The Impacts of Policy on the Financing of Renewable Projects: A Case Study Analysis

A CPI Report

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About CPI

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Executive Summary

What would it take to make renewable energy policy a success? One key determinant of success is whether policies encourage enough investment; another is the financial cost of this investment. Policy will set the conditions under which investment decisions are made, while these decisions will determine whether policy objectives are met and at what cost.

In this paper, we study six large-scale renewable electricity generation projects in the United States and Europe to evaluate how policy affects project economics, as well as the cost and availability of financing. We use this analysis to draw lessons for designing policies that can help reduce financing costs for renewable energy.

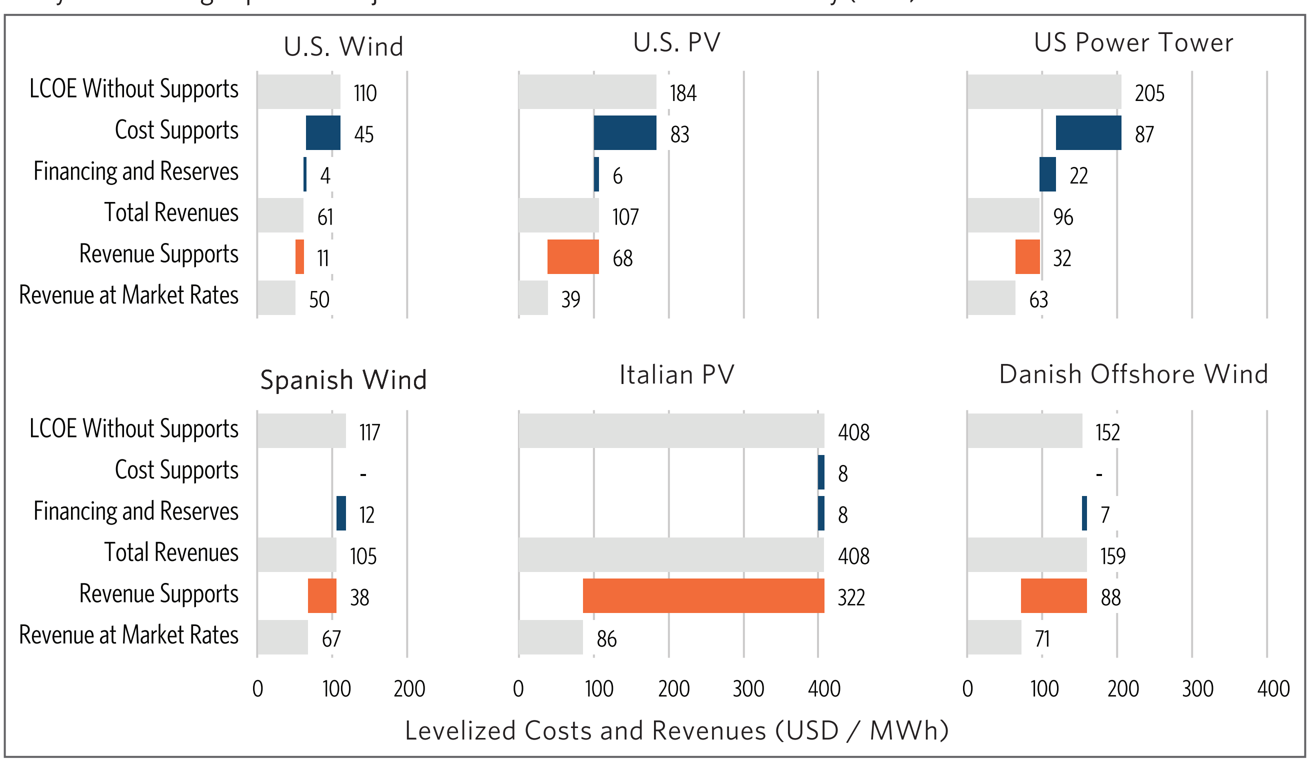
The six cases: policy support, returns, and project costs

We studied large onshore wind farms in the U.S. and Spain, utility-scale solar photovoltaic (PV) facilities in the U.S. and Italy, and two less mature technologies – a concentrated solar power tower in the U.S. and an offshore wind farm in Denmark. The figure below shows the impact of cost and revenue support policies and the incremental financing costs (relative to local utility financing costs) for these projects.

For these six projects - based upon our modeling of project costs, revenues, and returns - we found that:

- The projects would not have attracted investors without policy support. Policy supports provided 36 to 81% of the cost of electricity from these projects. U.S. projects utilized a

Policy and Financing Impacts on Project Revenues and Levelized Cost of Electricity (LCOE)



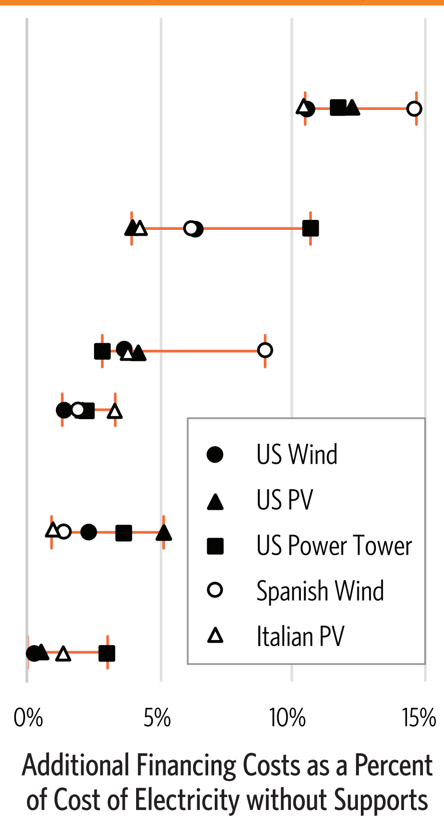
combination of cost and revenue supports, while European projects relied more heavily on revenue support.

