method to compare climate risk exposure through the utilization of these indices, it

2 For instance, Moody’s illustrates a sovereign’s susceptibility to climate change as a function of exposure and resilience, which influence the sovereign’s ability and willingness to pay its debts.
3 For instance, the Carbon Tracker initiative coin the term “Carbon Bubble,” which measures the amount of carbon that remains “unburnable” to comply with temperature rise and emissions regulation scenarios. They show that public companies with high carbon bubbles may not accurately evaluate future policy scenarios.
remains simplistic as it does not provide the actual financial risk exposure due to this portfolio composition. A growing number of companies have both brown and green energy connotations. Moreover, extant studies do not price shocks or scenarios in the value of an energy project’s debt and equity investment.

Climate risk assessment is challenging because climate risks are on a long-time horizon, their impacts are likely non-linear, they are inherently interconnected in the financial network, and they are uncertain on climate policy introduction. In particular, assessing the exposure of infrastructure assets to climate risks remains highly complicated. The spectrum of cash flow projection widely varies depending on asset profiles, regional circumstances, market awareness, and financial contracts, all of which need to be considered while the related data is limited. Lately, asset owners and managers seek to improve the reliability of climate risk assessment through specialized data. For example, Investec utilizes geospatial data and satellite imagery to inform sovereign debt investors on portfolio risk by examining the resource depletion rates and preservation practices [41]. The emergence of granular-level data and the increased attention on granular climate risk management, in combination, has brought the financial services industry to the point that separates project financed assets—mostly infrastructure assets—from an aggregated portfolio-level analysis. In 2020, a global think tank 2° Investing Initiative launched PACTA, which assesses financial portfolios’ alignment with climate scenarios by aggregating data from asset to company level [17].

While the latest industry tailwinds include the technological advancements that have enabled the increased availability and accessibility of this complex and granular data, many asset owners and managers today do not fully leverage advanced data that is becoming widely available. Key reasons for this are likely because (1) climate data needs to be transformed into a readily applicable form to the financial models used by asset owners and managers; (2) there are no standardized metrics to estimate climate risks that go into financial models; and (3) neither the providers of the data (e.g., environmental scientists and environmental or socioeconomic modelers) and nor the user of the data (e.g., investors) understand the various mechanisms through which various climate-related risks affect the financial resilience of the asset.

In this regard, the potential model outputs and methodologies of most concerns to investors are described in additional detail. Firstly, climate risk assessment requires a forward-looking perspective into a climate-changed future. The extension of existing natural catastrophe (i.e., nat
Insurance companies use their existing natural catastrophe risk assessment models and its own historical data on weather events to evaluate the costs of providing insurance coverage by considering even longer-term risks driven by the changing climate.
investors may evaluate parameters such as DSCR, collateral amounts, and the unsecured losses in events of default, whereas equity investors may place additional emphasis on IRR and cash distributions to equity. Given that capital structure and contract-level differences will affect the resilience assessment of two otherwise comparable assets, there remains a need to develop frameworks that can inform different investors based on their needs.

3 Framework to Price Integrate Climate-Related Risks

This section presents a framework that prices the climate resilience of an energy infrastructure project through a lens of the value of its debt and equity investments. The framework is based on a financial model designed to assess whether a project generates a sufficient and stable cash flow to withstand climate-related events that impact the project’s ability to repay debt and equity investors. As shown in Figure 1, the framework consists of three parts. It first identifies climate-related risk variables that are specifically relevant to the selected energy asset. It then develops single and combined risk scenarios based on these risk variables. Secondly, we build a baseline cash flow model of the asset, whose four main components are revenue, capital expenditures (CAPEX), operational expenses (OPEX), and financing costs. Our analysis covers climate risk exposure throughout the full project lifecycle, from the development phase through construction and into operation. We then price climate-related risks by simulating their impacts on the asset’s cash flow. We calculate the default conditions (for projects with debt in their capital structure) and the negative/positive effects on their cash-flow levels. Finally, we estimate the expected DSCR and IRR after a given variation in the values of key factors take place.
3.1 **Climate Risk Scenarios**

We specify risks amongst the physical, transition, and regulatory risks of climate change. Physical risks of climate change include risks due to chronic climate change and acute weather events. We evaluate the transition risks due to technology advancement separately from transition risks due to regulations that are being internalized in financial costs. Renewable energy’s increasing competitiveness appears to be firmly in-motion, with the uncertainty being the timing (i.e., ‘when,’ not ‘if’). Separately evaluating technology risk also allows regulatory risk to be applied and adjusted to synchronize with a firm’s planning assumptions and outlook. While we desire consistent and impactful policy action, we acknowledge the wide range of prognostications and viewpoints. While we comprehensively consider climate-related risks, we prioritize the risks that directly affect a project’s cash flow and thereby the default risk of its financial contracts. We use this lens when building the risk scenarios that the project is directly exposed to, often relying on the asset type, location, and financing structure.

We exclude risks that are already internalized in financial costs. For instance, adverse weather conditions can be considered as Force Majeure events. In lending documentation, the Force Majeure events are referred to as an ‘act of God,’ which include not only extreme weather events (e.g., hurricanes, floods, earthquakes) but also other political and market disturbances that are unusually severe and unexpected (e.g., war, acts of terrorism, labor strike disruption or disease outbreaks). Force majeure can be a contractual or statutory construct. Typically, contractual and litigation approaches are defined through the contract negotiations phase – lenders negotiate to
deal appropriately with changing weather patterns and address force majeure issues. In most cases, lenders request that borrowers (occasionally, the hosting government) purchase insurance, reinsurance, or guarantees, which increase a project’s insurance costs or other expenses. We will not prioritize the risks for which contractual and litigation approaches exist. We would instead consider the risks due to the shifting weather patterns that are different from Force Majeure weather events. For example, in the case of natural gas CCGT assets, we consider gradual increases in temperatures a consequence of climate change, which are a key physical risk to test. We identify the main risk variables that can affect the asset of interest through scientific literature review and market analysis. We then consider how the climate-related risk variables translate into changes in the inputs of the financial model. For example, for a natural gas CCGT plant case study, scientific studies indicate that increases in temperatures caused by climate change led to increased fuel usage and, therefore, higher variable operational expenses. Based on this approach, we project multiple climate-related risk scenarios and identify the impacted financial model inputs throughout the financial contract period.

