Current and Future Costs of Renewable Energy Project Finance Across Technologies

David Feldman,[1] Mark Bolinger,[2] and Paul Schwabe[1]

1 National Renewable Energy Laboratory
2 Lawrence Berkeley National Laboratory

NREL is a national laboratory of the U.S. Department of Energy
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List of Acronyms

ATB	Annual Technology Baseline
BNEF	BloombergNEF
CSP	concentrating solar power
DOE	U.S. Department of Energy
DSCR	debt service coverage ratio
EEI	Edison Electric Institute
EIA	US. Energy Information Administration
FRED	Federal Reserve Economic Data
GW	gigawatt
IOU	investor-owned utility
IPP	independent power producer
IRR	internal rate of return
ITC	investment tax credit
LADWP	Department of Water and Power
LCOE	levelized cost of electricity
LIBOR	London Inter-Bank Offered Rate
MACRS	modified accelerated cost recovery system
NREL	National Renewable Energy Laboratory
OPPD	Omaha Public Power District
POU	publicly owned utility
PPA	power purchase agreement
PSEG	Public Service Enterprise Group
PTC	production tax credit
ROE	return on equity
RoR	rate of return
SoBRA	Solar Rate Base Adjustment
SMUD	Sacramento Municipal Utility District
SOFR	Secured Overnight Financing Rate
WACC	weighted average cost of capital

Executive Summary

This report documents a consistent set of technology-specific U.S. financing cost benchmarks for renewable and conventional energy technologies. The benchmarks are intended for use in the National Renewable Energy Laboratory's Annual Technology Baseline (ATB), a cross-technology modeling and analysis framework of current and projected future cost of electric generation and storage technologies.[1] Renewable energy technologies covered in the ATB include land-based wind, offshore wind, utility-scale solar photovoltaic (PV), distributed PV, concentrating solar power (CSP), geothermal, and hydropower; conventional technologies covered include natural gas, coal, nuclear, and biopower.[2] Because ATB develops independent projections of the change in renewable energy costs and characteristics of new generating assets over time—while relying on other sources for conventional electric generation technologies—we focus our analysis reported here primarily on these renewable energy technologies, estimating both current and future financing costs to 2030. We also benchmark financing costs for new natural gas generation facilities, as they represent the vast majority of all recently installed conventional electricity generation.[3] In all cases, the goal is to portray consistent, representative financial transactions and financing terms.

While there is a wide variety of financial ownership structures and individual project characteristics for U.S. electric generation assets, we benchmark current finance costs for assets owned by independent power producers (IPPs) because this ownership status represents most new electric generation assets in the United States, particularly for renewable energy plants. IPPs use tax equity arrangements as the primary financial arrangement for most U.S. renewable energy assets, without the need for external financial partnerships. We benchmark IPPs primarily to simplify the complexity of formulating a common set of financial assumptions for a variety of technologies over time and to reflect that federal renewable tax credits are phasing down over the next few years.[4] We also estimate future changes to finance costs from the planned expiration of tax credits and a likely increase in interest rates from current historical lows, as both are assessed to be fairly certain and easy to quantify. Lastly, we benchmark financial costs for renewable energy assets assuming these projects sell their electricity through long-term power contracts, or

[1] The financing cost benchmarks are used in ATB to calculate levelized cost of energy for each technology over time and can be more generally used in other analyses that require current or future financing inputs for various technologies.
[2] While biopower can be considered a renewable energy technology, NREL does not perform research in that area; biopower is treated in the ATB similar to conventional electric generation technologies.
[3] Feldman and Margolis (2020) report that from 2010 to 2019, 79% of conventional U.S. electric generation technology capacity additions (including biomass) were natural gas facilities.
[4] Other reasons for not modeling tax equity transactions include that not all owners of electric generating assets enter into tax equity arrangements, and that far fewer will do so in the future given the current phasedown of federal tax credits. In addition, despite tax equity having a relatively low internal rate of return (IRR) of 6%–8% according to Norton Rose Fulbright (2020a) compared to the cost of equity estimated in this report ranging from 7.5% to 10%, the costs and complexity of tax equity transactions make them more inefficient and also mask the transparency required for cross-technology comparisons over time, given different emphasis on different metrics. For example, a tax equity provider may be more interested in its return on investment (ROI)—that is, the total amount of return it receives in excess of its initial investment, regardless of time—than its rate of return (RoR) or internal rate of return (IRR; i.e., the annualized return of an investment over a period of time). For example, investors in a solar project may receive a considerable portion of their initial investment back in the first year in the form of tax credits and depreciation expense benefits, and nearly all their return in the first five years of an investment, so that the IRR does not properly convey the amount of money made on a transaction to the same degree as ROI.

power purchase agreements (PPAs); IPP financing structures in the United States are currently based primarily on projects obtaining these contracts before receiving construction funding. Natural gas plants are typically not able to obtain contracts of such a long duration, and so we benchmark natural gas plants assuming quasi-merchant electricity sales. However, there are many other factors that could affect financing costs that are less certain to occur and are more difficult to quantify in terms of their impact; we discuss these additional factors in the report, but we do not incorporate them into future estimates of financing costs.

We collect data from a variety of sources that have exposure to different renewable and conventional energy technology financings, both in the United States and abroad. Sources include confidential industry interviews with renewable energy project developers, owners, financiers, consultant, and analysts; IPP public filings; public and privately reported project-level financial data; and government-reported interest-rate data. The vast majority of all research was performed before the novel coronavirus pandemic and therefore the benchmarks do not capture any change, now or in the future, caused by it. Table ES-1 (next page) summarizes the identified financial assumptions by technology during a project's operation for an IPP-owned electric generation asset, incorporating our current benchmarks with future changes in financing costs discussed above. The electricity sales are categorized as power purchase agreements (PPAs) or quasi-merchant.

We combine these assumptions[5] with the 2020 ATB project cost, operation and maintenance cost, capacity factor, tax rate, and lifetime assumptions and calculate a projected weighted average cost of capital (WACC) for the different technologies, as summarized in Figure ES-1 (page viii).[6]

Under these assumptions, the initial financing term WACC on technologies with tax credits decreases as these credits phase out. The after-tax benefit that tax credits provide will—all else being equal—be replaced by a greater amount of cash revenue (e.g., via higher PPA prices), which in turn will allow greater leverage. And because debt is typically less costly than equity, this shift in capital structure toward more debt will lower overall financing costs (i.e., WACC), thereby partially mitigating the loss of tax benefits. WACC subsequently increases from 2025 to 2030 as interest rates rise. We project an increase consistent with the Congressional Budget Office (CBO) estimate of the increase in 10-year Treasury bond yields from 2019 (2.1%) to 2030 (3.1%, or a 100 basis point increase) in all-in construction and term debt interest rates by 2030 (CBO 2020). WACC also varies by technology; we estimate that solar PV and wind electricity generation assets have lower cost of capital, owing to lower equity return expectations and higher leverage. It is also important to keep in mind that while financing costs can vary by technology, they currently also vary greatly (1) by project ownership (independent power producer versus investor-owned utility versus publicly owned utility) and (2) based on the individual characteristics of a project, its owner, and when and where it is built.

[5] We choose 2025 as the starting point for the interest rate increase to simplify calculations and assumptions, given that 2025 is when all tax credits will have expired or reverted to their lower value. This is a reasonable assumption given the recent announcement that the Federal Reserve plans to keep interest rates near zero through 2022 (Timiraos 2020).

[6] The 2020 ATB also has cases that reflect no consideration of tax credits and no change in interest rate. For these cases, we ran separate leverage calculations, but input the same cost of equity and debt.

Table ES-1. Summary of Current and Future Financial Assumptions by Technology

		Construction			Operation		
Technology	**Electricity Sales**	**After-Tax Levered Equity Returns**	**Debt Interest Rate: 2018/2030**	**Leverage (i.e. debt fraction)**	**After-Tax Levered Equity Returns**	**18-Year Term Debt Interest Rate: 2018/2030**	**Leverage: 2018/2030**
land-based wind	power purchase agreement (PPA)	11.0%	4.0%/5.0%	80%	9.0%	4.0%/5.0%	32%/66%
offshore wind	PPA	12.0%	4.0%/5.0%	80%	10.0%	4.0%/5.0%	48%/67%
utility PV	PPA	9.75%	4.0%/5.0%	80%	7.75%	4.0%/5.0%	52%/65%
residential and commercial PV	PPA	10.75%	4.0%/5.0%	80%	8.75%	4.0%/5.0%	54%/67%
CSP	PPA	12.0%	4.0%/5.0%	80%	10.0%	4.0%/5.0%	46%/58%
geothermal	PPA	pre-drilling: 15.0% post-drilling: 10.0%	4.0%/5.0%	pre-drilling: 0% post-drilling: 75%	10.0%	4.0%/5.0%	58%/59%
hydropower	PPA	12.0%	4.0%/5.0%	80%	10.0%	4.0%/5.0%	65%/70%
natural gas	quasi-merchant	12.0%	5.0%/6.0%	80%	10.0%	5.0%/6.0%	73%

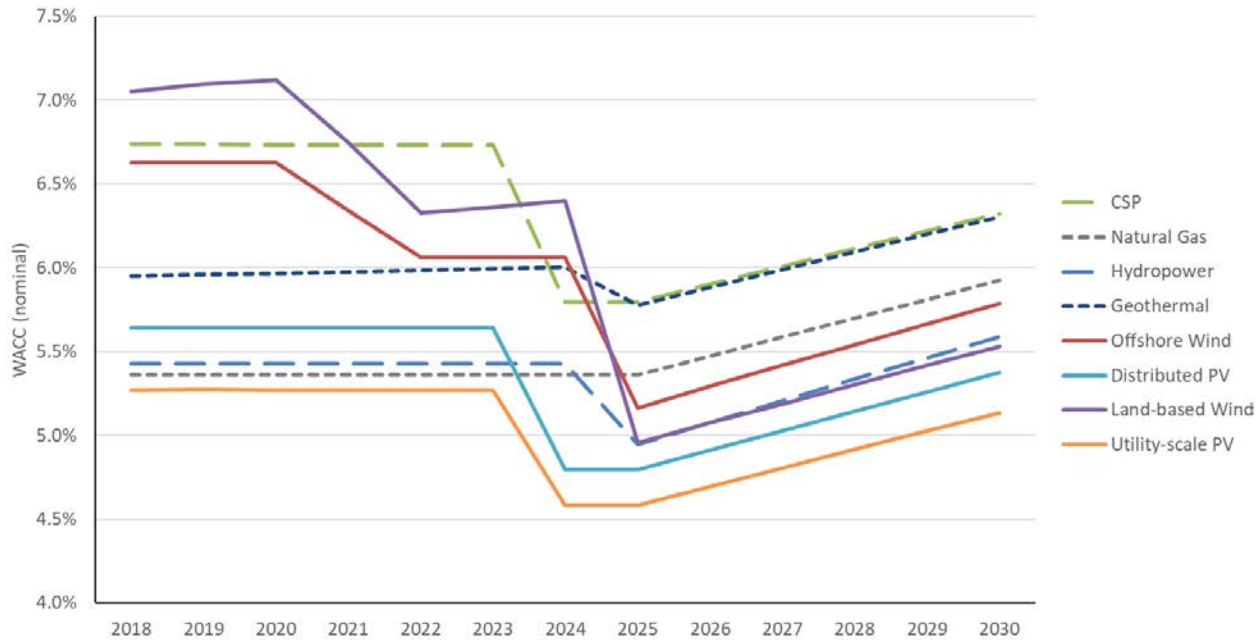

Figure ES-1. WACC of different technologies, 2018–2030

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1 Introduction

The purpose of the analysis reported here is to develop a consistent set of technology-specific U.S. financing cost benchmarks for the renewable and conventional energy technologies. The benchmarks are intended for use in the National Renewable Energy Laboratory's (NREL's) Annual Technology Baseline (ATB),[7] a cross-technology modeling and analysis framework of current and projected future cost of electric generation and storage technologies.[8] Renewable energy technologies covered in the ATB include land-based wind, offshore wind, utility-scale solar photovoltaic (PV), distributed PV, concentrating solar power (CSP), geothermal, and hydropower; conventional technologies in the ATB include natural gas, coal, nuclear, and biopower. [9] Because the ATB's develops independent projections of the change in renewable energy costs and characteristics of new generating assets over time—while relying on other sources for conventional electric generation technologies—we focus our analysis primarily on these renewable energy technologies, estimating both current and future financing costs to 2030.

We also benchmark financing costs for new natural gas generation facilities, as they represent the vast majority of all recently installed conventional electricity generation.[10] In all cases, the goal is to portray consistent, representative financial transactions and financing terms.

Various factors influence the financial costs associated with building, owning, and operating an energy asset. Key factors include the amount of risk associated with achieving the investor's desired rate of return, the level of marketplace competition for available projects and sources of capital (i.e., the balance of supply and demand),[11] and, to a lesser extent, the time and effort required to arrange a financial transaction. Each technology has its own specific risk factors during the construction and operation of plant, which may influence the underlying cost of financing. These "technology risks" relate to the likelihood of completing construction (including on-time and on-budget), and the likelihood of producing the expected amount of electricity; such factors that might influence the latter include resource availability, equipment failure, damage, underperformance, or operational failure. Figure 1, from Fitch Ratings (2015) demonstrates the indicative risk to fully develop (i.e., "complete") and operate different renewable technologies. Solar PV has lower construction and operation risk, as it is modularly built, involves few moving parts, and offers more predictable resource availability. Wind has more moving parts, though is still somewhat modular in design, and so it has slightly higher construction risk; however, because of more uncertainty in resource availability, it has more operation risk. Geothermal, CSP, and hydropower plants require more engineering in design

[7] https://atb.nrel.gov

[8] The financing cost benchmarks are used in ATB to calculate levelized cost of energy for each technology over time and can be more generally used in other analyses that require current or future financing inputs for various technologies.