- Except for the Italian PV facility, financing and project costs are in line with published benchmarks for renewable projects. The Italian PV facility had both high returns (estimated 27% equity return) and a high cost of electricity (more than double that of the U.S. PV facility). The high Italian Feed-in-Premium (FiP) made such returns possible. The rush to qualify for the premium prior to its expiration appears to have driven up equipment and installation costs.

The impact of policy on financing costs

We identified seven pathways through which policy can affect the cost of finance. Using financial models of each of the projects, we quantified the impact of these factors by comparing financing costs in various policy and project scenarios. The seven policy impact pathways and the results of the analysis are illustrated below.

Policy Impacts on the Cost of Financing



Policy Impact Pathway	Potential Impact on Financing Costs	Scenario
Duration of Revenue Support Whether support is concentrated in early years or spread over the life of a project will determine how a project is financed and thus		Revenue support duration reduced by 10 years
Revenue Certainty Exposure to price risks of commodity markets can influence the amount of debt a project can support and the cost of both debt and equity.		Fixed electricity price (Feed-in-Tariff or PPA) versus fixed premium (Feed-in-Premium)
Risk Perception Higher perceived risks may lead investors to demand higher returns or more security to compensate.		Equity Investors (Top): High end of required return range Debt (Bottom): Higher margin of security for debt payments
Completion Certainty The risk of delayed revenues due to late project completion may increase financing costs by reducing achievable leverage or requiring reserves or guarantees.		Assume a 1 year construction delay in making financing decisions
Cost Certainty The risk of unexpected costs – sometimes policy driven – can also increase the costs of financing due to the reduced amount of debt providers are willing to commit, or due to the cost of required guarantees or reserves.		Assume a 5% cost overrun in making financing decisions
Risk Distribution	The ability and cost to bear certain risks varies among investors, suppliers, consumers, and others. By changing which risks (e.g. commodity prices or inflation) are absorbed by which project stakeholder, policy can reduce or increase the financial cost of projects.	
Development Risks	The cost and success rate of developing a project will affect the attractiveness of the industry. A more attractive industry will have more competition, driving costs down.	

For all of the projects, three factors stood out:

- **The duration of revenue support had the largest impact on financing costs.** Debt providers match debt repayments to the expected cash flows over the life of the project. When revenue supports end early, projects must pay down debt faster to adjust for lower cash flows in later years. This effect increased financing costs by 11-15% of the cost of electricity when revenue support was reduced by 10 years (while increasing the level of support to reach required debt and equity returns).
- **Revenue certainty is the second most important factor.** In all six cases, the uncertainty of electricity prices is a much greater source of revenue risk than the uncertainty surrounding the wind or solar resource. A shift from fixed electricity prices - such as through a Feed-in-Tariff (FiT) or power purchase agreement (PPA) - to a combination of a premium plus market prices (normalized to maintain equity returns) leads to additional financing costs of 4-11% of the cost of electricity. Revenue certainty is more important to projects that require the lowest premium, as market prices impact a greater share of revenues, and to projects with either high equity costs or low-cost debt, as revenue certainty enables an increase in the low-cost debt. Fixed prices are not the only way to address revenue certainty. Since debt investors are concerned about downside risk, including a collar or minimum price can achieve nearly the same benefit as the fixed electricity price. In our Spanish Wind case, the FiP penalty was reduced from 6% to 1% by a collar.
- **Investors' perceptions of risk also significantly impact project financing costs.** Higher risk perceptions lead equity and debt investors to require increased returns or demand greater margins of error. The upper range of investor requirements would increase financing costs by 3-9% of the cost of electricity.

For less mature or more innovative projects, protection against losses is critical due to higher perceived risks of project failure. The risk of default – a project being unable to meet debt payments – discourages debt investors. Meanwhile, these projects often require higher equity returns to compensate for perceived risks, so the importance of debt in lowering financing costs is greater. Policies that offer investors some level of protection against default – or absorb the default risk by providing debt directly – can have a significant impact. For example, if the U.S. solar power tower were financed without debt (which was made possible by a loan guarantee and low-cost government loan) the project would have incurred additional financing costs of 38% of the cost of electricity.

Construction and completion risk can be covered through commercial arrangements, as in two of our cases where contracts with the constructors absorb this risk. In other cases, the sponsoring developer was also the constructor, earning higher returns, in part, to compensate for the elevated risks during construction. Because the financial cost of absorbing these risks can be high, policies or commercial guarantees that enable debt financing during construction can significantly reduce project financing costs (by 8-23% of the cost of electricity in the six cases). The length of the expected construction period also has a large influence on the benefit of guarantees or policies.

Institutional investors with the expertise to evaluate renewable projects will invest in renewable projects with revenue certainty and arrangements to insulate them from policy and completion risks (such as through policy support or private contracts). This was the case in both the U.S. PV and the offshore wind projects. To develop this capacity, investors are likely to require greater industry scale to justify investing in the expertise, training, and analytical support.