3.2 Cash Flow Analysis

We build a baseline cash flow model for the chosen asset. This analysis is particularly relevant to assessing debt investments’ probability of default. An asset owner must repay its debt and interest every payment period (often quarter or semi-annual based). Thus, short-term instability and fluctuation in cash flow can cause a breach in the ability to fulfill debt service obligations. One or two bad years can lead to a default on the debt, whereas equity investors are more intrinsically tolerant of short-term volatility, so long as there are enough proceeds to equity holders within a specific timeframe to make the equity returns attractive.5

We use the project finance structure as the dominant financing scheme instrument for energy infrastructure projects that are highly leveraged. Project finance is characterized as non-recourse lending, secured only by the project’s cash flow and pledged collateral, but not by the project owner's liability Sponsor(s) establishes a special purpose vehicle (SPV), which develops, owns, and operates a single asset. Lenders are entirely reliant on the asset and cash flows of that

5 Eventually, the equity investors are in a subordinated (junior) position to debtholders in the capital structure, and they are responsible for repaying the outstanding balance and fees and costs incurred due to the event of default. However, because of this higher risk position versus debt holders, equity holders expect higher returns for their investments in a project.
project for interest expenses and principal repayments. In the event of a borrower’s default, lenders can only use the project itself as collateral. On the contrary, with a recourse loan, a lender may recoup its investment when a borrower fails to pay the liability and if the value of the underlying asset is not enough to cover it. Thus, it is difficult to accurately assess the climate-related risk sensitivity of recourse loans used to finance the assets. Furthermore, the analysis of a project-financed investment allows us to evaluate whether the investment is a financially resilient asset on a standalone basis, regardless of the strength of the parent entity.

We project a project’s cash flow using four broad parameters: revenue, OPEX, CAPEX, and financing costs. The criteria and ranges of parameters can differ depending on the climate scenarios that we choose to test.

Revenue
The main revenue source for typical electricity generation assets is electricity (energy) sales and capacity payments (power sales) by participating in the wholesale markets. Power plants can also engage in bilateral contracts called Power Purchase Agreements (PPAs) to sell electricity (and if a renewable plant, sometimes the associated Renewable Energy Credits) to an offtaker for a specified price over a specified term [11]. The PPA allows the power plant to avoid the need to participate in wholesale energy markets and hedge the price volatility in the spot markets by selling energy for a determined price and escalation rate over a long period. For resources participating in wholesale markets, electricity sales are mainly a function of facility “nameplate” capacity, net capacity factor (i.e., how often was the plant operated and how much of its total theoretical capacity did it generate), and power price. Capacity payments are a function of facility nameplate capacity and capacity market auction prices and compensate the generator for the ability to provide a required power output on demand.

Capital Expenditures (CAPEX)
CAPEX consists of expenditures associated with design engineering and project management services, construction of civil works and facilities, right-of-way acquisitions, and equipment purchases [45]. The largest amount of CAPEX payments takes place during the project

6 These assets are usually physical, fixed, and non-consumable assets such as property, equipment, or infrastructure, and that have a useful life of more than one accounting period. CAPEX thus includes purchasing items such as new equipment, machinery, land, plant, buildings or warehouses, furniture and fixtures, business vehicles, software, or intangible assets such as a patent or license. The expenditure amounts for an accounting period are usually stated in the cash flow statement.
construction period, where the available funds (debt and equity) are drawn down to finance the capital expenditures required. CAPEX spending has a substantial effect on the short-term and long-term financial standing of a project because of the following reasons: its long-term effects on project performance, its irreversible nature, and how it impacts the income statement with regards to depreciation expenses in the following periods. Therefore, decisions regarding when and how much to invest in the project through capital expenditures are important factors with long-term, material consequences.

**Operating Expenses (OPEX)**

The OPEX mainly includes variable costs such as fuel costs (in the case of fossil fuel-powered plants), labor, and operation and maintenance (O&M) costs associated with incremental power production. It also includes fixed costs such as the fixed O&M fee associated with the power plant, insurance fees, land leases, and/or property taxes. Operating expenses are hence defined as the sum of all annual costs required to maintain the continued operations and optimum performance of projects [46]. If implemented, a carbon tax would be an additional variable OPEX. Alternatively, the use of CCS incurs additional OPEX to operate the carbon capture unit and underground injection for geologic storage. It also increases operating expenses through additional parasitic natural gas and electricity consumption.

**Financing Costs**

Financing costs are the expenses associated with borrowing capital to finance the upfront costs of a project. Although there are financing costs involved with both debt and equity capital, in this study, financing costs refer to the interest expenses (return on capital) and principal amortization payments (return of capital) given to the debt investors. Because financing costs can be understood as the reward given to investors to compensate them for taking investment risk and providing the upfront capital, projects with higher risks (such as capital-intensive projects or projects in developing economies) have higher financing costs [47]. The accounting period of a project is largely divided into two periods: construction and operation. For a large energy infrastructure project, the construction period takes 2-3 years on average, and it can be extended depending on the construction and development progress of the SPV or its contract parties. During the construction period, the borrower is typically not required to repay any of its principal or interest because the project does not operate to generate cash flows. To satisfy this characteristic, the construction loan is negative amortization, paid-in-kind financing where the interest expenses are
added to the loan’s principal balance and accrued over time. These expenses are called “interest during construction” and can sum up a significant cost associated with financing during the zero-cash-flow construction phase. Once the project starts its operation and generates revenues, it enters the operating period. The operating periods usually take 15-20 years depending on the lifetime of an asset (or the contracted PPA period), and the borrower must repay principal and interest as per the contracted cash flow waterfall. In some cases, when a project requires some time to be able to conduct its full operating capability and generate positive cash flow, investors put a grace period clause in the financial contracts. During the grace period, the borrower is obliged to pay the interest but no (or partial) principal.

3.3 Scenario Analysis and Cash Flow Simulation

We project a project’s cash flow under multiple climate scenarios, and compare output metrics of interest, such as DSCR and IRR, to test the resilience of energy assets under different climate scenarios. The DSCR metric indicates how many times a project can pay its total debt service in a certain period using the cash flow that the project generates. While DSCR is one of many measures that can evaluate an asset’s resilience, DSCR and equity IRR are the measures most widely used by investors during due diligence. Our cash flow assessment (and assessment of DSCR in each repayment period) differs from other financial modeling frameworks such as the traditional DCF method. Using a DCF model approach in project finance has a few limitations. Firstly, the single discount rate (i.e., weighted average cost of capital, WACC) does not account for varying levels of leverage through the project lifetime. WACC is a blended rate for the cost of capital, reflecting the required returns on the debt and equity components of the capital structure. Therefore, with varying levels of leverage over time, the WACC would also change, and using a methodology with a single discount rate does not strongly reflect the project’s true riskiness and valuation. Secondly, the DCF analysis ignores embedded optionality. Thirdly, tax rates and policies change throughout an infrastructure project’s multi-decade time horizon. The tax rate is also a critical component of the WACC calculation, furthering the limitations of a constant WACC used to discount all project cash flows.

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7 The DCF analysis is a method of valuing a project or asset by discounting the project's future cash flows based on the time value of money. DCF analysis finds the present value of expected future cash flows using a single discount rate, known as the weighted average cost of capital. The sum of all these discounted future cash flows is the present value (PV) of the asset, which is then used to evaluate a potential investment. If the PV calculated through DCF is higher than the current cost of the investment, the opportunity presents a positive net present value (NPV) and should be considered.
cash flows. However, these limitations 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.