[9] While biopower can be considered a renewable energy technology, NREL does not perform research in that area; biopower is treated in the ATB similar to conventional electric generation technologies.

[10] Feldman and Margolis (2020) report that from 2010 to 2019, 79% of conventional U.S. electric generation technology capacity additions (including biomass) were natural gas facilities.

[11] Lower perceived risk of cash flows to PV investors also affects the amount of marketplace competition because it expands the number of investors willing to fund a project, thus increasing the supply of capital.

and operation, permitting requirements, are more site-specific, and in the case of geothermal may have less certainty in resource availability.

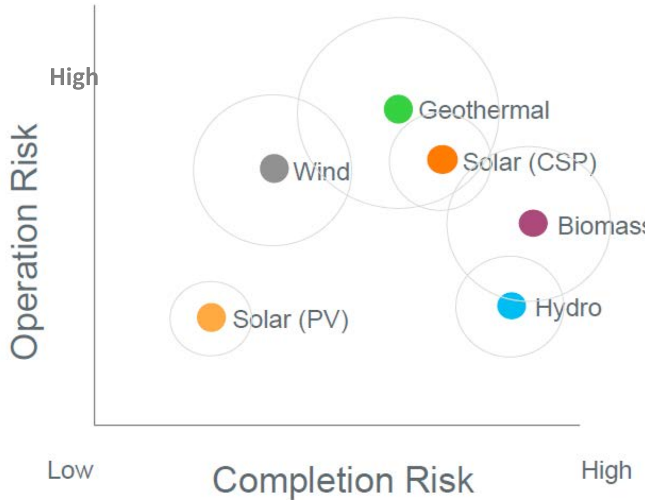

Figure 1. Financial risk by technology

Source: Fitch Ratings 2015

Sizes of bubbles represents variation in risk.

Beyond technology risk, two other determinants of financing costs among energy projects are project ownership and electricity sales agreement structure.

Project Ownership

In the United States, grid-tied energy generation assets are primarily owned by electric utilities and independent power producers (IPPs). Electric utilities can be for-profit (i.e., investor-owned utilities [IOUs], nonprofits [i.e., cooperatives], or publicly owned [POUs; i.e.; federal, state, or municipally-owned]). Each owner type typically has different return expectations and faces different rules and processes in terms of selling electricity and raising capital, which can influence financing costs.

Additionally, some of these regulatory or organizational strategies may limit the number of projects that can be owned by specific organizations (e.g., some co-ops may purchase the bulk of their electricity generation from a third-party, and some public utility commissions discourage utility ownership of electric generating assets in favor of a more market-based approach).

Ownership type also influences the ability to monetize tax benefits generated by projects. Certain companies may be limited or even prohibited from using these tax benefits and may need specific types of financial partners to invest in projects to take advantage of the benefits (i.e., tax equity investors).

Additionally, though the overall price of electricity is not directly tied to the cost of capital, it may be influenced by ownership in the case of utility-owned projects with tax attributes, because of normalization requirements. Normalization accounting requirements diminish the upfront stimulus of tax benefits by requiring utility owners to account for the benefits over the life of the project. Conversely, IPPs are for-profit corporations, operating within a more market-based competitive landscape.

Electricity Sales Agreements

IPPs generate revenue by making short-term electricity sales either through wholesale markets or via long-term contracts (i.e., power purchase agreements, or PPAs). Long-term contracts (e.g., 10–30 years) are typically far less risky, as the future sale price is known, as long as generation requirements are met. However, even if selling into the wholesale market, project owners may also protect against future price uncertainty through financial hedges, which come in several forms including synthetic PPAs, bank hedges, and proxy revenue swaps (Bartlett 2019). The longer the hedge or PPA contract, the more certainty in the electricity revenue over the life of a project. Typically, PPAs with electric utilities have longer terms than financial hedges and "avoided cost" PPA contracts mandated under the Public Utility Regulatory Policies Act. Electric utilities typically generate revenue through the sale of electricity to their customers. What they can charge, and the return they are allowed to achieve, are regulated and are often dictated by the rate-making process (i.e., the process in which utilities set electricity rates for customers).

Because of the impact that asset ownership and electricity sales agreements have on financial costs, we assess which types are most common in the U.S. market through the U.S. Energy Information Administration (EIA) Form 860 (EIA 2019a) and BloombergNEF's (BNEF's) U.S. Power Plant Stack (BNEF 2020a). As shown in Figure 2, while there are far fewer IOUs than publicly owned or cooperative utilities, IOUs service the vast majority of customers in the United States.

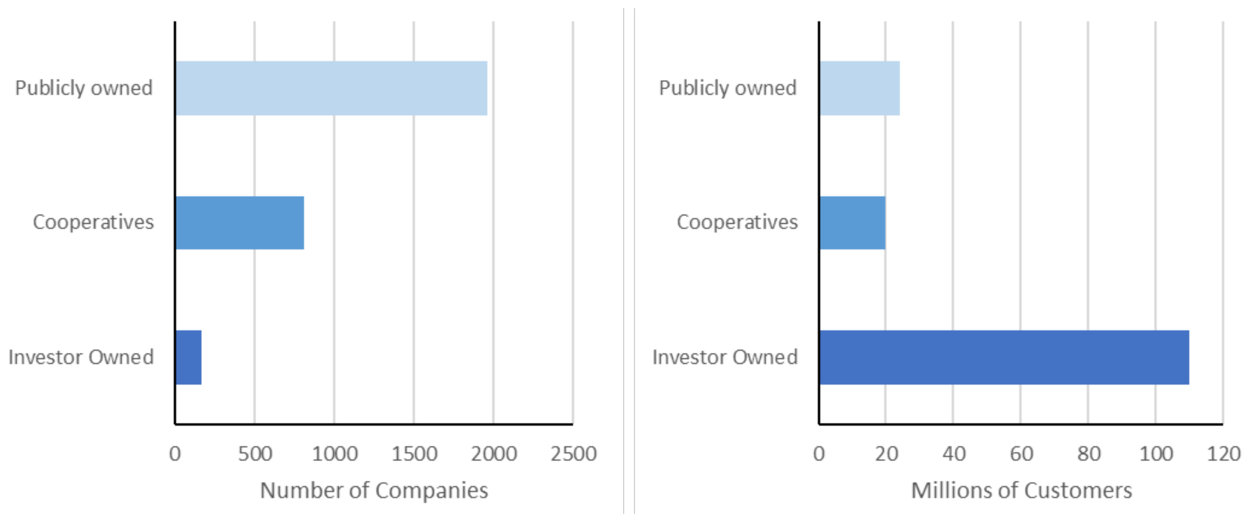

Figure 2. U.S. utilities by number of companies (left) and millions of customers (right), 2017

Source: EIA 2019b

Though IOUs represent the majority of U.S. customers, IPPs owned the majority of new U.S. generating capacity from 2010 to 2018 and therefore represent the majority of recent financial transactions (excluding refinancing existing electric generation assets and upgrading or repowering), as shown in Figure 3.

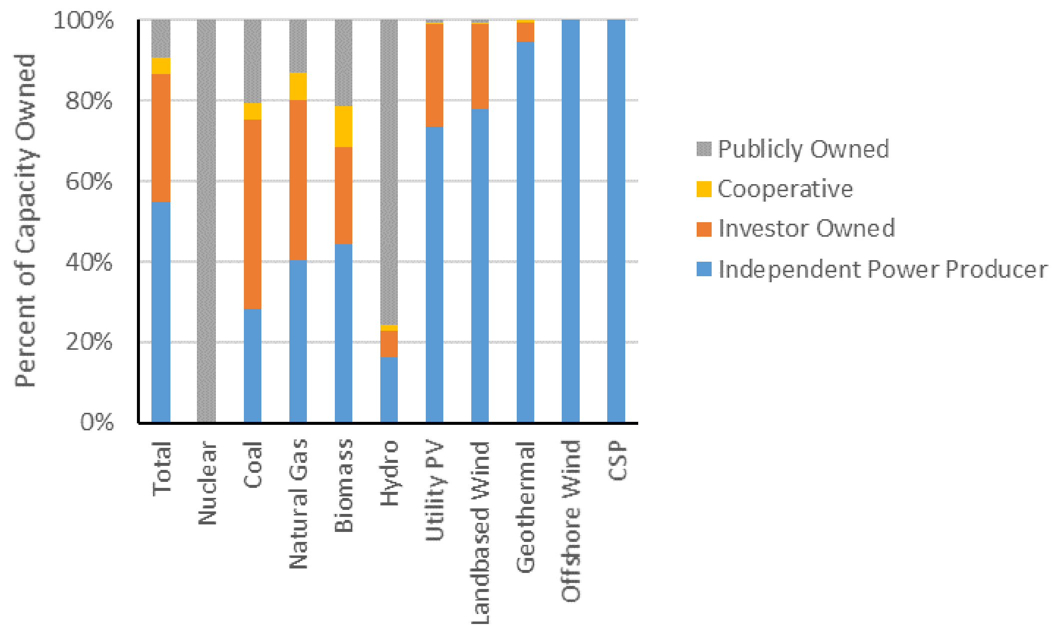

Figure 3. Percentage of new U.S. electric generation capacity beginning service from 2010 to 2018 owned, by company type

Source: EIA 2019a

Additionally, the IPP ownership percentage is significantly higher for renewable energy assets than fossil assets, with the exception of hydropower facilities. However, as shown in Figure 4, there is significantly more IPP ownership for new hydropower plants with capacities below 150 MW. From 2010 to 2019, approximately half of all new hydropower installed in the United States had capacities under 150 MW, with the other half coming from one plant.[12]

[12] Additionally, the ATB represents hydropower plants of sizes below 150 MW.

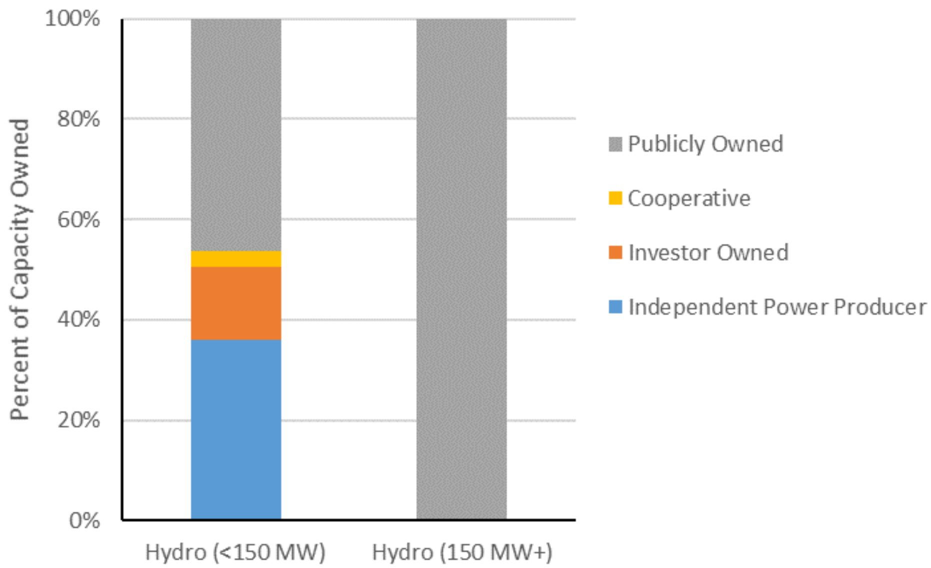

Figure 4. Percentage of new U.S. hydropower capacity beginning service from 2010 to 2018 owned, by company type and system size,

Source: EIA 2019a

A significant portion of IPPs are either large companies focused in the energy space—often an unregulated arm of a regulated utility company—or financial infrastructure investment institutions, and they often own generating assets of different technologies. Many are also publicly-traded companies, which typically have access to lower-cost financing than private companies. Table 1 shows the top ten IPPs by technology capacity within the United States at the end of February 2020.

Table 1. Top Ten U.S. IPPs, by Technology Capacity (as of February 2020)

(P: energy company with shares traded on a stock exchange; Pr: private energy company; F: financier; D: developer)

Rank	Land-based Wind	Offshore Wind	Utility-scale PV	CSP	Geothermal	Hydropower	Natural Gas
1	NextEra (P) 14.4 gigawatts (GW)	Ørsted (P) 30 MW	ConEd (P) 2.1 GW	NRG Energy (P) 0.7 GW	Energy Capital Partners (F) 1.7 GW	Brookfield (P) 1.7 GW	Energy Capital Partners (F) 27.6 GW
2	Iberdrola (P) 7.1 GW	*Vineyard Wind (P)*	NextEra (P) 2.0 GW	Atlantica Yield (F) 0.3 GW	Ormat Technologies (D) 0.8 GW	Exelon (P) 1.6 GW	Vistra Energy (P) 25.7 GW
3	EDP (P) 5.0 GW	*Wind Energy Systems Technology (D)*	Southern Co. (P) 1.7 GW	NextEra (P) 0.3 GW	Berkshire Hathaway/ MidAmerican (P) 0.4 GW	Engie (P) 1.4 GW	NRG Energy (P) 24.6 W
4	Invenergy (P) 3.4 GW	*Fishermen's Energy (D)*	Berkshire Hathaway/ MidAmerican (P) 1.3 GW	Energy Capital Partners (F) 0.2 GW	AltaRock Energy (D) 0.1 GW	ArcLight Capital Partners (F) 0.6 GW	LS Power (Pr) 12.8 GW
5	Enel (P) 3.2 GW	*Equinor (D)*	Dominion Energy (P) 1.3 GW	US Renewables Group (F) 0.1 GW	AES Corp. (P) 0.1 GW	LS Power (P) 0.5 GW	Exelon (P) 9.2 GW
6	Global Infrastructure Partners (F) 2.7 GW	—	Capital Dynamics (F) 1.0 GW	Acciona (P) 0.1 GW	EnergySource (D) 0.1 GW	Emera (P) 0.3 GW	Riverstone (F) 9.0 GW
7	Electricite de France (P) 2.6 GW	—	Global Infrastructure Partners (F) 0.9 GW	—	Enel (P) 0.1 GW	Riverstone Holdings (F) 0.3 GW	Southern Co. (P) 8.8 GW

Rank	Land-based Wind	Offshore Wind	Utility-scale PV	CSP	Geothermal	Hydropower	Natural Gas
8	BlackRock (F) 2.4 GW	—	AES Corp. and AIM Co. (P) 0.8 GW	—	—	Enel (P) 0.2 GW	Public Service Enterprise Group, or PSEG (P) 7.5 GW
9	RWE (P) 2.2 GW	—	First Solar (D) 0.7 GW	—	—	JP Morgan (F) 0.2 GW	Tenaska (Pr) 7.2 GW
10	Pattern Energy (D) 2.0 GW	—	Canadian Solar (D) 0.6 GW	—	—	Royal Dutch Shell (P) 0.2 GW	ArcLight Capital Partners (F) 7.1 GW
Top-ten U.S. IPP capacity as a percentage of total U.S. installed capacity, by technology	43%	100%	35%	100%	88%	7%	27%

As of the end of 2019, only one offshore wind facility, Block Island Wind Farm, had been installed; however, several were under active development; The companies listed in *italics* are the owners of the offshore wind projects under active development.