Next Steps

Our aim is to extend these analyses to explore the impact of policy design options on renewable policy effectiveness more generally and to apply the lessons to policy options currently under consideration by policymakers. Several areas of immediate interest include:

- Extending the analysis to other geographies. In particular, we are interested in whether these insights apply to emerging economies and why or why not.
- Exploring a greater set of policy design options – for instance, extending the revenue certainty analysis to evaluate the impact of support incentives that are variable, such as renewable energy credits (U.S., India), renewable obligation certificates (UK) or green certificates, or assessing the impact of cost versus revenue supports.
- Evaluating the impact of changes in design features – for example, how sensitive are financing costs to the level of a price collar or whether tapered incentives have the same duration impact?
- Analyzing the tradeoffs with lower financing costs – for example, do the lower financing costs on offer through FiTs justify the additional risk that may be absorbed by government or ratepayers?
- Understanding how financiers and developers will alter their financial requirements when investing in portfolios of projects – for example, how does the cost of increasing development uncertainty impact willingness to invest in renewable projects?

1 What can project finance case studies tell us about renewable policy effectiveness?

Effective renewable energy policy would encourage the provision of enough renewable energy to meet policy objectives, drive innovation and cost reduction for new technologies, and would do so cost effectively, equitably, and without introducing significant risks. Where companies or other private sector investors are the main sources of funding to meet these goals, financing lies at the heart of their decision-making process and has a crucial impact on how much renewable energy these investors decide to provide, at what cost, and with what associated risks. In other words, financing is a key determinant of the effectiveness of renewable energy policy.[1]

Renewable projects, their investors, and the policy environments in which they might operate are diverse and heterogeneous. Thus, there is no single prescription that tells us how to design policy so that renewable projects are financed effectively. In this paper, we identify some general principles of how policy influences investment decisions, with a view towards building tools to help policymakers design policies that can effectively and efficiently leverage investment in the renewable space. To do so, our analysis and discussion has several parts:

- First, we set out the specific mechanisms, or pathways, through which policy can impact the financing of renewable projects.
- Next, we explore the different types of investors that might participate in renewable energy projects and begin to show how each of these policy "impact pathways" would affect their investment decisions.
- As a third step, we have studied a series of cases based on real world renewable energy projects in the U.S. and Europe. Applying this framework of policy impacts on potential investor types, we attempt to understand how policy has affected – or could have affected – the investment decision, costs, and risks of each project. In particular, we address three basic questions:
  - » How did policy affect project costs, revenues, and returns?
  - » How can policy impact the cost of financing these projects?
  - » How could policy help attract capital?
- Finally, we will bring the findings from these case studies together to identify where there may be common lessons and under which circumstances these lessons might be applicable.

1 In CPI's "Renewable Energy Financing and Climate Policy Effectiveness" Working Paper, we explored how financing can be used to diagnose policy effectiveness outcomes, focusing on deployment of renewable energy, cost-effectiveness, distribution of risks, costs and benefits, innovation outcomes, and policy stability as key policy effectiveness criteria.

2 What are the pathways by which policy impacts project financing?

In general, policy can affect the investment environment by influencing the allocation of costs and revenues, the allocation of risks, and the technology choices and business practices of electricity market participants and other key stakeholders. From our analysis of the six cases discussed below, as well as interviews with a range of stakeholders, we find that these influences can be best understood through the following policy impact pathways:

Duration of revenue support

The term of a project's financing is often directly linked to the duration of policy support measures. Different classes of investors have different investment horizons, and their investment decisions are strongly influenced by a project's financing term.

Revenue certainty

Revenue streams from the sale of electricity from renewable projects can be volatile – for example, due to variability in the wind or solar resource, poor technology availability, and/or changing market prices for the electricity generated. Investors may demand a premium to bear these risks, and policies that can either directly or indirectly improve revenue certainty can help reduce these costs.

Risk perception

Investors' perceptions of project risks play a significant role in determining the amount and cost of financing made available. Such perceptions can be significantly tied to policy regimes – investors are likely to demand a premium for projects that depend on substantial, ongoing incentives to compete, depending on their perceptions of the political sustainability of the incentives. These perceptions will vary by region and over time.

Cost certainty

Construction and operational cost uncertainties can substantially impact investor returns. Policy requirements that lead to the establishment of various reserve accounts or performance guarantees – as well as up-front incentives – can reduce these risks or shift them to other stakeholders who are comfortable bearing them.

Completion certainty

The timing of completion and operation is often critical for meeting investor return requirements, and the risk that a generating facility based on a new technology will not meet its target operational date is one that few investors are willing to bear without substantial premiums. Policy can often substantially impact or shift the burden of these risks.

Risk distribution

Different investors are comfortable bearing different risks: they may have business processes to reduce certain risks or may even have offsetting risks. Policy can influence the allocation of risks among project stakeholders or reduce the impact of these risks on financing costs, thereby broadening the base of interested investors.

Development risks

Only a fraction of projects in a development pipeline ever get built, due to barriers such as competing outside stakeholder interests and regulatory delays or impediments. Policies that can reduce development timeframes and increase success rates can substantially improve developer capital efficiency and returns and attract investor interest.

3 Who are the potential investors and what do they care about?

A range of financial instruments is used to provide capital to renewable energy projects. These financial instruments include multiple types of debt, equity, and mezzanine finance. The return requirements of investors, as well as the mix of finance types used, ultimately determine the cost of capital of a project. The following description of investor characteristics draws from earlier work framing our approach to effectiveness analysis in the financing of renewables [CPI (2011)].