We test whether the project exhibits sufficient net cash flow in each period of operation to make debt service payments on time. This methodology can account for the varying levels of leverage over time and does not require the calculation of the WACC. A project’s cash flow is summarized using the cash flow waterfall, which is based on the priority and seniority of each cash inflow and outflow (as shown in Figure 2). Cash flow available for debt service (CFADS) is calculated in the cash flow waterfall by netting out from Revenue the OPEX, CAPEX, and working capital adjustments. CFADS is the most significant line in the cash flow waterfall because it drives all debt repayment calculations and ratios, including DSCR. DSCR is calculated by dividing CFADS generated in a certain period by the total debt service payments (interest expense plus principal amortization).

![Cash Flow Waterfall Diagram]

**Figure 2 Cash Flow Waterfall**

For fixed-income investors, having a higher DSCR is critical because it tests whether a project can pay debt service and how much buffer exists in each period. A DSCR of less than 1.0x would mean a negative cash flow, bearing in mind the total debt service is higher than the CFADS.
A DSCR of 0.90x means that there is only enough cash flow to cover 90% of annual debt payments. Conventionally, energy infrastructure project finance requires DSCR ranges within 1.5x and 2.0x. If not, potential lending syndicate partners are unlikely to get onboard. Otherwise, they often request contingency plans from borrowers, such as an account control clause. The account control agreement is an agreement among the borrower, the collateral agent, and the bank in which the borrower holds its deposit or a securities account. Then, in the event of default (EOD), the collateral agent notifies the deposit bank to transfer control over the account to the collateral agent. Another similar requirement is a Debt Service Reserve Account (DSRA) in which the borrower preemptively needs to deposit the total debt service amount expected in the following period into a separate account to ensure it has enough funds to satisfy future debt service obligations.

In addition to investigating the risks to debt investors, we also evaluate equity investment risk and upside using IRR metrics. For equity investors, maximizing the return on equity is critical. The downside risk is that a project may not deliver the expected return or that the asset value declines in value due to changes in market conditions. Yet, we modify the IRR expectations across projects because higher-risk projects require that investors underwrite and expect higher IRRs to compensate for the additional risk. Given that assumptions and risk factors can vary significantly between projects, the value in our IRR analysis is not in determining what the absolute IRR in a project is, but instead in observing and interpreting how IRRs across different scenarios compare to the base case, “no-risk” scenario IRR.

This analysis provides a more detailed explanation of which climate risk variables affect specific elements of a project’s cash flow, as well as when and how such impacts are materialized. We can provide specific insights for investors on how to evaluate the resilience and returns of a project with respect to asset properties (e.g., system size, generating capacity), leverage (debt vs. equity), upfront spending on climate resilience (higher upfront CAPEX vs. OPEX), and financial terms (e.g., cash flow margin, debt tenor, amortization schedule, DSCR covenants, equity IRR expectations). Project finance modeling also allows us to understand the mechanics of the project, its operational contracts (power purchase agreements, O&M agreements, fuel-supply contracts), its capital structure, and its business model, and thus be cognizant of the risks involved.
4 Case Study – Application of the Framework

This section presents a case for a new natural gas CCGT plant in the PJM power pool. This region represents the current “rush to gas” meaning that new power plants are being built to replace uneconomic or retiring coal plants and inefficient natural gas plants in the mid-Atlantic and Appalachian states [48]. In 2019-22, 20 GW of new gas capacity with an associated $8-10bn of debt financing will come online in PJM alone [49]. More broadly across the entire US, this “rush to gas” could mean up to $500bn in capital costs in the next 10 years to replace the aging power plant fleet, and most of these assets will be in PJM or the Electric Reliability Council of Texas (ERCOT), selling power via a riskier merchant revenue model rather than contracted off-take. A merchant model is naturally more volatile because revenue is defined by bidding into an energy market auction, which determines electricity sales price, as well as a capacity market auction, which determines fixed capacity payments, rather than a contracted power-purchase agreement with long-term fixed sales price or capacity payments. Prior to the full case study, we highlight that its primary purpose is not to get fully accurate inputs and outputs of the climate risk assessment but to demonstrate the application of the proposed framework.

4.1 Financing the Natural Gas CCGT

Project-financed merchant plants in PJM can typically find lenders willing to accept a capital structure of 65% debt and 35% equity with 6-7% interest rates [50, 51]. In order to be more conservative with our financing assumptions, our model utilizes a 60% Loan-to-Cost ratio with 60% of the construction costs funded by debt and 40% funded by equity. The detailed inputs of base case natural gas investment are shown in Table 1.

<table>
<thead>
<tr>
<th>Table 1. Base Case Key Assumptions</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Source</strong></td>
</tr>
<tr>
<td>Plant Specs</td>
</tr>
<tr>
<td>Plant Type</td>
</tr>
<tr>
<td>Location</td>
</tr>
<tr>
<td><strong>Revenue Model</strong></td>
</tr>
<tr>
<td>Nameplate Capacity</td>
</tr>
<tr>
<td>Heat Rate</td>
</tr>
<tr>
<td>Combustible Price</td>
</tr>
</tbody>
</table>
The table provides key assumptions of the natural gas CCGT plant in the PJM power pool case. We note that the assumptions represent conventional cases in consideration of the plant specs, time period, and geographical location. They are not from a specific standing project.

### Climate Risk Scenarios

#### 4.2.1 Climate-related Risks

**Chronic Climate Change**

Chronic climate change with severity that increases incrementally is known to present significant physical risk – and previous assessments have concluded this could cause natural gas power plant capacity declines as high as 10-15% by 2040 for an entire portfolio [52, 53]. The main culprit is water scarcity and water temperature increase affecting power plant cooling water systems, specifically “once-through” systems which intake surface water (often from rivers) and discharge warmer water. Given the significant revenue impact of a 10-15% drop in plant capacity, we conducted a detailed literature review of cooling water risk. Our most important finding is that water risk applies to power plants with once-through cooling systems, whereas closed-loop systems are only vulnerable in the most extreme example of water temperature increase.