Source: BNEF 2020a

Even though many IPPs have large balance sheets, they often partner with additional equity investors for certain projects, especially those with large tax benefits, such as those associated with the federal investment tax credit (ITC) or production tax credit (PTC). Though many IPPs can take advantage of some of (if not all) the tax benefits associated with projects, partnerships may be more economical in many instances. These partnerships, also called tax equity arrangements, offer lower-cost capital for a portion of the cost of eligible projects in exchange for the associated tax benefits. However, tax equity participation also comes with the costs of structuring, and arranging the complex financial arrangements, and removing them when they are no longer needed. Norton Rose Fulbright (2020a) reported that approximately $12 billion in tax equity was raised in both 2018 and 2019 for solar and wind projects, representing approximately 40% and 55% of total project costs, respectively. Based on pricing data reported by Lawrence Berkeley National Laboratory for solar (Barbose and Darghouth 2019; Bolinger, Seel and Robson 2019) and wind (Wiser and Bolinger 2019), and on the notion that financial closings can precede the commercial operation date of a plant by a year or more, we estimate that these transactions contributed capital to the vast majority of solar and wind plants in 2018 and 2019.

IPP financing structures in the United States are also currently based primarily on having long-term contracts. Bolinger, Seel and Robson (2019) report that from 2006 to 2019 there were only a few IPP solar projects without a long-term contract (i.e., “merchant”); Wiser and Bolinger (2019) report that 23% of wind projects installed in 2018 were merchant or quasi-merchant; Uría-Martínez et al. (2020) reported that of the hydropower plants that received Federal Energy Regulatory Commission licenses from 2007 to 2018 and are now operational or under construction, none was reported as merchant;[13] and geothermal projects also primarily rely on PPAs, with Hernandez, Richard, and Nathwani (2016) reporting data on approximately 1 gigawatt (GW) of geothermal PPAs. Natural gas plants are unable to get electricity price contracts of the same length as renewable energy generation assets because of an inability (or prohibitive cost) to lock in or hedge fuel prices for more than a few years. According to the EIA, the average expiration date reported in 2019 for natural gas contracts for electricity generation plants was October 2021—or a little over two years.[14] Renewable energy projects have little to no fuel risks and are able to contract electricity for much longer periods —typically 10–30 years.[15]

Though we focus on the risks associated with technology, ownership, and electricity sales, it is important to note that there are a variety of other risks associated with projects, which are large contributors to the wide variation in financing costs of individual projects. According to Feldman et al. (2018) and Bartlett (2019), these risks include the:

- Political risk
- Regulatory uncertainty
- Development risk

[13] An inability to obtain a PPA was cited as the primary reason for project cancellations.
[14] The average expiration date for a coal contract in 2019 was July 2021.
[15] Some renewable energy projects have recently contracted shorter-term contracts, increasing the percentage of cash flow over the lifetime of a project that is uncontracted at the beginning of the contract (Norton Rose Fulbright 2019a).

- Government support (if any)
- Credit-worthiness of the project owner
- Credit-worthiness of the electricity offtaker
- Length of the contract (if any)
- Whether the electricity price is firm or changes with the market
- Supply and demand of competing electricity
- Underlying inflation rate
- Cost of the underlying base interest rate.

Additionally, financing costs can be influenced by economies of scale (e.g., some investment sources have minimum investment thresholds), supply and demand of sources of financing, or preexisting relationships between project developers and financiers. For these reasons, there is a wide range in financing costs across the United States, even for the same types of project.

In summary, while there is a wide variety of financial ownership and electricity sales structures and individual project characteristics for U.S. electric generation assets, most of them are owned by IPPs, and a much higher percentage of renewable assets are owned by IPPs. While IPPs that own conventional electric generating assets typically sell their power either into wholesale markets or under short-term contracts, most renewable energy generation assets sell electricity via long-term contracts. IPPs are typically large companies with big balance sheets (i.e., a significant amount of assets [including cash] and equity, which can be used to directly fund projects or raise more capital to fund projects) and access to low-cost capital, often through public markets. However, the vast majority of renewable energy projects receiving tax credits also receive a large percentage of funding (~40% for solar, 55% for wind) from tax equity providers (Norton Rose Fulbright 2020a). Tax equity participation is likely to greatly diminish as the tax credits phase out (or down), leaving ownership interest to come principally from large IPPs that likely can raise more funding from debt providers than currently exists today. However, electric utilities also own a significant share of new electric generating assets, including renewable energy projects (although not as great a percentage as older, larger plants), and in the case of hydropower, are the principal form of asset ownership. Utilities sell this power to their customers via a regulated process, and they receive a regulated return. Looking into the future, when all tax credits will have expired or reverted to their lower value, utility ownership of renewable assets may increase as utilities are no longer hampered by normalization accounting of tax benefits.

Based on this landscape, and on our emphasis on renewable energy, we focus most of our efforts in benchmarking financing costs for a project owned by an IPP with sales governed by a long-term electricity contract. For conventional technologies, we benchmark the financing costs of a natural gas project owned by an IPP, without a long-term contract. While tax equity arrangements are the primary financial arrangement for most U.S. renewable energy assets, we benchmark the financing costs of an IPP that is able to use the tax benefits associated with tax equity directly without the need for external financial partnerships. We do this for a variety of reasons, but most notably to simplify the complexity of formulating a common set of financial assumptions for a variety of technologies over time.[16] We also compare the financing costs of

[16] Other reasons for not modeling tax equity transactions include that not all owners of electric generating assets enter into tax equity arrangements, and far fewer will do so in the future given the current phasedown of federal tax

IPP ownership to the financing costs of IOUs and POUs. The vast majority of all research was performed before the novel coronavirus pandemic and therefore the benchmarks do not capture any change, now or in the future, caused by the pandemic.

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credits. In addition, the costs and complexity of tax equity transactions make them relatively inefficient and also mask the transparency required for cross-technology comparisons over time, given different emphasis on different metrics. For example, a tax equity provider may be more interested in its return on investment (ROI)—that is, the total amount of return it receives in excess of its initial investment, regardless of time—than its rate of return (RoR, or IRR)—that is, the annualized return of an investment over a period of time. For example, an investors in a solar project may receive a considerable portion of their initial investment back in the first year in the form of tax credits and depreciation expense benefits, and nearly all their return in the first five years of an investment that the IRR does not properly convey the amount of money made on a transaction to the same degree as ROI.

2 IPP Ownership

We collected data from a variety of sources that have exposure to different renewable and conventional energy technology financings, both in the United States and abroad. Sources include confidential industry interviews with renewable energy project developers, owners, financiers, consultant, and analysts; IPP public filings; public and privately reported project-level financial data; and government-reported interest-rate data. Doing so, we endeavored to accurately represent typical financing costs for each technology as well as the differences, if any, between technologies. Data points include:

- Construction financing
  - After-tax cost of levered equity[17] during the construction of the asset
  - Cost and amount of debt during the construction of the asset
- Term financing
  - Required debt service coverage ratio (DSCR) that debt providers use to determine the amount of debt (i.e., leverage) they would provide to a project during the operation of the asset
  - Cost-of-term debt—or a loan with a set payment schedule of interest and principal—during the operation of the asset
  - After-tax cost of levered equity during the operation of the asset.

2.1 Construction Financing

Based on confidential industry interviews, there is a premium of approximately 200 basis points (2%) on the cost of equity during construction for each renewable energy project, relative to the cost of equity during plant operation, to account for construction risk. The exception to this is the construction financing costs for geothermal projects, where the cost of equity during construction is separated into at least two stages. The first round of equity investment occurs pre-drilling of site wells, where the resource potential is unknown and there is no long-term site control, completed permit, or PPA in place. During this period, it is typically not possible to obtain construction debt to finance development and pre-construction costs, and the cost of equity is usually higher. Once the wells have been drilled and the geothermal resources found to be viable, site control is in place, permits have been obtained, and a PPA has been contracted, the risk on invested capital is greatly reduced, meaning the required equity return is lower and construction debt can be obtained.[18] While all electric generation technologies have some form of initial development risk before construction occurs in earnest, geothermal is somewhat unique in the level of time, risk, and percentage of capital that must be expended before plant construction.

[17] The after-tax cost of levered equity is the cash flows—after accounting for taxes—an investor requires to make an equity investment in a project that is also funded through a loan (i.e., with leverage).

[18] As mentioned before, finance varies significantly between projects. Ormat Technologies is a notable exception to the geothermal construction financing described above. As one of the top two operators of geothermal projects in the United States, Ormat Technologies finances the construction of its projects from a combination of short-term corporate bonds, cash flow from operating projects, and lines of credit. Still, Ormat Technologies assesses a higher cost of capital during construction than during plant operation.

Interestingly, once a plant can proceed to construction, the cost of debt is relatively consistent across technologies. According to Norton Rose Fulbright (2020a), interest during construction is approximately 50 basis points lower than term debt. Though there is no operational cash flow on which debt providers can depend on for payment, construction loans are significantly shorter in nature than term loans, and construction debt is only provided to projects with guaranteed financing once a project begins operation (and implements risk-limiting measures)—meaning the risk is mostly tied to whether a project completes construction. Also, construction debt providers do not fund the entire portion of construction costs, which motivates project owners to complete construction or lose the funds they used during construction (typically 10%–25% and representing the first dollars spent).

Because of the inherently greater construction risk associated with offshore wind, geothermal, and hydropower technologies, we assume construction debt and term debt are priced the same (i.e., are not 50 basis points lower than term debt).

2.2 Term Financing

2.2.1 Term Debt

Term debt—which is sourced primarily in the commercial bank market, but sometimes through the bond market—makes up a significant portion of the capital stack for IPP project owners using project finance. For deals involving third-party tax equity investors, term debt most often takes the form of "back leverage," by which the debt is secured not by the underlying project assets but instead by the IPP-owner's equity stake in the project company (i.e., back leverage is secured and serviced only by the cash allocated by the project company—typically a special-purpose LLC created solely to own the project—to the IPP sponsor over time). In contrast, under the simplifying assumption of no third-party tax equity (i.e., that the IPP sponsor can make efficient use of tax benefits on its own), term debt is typically secured by the project assets. Historically, back leverage has been priced at a small premium to project-level debt (reflecting the slightly inferior collateral position), but in recent years, increasing market liquidity (i.e., the supply of capital outstripping demand) has all but erased this premium, and back leverage and project-level debt are now widely considered to have essentially the same terms and conditions (Norton Rose Fulbright 2020a).

The "all-in" or total interest rate charged on term debt is a function of three independent components: the base rate, the bank spread, and the swap rate (Bolinger 2018). The base rate is a short-term interest rate that can be thought of as a proxy for the bank's cost of funds. Historically, the three-month London Inter-Bank Offered Rate (LIBOR) has served as the base rate for renewable energy projects using project finance in the United States. However, as a result of a recent price-manipulation scandal involving LIBOR, the market is in the early stages of a transition to a new base rate based on the Secured Overnight Financing Rate, or SOFR (Norton Rose Fulbright 2020b).

The second component of all-in term debt interest rates, the bank spread, is simply the margin that banks charge on top of the base rate (whether LIBOR or SOFR). The size of the bank spread reflects several things, including the bank's cost of funds (to the extent that the base rate is an imperfect proxy for cost of funds), the risk of getting repaid (riskier projects typically have larger bank spreads), market liquidity (more capital flowing typically means lower bank spreads, all else equal), and profit margin. As such, the bank spread is the only interest rate component whose magnitude is based, at least in part, on the underlying renewable energy asset being financed—both the base rate and the swap rate (described below) are generic benchmarks that are not at all tied to the underlying asset.

Adding the bank spread to the base rate yields a floating debt interest rate that will vary over time as the base rate—a short-term interest rate—moves around, for example, with changes to monetary policy (as shown in Figure 5, the three-month LIBOR has closely followed the overnight federal funds rate over time). This floating interest rate is applicable mostly just for short-term (e.g., six months to two years) construction debt, where the risk of significant changes in the base rate are minor, given the short time frame.

For term debt of longer duration, however, most banks require borrowers to swap out the floating interest rate for a fixed rate over the full term of the loan. This requires consideration of the third component all-in interest rates—the fixed-for-floating swap rate (or just the "swap rate") over the applicable loan term. The swap rate is the fixed interest rate that banks demand be paid in exchange for paying out the base rate (e.g., three-month LIBOR) over the life of a loan; as such, it represents banks' views on future movements in the base rate. Given that the borrower is simultaneously paying the base rate (i.e., the first component of all-in interest rates) and also being paid the base rate (as one-half of the swap transaction), the borrower's base-rate exposure cancels out altogether and the all-in fixed interest rate is comprised solely of the swap rate plus the bank spread.