3.1 Investor Characteristics

Debt investors bear the least risk and expect the lowest returns. They generally do not invest in projects that use unproven technologies and often require contractual arrangements that protect them from technology-related delays or underperformance. Similarly, debt investors can be wary of policy and regulatory risk when cash flows depend on policy support. Debt investors usually earn a specified coupon rate, or a specified margin above a benchmark interest rate.[2]

Debt investors are particularly concerned with the default risk of their investment. Providers of debt conduct rigorous assessments of project risks, scenarios in which the borrower would default (be unable to make a debt payment), and the likelihood of those scenarios. The assessment of default risk determines whether project debt is "investment grade" – an important consideration for many institutional investors.

The debt service coverage ratio (DSCR) – cash flows available for debt service divided by debt service payments – is an important metric in assessing default risk. Lenders to wind projects look at the debt service coverage ratio under a variety of wind resource scenarios. For example, they might require that low wind conditions with a 10-percent chance of occurring generate sufficient cash flows to cover 1.2-1.4 times the amount of debt payments. Certain contractual conditions may be used to maintain adequate debt service coverage, like cash sweeps[3] or sculpted amortization schedules.[4]

Mezzanine investors have a variety of investment objectives. They might require the predictability of returns offered by debt-like instruments, while

Institutional Investors

This class includes entities such as pension funds and insurance companies. They can be debt, mezzanine, or project equity investors. They generally have long-term cash requirements around which they will tailor their mix of investments in order to trade-off duration risk and volatility against returns. These investors manage a large volume of capital, have long investment horizons, and a relatively low tolerance for risks associated with policy or technology uncertainty.

These preferences are well matched by the features of traditional infrastructure projects, which tend to be capital intensive, require longer time-horizons, and generally involve low policy or technology risks. Renewable deployment could benefit tremendously from increased investment from these investors, but policy and technology risk concerns must be overcome. In two of our cases with investment from institutional investors, we sought to better understand how policy can help address their concerns about renewable projects.

2 When a debt instrument carries a fixed interest rate, this is typically referred to as the "coupon rate." When a debt instrument specifies a margin rather than a fixed rate, the margin is usually measured in basis points above an interbank rate, such as LIBOR or EURIBOR.

3 Cash sweeps capture cash flows that would not be used to service debt for advance repayment of debt principal and interest. This contractual clause is designed to protect debt investors from unexpectedly low project cash flows. Cash sweeps reduce the amount of project cash flow available for project equity investors.

4 Sculpted amortization allows debt service payment amounts to vary with cash flows, to account for variation in cash flows across seasons. This is another way of protecting debt investors from low project cash flows, by capturing additional payments when cash flows are high. Sometimes amortization schedules are sculpted to maintain a constant debt service coverage ratio.

Table 1 - Summary of Investor Characteristics

Investor Type	Risk Requirements	Metrics of Interest	Cost of Capital
Debt	Low risk tolerance, typically will not bear technology or completion risks, and are often insulated from operational risks.	Debt service coverage ratio (DSCR), Margin or Interest Rate	Low
Mezzanine	Somewhat low risk tolerance, will bear some operational risks but not completion risks.	IRR, Interest Rate, and Default Probability (for Fixed-Income Instruments)	Low – Medium
Balance Sheet Equity	Bears all project risks.	IRR, other metrics relevant to internal decision-making	Medium
Project Finance Equity	High risk tolerance, willing to concentrate project risk by increasing project leverage.	Project IRR, Levered IRR	Medium - High

tolerating more default risk than debt if it affords them a higher rate of return. They might prefer equity with a capped return in exchange for limited exposure to equity risks.

Tax equity is a mezzanine investment instrument generated by the structure of tax incentives for renewable energy in the U.S. Tax equity investors realize returns primarily based on tax credits for investment in or production of renewable energy and tax benefits derived from accelerated depreciation of a project's capital cost. Tax equity investors must have sufficient tax liability to absorb these tax benefits. Tax equity investors are protected from many of a project's cash flow and revenue risks, but because their return relies entirely on tax and depreciation policy, they are exposed to regulatory risk, should tax and depreciation policy change.

Balance sheet equity investors are typically large utilities that finance new projects entirely from their own capital. By providing all of the capital required to build a project, they also take on most or all of the project risks. Balance sheet investors may use a range of metrics to evaluate a project and to evaluate its impact on their portfolio of investments. For instance, they might look at the internal rate of return (IRR) of a project as a metric of profitability. This IRR is usually compared with the company's cost of capital, as well as with a "hurdle rate" designated for a particular type of project, given its risk profile.

Project finance equity investors take an ownership stake in their projects as well, often coupled with other equity partners, mezzanine investors, and debt. In project finance arrangements, equity investors bear the most project risk and are compensated with higher potential returns. Equity investors, often also the developers of projects, can increase leverage (the proportion of debt) to increase their return. However, increased leverage also concentrates project risks with a smaller amount of capital. Because project developers have control over many aspects of a project, they may be better suited to manage or mitigate project risks.

When equity is invested alongside debt, the metric of interest is usually a "levered IRR," the rate of return after debt is serviced. Equity investors evaluate the rate of return they receive given the risks they absorb. In this sense, equity investors are most interested in the risk-adjusted rate of return on their investment.

3.2 Return Benchmarks

In order to make this discussion of investor behavior more concrete, we provide some recent published estimates of rates of returns required by various investors for renewable projects in the U.S. and Europe as benchmarks. In the next section, we will compare our modeled after-tax (levered, if debt is involved at the project level) IRRs for equity investors in the cases we studied to these benchmarks as one measure of policy impact. We will also use the benchmarks instead of our computed returns in our analysis of the impact of policy on financing costs. This is to avoid complications associated with the potential that the specific investors in our projects may have had return requirements stemming from their particular financial needs.