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<table>
<thead>
<tr>
<th></th>
<th>Capacity Factor</th>
<th>Anual Generation</th>
<th>Power Price</th>
<th>Spark Spread</th>
<th>Capacity Payments</th>
</tr>
</thead>
<tbody>
<tr>
<td>%, Year 1</td>
<td>65</td>
<td>2,847,000</td>
<td>39.80</td>
<td>17.00</td>
<td>120.00</td>
</tr>
<tr>
<td>MWh, Year 1</td>
<td></td>
<td></td>
<td>USD per MWh, Year 1</td>
<td>USD per MWh, Year 1</td>
<td>USD per MW per day</td>
</tr>
</tbody>
</table>

| CAPEX                | Construction Start Date | 2020 | Start year |
|                      | Construction Length     | 3    | Years      |
|                      | Construction CAPEX      | 1,000,000.00 | USD per MW installed ("all-in") |
|                      | Construction CAPEX      | 500,000,000.00 | USD (total, "all-in") |

| OPEX                 | Fixed O&M             | 11,000.00 | USD per MW per year |
|                      | Fuel Cost & Variable O&M | 22.80     | USD per MWh, Year 1 |
|                      | Property Tax and Insurance | 7,500,000.00 | USD per year |

| Financing            | Debt Tenor            | 15 | Years |
|                      | Interest Rate         | 6.0 | %, Annual |
|                      | Debt to Equity Ratio  | 60/40 | |

Electronic copy available at: https://ssrn.com/abstract=3736415
Additionally, power plants with once-through cooling systems generate ~30% of U.S. electricity (typically older plants), thus water risk is widely applicable [54].

To further explain how a project’s revenue can be affected: a plant curtailment can result if streamflow decreases severely and adequate cooling water is not available. Alternatively, state or municipal regulations on water discharge temperatures (intended to protect marine habitats) can restrict plant operations. In recent years, these water risks have caused temporary curtailments for coal and nuclear plants in the Northeast, Southeast, and Texas, affecting natural gas plants in the future. While intra-year water scarcity is difficult to predict, a consistent year-over-year accumulation of water risk is expected and can cause continued year-over-year decreases in capacity factor [54]. Gradual deterioration of capacity factor and revenue creates significant risk for long-term infrastructure assets, such as project-financed plants, and could potentially affect many more plants than singular extreme weather events. More broadly, water is a known risk for utility companies, which can suffer negative stock market reactions during heat waves and droughts [55].

Increased air temperature can slightly reduce natural gas CCGT plant efficiency, causing an increase in fuel usage [56]. While important to consider, the risk to asset cash flow is minimal because the impact is a less than 3% change in natural gas fuel expense even in 4°C scenarios. However, increases in air and water temperature are likely to be linked, so we have also developed and considered scenarios where these risks are simulated in unison. A natural gas CCGT plant could experience the impact of both plant curtailment (due to water risk) and decreased plant efficiency (due to air temperature). Hence, the compounded effect of these risks is analyzed through the development of a risk scenario that tests for both the capacity factor and fuel usage metrics.

**Acute Extreme Weather Events**

While extreme weather events can suddenly cause plant downtime or repair expense, the projected probability of occurrence for a single plant is still very low, even with a changing climate [53]. We include the increased risk of extreme weather by incrementally increasing insurance premia through the asset’s life. The insurance premia hikes are modeled as 15% per annum increases based on

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8 New U.S. natural gas power plants are usually (or even pervasively) built with closed-loop systems, which is advantageous for long-term resilience.
on an expert interview [57]. We choose not to granularly distinguish plant insurance cost by US region, as the highest risks are not concentrated in a single region but vary, spanning [52]. Forzieri et al. [58] find that damages to infrastructure due to climate change-driven acute weather events could multiply six-fold by mid-century and amount to more than ten times the damage of €3.4 billion per year (in 2018) by the end of the century. While an individual energy asset may be protected by insurance, the insurance industry and broader financial system still bear significant “tail risk,” which is not reflected in our scenario analysis.

**Advancements in Competing Technologies and Changing Markets**

Renewable energy technology advancement and cost reductions have been dramatic since 2010, particularly for utility-scale solar PV and offshore wind [59]. These trends and the continued decrease in energy storage costs are projected to continue [60, 61]. As renewable energy technologies continue to advance, the cost of new-build clean energy portfolios may become cheaper than operating efficient natural gas CCGT by 2025-30 [48]. Despite decades of technology advancement, improvement in techniques, and increases in economies-of-scale, the cost of producing oil, gas, and coal has largely remained flat or increased. This is because the fossil fuel industry continues to extract resources, and it does so from subsurface accumulations that are increasingly deeper, more complex, and lower quality. On the contrary, wind and solar are almost infinite resources. Therefore, industry advancements and economies-of-scale throughout the entire supply chain have actually achieved dramatic reductions in the cost of producing renewable energy.⁹

**Regulatory Risks**

We evaluate the impact of regulatory risks separately from the physical climate-related risks. Policy actions responding to climate change can vary significantly, and separate consideration of these events aims to maximize the flexibility of our scenario analysis methodology. Policy intervention at the international, national, or state levels could take many forms, including carbon

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⁹ A widely cited example is the manufacturing cost reductions for solar PV modules from >$5/W in 2000 to <$0.5/W in 2015 (54). Additionally, offshore wind (which yields higher capacity factors than onshore) and solar energy combined with storage are upending the convention that intermittent renewables will always need ‘baseload’ natural gas plants (55). Renewables have already led to lower capacity factors for fossil fuel power plants, and this trend is expected to continue across almost all independent system operators (ISOs) and regional transmission organizations (RTOs) (56). As more distributed and intermittent resources are incorporated, changing grid dynamics demand flexible operations of fossil fuel plants. A well-known example is California’s ‘duck curve,’ where natural gas plants must ramp-down significantly during sunlight hours due to solar PV output (57).
pricing, renewable portfolio standards, or even mandated CCS on existing fossil fuel plants. Stechow et al. (2011) [62] find that two schemes, a CCS bonus incentive or a carbon dioxide price guarantee, prove to be strong and effective policy instruments for implementing a CCS policy. These policy implementations could be manifested as sudden climate policy “shocks” following significant events, such as future Paris Agreement disclosures, a dramatic scientific discovery (i.e., methane release from permafrost), or U.S. political party power transitions [23]. Regardless of environmental economists' substantive rationality, scientific phenomena such as climate change can drive institutional changes unexpectedly [63].

To maximize applicability across regulatory regimes globally, we chose to represent the impact of policy risk by simulating carbon pricing, utilizing carbon price trajectories aligned with limiting warming 1.5°C or 2°C by Carbon Pricing Leadership Coalition [64]. If a carbon pricing scheme is implemented, the initial market response would likely pass through most of the impact to electricity consumers in the form of higher energy prices. However, there is uncertainty in the long-term market response due to competition from clean energy alternatives and impacts of the price elasticity of electricity demand [65]. One pre-emptive mitigation against carbon price risk is to install CCS facilities on new fossil fuel plants. The added CAPEX and OPEX can be partially offset by the additional revenue generated from selling CO2 (to enhanced oil recovery [EOR] customers or other niche markets) or storing CO2 underground and collecting Section 45Q tax credits (if a U.S. project). We explore the economic viability of installing CCS while also noting that not all locations are conducive to CCS. Although an abundance of total underground CO2 storage capacity exists in the U.S., many states in the Southwest, Atlantic Coast, or Upper Midwest lack capacity [66]. Building long-distance CO2 pipelines are very capital intensive. Thus, fossil fuel plants that are not close to carbon storage capacity are exposed to higher risk from potential carbon pricing unless large-scale economic CO2 re-use technologies are commercialized [67].