Figure 5 shows the daily history of all three underlying components, as well as the all-in floating and fixed interest rates, going back to 2005. The overnight federal funds rate is included as well. Though they do not always move in tandem, since early 2019, both the base rate and the 20-year swap rate have moved lower, while bank spreads have—until very recently—held steady, resulting in both floating and 20-year fixed interest rates below 4%. The recent market turmoil caused by the novel coronavirus has pushed the base rate even lower (as the Federal Reserve has cut the federal funds rate to 0%), though at the same time, bank spreads have moved higher by at least 50 basis points, reflecting market uncertainty and liquidity concerns (Norton Rose Fulbright 2020c).

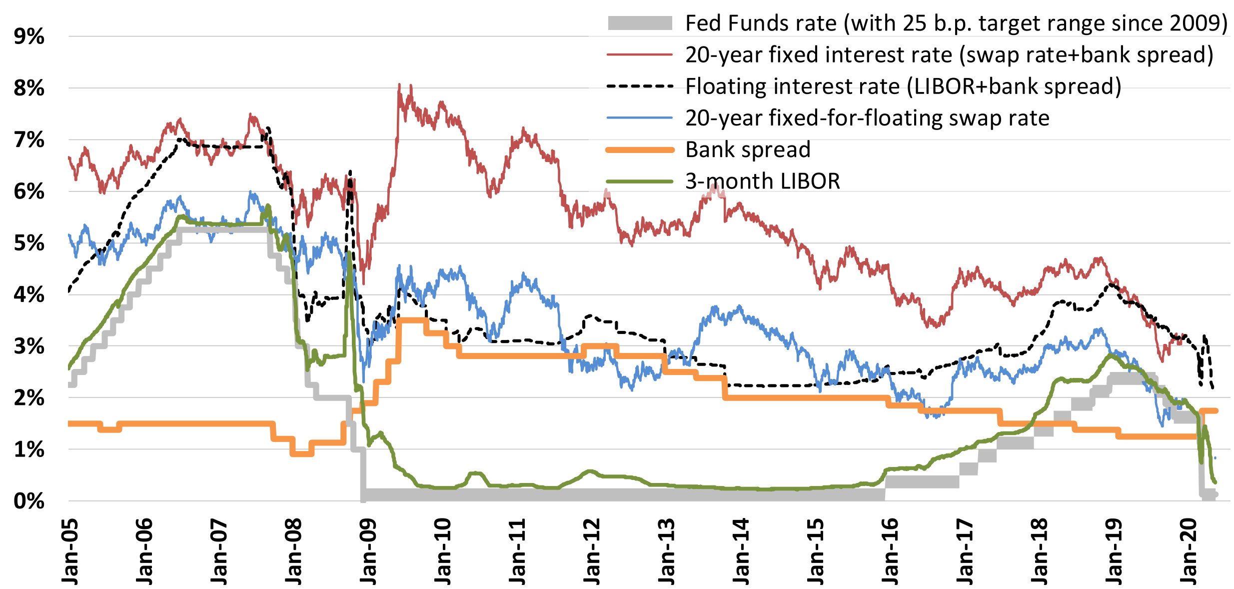


Figure 5. History of debt interest rates and components

Sources: U.S. Federal Reserve Bank 2020; Intercontinental Exchange 2020; Norton Rose Fulbright 2020a

b.p: basis points

Whereas Figure 5 builds up a theoretical history of project finance interest rates from underlying components, Figure 6 shows some empirical data points on debt interest rates from relatively recent renewable energy project financings. Though there is clearly some spread depicted—particularly in 2019, which is perhaps a function of the sharply declining interest rate environment in that year, as shown in Figure 5—the empirical interest rates shown in Figure 6 are nevertheless roughly consistent with the trends shown above in Figure 5. Though all-in term debt interest rates have fallen below 4% over the past year, our modeling analysis assumes a 4% interest rate for all technologies, on the grounds that interest rates are unusually low at present and that the inclusion of bank closing fees and necessary reserve accounts will likely push a sub-4% rate up toward the 4% level regardless.[19] We also do not assume technology-specific interest rates because we could not definitively differentiate each technology, given the limited data spread. For example, land-based wind and utility-PV, which represent the majority of U.S. (and global) renewable energy generation loans, overlap considerably in rates. In addition, our data set appears to suggest geothermal projects tend to have higher rates and distributed PV have lower rates; however, these technologies have much smaller sample sizes, there is still overlap with other technologies, and there may be individual project-specific circumstances that push loans higher or lower.

[19] Various costs are associated with securing a loan. Banks often charge fees for arranging a loan, which may range from 1% to 3% of the principal of the loan (Mendelsohn et al. 2012) estimated bank closing fees of 2.75%); additionally, they may require that a borrower set aside cash up front into one or more accounts as a reserve to cover unexpected fluctuations in cash flow. These arrangements effectively push the cost of a loan higher than the stated interest on a loan.

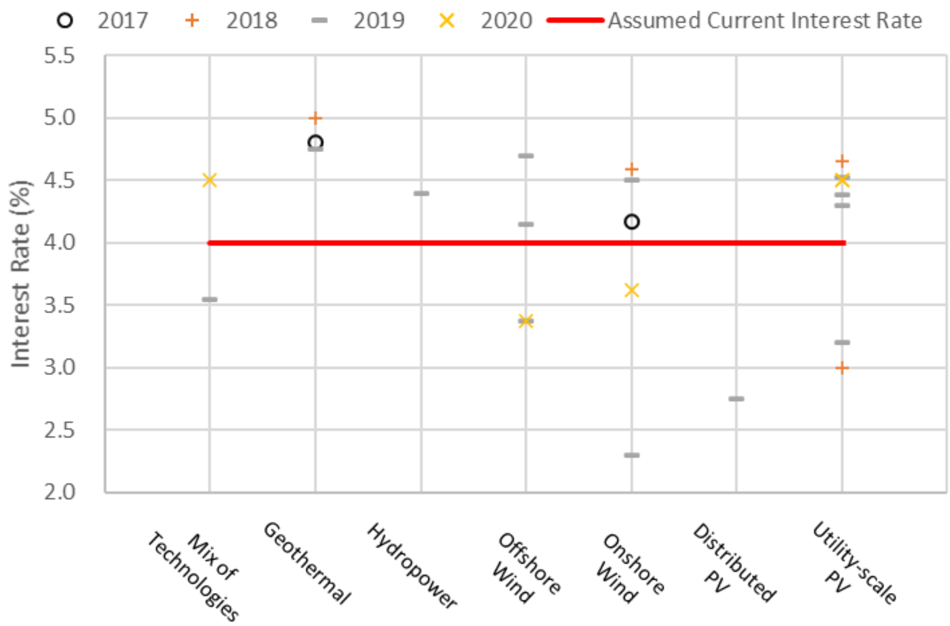


Figure 6. Empirical all-in term debt interest rates for loans initiated over time, by technology

Each data point represents a collected value, which may include the capacity-weighted average rate for a company or portfolio or an analyst estimated value.

Sources: Berkshire Hathaway Energy 2018; Terraform Power 2019, 2020; Brookfield Renewable Partners 2020; Bank of America 2020; BNEF 2019; Guillet 2018; Norton Rose Fulbright 2020, 2019b, 2019c; Ormat Technologies 2019, 2018

Table 2 (page 18) shows our construction and term debt interest rate assumptions for each technology, in both 2018 and 2030. These assumptions are informed by a bottom-up buildup of all-in interest rates from the underlying components described above (and shown in Figure 5), Congressional Budget Office (CBO) interest rate projections (CBO 2020), as well as the empirical interest rates shown in Figure 6. The modestly higher interest rates in 2030 are consistent with CBO's projection of a 100 basis point increase 10-year Treasury bond yields from 2019 to 2030 (from 2.1% in 2019 to 3.1% in 2030), and reflect that interest rates are currently at abnormally low levels and are therefore likely to increase in the future. For example, at its June 2020 meeting, the Federal Reserve Bank's Federal Open Market Committee projected the overnight federal funds rate—a benchmark interest rate that is the Federal Reserve's primary monetary policy tool—will remain near 0% through 2022 but then increase to ~2.5% over the longer run, five or six years from now (FOMC 2020). Though changes to the federal funds rate do not flow through directly one-for-one to term debt interest rates (e.g., see Figure 5, above), in general, tighter monetary policy (i.e., a higher federal funds rate) is associated with higher interest rates across the board. This view is further supported by the U.S. Department of the Treasury (Treasury) yield curve, which currently pegs the 10-year benchmark Treasury bond yield at roughly 60 basis points above the one-month T-bill yield, implying a slight rise in interest rates over the coming decade.

2.2.2 Debt Service Coverage Ratio

Though the all-in interest rate determines the cost of the loan, the size of the loan is governed by the minimum debt service coverage ratio (DSCR) required by the lender. The DSCR is simply a measure of the amount of net operating income that must be freely available over time to service the loan; it both represents and dictates the size of the "cushion" required by the lender to ensure the loan will be repaid—even under "worst-case" operating conditions.

The required DSCR is largely a function of the uncertainty surrounding future revenue generated by the project. For renewable energy projects—which may have variable weather-dependent output but often fixed-price PPAs in place—revenue uncertainty mostly boils down to resource uncertainty (though it also depends on a host of other factors, including curtailment, availability, and offtaker credit risk). As a result, lenders typically require a DSCR of 1.0 under a worst-case or "P99" resource forecast (i.e., a long-term resource forecast that has a 99% probability of exceedance). In other words, lenders typically require that even in the worst-case or most-unlikely resource scenario, the project should still generate just enough net free cash to repay the loan (i.e., a 1:1 ratio between of cash flow and debt service). In turn, this P99 DSCR of 1.0 translates into a P50 DSCR that is higher than 1.0, based on the gap (reflecting relative uncertainties) between the P99 and P50 (i.e., median) resource projections. For solar PV projects, P50 DSCRs of ~1.30 are common (Norton Rose Fulbright 2020a). For wind projects, P50 DSCRs tend to be higher (e.g., ~1.40) simply because wind resource projections are more uncertain than solar resource projections (Norton Rose Fulbright 2020a).

Figure 7 shows empirical DSCR data gathered from various sources (and at different levels of probability of exceedance), while Table 2 (page 18) shows our benchmark P50 DSCR assumptions for each technology based on the empirical data in Figure 7. While certain data points in Figure 7 were gathered from sources with information on one technology's DSCR, most data points come from data sources covering multiple technologies (and therefore offer a comparative perspective).

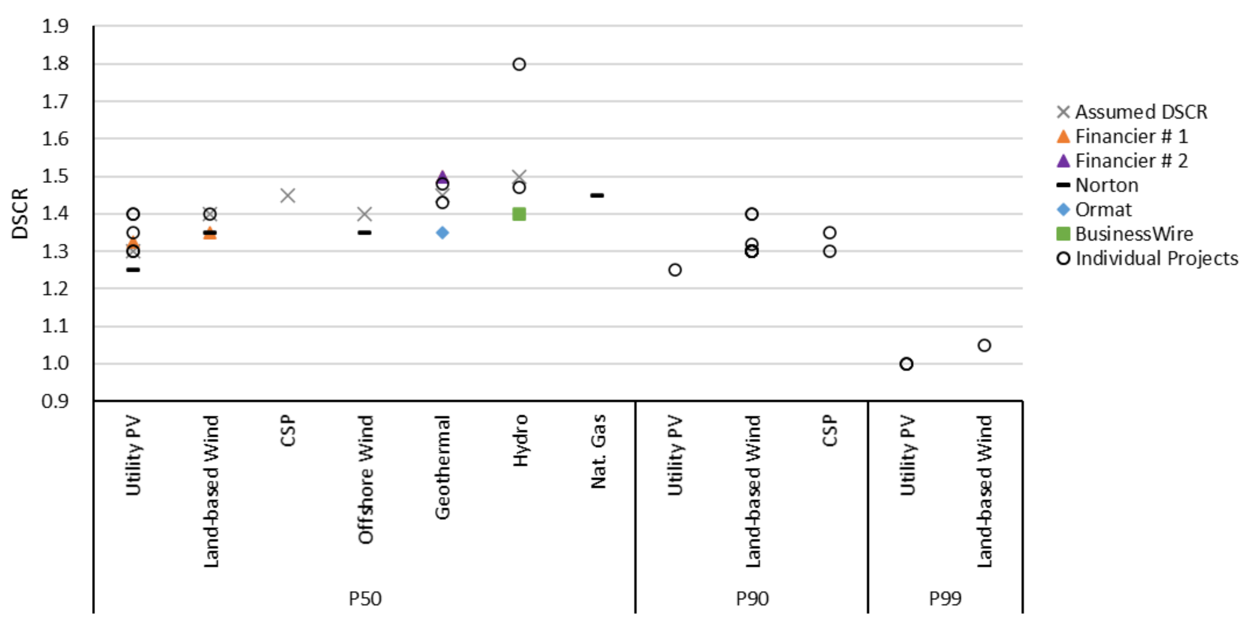


Figure 7. Empirical DSCR data at different probability of exceedance levels, by technology

Sources: Norton Rose Fulbright 2019c, 2020a; Financier 1 2020; Financier 2 2020; Ormat Technologies 2020; BusinessWire 2015; Credit Agricole 2018a, 2019b; Fitch Ratings 2015

2.2.3 Term Equity

While financing for IPP-owned electric generation assets comes from various sources and can involve multiple owners including tax equity, we focus our analysis on the after-tax equity return requirements of assets solely owned by IPPs. These large companies typically have access to significant capital through ongoing operations and public capital markets; however, because debt is almost always less costly than equity,[20] equity investments in electric generating assets only cover the portion of the project not funded through debt—thus, representing "levered" returns. Figure 8 summarizes 31 separate data points gathered from 15 sources for the levered after-tax cost of equity by technology type. In some instances, unlevered equity returns were provided, which we convert to levered via a derivation of the weighted average cost of capital (WACC) formula.[21] For example, we calculate a 7.5% unlevered rate of return to be equivalent to a 10.5% levered rate of return.