U.S. Return Benchmarks

Table 2 below, taken from [Mintz Levin (2010)], provides an estimate of rates of return typically expected by U.S. project investors.[5]

European Return Benchmarks

Similarly, we compiled estimates of some corresponding benchmarks for returns observed for renewable projects in European countries (Table 3).[6]

McKinsey (via GRE Holdings) provided more detail on the variation of PV returns observed across Europe (Table 4).

5 Here CSP refers to all Concentrating Solar Power projects, and in particular would be relevant for the U.S. solar power tower case. LIBOR is the London Interbank Offered Rate.

6 EURIBOR is the Euro Interbank Offered Rate

Table 2 – Rate of Return Benchmarks for U.S. Renewable Projects

Finance Type	Technology	Rate of Return	Availability
Term Debt	Wind	LIBOR + 250-300bp	High
	Solar PV	6.5-7.5%	Fair to High
	CSP	7.5-10%	Low
	Geothermal	8-12%	Low
Unlevered Tax Equity	Wind	7-10%	Fair
	Solar PV	9-13%	Fair to Low
	CSP	12-15%	Low
	Geothermal	10-12%	Low
Levered Tax Equity	Wind	10-13%	Fair
	Solar PV	13-20%	Fair to Low
	CSP	15-18%	Low
	Geothermal	13-15%	Low
Sponsor or Private Direct Equity	Wind	6.5-14.5%	High
	Solar PV	7-18.5%	Fair
	CSP	15-20%	Fair to Low
	Geothermal	10-15%	Low

Reproduced from Mintz Levin (2010). Renewable Energy Project Finance in the U.S. : An Overview and Midterm Outlook, Whitepaper, http://www.mintz.com/media/pnc/2/media.2372.pdf

Table 3 – Rate of Return Benchmarks for European Renewable Projects

Finance Type	Technology	Rate of Return	Source
Term Debt	Onshore Wind	EURIBOR + 200-300bp	Project Finance Magazine
	Offshore Wind	EURIBOR + 300bp+	Project Finance Magazine
	PV	EURIBOR + 250-350bp	Project Finance Magazine
Unlevered Equity	Onshore Wind	5-9%	Macquarie
	Offshore Wind	4-13%	KPMG
	PV	10-11%	Solar Energy Partners
Levered Equity	Onshore Wind	8-16%	Macquarie
	Offshore Wind	NA	
	PV	15-18%	Solar Energy Partners

Table 4 – Rate of Return Benchmarks for European Solar PV Projects

Market	Centralized Solar Equity IRR in 2008-2009
Stuttgart, Germany	6-8%
Seville, Spain	21%
Palermo, Italy	17-26%
Nice, France	3-13%
Athens, Greece	17-23%

Source: McKinsey & Company, via GRE Holdings Presentation.

4 What do the six cases tell us about how policies impact investor decisions?

We use the policy impact pathways introduced earlier to study policy influences on the financing of six renewable projects, based on publicly available information. CPI developed the financial model described in Appendix A to enable a quantitative assessment of the impacts on the projects studied. We used publicly available data, interviews, and financial modeling to draw lessons from the six cases described in the Table 5.

We describe the U.S. cases and policies in Section 4.1 and the European cases in Section 4.2. We then discuss the projects' returns, costs, and revenues based upon publicly available information in Section 4.3. In Section 4.4 we present the potential impacts of the pathways identified in Section 2 on the cost of capital for these projects, and in Section 4.5 we discuss ways in which the projects were able to attract capital from non-traditional investors.

4.1 U.S. Cases and Policies

Generic U.S. Wind based on First Wind Milford (Utah)

We used the cost, performance, and other key features of the 204 MW Milford wind farm developed by First Wind, as well as some generic features of First Wind's financing approach, as a proxy to build a model for a generic U.S. wind project. In particular, we assumed the use of a tax equity flip-financing arrangement, commonly used in the U.S. to take advantage of tax benefits, such as accelerated depreciation. As was the case for Milford itself, we assume the project utilizes a tax grant, and we assume that the project was built to deliver electricity to help satisfy a California RPS through a long-term PPA. The key policy impact question for this case is how the mix of cost and revenue support policies ultimately affects the cost of financing the project.

Utility Scale PV based on Greater Sandhill (Colorado)

The 19 MW Greater Sandhill Photovoltaic project was fully commissioned in March 2011, in Colorado's Alamosa County. It is one of the largest deployments of solar PV technology in the U.S. The project relies on a range of renewable energy policies, including Colorado's RES, the US tax grant, and potentially, 100% bonus depreciation and Alamosa County tax credits. The project attracted tax-motivated equity and debt financing from two major institutional investors. Key policy impact questions for this case study are focused on determining how policies enabled investment by institutional investors.

Solar Power Tower based on BrightSource Ivanpah (California)

The Ivanpah Project, currently under construction, will be the largest solar thermal electricity generating facility in the world when it begins operating in 2013. The 392 MW, $2.2 billion facility will be built it phases, eventually consisting of three power towers. The project's construction is substantially a result of U.S federal and state policies:

- a $1.6 billion federal loan guaranteed by the U.S. DOE,
- an estimated $570 million cash grant,
- accelerated depreciation,
- lease of federal lands,
- a long term PPA with utilities bound by California's RPS, and
- exemption from property taxes for solar property.