<table>
<thead>
<tr>
<th>Risk Category</th>
<th>Risk Factor</th>
<th>Risk Assumption</th>
<th>Type of Estimate</th>
<th>Reference</th>
</tr>
</thead>
<tbody>
<tr>
<td>Physical</td>
<td>Chronic</td>
<td>Water scarcity limits available cooling water forces a natural gas CCGT to curtail production capacity and decrease the capacity factor. We assume a plant’s capacity factor drops by 1.5% p.a. when water scarcity risk is present.</td>
<td>binary</td>
<td>Henry &amp; Pratson (2019) [54]</td>
</tr>
<tr>
<td>Risk Factor</td>
<td>Description</td>
<td>Categorization</td>
<td>Reference</td>
<td></td>
</tr>
<tr>
<td>---------------------</td>
<td>-------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------</td>
<td>-------------------------</td>
<td>------------------------------------------------</td>
<td></td>
</tr>
<tr>
<td>Air temperature</td>
<td>Higher air temperature decreases the efficiency of a natural gas CCGT, which increases fuel usage. We assume a plant’s fuel usage increases by 0.15%, 0.10%, and 0.08% p.a. when air temperature risk is high, medium, and low, respectively.</td>
<td>categorical (high/medium/low)</td>
<td>Ibrahim &amp; Rahman (2013) [56]</td>
<td></td>
</tr>
<tr>
<td>Acute extreme weather</td>
<td>The prevalence of acute extreme weather events results in a continued increase in plant insurance costs and premia beyond normal inflation rates or historical norms. We assume a plant pays incrementally increasing insurance premia by 15%, 10%, and 5% p.a. when extreme weather risk is high, medium, and low, respectively.</td>
<td>categorical (high/medium/low)</td>
<td>Hempel (2018) [57]</td>
<td></td>
</tr>
<tr>
<td>Market</td>
<td>Renewable energy cost reductions at a faster-than-expected rate result in lower energy market prices due to the auction-based competitive bidding mechanism of wholesale energy markets and the ability of renewable energy generators to submit low bids. We assume that the lower wholesale energy prices will translate into lower sales revenue for the CCGT plant because of its merchant energy sales mechanism. We assume the electricity sales price as $35, $40, and $42 per MWh flat after 2030 when the market risk due to competitive renewables is high, medium, and low, respectively.</td>
<td>categorical (high/medium/low)</td>
<td>Dyson, et al. (2018) [48]</td>
<td></td>
</tr>
<tr>
<td>Transition</td>
<td>We assume impacts of implementation of carbon pricing regulations, utilizing carbon price trajectories aligned with Paris Agreement temperature objectives (limiting temperature rise by limiting warming 1.5°C or 2°C) conducted by Carbon Pricing Leadership Coalition. If a carbon pricing scheme is implemented, the initial market response would likely pass through most of the impact to electricity consumers in the form of higher energy prices. The high and low-risk scenarios are represented as a 25% and 50% cost pass-through to consumers, respectively.</td>
<td>categorical (high/low)</td>
<td>Stiglitz, et al. (2017) [64]</td>
<td></td>
</tr>
<tr>
<td>Regulatory</td>
<td>We assume impacts of implementation of mandated CCS due to policy intervention. Firstly, CCS operation may reduce plant efficiency due to parasitic losses and decreases capacity factor. Also, CCS installation and operation can increase CAPEX and OPEX. CAPEX requirements can vary to account for the uncertainty in the upfront costs incurred. Since these impacts are likely to co-occur, we consider 5% capacity factor loss, $15/ton variable O&amp;M cost increase, and $200 million or $400 million CAPEX increase in a combined manner. As noted, CAPEX increase varies between $200 million and $400 million in low and high-risk scenarios.</td>
<td>categorical (high/low)</td>
<td>Rogers (2018) [68]</td>
<td></td>
</tr>
</tbody>
</table>

The table provides descriptions of selected risk factors. Types (physical and transition) of climate-related risks and their sub-categories (e.g., chronic and acute physical risks, market risks, regulatory risks) are based on TCFD guidelines. The table shows a selective list of climate-related risk factors that we assume to be relevant to the natural gas CCGT plant in the PJM power pool case. The selection of risk factors is from the literature review. We note that it is not exhaustive, acknowledging the list can be extended as we add more risk considerations. We also note that the selected risk factors are not mutually exclusive, and some overlap can exist.

### 4.2.2 Scenario Building

Our baseline ‘no-risk’ scenario is described in Table 1, using CAPEX, OPEX, and power price assumptions representative of current conditions in PJM territory. The baseline scenario projects
an after-tax equity IRR of 14% and a DSCR greater than 2.0x during the project’s debt term, which are in the acceptable ranges that average market investors see the project as “bankable.” The assessment of DSCR is relatively straightforward as it is a covenant to keep the minimum DSCR of 1 or higher (otherwise, a project goes default). Whereas IRR range has a greater spread, and its assessment can be subject to individual investors’ risk-return expectations. We assume that a 14% IRR is in line with or superior to other typical equity investments in infrastructure. Given the lower risk levels associated with infrastructure assets, which are characterized by steady and contracted cash flows, monopolistic market conditions, as well as barriers to entry due to their capital-intensive nature, the expected equity returns for infrastructure are lower when compared with other asset classes. As outlined in Spohr. et al. (2021) [69], previous studies on infrastructure investment returns have found that listed and unlisted infrastructure funds attain IRRs that range from 5.5% to 20%, rendering the baseline scenario for our case study in line with average infrastructure returns.

To evaluate the potential impact of climate risks, we created 12 climate risk scenarios that test a single risk factor or a combination of multiple risks, summarized in Table 3. The physical, technology, and regulatory risk severity levels leverage environmental science and energy market research described in Section 4.2.1.