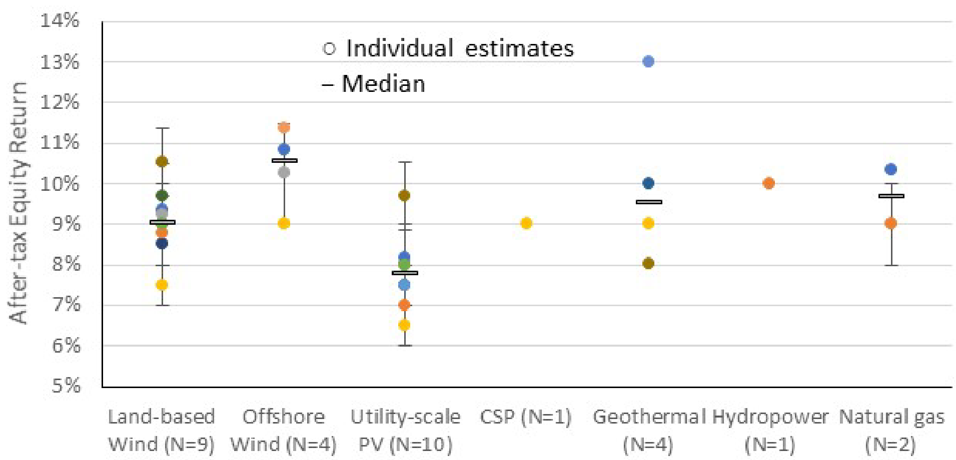


Figure 8. Empirical data and medians of the after-tax levered cost of equity, by technology

Error bars represent estimates given with ranges.

Sources: Bank of America 2020; BNEF 2019; Financier 3 2020; Financier 4 2020; Financier 1 2020; Financier 5 2020; Financier 6 2020; Financier 7 2020; Financier 8 2020; Financier 9 2020; Financier 10 2020; Nextera Energy 2019; Norton Rose Fulbright 2020a; Ørsted 2018; Ormat Technologies 2020

As shown in Figure 8, utility-scale PV requires the lowest after-tax levered rate of return, with a median of 7.75%, and is followed by land-based wind at 9.00%. This would seem to follow the premium in perceived risk between utility-scale PV, with fewer moving parts and lower predicted resource variability than land-based wind. For example, Fitch Ratings (2020) stated, "more than a decade of analysis shows that solar resources are consistently more stable and predictable than wind, resulting in less volatile revenues and generally higher ratings."

Given the limited data points for the other technologies (i.e., offshore wind, CSP, geothermal, hydropower, and natural gas), their overlapping data points, and the premium assessed over wind

[20] Debt investors lend money for a predetermined period of time and have a legal claim to any assets up to the amount borrowed, plus the interest, and that right supersedes that of the equity investor. Because there is more certainty and seniority to their cash flow than equity investors, debt is typically a less expensive form of capital than equity.

[21] levered cost of equity (i.e. WACC) = unlevered cost of equity / equity capital contribution – cost of debt * (1 – tax rate) * debt capital contribution / equity capital contribution. A 4.0% cost of debt, a combined effective corporate tax rate of 25.7%, and a debt contribution of 40% were assumed.

and PV by data sources that provided multiple values, we assume a 100 basis point premium over land-based wind. This premium is slightly lower than the premium reported by individual data sources when comparing these technologies to onshore wind (which ranged from 120 to 150 basis points); however, the 100 basis point premium provides values more consistent with their median data points. We were unable to obtain specific returns for distributed PV, but Norton Rose Fulbright (2020a) estimates that tax equity rates for distributed PV are approximately 100 basis points higher than utility-scale PV transactions; therefore, we assume a similar premium for after-tax levered equity returns. Though they are not included in Figure 8, we were also able to obtain data on equity rates where the PPA offtaker is a corporation or the owner uses a financial hedge; the data sources indicate a rate of return between 10% and 12% for wind and utility-PV projects (Financier 11 2020).

2.3 Summary of Current IPP costs

Table 2 summarizes our financial assumptions by technology during the project's construction and operation. As noted in the table and above, the electricity sales for natural gas plants are assumed to come from short-term quasi-merchant plants, unlike the long-term PPA sales assumed for the renewable energy technologies. This is likely a large contributor to the higher cost of equity and DSCR shown in Table 2.

Table 2. Summary of Current IPP Financial Assumptions

		Construction			Operation		
Technology	**Electricity Sales**	**After-Tax Levered Equity Returns**	**Debt Interest Rate**	**Leverage**	**After-Tax Levered Equity Returns**	**18-Year Term Debt Interest Rate**	**P50 DSCR**
land-based wind	PPA	11.0%	3.5%	80%	9.0%	4.0%	1.40
offshore wind	PPA	12.0%	4.0%	80%	10.0%	4.0%	1.40
utility PV	PPA	9.75%	3.5%	80%	7.75%	4.0%	1.30
residential and commercial PV	PPA	10.75%	3.5%	80%	8.75%	4.0%	1.30
CSP	PPA	12.0%	3.5%	80%	10.0%	4.0%	1.45
geothermal	PPA	pre-drilling: 15.0% post-drilling: 10.0%	4.0%	pre-drilling: 0% post-drilling: 75%	10.0%	4.0%	1.45
hydropower	PPA	12.0%	4.0%	80%	10.0%	4.0%	1.50
natural gas	quasi-merchant	12.0%	3.5%	80%	10.0%	5.0%	1.45

These financial assumptions are used as input values to calculate the WACC in the 2020 ATB. WACC is used in the ATB as the discount rate input to the capital recovery factor for the levelized cost of electricity (LCOE) formula. There is some incongruity to this method, in that the variables shown in Table 2 are inputs to project finance cash flow models, and those models differ from the simple LCOE formula used in ATB. Using these inputs to derive the WACC that feeds into the LCOE formula might create slightly lower finance costs, and thus lower costs of electricity, than are warranted. For example, the WACC (and LCOE) formula assumes a steady debt-to-equity ratio over the project life; however, in project finance, principal is typically paid down, creating more equity in a project over time. Feldman and Schwabe (2018) examine this issue.

3 Utility Financing

This section illustrates financing practices for utility ownership of power generation assets. Though the ATB uses data under an IPP model, it is also important to characterize and quantify the cost of financing utility-owned projects because utilities currently own a significant amount of U.S. electric generating assets, including renewable energy assets, as demonstrated in Section 1, and utilities may own a larger share of renewable energy assets in the future.

We describe two primary ownership types prevalent in the U.S. marketplace: privately-owned IOUs and POU organizations such as municipals, power authorities or districts and cooperative utilities and other variations. Under the utility-ownership model, IOUs or POUs may own some or all of the electric generation required to serve their customers, as well as the transmission and distribution infrastructure. In contrast to IPPs, utility financing practices and costs (with some notable exceptions; e.g., Florida's Solar Rate Base Adjustment) do not differentiate financing cost by generation technology type; rather, the main driver for costs are regulatory restrictions and allowances, availability of capital, and credit rating for each type of utility.

3.1 IOU Financing

IOUs provide electricity services to 72% of utility customers in the United States, which represents 220 million Americans (EIA 2019b; EEI 2019a). IOUs' business strategy and electricity rates are regulated at varying levels by state utility commissions. Like IPPs, IOUs are for-profit corporations that are taxable at the federal level; they are eligible to receive federal tax benefits afforded to qualifying renewable energy project owners, including the PTC, ITC, and modified accelerated cost recovery system (MACRS) benefits. Of the 47 U.S. IOUs tracked by the Edison Electric Institute in 2018, 42 had directly tradable stock and 5 operated as subsidiaries of parent corporations or other business variations (EEI 2019).

In the IOU ownership-model, we assume investment in a power generation asset reflects the capital structuring and cost of capital for the utility overall, as the IOU's regulatory body permits it to recover costs from all its capital investments, irrespective of technology, including electric generation assets.[22] Estimating representative financing costs requires three input parameters specific to IOUs: (1) the average return on equity (ROE), (2) the average cost of debt, and (3) the composition of debt and equity in the IOU's capitalization.

A utility's ROE is largely determined by its regulator and typically results from a rate case. The average awarded ROE for IOUs has trended downward since the late 1990s largely because of steady decreases in the economy-wide benchmark interest rates (see Figure 9). According to EEI (2019a), the averaged awarded ROE for tracked IOUs fell from 10.54% in 2009 to 9.70% in 2019.

We estimate the cost of debt for IOUs using the range of IOU's bond credit ratings from the Edison Electric Institute (EEI) and aggregated corporate bond yields (i.e., stated interest rates) reported by the Federal Reserve. EEI reports that as of 2019, 43 of the 45 IOUs were rated as

[22] As mentioned previously, there are notable exceptions to this assumption where a regulatory authority permits a utility to achieve a specific return from a specific type of investment. For example, through the use of a Solar Rate Base Adjustment, or SoBRA, by several Florida utilities, the public service commission can approve the addition of solar projects of a utility rate base without a full rate case.

"investment grade," with two utilities rated BBB- (the lowest investment-grade rating), another two rated A or higher (the highest investment grade ratings), and the remaining 39 with an average credit rating of BBB. To construct the cost of debt for IOUs, we average reported yields for the lowest and highest rated investment grade corporate bonds. The resulting average corporate yield for 2019 was 3.9%, as noted in Table 3, but by Q4 2019, it had dropped to 3.5% (EEI 2020; FRED 2020a, 2020b). Figure 9 shows the ROE and average investment grade corporate bond yields from 2010 to 2019. The 10-year Treasury bond rate is shown to illustrate the spread of ROE and debt yield relative to the benchmark government interest rate.

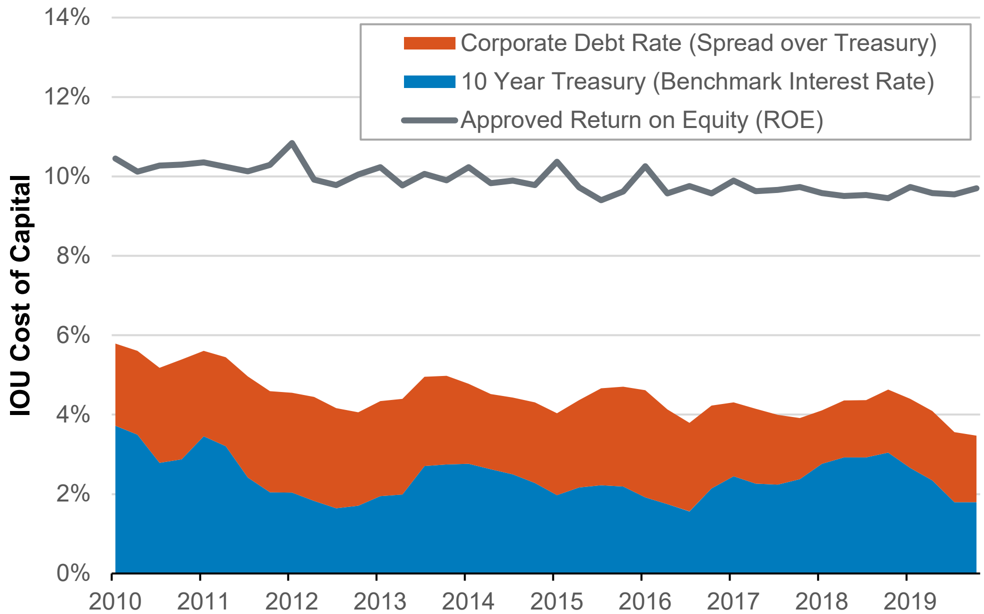


Figure 9. IOU average ROE and investment grade corporate debt yield, 2010 to 2019

Sources: EEI 2020; FRED 2020a, 2020b

IOU capital structure held steady from 2010 to 2019. The average capital structure of IOUs over that period ranged from 43% to 47% equity, with the corresponding 53%–57% made up of debt (EEI 2019b). Unlike the IPPs, IOUs traditionally do not partner with third-party tax equity providers and instead may use the tax credit in-house, which is known as "self-sheltering."

From the estimates of ROE, corporate bond yields, and capital structure, we calculate the annual WACC for the IOU ownership model. Table 3 presents the estimated WACC for IOUs from 2010 to 2020, which range from 5.8% to 6.4%. The WACC in Table 3 is an after-tax value, as the interest payments on debt are tax deductible for IOUs.

Table 3. Capital Structure, Return, and WACC Estimates for IOUs, 2010–2019

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Equity capitalization (%)	43.2	43.7	43.3	43.3	46.9	46.4	44.7	44.4	45.0	45.0
Debt capitalization (%)	56.7	56.3	56.8	56.7	53.1	53.6	55.4	55.6	55.0	55.0
Return on equity (%)	10.3	10.3	10.2	10.0	9.9	9.9	9.8	9.7	9.5	9.6
Debt interest rate (%)	5.5	5.2	4.3	4.7	4.5	4.4	4.2	4.1	4.4	3.9
Federal tax rate (%)	35	35	35	35	35	35	35	35	21	21
WACC (%)	6.5	6.4	6.0	6.1	6.2	6.1	5.9	5.8	6.2	6.0

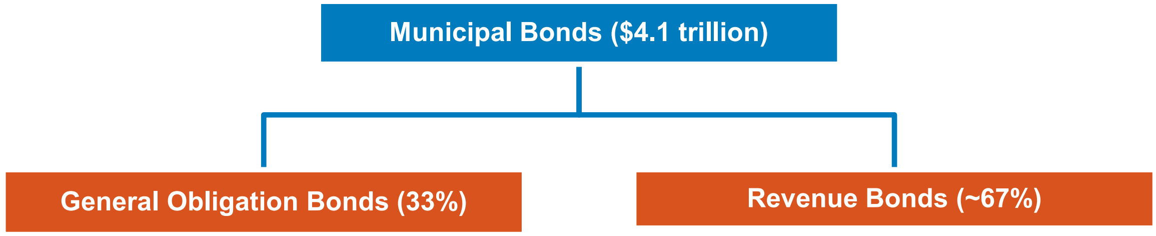
3.2 Publicly-Owned and Cooperative Utility Financing

In addition to IOUs, EIA also classifies utilities as either public or cooperative. Public utilities may include federal, state, or municipal electric service companies run by governmental entities. Cooperative utilities are nonprofit organizations owned by their members. Although there are important but subtle distinctions between public and cooperative utilities, we group these non-IOUs together for the sake of simplicity as POUs.