The developer was able to use the government investment to bring in substantial private capital from outside investors, including a relatively new tax-motivated investor to this space. Key policy impact questions for Ivanpah include how this mix of policies combined to make the project viable, and how the policies allocated risks and rewards among government and private stakeholders in order to enable significant private investment in the scale-up of this innovative technology.

Table 5 - Project Summaries

U.S. Cases	Description	Key Issues
Generic U.S. Wind based on First Wind Milford (Utah)	• An estimated $445 million, 204 MW wind farm • Assumed tax equity financing and a long term Power Purchase Agreement (PPA) with a California utility in response to 2007 request for proposals	• How does the mix of up-front tax subsidies and long term revenue support through fixed-price contracts impact the cost of financing the project?
Utility Scale PV based on Greater Sandhill (Colorado)	• An estimated $94 million, 19 MW PV installation by SunPower • Attracted debt and equity investment by institutional investors (John Hancock , MetLife) • Long-term, above market PPA awarded to meet state solar generation standard	• How did policy help attract institutional investors to this project?
Solar Power Tower based on BrightSource Ivanpah (California)	• $2.2 billion, 392 MW solar power tower to be built with a $1.6 billion government loan	• How did policy attract investment in a first-at-scale facility, and were all the policies used necessary?
	• Attracted $598 million in private financing, including a $168 million tax-motivated investment from Google	• How did policy allocate risks and rewards among stakeholders?
European Cases	**Description**	**Key Issues**
Generic Spanish Wind based on Villanueva (Spain	• 130 million EUR, 70 MW onshore wind farm	• How do market price risks and policy risks in Spain's Feed-in-Premium (FiP) and Feed-in-Tariff (FiT) support schemes impact investors?
Utility Scale PV based on Rovigo (Italy)	• 275 million EUR, 60 MW PV installation • Received a significant Italian FiP	• The oversubscription of the FiP led to very high program costs and subsequent changes to the FiP. How did such changes impact risk perception and financing costs?
Offshore Wind based on Anholt (Denmark)	• 9.3 billion DKK (1.4b EUR), 400MW Offshore wind farm • Pre-completion commitment of funding from a Danish Pension Fund	• How did policy help attract institutional investors to this project?

U.S. Renewable Policies

U.S. Department of Energy (DOE) Loan Guarantee
The DOE guarantees loans made to renewable projects by private lenders or by the U.S. Federal Financing Bank. The cost to the DOE of providing the guarantee is being covered by funds made available by the U.S. Recovery Act of February, 2009.

Tax Credits and Grants
U.S. wind projects built by 2013 are eligible for production tax credits (PTC: $0.02 per kWh for 10 years), and solar built by 2017 for investment tax credits (ITC: 30% of eligible project costs). If they begin construction by the end of 2011, they can apply for a grant in lieu of either tax credit for 30% of eligible project costs. These grants were authorized by Section 1603 of the Recovery Act.

Accelerated and Bonus Depreciation
Renewable projects can accelerate the rate of depreciation for tax purposes of their renewable property from the life of the project down to 5 years. In addition, projects placed into service by the end of 2011 (2012) can claim 100% (50%) bonus depreciation (depreciation of 100% (50%) of the property's value in the first year).

Use of Federal Lands
The U.S. leases Federal lands for renewable generation, with payments set using rural land market value benchmarks with a surcharge for solar property use.

Renewable Energy or Portfolio Standard (RES or RPS)
Demand for renewable electricity in states are often driven by requirements that load-serving utilities derive a target fraction of their electricity generation from (non-hydroelectric) renewable sources by a target date. To meet this requirement, many utilities have been offering long-term power purchase agreements (PPAs) to project developers at the avoided cost to the utility of financing the generation itself.

Property Tax Exemptions for Renewable Property
A number of states exempt renewable facilities from property taxes in order to attract investment.

Sales Tax Exemption
A number of U.S. states exempt purchases of equipment or services for renewable electricity generating facilities from sales / use taxes.

Key Modeling Assumptions

In Table 6 below, we summarize some of the key parameters used to model U.S. project costs, revenues, and returns. The financial model itself is described in greater detail in Appendix A.

Table 6 – Key Modeling Assumptions for U.S. Projects

	Generic U.S. Wind based on First Wind Milford	Utility Scale PV based on Greater Sandhill	Solar Power Tower based on Ivanpah
Project Size	203.5 MW AC	18.5 MW AC	376.6 MW AC
Production	450,953 MWh / Yr	48,004 MWh / Yr	975,000 MWh / Yr
Project Cost	445m USD	94m USD	2.2b USD
Grant Amount	120.1m USD	25.4m USD	570m USD
First-Year PPA Rate	98.4 USD / MWh	147 USD / MWh	161 USD / MWh
PPA Duration	20 Years	20 Years	25 Years
First-Year Market Rates	68 USD / MWh	53 USD / MWh	83 USD / MWh
Fixed O&M	28 USD / kW-Year	22 USD / kW-Year	64 USD / kW-Year
Accelerated Depreciation	5-Year Modified Accelerated Cost Recovery System (MACRS)	5-Year MACRS, does not apply with 100% bonus	5-Year MACRS
Bonus Depreciation	50%	100%	0%
Base Case Term Debt	Optimized	45m USD	1.6 b USD
Required Min DSCR	1.3x	1.4x	1.4x
Debt Interest Rate	7.0%	7.028%	4.7%
LCOE Discount Rate	8.25%	7.88%	8.25%

Sources:

Generic Wind: First Wind S-1, SCPPA 2009-10 Annual Report, US Treasury, 2007 California MPR Model, EIA.