Table 3. Selected Climate-related Risk Scenarios

<table>
<thead>
<tr>
<th>Scenario Label</th>
<th>Risk Factor(s) Considered</th>
<th>Risk Level</th>
<th>Estimated Impacts on a Project Cash Flow</th>
</tr>
</thead>
<tbody>
<tr>
<td>(a)</td>
<td>Water scarcity</td>
<td>High</td>
<td>- -1.5% p.a. capacity factor</td>
</tr>
<tr>
<td>(b)</td>
<td>Air temperature</td>
<td>High</td>
<td>- +0.15% p.a. fuel usage</td>
</tr>
<tr>
<td>(c)</td>
<td>Extreme weather</td>
<td>High</td>
<td>- +15% p.a. insurance premium</td>
</tr>
<tr>
<td>(d)</td>
<td>Low-cost renewables</td>
<td>High</td>
<td>- $35/MWh flat 2030+ electricity sales price</td>
</tr>
</tbody>
</table>
| (e)-1          | Combined: water scarcity, air temperature, extreme weather, low-cost renewables | 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 |
| (e)-2          | Combined: air temperature, extreme weather, low-cost renewables | High | - +0.15% p.a. fuel usage  
- +15% p.a. insurance premium  
- $35/MWh flat 2030+ electricity sales price |
<table>
<thead>
<tr>
<th></th>
<th>Risk Factor Description</th>
<th>Probability</th>
<th>Impact Description</th>
</tr>
</thead>
</table>
| (e)-3 | Combined: air temperature, extreme weather, low-cost renewables | Medium      | - +0.10% p.a. fuel usage  
- +10% p.a. insurance premium  
- $40/MWh flat 2030+ electricity sales price |
| (e)-4 | Combined: air temperature, extreme weather, low-cost renewables | Low         | - +0.08% p.a. fuel usage  
- +5% p.a. insurance premium  
- $42/MWh flat 2030+ electricity sales price |
| (f)-1 | Carbon Pricing                                               | High        | - $30/ton carbon price starting 2025  
- Electricity sale price increases to absorb 25% of carbon price |
| (f)-2 | Carbon Pricing                                               | Low         | - $30/ton carbon price starting 2025  
- Electricity sale price increases to absorb 50% of carbon price |
| (g)-1 | CCS Mandates                                                 | Low         | - $200mm CapEx and $15/ton variable O&M  
- -5% Capacity factor due to parasitic losses |
| (g)-2 | CCS Mandates                                                 | High        | - $400mm CapEx and $15/ton variable O&M  
- -5% Capacity factor due to parasitic losses |

The table provides descriptions of the twelve selected climate-related risk scenarios. Scenarios (a)-(d), (f)-1, 2, and (g)-1,2 simulate single risk factors while scenarios (e)-1, 2, 3, 4 simulate combined risk factors.

Water scarcity assumptions are based on Henry & Pratson (2019) [54] in which the ‘high risk’ scenario is based on a natural gas power plant with an open-loop cooling water system. However, we observe that more modern plants typically employ closed-loop cooling water systems, and we consider these assets to have low-or-no water scarcity risk. This indicates that water scarcity risk potentially has a binary characteristic, based on the plant design, which is why we chose to model water scarcity risk in only two scenarios (see scenarios (a) Water Scarcity – High Risk and (e)-1 All Factors – High Risk in Table 2). Air temperature increase assumptions are based on the World Resources Institute’s research, and the resulting impact on natural gas turbine efficiency is based on Ibrahim & Rahman (2013) [56]. Projected renewable energy cost reductions are based on Rocky Mountain Institute research (2018) [48], and we have developed High, Medium, and Low risk scenarios to account for the uncertainty and variability in future wholesale electricity prices. Our regulatory risk scenarios assume carbon pricing consistent with meeting the IPCC’s <2°C target, which is published by the Carbon Pricing Corridors Initiative and the Potsdam Institute for Climate Impact Research.

Existing asset-level climate risk research often focuses on the detailed analysis of a single risk factor’s frequency, likelihood, and impact. However, we find that it is critical to develop risk scenarios applicable to the asset and collectively simulate multiple risk factors to illustrate a more realistic outcome for debt and equity investors. Thus, we have aggregated High, Medium, and Low-risk scenarios that combine all physical and technological risks. One limitation of our
approach is that there are several potential combinations of scenarios for how multiple physical and technological risks can manifest at differing severity levels. Hence, instead of running every single scenario combining the different risk metrics, we propose developing High, Medium, and Low risk scenarios that reflect these risks in an aggregated manner (see scenarios (e) in Table 3).

**Risk Impacts on Revenue**

For a natural gas CCGT, decreased revenue could result from a capacity factor drop (e.g., generating less units of power to sell) or a decrease in the electricity sale price. The risk factors that could affect revenue are:

- Water scarcity limits available cooling water, forces a natural gas CCGT to curtail production capacity, and decreases the capacity factor
- Renewable energy cost reductions result in lower energy market price, due to the auction-based competitive bidding mechanism of wholesale energy markets and the ability of renewable energy generators to submit low bids
- Implementation of a mandated CCS facility reduces plant efficiency due to parasitic losses and decreases capacity factor

**Risk Impacts on Expenses**

For a natural gas CCGT, increased expenses could result from a change in fixed O&M costs (e.g., plant insurance) or variable O&M costs (e.g., fuel usage or carbon price). Additionally, installing CCS facilities (in response to policy action or pre-emptively) has specific impacts, such as added fuel usage and electricity consumption (for the solvent-based capture unit) and additional fixed O&M costs to operate the CCS equipment. The risk factors that can affect expenses are:

- Higher air temperature decreases the efficiency of a natural gas CCGT, which increases fuel usage
- The prevalence of acute extreme weather events results in a continued increase in plant insurance costs and premia beyond normal inflation rates or historical norms
- Implementation of a carbon price or mandated CCS due to a policy intervention results in a carbon price expense, or increases in fixed and variable O&M costs due to the mandatory CCS facility
- Implementation of a mandated CCS facility creates significant CAPEX requirements, which were varied to account for the uncertainty in the upfront costs incurred
For our scenario analysis, we have not varied the upfront CAPEX assumptions, except for the scenario of installing CCS, which incurs both additional CAPEX and OPEX. While climate risk factors are likely to affect CAPEX requirements for future energy projects, we did not see an obvious pathway directly impacting upfront CAPEX during the natural gas CCGT’s 2020-2022 construction period (except for acute weather events, which are likely covered by insurance).

4.3 Results and Discussion

Table 4 provides a summary result from our scenario analysis, which includes the assessment of default, EOD, and IRR under the twelve selected scenarios. EOD is defined as the DSCR metric dropping below 1.0x, which indicates that the CFADS generated in an interest period is less than the total debt service due, such that all the debt obligations are not met. We acknowledge that project financing structures and credit agreements may set the default threshold to a DSCR limit much higher than 1.0x by having debt covenants that state minimum DSCR should be 1.5x or even 2.0x. These limits depend on the risk assessment of a project, and credit agreements may have cash sweep provisions or DSRA requirements to mitigate risks to debt investors. To show an absolute default case in which CFADS is less than the total debt service in a certain period, we have taken the default threshold to be 1.0x. We note that the projection of DSCR and IRR can provide quantitative information that can help examine a project’s bankability (e.g., if DSCR goes below 1, it means that the project is likely to be unable to repay at the period). But we do not determine whether the project is worthwhile to invest in and instead defer it to users of the framework to set their own threshold and decide. The DSCR covenants lenders impose on projects are highly dependent on the overall risk levels of the project. For instance, a lender that wants to set a more conservative threshold can require that the project keeps its DSCR over 1.5 in all pay periods. The framework’s outputs can help users structure the infrastructure’s financing as per their unique risk preference. The user-based threshold is also applicable to set IRR threshold: users can refer to benchmark projects to set the target IRR. In this regard, we acknowledge in advance that the levels of DSCR and IRR we use in our case study are arbitrary.