POUs collectively serve more than 44 million customers and constitute the greatest number of utilities by count in the United States. EIA (2019b) lists 812 cooperative utilities and 1,958 public utilities in the United States in 2017. POUs are owned by the community at-large or their members rather than by equity investors or shareholders. This ownership structure does not readily allow for capital to be raised through equity investment in the enterprise itself, such as with IOU stock. Instead, the POU ownership model primarily raises capital through nontaxable debt issuances with prespecified rates of returns to lenders.

POUs are generally eligible to issue nontaxable debt (also referred to as tax exempt debt) through issuance of a specific type of bond, known as a municipal bond. The proceeds from a nontaxable municipal bond issuance fund the costs of infrastructure projects including power generation and promise a return to the lender (i.e., the bond's investor) at a specified rate and maturity date. More than $4.14 trillion dollars of municipal bonds were outstanding at year-end 2019 (SIFMA 2020).

Municipal bonds come in two primary forms—both are typically tax exempt. State and local governments issue general obligation bonds for projects that do not generate revenue on their own and require public taxation or voter approval (e.g., funding for schools and education). In contrast, POUs generally issue revenue bonds to fund infrastructure projects with dedicated revenue streams, such as power generation assets. The revenue from the project or the POU itself is pledged to repay the bond costs. For purposes of this report, we focus on revenue bonds as the main financing vehicle for POUs to raise capital for energy assets. Figure 10 illustrates key differences between general obligation and revenue bonds.



Distinguishing Characteristics

Issuer	State and local governments	Issuer	Electric, gas, water, and waste utilities, transportation authorities, hospitals
Pledged by	Taxing authority of issuer (limited and unlimited), all legally available resources	Pledged by	Gross or net revenues of the enterprise or project
Purchasers/ investors	Retail (46%), mutual funds (27%), banks and credit unions (12%), insurance (12%), other (3%)	Purchasers/ Investors	Retail (46%), mutual funds (27%), banks and credit unions (12%), insurance (12%), other (3%)
Voter approval	Yes	Voter approval	No
Tax exempt Interest	Yes	Tax exempt interest	Yes
First issuance	New York State (1812)	First issuance	New York State Port Authority (1926)

Figure 10. Characteristics of municipal bonds outstanding year-end 2019

Sources: SIFMA 2020; Invesco 2019

Interest payments received on revenue bonds are generally exempt from federal income and some state income taxes. POUs can therefore issue tax-exempt bonds with lower interest rates and can remain competitive with higher yielding taxable bonds. The bond investor's return advantage of tax-exempt debt is illustrated in Figure 11. A tax-exempt bond with a stated interest rate (i.e., yield) of 3% is equivalent to 4.62% taxable yield at the 35% marginal tax bracket and 5% taxable yield at the 40% marginal tax bracket.[23] Table 4 shows tax exempt yields from 1% to 5% and the equivalent taxable yields.

[23] The marginal tax yields in Figure 11 includes the net investment income tax rate of 3.8% that is applied to individuals and trusts with income over statutory defined thresholds (Invesco 2019).

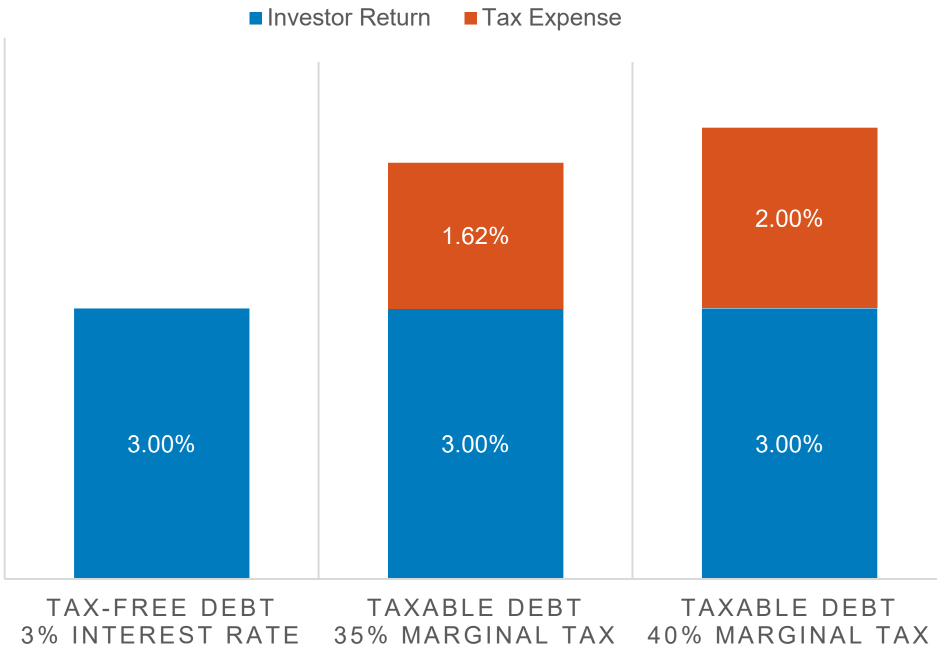


Figure 11. Comparison of 3% tax-exempt debt and equivalent taxable yields

Table 4. Comparison of 1%–5% Tax-Exempt Debt and Equivalent Taxable Yields

Tax-Free Yield % (Interest Rate)	1.0	1.5	2.0	2.5	3.0	3.5	4.0	4.5	5.0
Equivalent Taxable Yield % (35% Marginal Tax Bracket)	1.54	2.31	3.08	3.85	4.62	5.38	6.15	6.92	7.69
Equivalent Taxable Yield % (40% Marginal Tax Bracket)	1.67	2.50	3.33	4.17	5.00	5.83	6.67	7.50	8.33

Source: Invesco 2019

Interest rates offered by revenue bonds vary according to both macroeconomic conditions and bond-specific factors. Macroeconomic effects may include current interest rates, expectations of future interest rates, investor demand for bonds or alternative investments, and other factors. Bond-specific considerations might include service territory characteristics (e.g., condition of utility assets, area wealth), utility financial strength, management metrics, legal provisions, and term to maturity to name a few (Moody's 2014).

POUs typically disclose key financial metrics such as bond issuance amounts and yield in annual financing statements. We collected revenue bond yields from published financial statements from 7 of the 20 largest POUs in the United States to construct a representative data sample of POU bond financing rates (APPA 2019). POUs in the revenue bond data sample include the Salt River Project, CPS Energy, the Los Angeles Department of Water and Power (LADWP), JEA, Omaha Public Power District (OPPD), Austin Energy, and the Sacramento Municipal Utility District (SMUD). Other POUs either did not report or issue revenue bonds during that time, or they do not generally own power generation assets; or, the bond's cost data were not easily discernible from other long-term costs. Figure 12 shows the stated yield and maturity for 29 revenue bond issuances during the sample period. The length of term until maturity is denoted by circle size. The range of interest rates (1.5%–6.5%) is narrow from 2017 to 2019, with maturities ranging from 2.0 to 27.5 years.[24] The average interest rate and term in 2019 is ~4.1%, with ~16.6 years to maturity.

Due to the absence of equity capital in the POU financing model, proceeds from revenue bond issuance typically fund 100% of a project's upfront costs. The WACC under the POU ownership structure in 2019 is therefore the average value of revenue bond yields in the data sample, or 4.1%.

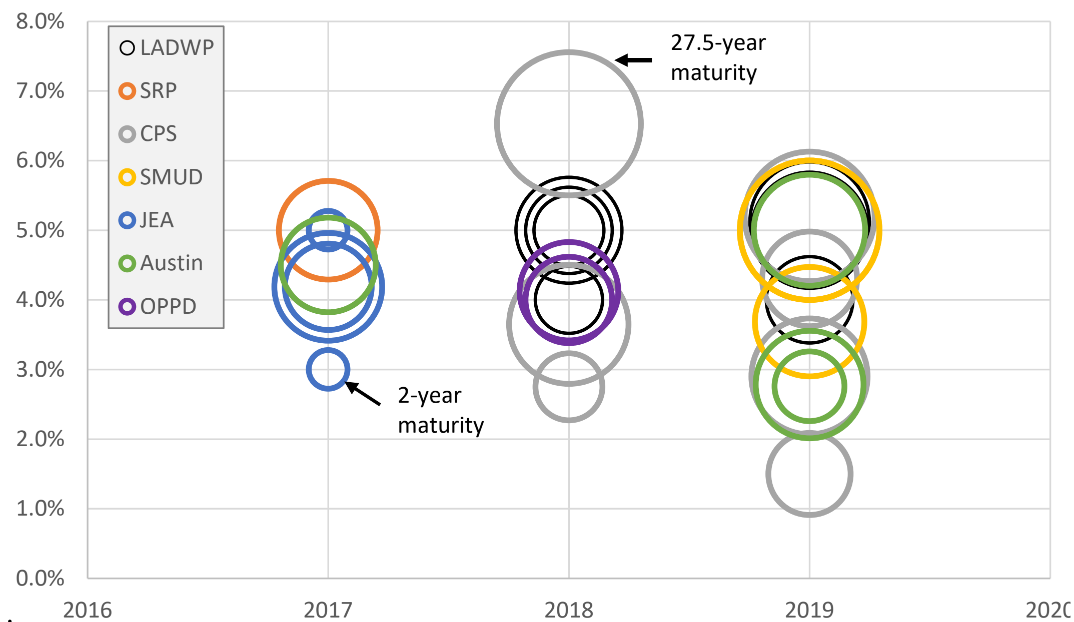


Figure 12. Revenue bond yields, 2017–2019

Sources: Austin 2019; CPS Energy 2020; JEA 2019; LADWP 2020; OPPD 2019 SRP 2019 SMUD 2020

3.3 Qualitative Comparison of IPPs, IOUs, POUs

The preceding sections describe the capital contributions and the variations in costs of capital from IPP, IOU, and POU financing models. Each of the different financing approaches have both advantages and disadvantages. These considerations are highlighted in Table 5 (page 26).

As tax-paying entities, IPPs can utilize federal support mechanisms for certain renewables (i.e., PTC/ITC and MACRS) and can deduct interest payments from federal taxes, but they must pay income taxes on profit. The tax treatment of IOUs generally follow IPPs except that IOUs have difficulty using the federal support mechanisms for renewables to the maximum extent possible because of tax normalization accounting rules.[25] POUs, by contrast, do not pay federal income

[24] Refinancing revenue bonds before their maturity, a practice known as "refunding," is a common practice.
[25] Normalization accounting rules generally require IOUs to spread the value of the ITC over the operating life of the asset when rate-basing the project, rather than inputting the benefit in the first year. IOUs are also required to spread the accelerated deprecation benefit over a longer time frame (likely 12 years) than the typical five-year

taxes on revenue and can issue tax-exempt debt, but they accordingly are ineligible for federal tax benefits. These differing ownership characteristics lead to different approaches to financing renewable generation projects, each with different costs.

Table 5. Qualitative Comparison of Different Financing Approaches by IPPs, IOUs, and POUs

Consideration	IPPs	IOUs	POUs
Income subject to federal and state taxation	Yes	Yes	No
Can use federal tax benefits for renewables (ITC or PTC)	Yes	Yes, subject to tax "normalization" accounting	No
Can use accelerated depreciation of qualifying costs	Yes	Yes, subject to tax "normalization" accounting	No
Interest payments on taxable debt are deductible from federal income taxes.	Yes	Yes	No
May issue debt exempt from federal and some state income taxes	No	No	Yes

As shown in 26Table 5, IPPs, IOUs, and POUs have comparative advantages and disadvantages in financing renewable energy projects. These considerations vary in terms of both magnitude and direction of impact (i.e., cost advantage and disadvantages). In most cases, the IPP scenario currently returns the lowest relative costs, owing to (1) inclusion of lower cost tax equity (relative to shareholder equity assumption) and (2) the ability of IPPs to use the full stated value of the ITC and five-year MACRS. As we model a future scenario without an ITC, however, we see a smaller cost advantage between IPP and IOU ownership, as well as scenarios that reflect POUs with as the lowest financing cost option. However, there are many variations and combinations on these structures, including a recent Internal Revenue Service private letter that clarified how IOUs can participate in tax equity financing without the normalization adjustment that IOUs are exposed to in self-ownership.

The ATB uses an assumed IPP financing structure because the majority of new electric generation assets, and the vast majority of new renewable energy generation assets, are owned by IPPs. If the ATB used IOU or POU financing structures, it would likely increase the cost of financing in the short-term for projects receiving tax credits. As the tax credits phase down, the difference would likely be reduced and the POU financing structure, assuming 100% tax-exempt debt financing and no corporate income taxes, might be less expensive. That being said, individual circumstance, both currently and in the future, may make a specific type of ownership the most economically viable; additionally, there may be other factors, beyond financial costs, that would cause one financing type to be the preferred approach for electric generation asset ownership.