Greater Sandhill: FERC, PPA Approval Proceeding with CO PUC, US Treasury Dept, EIA, MetLife of CT 2010 10-K.

Ivanpah: BrightSource S-1, US Treasury, EIA, BLM Record of Decision for Ivanpah, California MPR Model, CPUC Approval of SCE and PG&E PPAs. The impact of time-of-day factors are modeled as a 25% premium added to estimated Ivanpah PPA and market rates relative to MPR rates / EIA forecasts. Further, a fraction of the tax grant (assumed as needed to achieve the min DSCR) is assumed to pay down principal on the DOE term debt, as noted in the case of Kahuku Wind's loan guarantee in First Wind's S-1.

4.2 European Cases and Policies

Generic Spanish Wind based on Villanueva (Spain)

The Elecnor Villanueva wind farm is a 66.7 MW project near Valencia, Spain. The project was commissioned in November 2009. The key support provided to this project came in the form of a Feed-in-Premium (FiP) for wind projects. Spain allows wind projects to receive a 29.2 EUR / MWh FiP (adjusted annually for inflation) above market rates, adjusted such that the sum of the premium and market rates falls with an inflation adjusted price collar between 71.3 - 84.9 EUR / MWh. This incentive scheme is revisited every four years, and can be adjusted to meet target project IRRs of 5-9%. Key policy impact questions here include the effect of market price risks on investors (and how that market price risk may differ with incentive design), as well as the impact of policy uncertainty on investment practices.

Utility Scale Solar PV based on Rovigo (Italy)

The Rovigo solar PV plant was commissioned in Northern Italy in December 2010. Boasting a 70

MW DC capacity, the EUR 320 million PV plant was the largest single operating PV system in Europe at its completion date. The PV system was completed, interconnected and commissioned in nine months. The project benefited from a:

- EUR 346/MWh FiP fixed for 20 years (without any inflation adjustment)for solar PV
- Guaranteed offtake of electricity at market rates for 20 years
- A reduced VAT rate (10% instead of 20%) for construction costs.
- Priority dispatch
- One-stop shop for permitting

In the spring of 2010, major uncertainty surrounded the future of FiPs in Italy beyond 2010. To benefit from the higher premium, the developer completed the large scale plant in less than 9 months. FiPs are funded by all Italian ratepayers via a specific cost component on the bill. Key policy impact questions for Rovigo are focused on the rush to project completion due to the uncertain future of the generous premium, the level of the FiP, and the sustainability of the FiP.

Offshore Wind based on Anholt (Denmark)

Anholt, when completed in 2013, will be a 400 MW offshore wind farm, so far the largest to be built off the coast of Denmark. It benefits from a Feed-in-Tariff (FiT) for its first 20 TWh of production (roughly 13 years' worth), and is the first large offshore wind farm to attract pre-completion commitment for equity financing from institutional in-

European Renewable Policies

Feed-In-Tariff (FiT)
A FiT guarantees that for a certain term, renewable electricity generated by a qualifying facility must be purchased at a certain fixed price which provides a fixed return to the producer.

Feed-In-Premium (FiP)
A FiP provides a premium above market rates for renewable electricity over some fixed term.

Renewable Energy or Green tradable certificates (REC or GTC)
A REC or GTC allows projects to generate environmental benefits that may be traded or sold separately or bundled with the electricity generated. The value of a REC arises from the establishment of environmental goals (such as an RES) which allow compliance through their purchase.

Reduced Value-Added Tax (VAT)
A number of nations reduce the level of the VAT for purchases of equipment or services for renewable electricity generating facilities from 20% to 10% or 5%.

Offtake contract
The "ritiro dedicato" is an optional simplified sale and purchase contract between the PV producer and the Italian agency managing the feed-in premium system. Only the quantity risk is removed, as it is a guaranteed offtake contract for the electricity at market-related prices.

Accelerated and simplified permitting – One-stop shop for permitting
A legislative decree of 2003 in Italy provides a single authorization procedure rather than submitting several permitting applications to various administrative layers. Italian regions or provinces are empowered to issue these authorizations.

Cap-and-trade markets - EU ETS
The EU has instituted a declining cap on carbon dioxide emissions along with a market to allow trading of emissions permits. The EU ETS targets combustion installations above 20 MW and therefore includes the power sector.

vestors (two Danish pension funds). Key questions for Anholt are focused on determining which policy features made institutional investors comfortable with investing in a project with relatively high costs and revenues dependent on policy stability.

Key Modeling Assumptions

In Table 7, we summarize some of the key parameters used to model European project costs, revenues, and returns. The financial model itself is described in greater detail in Appendix A.

4.3 How did policy affect project costs, revenues, and returns?

In this section, we discuss key economic and financial metrics for the projects we studied, based upon cash flow modeling of their finances reconstructed from public sources. We use the model to estimate the internal rates of return realized by equity investors (the equity IRR, see Table 8) as well as the contribution of various support policies to the costs and revenues of the project (see Figure 1).