Table 4. Scenario Analysis Findings: Assessment of Default and Event of Default(s)

<table>
<thead>
<tr>
<th>Scenario Label</th>
<th>Risk Factor(s) Considered</th>
<th>Risk Level</th>
<th>Default (DSCR&lt;1)</th>
<th>Event of Default* (DSCR&lt;1.5)</th>
<th>IRR</th>
</tr>
</thead>
<tbody>
<tr>
<td>(a)</td>
<td>Water scarcity</td>
<td>High</td>
<td>-</td>
<td>-</td>
<td>10%</td>
</tr>
<tr>
<td></td>
<td>Air temperature</td>
<td>High</td>
<td>-</td>
<td>-</td>
<td>13%</td>
</tr>
<tr>
<td>---</td>
<td>-----------------</td>
<td>------</td>
<td>---</td>
<td>---</td>
<td>-----</td>
</tr>
<tr>
<td>(c)</td>
<td>Extreme weather</td>
<td>High</td>
<td>-</td>
<td>-</td>
<td>12%</td>
</tr>
<tr>
<td>(d)</td>
<td>Low-cost renewables</td>
<td>High</td>
<td>⬤</td>
<td>⬤</td>
<td>1%</td>
</tr>
<tr>
<td>(e)-1</td>
<td>Combined: water scarcity, air temperature, extreme weather, low-cost renewables</td>
<td>High</td>
<td>⬤</td>
<td>⬤</td>
<td>Negative</td>
</tr>
<tr>
<td>(e)-2</td>
<td>Combined: air temperature, extreme weather, low-cost renewables</td>
<td>High</td>
<td>⬤</td>
<td>⬤</td>
<td>Negative</td>
</tr>
<tr>
<td>(e)-3</td>
<td>Combined: air temperature, extreme weather, low-cost renewables</td>
<td>Medium</td>
<td>-</td>
<td>⬤</td>
<td>5%</td>
</tr>
<tr>
<td>(e)-4</td>
<td>Combined: air temperature, extreme weather, low-cost renewables</td>
<td>Low</td>
<td>-</td>
<td>⬤</td>
<td>8%</td>
</tr>
<tr>
<td>(f)-1</td>
<td>Carbon Pricing</td>
<td>High</td>
<td>⬤</td>
<td>⬤</td>
<td>Negative</td>
</tr>
<tr>
<td>(f)-2</td>
<td>Carbon Pricing</td>
<td>Low</td>
<td>⬤</td>
<td>⬤</td>
<td>1%</td>
</tr>
<tr>
<td>(g)-1</td>
<td>CCS Mandates</td>
<td>Low</td>
<td>-</td>
<td>-</td>
<td>10%</td>
</tr>
<tr>
<td>(g)-2</td>
<td>CCS Mandates</td>
<td>High</td>
<td>-</td>
<td>-</td>
<td>4%</td>
</tr>
</tbody>
</table>

The table summarizes our findings from simulating the twelve selected climate-related risk scenarios. We project each scenario assessing whether they can repay the due principal and interest on time at each pay period (i.e., DSCR is above 1). If the asset goes default, we mark it as “⬤” and note the year of default. Otherwise, we mark it as “-”, meaning that the project is expected to generate sufficient cash flow throughout the contracted period. In addition, we also assess the event of default (EOD), whose threshold entirely depends on the terms and conditions of the asset’s financial contract. We set 1.5 as DSCR covenants to experiment. We note that the threshold is up to the user. For instance, a user wants to set a more conservative threshold that the project should keep its DSCR over 1.5 or higher in all pay periods. We also project the project’s IRR under each scenario, which is more of equity investors’ concern. We do not set any threshold to test whether the project generates sufficient IRR because the level of acceptable IRR varies by investors.

When we perform a scenario analysis by applying each physical and technological risk in isolation, we find that risk of default is possible due to competition from renewable energy. As shown in Figure 3, the default risk due to high renewable energy penetration only materializes after 2034, representing a reduced risk for existing natural gas plants or plants constructed in the next few years (such as our asset example). However, this also means that natural gas plants may not be a resilient investment as a “transition fuel” beyond the near-term. Furthermore, this default event occurs because of the merchant basis of the energy sales and the lack of a PPA ensuring a
defined offtake price over a substantial period of time, exposing the natural gas plant to any downside risk in wholesale market prices. It may be risky to construct new natural gas plants past 2025 due to competition from renewable energy, which will likely ‘cap’ wholesale energy market prices and decrease revenues for natural gas plants. Given the ‘Rush to Gas’ in PJM and ERCOT, it appears that project developers do not appreciate the energy price and revenue downsides [48]. One regulatory or market response could be an increase in fixed payments for capacity. However, such a change likely favors natural gas ‘peaker’ plants (rather than CCGT) due to their ability to quickly ramp up power generation, which has lower upfront CAPEX and less-efficient designs.

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Figure 3 DSCR Under High Severity Risks, Evaluated in Isolation

If we apply the physical and technology risks collectively, we observe that the scenarios are significantly more detrimental with default risk as early as 2030 in the All Factors – High Risk scenario (see Figure 4). The ability to develop tailored scenarios that aggregate different risk factors and make these observations, as shown in Figure 4, is a significant contribution of this framework. An analysis of collective risk impact through time is an effective tool to visualize and assess climate risk, and the gradual accumulation of climate risk can turn an attractive 14% Levered IRR investment into a distressed asset in less than 10 years. Additionally, although the aggregated Medium and Low scenarios may not represent an absolute default risk or a breach of
1.0x IRR, they would result in significant underperformance for equity investors. We also note that once default risk materializes (e.g., DSCR<1.0x), it is unlikely that an asset will be able to recover and improve cash-flow to continue making debt service payments. This persistent cash flow shortfall is likely to increase in severity due to a combination of lower revenues and increasing expenses.

Figure 4 DSCR Under Collective Risks, Evaluated in Varying Severity Levels

In the realm of regulatory risk, implementing a carbon pricing scheme is potential adversity for fossil fuel plants (see Figure 5). Within this risk scenario, it is unknown how much of the carbon price will be “pass-through” to customers in the form of higher electricity prices and how long this will be sustained. In a moderate carbon price environment (e.g., <2°C scenario, $30/ton starting in 2025), our results show that at least 50% pass-through is required through the entire 15-year debt term to maintain solvency for our natural gas CCGT plant case study. To maintain a portion of carbon price pass-through, power prices must continually escalate as carbon price increases. For our <2°C scenario carbon pricing, this means an electricity price of >$70/MWh is required in 2037 to support a 50% carbon price pass-through. However, the competition on the grid (a clean energy portfolio of wind, solar, energy storage, and demand response technologies) will continue to drive cost reductions due to the economies-of-scale and learning curve effects.
discussed in Section 4.1. Thus, it is difficult to imagine that an electricity price of >$70/MWh will be sustained in the wholesale markets, given projected cost declines for a portfolio of clean energy technologies on the grid, where renewable sources will be able to bid into the markets in a cost-competitive manner [48]. Figure 5 shows the impacts of carbon price risk on the project DSCR levels at varying levels of market pass-through.