MACRs schedule allows. In combination, these both negatively impact the overall value of these tax benefits to IOU customers by extending the time to realize the full stated benefits.

4 Future Financing

A variety of factors will influence future financing costs for electricity generation technologies. In this section, we estimate future changes to finance costs caused by the planned expiration of tax credits and a likely increase in interest rates (from current historical lows), as both are fairly certain and easy to quantify. However, there are many other factors that could affect financing costs that are less certain to occur and/or are harder to quantify in terms of impact; we discuss these additional factors below, but we do not incorporate them into future estimates of financing costs.

4.1 Changes in Interest Rate

All-in interest rates on term debt are abnormally low by historical standards. As shown in Figure 5 (above), 20-year fixed interest rates had fallen to around 3% just prior to the novel coronavirus outbreak (which has since roiled the markets). These historically low interest rates have been enabled, in part, by reductions in the three-month LIBOR base rate, which followed the overnight federal funds rate lower throughout 2019 as the Federal Reserve reversed and then began easing its monetary policy stance. This monetary easing continued in 2020 in an attempt to combat the economic decline caused by the novel coronavirus, culminating on March 15, 2020 with a 100 basis point reduction in the federal funds rate to the current target range of 0.00%–0.25%.

Although the Federal Reserve may eventually tighten monetary policy by raising the federal funds rate once the economy recovers from the current pandemic-induced downturn, the markets are not expecting that to happen any time soon. For example, trading activity in the federal funds future contract on the Chicago Mercantile Exchange suggests market participants currently expect the federal funds rate to remain at its current 0.00%–0.25% target range for at least another nine months—i.e., through the March 17, 2021 meeting of the Federal Reserve's Federal Open Market Committee (CME Group 2020). And, as mentioned earlier, the Federal Reserve's Open Market Committee—i.e., the very group that controls the federal funds rate—projects that it will remain at current levels through 2022 before eventually rising to a median projection of 2.5% over the longer run, in five or six years (FOMC 2020). An even longer period of sustained easing is certainly possible—for example, Figure 5 shows that the federal funds rate (and with it, the three-month LIBOR base rate) remained at or near 0% for an unprecedented seven straight years from 2009 to 2015, in the wake of the Great Recession of 2008. The CBO estimated that the 10-year benchmark Treasury bond yield will increase from 2.1% in 2019 to 3.1% in 2030—an increase of 100 basis points (CBO 2020).

Given today's combination of historically low interest rates coupled with uncertainty over how long they will last, we project an increase consistent with CBO's estimate of 10-year Treasury bond yields from 2019 to 2030 (100 basis points across the board) in all-in construction and term debt interest rates by 2030. This modest increase is generally consistent with the Federal Reserve's view that the federal funds rate will eventually move higher, and also with the Treasury yield curve, which currently pegs the 10-year benchmark Treasury bond yield at roughly 60 basis points above the one-month T-bill yield (implying a slight rise in interest rates over the coming decade).

4.2 Changes in Tax Credits

Renewable energy project finance will also be significantly impacted by the ongoing phasedown of federal tax credits. By providing a significant portion of a project's after-tax return in the form of a tax credit as opposed to cash revenue that can support and service debt, federal tax credits like the PTC and ITC restrict the amount of debt that a renewable energy project can support.

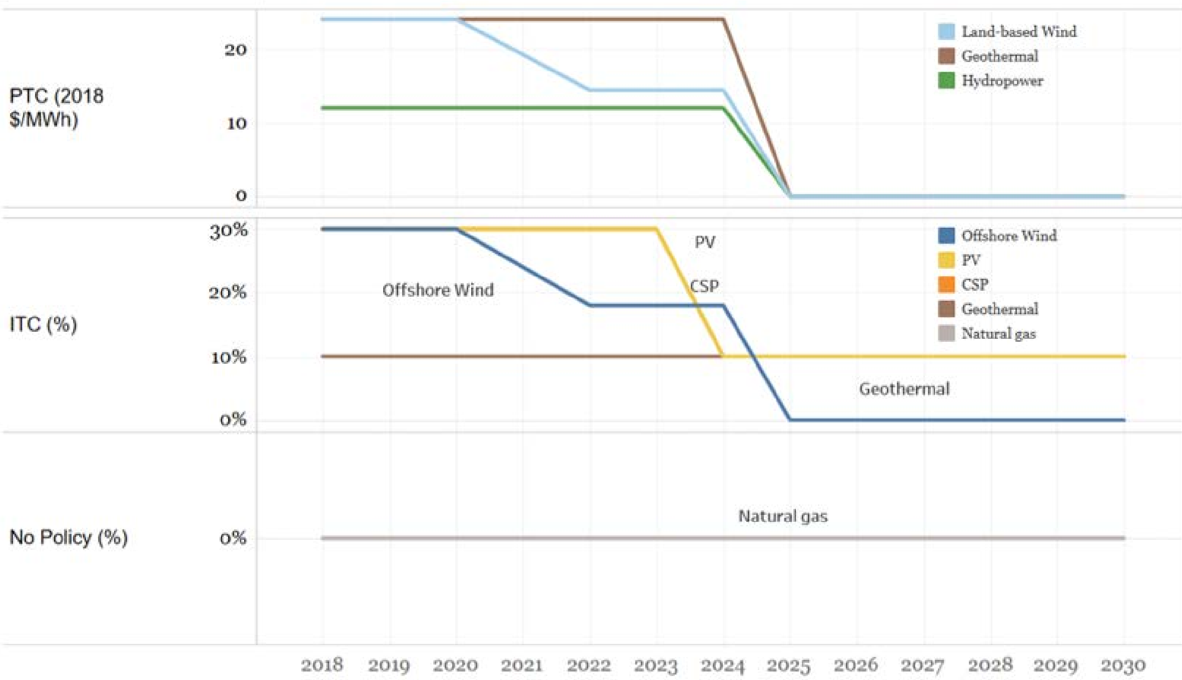


Figure 13. Tax credit assumptions for electric generating assets, by online date

We assume eligible projects use the full duration of the "safe harbor" window in order to receive the maximum tax credit level. We also assume offshore wind projects elect the ITC over the PTC in order to maximize economic value (though there may, in reality, be a few projects that choose the PTC over the ITC, depending on installed cost, anticipated capacity factor, and tax equity preferences). We never assume a 40% PTC (or similar ITC percentage for offshore wind) because of the step back up to 60% in the following year. Eligible hydropower facilities that receive the PTC include new power dams.

While both the PTC and ITC phase down over the next few years (Figure 13), the after-tax benefit that each provides will—all else being equal—be replaced by a greater amount of cash revenue (e.g., via higher PPA prices), which in turn will allow greater leverage. And because debt is typically less costly than equity, this shift in capital structure toward more debt will lower overall financing costs, thereby partially mitigating the loss of tax benefits. We use a cash flow model, with the technology cost and performance input assumptions from the ATB, as well as the financing assumptions in this report, to calculate project leverage by technology each year, while maintaining the DSCR requirements. As shown in Figure 14, our modeling accounts for the greater leverage that is possible as the PTC and ITC phasedown over the next few years.

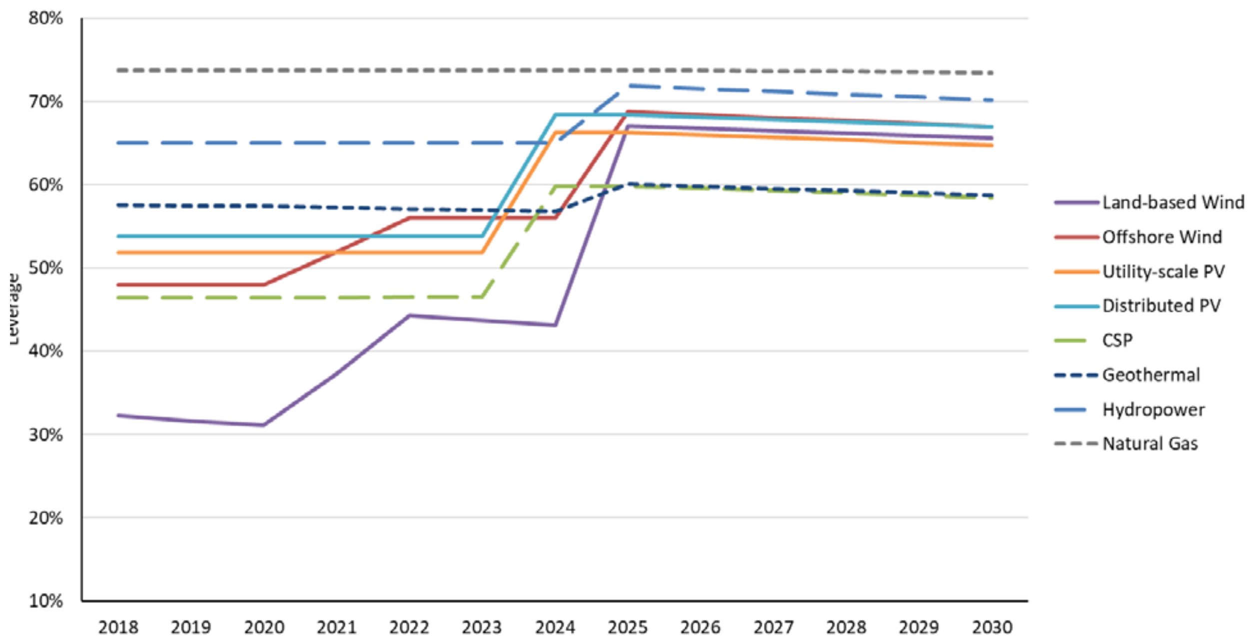


Figure 14. Leverage assumed in cash flow modeling as tax credits phase down

Because solar and geothermal projects benefit from a permanent 10% tax credit, their respective leverages tend to be at the lower end of the post-phase-out range (i.e., from 2025 to 2030). In general, the calculated leverages shown in Figure 14 for all technologies over this post-phase-out period (i.e., 60%–75% leverage from 2025 to 2030) are fairly consistent with leverages achieved by 174 global renewable energy projects that also do not receive tax credits, as summarized in Figure 15.

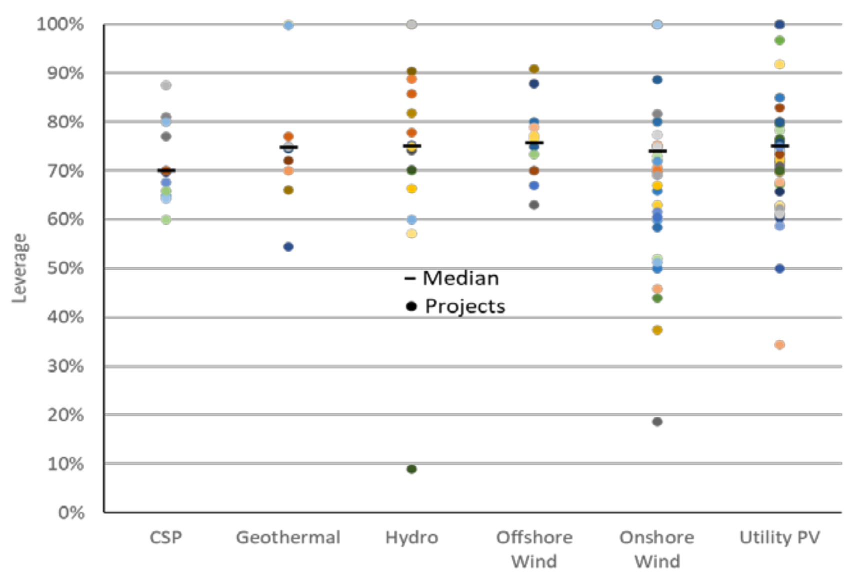


Figure 15. Leverage of global renewable energy projects, by technology

Sources: BNEF 2020b; Financier 1 2020; World Bank 2014; New Energy Update 2019; Thompson Reuters 2018, 2019

Although leverage varies significantly among individual projects, the median leverage is generally around 75%, with no clear differences between technologies. The differences are further lessened when the projects that received more than 80% financing through debt are removed, with the median dropping to around 70% for all technologies, which roughly matches the approximate leverage calculated for technologies in the 2020 ATB. Many of these high-levered projects received government, or quasi-government (e.g., World Bank), assistance in the form of nonmarket loan terms (e.g., 30-year terms), loan guarantees, or favorable credit guidelines. Many also received lower interest rates or higher equity returns (e.g., in the mid-teens) than projects in the United States, both of which allow for greater leverage for a given DSCR.

Beyond the obvious impacts on capital structure, the phasedown of tax credits will likely have additional—but harder-to-quantify—impacts on project finance, so we have not tried to quantify them. For example, the equity return on renewable energy investments will likely become more risky because of the greater amount of leverage at play and the fact that a significant portion of each project's after-tax return will no longer be secured by federal tax credits. In addition, the reduction in tax benefits could encourage more electric utility ownership of renewable energy projects, which is currently hindered by tax normalization issues that make utility ownership less competitive than IPP-ownership (Blank and Richardson 2020). That being said, IPP ownership should also become more competitive than it currently is because of the greater leverage that will be possible with the decline in tax credits, as noted above.

4.3 Other Factors that May Influence Future Financing Costs

A significant portion of current financial risk to renewable energy generation plants is mitigated by long-term, fixed contracts, with relatively stable counterparties. Currently, variation in the length of the contract and the creditworthiness of the offtaker contributes to a range in financing costs. Additionally, as discussed in Section 1, most new renewable energy generation plants are owned by IPPs. In the future, several different factors may change electricity sales revenue, and in turn, financing costs, including the following.

Movement Away from PPAs: Renewable portfolio standards have been major contributors to the adoption of long-term PPAs for renewable energy generation assets. Because many states have required an increasing, or at least constant, percentage of utilities' electricity to sales come from renewable energy facilities, PPAs have been long-term solutions for both utilities and project owners. However, IPP electricity sales from conventional electricity generation plants have not had this benefit for a variety of reasons; instead, they sell into wholesale markets, with limited future price certainty. To the extent that utilities or other offtakers (e.g., corporations) no longer feel the need or see an advantage to entering into these long-term contracts, this could create more price risk for renewable energy projects. Future price uncertainty could also rise if PPA contract durations shorten, increasing the percentage of cash flow over the lifetime of a project that is uncontracted at the start of commercial operations. That being said, many states and corporations in recent years have increased their mandates for carbon free electricity (DSIRE 2020; Domonoske 2020), which could continue to drive the need for purchases of renewable energy. Given the uncertainties involved, we do not adjust our future financing assumptions to account for changes in the use of PPAs or their durations.

Increased Curtailment: As the market penetration of renewable energy increases, so too does the risk of curtailment of variable generation. Most PPAs already anticipate a certain amount of curtailment, and allocate that risk among counterparties. For example, a PPA might allow the offtaker to curtail the project for economic reasons during a certain number of hours each year without having to compensate the project for lost revenue, or it might designate who bears the risk of reliability-based curtailment ordered when a grid operator exceeds a certain threshold. Going forward, these considerations are likely to become more important, and could impact the riskiness of renewable energy PPAs and, hence financing costs. On the other hand, increasing interest in medium- and long-duration battery storage could at least partly address curtailment risk from a physical, rather than contractual, angle. We do not adjust our future financing assumptions for increased curtailment risk, given the uncertainties over how it might affect financing.

Increase in Use of Financial Hedges: As the cost of renewable generation continues to drop and PPA prices converge with wholesale power prices, financial hedge products are becoming increasingly common in lieu of traditional PPAs in some markets (Bartlett 2019). These hedges are typically structured as a "contract for differences," where the counterparties—the project and a financial institution (or, increasingly, a corporate offtaker)—agree on a "strike price" that effectively becomes the de facto price of power locked in by the project.[26] If wholesale power prices exceed the strike price, the project pays the financial institution the difference (while selling its energy into the local wholesale power market). If wholesale power prices fall below the strike price, the project still sells its energy into the local wholesale power market, but the financial institution makes up the shortfall between the wholesale power price and the strike price. These types of hedges are common in the power industry, particularly for gas-fired generation, but they are typically of shorter durations, partly because of the fuel price risk associated with conventional generation. For wind projects, these types of hedges typically run 10–12 years (i.e., just long enough to cover the 10-year PTC window). For solar projects, they might be slightly shorter in duration (e.g., 8–10 years). While not as common as with other renewable projects, these hedges are becoming more common as solar PPA prices continue to decline. In either case, these hedges lock in prices for much shorter durations than does the typical wind or solar PPA—which, in turn, means greater market risk, particularly once the hedge has ended. Going forward, there will be increasing focus on this post-hedge "merchant tail" period, given that—particularly in high concentrations—wind and solar power tend to drive down wholesale power prices and thereby erode the incremental value they provide to the grid (a phenomenon sometimes referred to as "eating their own lunch"). As "merchant tail" risk grows, project financing might become shorter-term in nature (and/or more expensive), as investors seek to avoid that risk. On the other hand, as interest rates rise from today's historically low levels, the distant cash flows associated with the merchant tail will be more-heavily discounted, and so will carry slightly less weight than they do when discount rates are low. Given the uncertainties involved, we do not adjust our future financing assumptions to account for shorter contract durations or increasing merchant tail risk.

Fewer Creditworthy Regulated Utility Offtakers: A contract with a creditworthy counterparty can greatly mitigate financial risk, and in the case of renewable energy projects, most counterparties are regulated utilities with relatively high credit ratings. Investor-owned utility

[26] There are several different types of hedges in the marketplace, each with its own risk profile. For more information, see Bartlett (2019).

average credit rating at the parent company level in 2019 remained at investment grade BBB+ for a sixth straight year (EEI 2020). However, in 2018, Moody's Investor Service downgraded its overall outlook of the U.S. utility sector because of changes in the tax code and the challenges facing the utility industry (Foehringer Merchant 2018). When PG&E entered bankruptcy, it was reported that it attempted to renegotiate its long-term renewable energy PPAs, adding more risk to future long-term PPAs, though most contracts are still in place (Saint John 2019). While the increased risk of the changing utility landscape and what regulators and the industry are doing to mitigate these risks is an analysis unto itself, an increase in the future of utility bankruptcy could increase PPA counterparty risk and increase financing costs for renewable energy assets. Given the uncertainties involved, we do not adjust our future financing assumptions to account for a change in creditworthiness of PPA offtakers.

Changes in Regulation: Regulatory risk can be significant, particularly in other parts of the world. The United States has provided a relatively stable regulatory environment for operating renewable energy plants. Though regulatory changes have sometimes adversely affected future projects, existing projects have most often been grandfathered or shielded from such changes. To the extent that this unwritten compact changes going forward such that adverse regulatory changes affect existing projects as well, this risk could increase the financing costs of future projects.

Changes in Perceived Technology Risk: The industry is actively working on reducing the perceived risks to the construction and operation of renewable energy generation projects. Research and development is being funded for better resource forecasting, improved siting for better performance, improved operation and maintenance procedures, and lower hardware failure rates. These improvements can create more certainty in electricity generation over the expected life of an asset. On the other hand, an increase in maintenance or quality issues might increase the future perceived risk. We did not incorporate any of these changes in risk into future financing costs.

4.4 Summary of Financing Cost Changes Over Time

Table 6 (page 34) summarizes our financial assumptions by technology during the project's operation for an IPP-owned electric generation asset, incorporating our current benchmarks with the future changes in interest rates and tax credits discussed above.

We input these assumptions,[27] the leverage calculations summarized in Figure 14 (page 29), along with other technology-specific inputs from the 2020 ATB, to calculate WACC for the different technologies, according to the following formula:

Equation 1. WACC Formula

$$WACC = After\text{–}Tax\ Levered\ Equity\ Return \times (1 - Leverage) \\ + Debt\ Interest\ Rate \times Leverage \times (1 - Tax\ Rate)$$

[27] We choose 2025 as the starting point for the interest rate increase to simplify calculations and assumptions, given that is when all tax credits will have expired or reverted to their lower value.

These WACC estimates are shown in Figure 16 (page 35) as well as the ATB as a 'Market + Policies' financial case.[28]

Under these assumptions, the WACC on technologies with tax credits decreases as these credits phase out. WACC subsequently increases from 2025 to 2030 as interest rates rise.

[28] The 2020 ATB also has cases that reflect no consideration of tax credits and no change in interest rate. For these cases, we ran separate leverage calculations but input the same cost of equity and debt. WACCs for both cases are shown in the ATB: https://atb.nrel.gov/electricity/2020/images/financials/2020-supporting-financials-WACC.png.

Table 6. Summary of Current and Future Financial Assumptions by Technology

		Construction			Operation		
Technology	**Electricity Sales**	**After-Tax Levered Equity Returns**	**Debt Interest Rate: 2018/2030**	**Leverage**	**After-Tax Levered Equity Returns**	**18-Year Term Debt Interest Rate: 2018/2030**	**Leverage: 2018/2030**
land-based wind	PPA	11.0%	4.0%/5.0	80%	9.0%	4.0%/5.0	32%/66%
offshore Wind	PPA	12.0%	4.0%/5.0	80%	10.0%	4.0%/5.0	48%/67%
utility PV	PPA	9.75%	4.0%/5.0	80%	7.75%	4.0%/5.0	52%/65%
residential and commercial PV	PPA	10.75%	4.0%/5.0	80%	8.75%	4.0%/5.0	54%/67%
CSP	PPA	12.0%	4.0%/5.0	80%	10.0%	4.0%/5.0	46%/58%
geothermal	PPA	pre-drilling: 15.0% post-drilling: 10.0%	4.0%/5.0	pre-drilling: 0% post-drilling: 75%	10.0%	4.0%/5.0	58%/59%
hydropower	PPA	12.0%	4.0%/5.0	80%	10.0%	4.0%/5.0	65%/70%
natural gas	Quasi-merchant	12.0%	5.0%/6.0	80%	10.0%	5.0%/6.0	73%

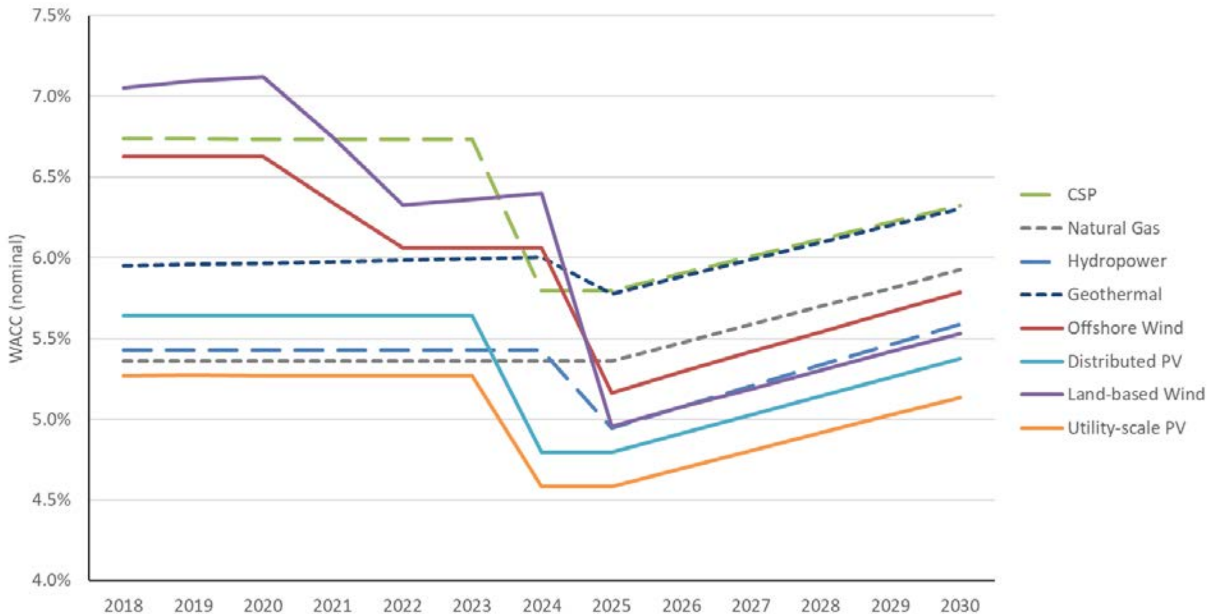


Figure 16. WACC of different technologies, 2018–2030

It is important to keep in mind that financing costs are one piece of the overall competitiveness of a project. Though projects receiving tax credits may have lower leverage, and thus a higher WACC, they benefit from the tax credits, which reduce the LCOE on net. For example, because of the benefits of receiving PTCs, the LCOE of land-based wind is lower in 2018 than its up-front capital expenditures, meaning there is not a lot of project operational cash flow in the model (received from the cost of energy) that can go toward paying off debt over the life of the project; thus, the DSCR dictates that it has a lower level of debt causing a higher WACC. As the PTC phases down, land-based wind's cost of energy goes up (relative to its capital expenditures) and it can now service more debt, and so has a lower WACC. Natural gas has the highest calculated leverage, yet it also has the highest WACC because it faces a higher cost of debt and equity (owing, in part, to it being the only technology analyzed to not have fully contracted cash flows). However, in 2018, natural gas still has some of the lowest LCOEs in the ATB, does not depend on long-term fixed contracts, and may be more competitive in markets for reasons not captured by LCOE (e.g., capacity credit). Some might argue that the financing cost for a new CSP plant would be even higher than reported in Figure 16 because no new CSP projects are under active development in the United States and therefore they represent a risk investment. However, financing is not holding CSP development back in the United States; it is the lack any CSP projects with long-term PPAs, permitting, and environmental approvals that are needed to receive financing.[29] Globally, several gigawatts of CSP projects, including the newer technology "power tower" projects with storage, have received financing in the past few years at rates lower than the those assumed in this report; however it would undoubtedly be easier to finance a plant using trough technology, all other things being equal, because of its longer track record. These projects were financeable because long-term power agreements were made available at rates that could support the upfront and ongoing costs of a CSP plant. The U.S. market has not as of yet realized such agreements for CSP, instead opting for lower LCOE PV, wind, and batteries projects.

[29] One could argue that financing is holding-up merchant CSP plants from entering operation, but the same holds true for most U.S. renewable energy projects.

5 Conclusion

In the analysis, we attempted to estimate financing costs over time across a broad range of renewable electric generation technologies to inform the Annual Technology Baseline (ATB).

Several types of corporate structures have access to different kinds of equity and debt, which they use to finance electric generation assets. A project's construction, operation, and contract risk are important factors in determining these costs and the capital structure used. However, there are also political and regulatory considerations (e.g., the availability and size of tax credits, normalization accounting rules for utilities) and macroeconomic factors (e.g., supply and demand of capital, and the federal funds rate) that also determine overall financing costs. These vary by energy technology, by project ownership (IPP versus IOU versus POU), and also over time.

Variation in project finance costs also exists based on the individual characteristics of a project, its owner, and when and where it is built. Looking forward, many other factors may change the underlying risk to project cash flows.

Because renewable energy projects tend to be capital-intensive and have lower operating costs, financing costs often can be a more important contributor to LCOE than for conventional electric generation plants. NREL's ATB LCOE projections have historically been affected primarily by its projections of technology cost and performance over time. Going forward—and as a result of the work described in this paper—the cost of finance can be used in the ATB, or for other analyses that require current or future financing inputs for various technologies, as another important distinguishing variable both across technologies and over time. Potential future work that progresses this analysis could include quantifying the range in financing costs across technologies depending on the project risk profiles and availability of capital in the marketplace. Additionally, it could be useful to perform a more in-depth quantitative comparison of the cost of financing between IPPS, IOUs, and POUs.

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