Figure 5 DSCR Under Carbon Price Risk, Evaluated in Varying Market Absorption Levels

To mitigate carbon price risk exposure, project developers could choose to build natural gas CCGT plants with CCS pre-emptively, thereby mitigating the project's CO2 emissions. Given that few such plants have been built, the incremental CAPEX associated with CCS is uncertain, where installation cost is the main factor in determining whether pre-emptive CCS is economically viable given the current technology level and financial incentives (e.g., Section 45Q tax credits). While section 45Q tax credits provide additional “revenue” to support a larger project finance loan, most of the CCS CAPEX would need to be funded by equity to maintain a DSCR greater than 2.0x. Section 45Q tax credits can be considered “revenue” if a parent company that can monetize tax credits through a taxable income base buys the credits via a “tax sharing agreement” with a subsidiary. Therefore, the exchange of tax credits in return for revenue in cash form can enable a
larger project finance loan. However, if a tax equity investor monetizes the Section 45Q tax credits, it may provide upfront financing to cover project development costs, but in this case, it is unlikely that these credits could be considered additional “revenue” to support a larger project finance loan. To model the viability of the scenario where the project owner pre-emptively installs CCS to mitigate carbon price risk exposure, we need to compare this scenario on an apples-to-apples basis with other scenarios where the capital structure only consists of debt and equity investors. Hence, it is appropriate to model a similar capital structure without a tax equity investor, with a revenue-for-tax-credit exchange structure with a parent company. Our results show that if the low-end of CCS CAPEX can be delivered (e.g., $200mm CAPEX to store 1 million tons CO\(_2\) per year), then a 10% IRR is possible. While this IRR is lower than our “no risk” baseline scenario (14% IRR), a 10% IRR investment may still pass an infrastructure investor’s “hurdle rate.” However, if CCS CAPEX doubles to $400mm, the levered IRR is estimated to be 4%, indicating that the project becomes an unattractive investment even under base case projections.

When considering the results of all the climate risk scenario analysis performed for our natural gas case study, it becomes clear that technological and regulatory risk factors pose greater threats to the investment than physical risk factors. There are two noteworthy trends and associated risks that can adversely impact investments in existing natural gas assets or influence future plant investment. Firstly, renewable energy technologies, particularly solar PV, onshore wind, and offshore wind, continue to deliver cost reductions, which will increase competition and can reduce or cap wholesale energy market prices. Lower energy prices directly impact natural gas CCGT revenues and particularly threaten plants with merchant revenue models. Secondly, implementation of carbon pricing resulting from regulatory action can quickly shrink equity returns and increase default risk for debt investors, even if wholesale energy market prices increase to reflect a “pass-through” of the costs to customers. New natural gas plants can mitigate exposure to this regulatory carbon pricing risk by pre-emptively installing CCS to minimize carbon emissions. If CCS can be constructed efficiently (e.g., $200m for 1 million tons CO\(_2\) per year), the equity IRR is still robust enough to attract investment, especially considering the diminished risk level and increased resilience of the asset. However, if the required CCS CAPEX is higher, CCS facilities become a difficult investment proposition.

Through the consideration of various climate risks with various severity levels, evaluated both in isolation and collectively, we have assessed the climate-related resilience of a natural gas CCGT
power plant. Our framework allows for the analysis of the performance of debt and equity investments in energy infrastructure projects through actionable metrics such as DSCR and equity IRR. This case study demonstrates the holistic range of climate-related risks that can be considered and evaluated using this framework and the ability to tailor the risk scenarios based on climate science literature and the user’s perspective on which operational and financial inputs are more exposed to different risks. By combining a scenario analysis framework with a climate and environmental science approach, the users of this methodology can evaluate the resilience of their investments to climate-related risks that are likely to impact the energy infrastructure project over its multi-decade investment horizon.

5 Conclusion
Climate change, rapid technological change, and market and regulation shifts toward a low-carbon economy pose challenges and open new opportunities for asset owners and operators of long-term infrastructure assets. The energy industry, a dominant sector within the long-term infrastructure category, has already experienced the direct and indirect impacts of climate change on the value of investment portfolios. Given the complexity of financial contracts used to support energy assets and the growing impact of climate change on asset performance, a new approach to climate risk analysis should be at a more granular, asset-level to enable investors to select energy projects and price risks based on the specific climate resilience. Thus, this study presents an integrated climate-related risk assessment framework that can support asset owners and managers in assessing and managing climate-related financial risks of energy assets. We use cash flow modeling and scenario analysis methodologies to estimate the selected asset’s financial default risks under multiple climate-related risk scenarios. Through this new approach, we are not only able to estimate a lumpsum probability of default (or the total value of an asset) but also be able to assess the size and time of the losses by the given default. As mentioned, this study is the first of the research series that price climate-related risks at an asset level. While this study presents the framework design, the subsequent study, In et al. (2021) [25], provide an in-depth, comparative case study to demonstrate how to apply the framework and to compare risks and opportunities across different energy assets.

The unique value of this methodology is that it demonstrates methods to apply climate-related risks generated from existing climate risk assessment models. Moreover, it assesses how
the climate-related risks would affect the selected asset’s financial resilience, especially in the form and through metrics that can be directly usable by investors. Data on the potential timing, magnitude, and frequency of these climate-driven risks will allow asset owners and managers to invest in and develop infrastructure that is resilient in terms of multiple climate metrics. For example, asset owners may seek to estimate the required investment to make their corporate campuses, data centers, and R&D facilities more resilient to flood risks and weather events. They can choose to evaluate metrics such as optimal levels of insurance purchase and energy-efficiency features to incorporate. The industry needs a climate risk assessment tool that can assess the climate resiliency of infrastructure assets in a financial value. We thus assess the performance of infrastructure assets at the cash flow level, making granular estimates of the timing and magnitude of risks borne by the changing climate. This information provides immediate, actionable data to managers on the financial benefits of designing and building climate-resilient infrastructure.

The goal of this study is to introduce a new methodology that can provide the link between environmental and socioeconomic data and an energy infrastructure asset’s financial value, using cash flow parameters to translate the data into financial implications. In other words, we do not analyse the actual project or portfolios: this is mainly due to the lack of data availability and access. For instance, asset-level (or regional) climate data has been extremely challenging to obtain – yet recently, advanced technologies are contributing to improving this data availability. Also, financing terms and conditions of individual energy assets and projects are proprietary and thus kept as private. While some level of data is being provided on public platforms, this methodology requires is higher level of granularity (for instance, leverage, margin, tenor and other special financing conditions). We discuss how future research can use more asset-level data, which can be leveraged to empirically validate this proposed methodology.

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