Key Findings

- **Costs and Returns:** The equity returns and costs for the projects are in line with expected ranges, with the exception of the Italian PV case. The returns for this case are just above McKinsey's range of estimates for returns on Italian PV projects, but are substantially higher than returns for PV projects in neighboring countries. The levelized cost of electricity for the Italian PV case is double that of the U.S. PV case, but in line with Italian costs. Both returns and costs appear to have risen be-

Table 7 – Key Modeling Assumptions for European Projects

	Generic Spanish Wind based on Villanueva	Utility Scale PV based on Rovigo	Offshore Wind based on Anholt
Project Size	66.7 MW AC	60 MW AC	400 MW AC
Production	146,000 MWh / Yr	88,500 MWh / Yr	1,400,000 MWh / Yr
Project Cost	124m EUR	320m EUR	9.3b DKK (1.4b EUR)
First-Year FiP Rate	31.3 EUR / MWh	332 EUR / MWh	-
First-Year FIT Rate	-	-	1,015 DKK (154 EUR) / MWh
FiP or FIT Duration	20 Years	20 Years	For 20 TWh of electricity
First-Year Market Rates	50 EUR / MWh	70 EUR / MWh	340 DKK (50 EUR) / MWh
Fixed O&M	29 EUR / kW-Year	22 EUR / kW-Year	670 DKK (98 EUR) / kW-Year
Base Case Term Debt	Optimized	240m USD	-
Base Case VAT Facility	Optimized	26m USD	-
Required Min DSCR	1.3x	1.4x	-
Debt Interest Rate	5.08%	6.48-6.98%	-
LCOE Discount Rate	8.00%	8.00%	8.00%

Sources:
Generic Spanish Wind: AEE, Elecnor, OMIE Website, Project Finance Magazine, RES Legal, BNEF, Bloomberg.
Rovigo: SunEdison, First Reserve, Partners Group, MEMC SEC Filings, Vento Region (EIS), GSE, GME, IEA, Andromeda Finance, Bloomberg, Project Finance Magazine, RES Legal, BNEF.
Anholt: DONG Energy, PensionDanmark, PKA, Danish Energy Agency, Deloitte, Nordpool, RES Legal, BNEF, Project Finance Magazine, Bloomberg. Note that subsequent to our analysis, DONG Energy was able to acquire construction financing for Anholt.

cause of the high incentive level, possibly due to supply pressures associated with the rush to take advantage of the incentive before it wound down in 2011.

- **Cost support mechanisms:** Tax-related incentives cover roughly 41-45% of levelized project costs for U.S. projects, while cost support mechanisms play virtually no role in European projects.
- **Revenue support mechanisms:** For U.S. cases, revenue support through price premiums implicit in long term PPAs cover an additional 10-37% of project costs, while European projects rely primarily on a single revenue support policy (a FiT or a FiP) covering 36-79% project costs.
- **Impact of policies on project costs:** U.S. projects make use of multiple revenue and cost support measures from various levels of government. While the total levels of support were substantial, the costs of these facilities were in line with or below estimates for similar facilities.

Levelized Cost Calculation

We calculate the contributions of policies to levelized cost of electricity (LCOE)[7] by starting with a counterfactual project scenario in which the project is financed without cost supports. In this scenario, we include capital costs and operating expenses (excluding any tax concessions which might reduce either), and tax benefits from 20-year straight line depreciation. Discounting these costs by using a utility cost of capital (varying slightly by case to reflect local utility returns, but all very close to 8%), we arrive at an estimate for

7 By a levelized cost or revenue, we mean the (present value of) total project costs or revenues for each kWh of electricity produced by the plant. This provides a single, aggregate measure of costs or revenues associated with electricity production that can (roughly) be compared across technologies and projects.

Table 8 – Summary of Project Costs, Revenues, and Returns

	US Wind	Greater Sandhill	Ivanpah	Spanish Wind	Rovigo	Anholt
Key Financial Metrics						
Equity IRR (%)	11%	15%	17%	10%	27%	9%
Benchmark Equity IRR Range (%)	10.5-14.5%	13-18.5%	15-20%	8-16%	17-26%*	4-13%**
Cost of Capital (%)	10%	11%	6%	8%	10%	9%
Policy Impact on Costs and Revenues						
LCOE without Supports (USD / MWh)	110	184	205	117	408	152
*Benchmark LCOE Range (USD / MWh)****	79-111	155-320	186-636	85-150	410-616	100-200
% of LCOE Covered by Cost Support	41%	45%	43%	-	2%	-
% of LCOE Covered by Revenue Support	10%	37%	16%	36%	79%	55%
Policy Impact on Returns						
Equity IRR Without Grant (%, US)	2%	4%	5%	-	-	-
Equity IRR Without Accelerated Depreciation (%, US)	6%	8%	10%	-	-	-
Equity IRR Without Revenue Support (%)	5%	<0%	3%	2%	<0%	2%

* The benchmark range of returns is for Italian PV projects rather than European PV projects more generally.

** Unlevered figure. All other benchmark figures represent levered IRRs

*** For US cases, EIA Annual Energy Outlook 2011, range of costs in 2009 USD for new generation coming online in 2016, excluding transmission investment. For Spanish Wind and Anholt, the range of costs across Europe, and for Rovigo, in Italy, as reported in IEA Projected Costs of Generating Electricity 2010.

the cost of electricity in the absence of incentives—the LCOE without supports. We then add in the discounted impact of cash flows associated with cost-based incentives. Finally, we add the impact of financing cash flows (relative to the assumed utility discount rate) to arrive at the LCOE after cost supports and financing.

Similarly, we calculate levelized after-tax revenues starting with the levelized revenue stream from a forecast of expected market rates and then add in the contribution of additional sources, including cash incentives, feed-in premia, and incremental revenue from an above-market PPA or tariff. Note that for the European cases, the revenue lines include value-added-tax (VAT) collections used to offset the VAT paid during project construction.

Policy Impacts on Costs and Revenues

The results of these calculations, presented in Figure 1, show several key aspects of U.S. and European renewable generation projects.

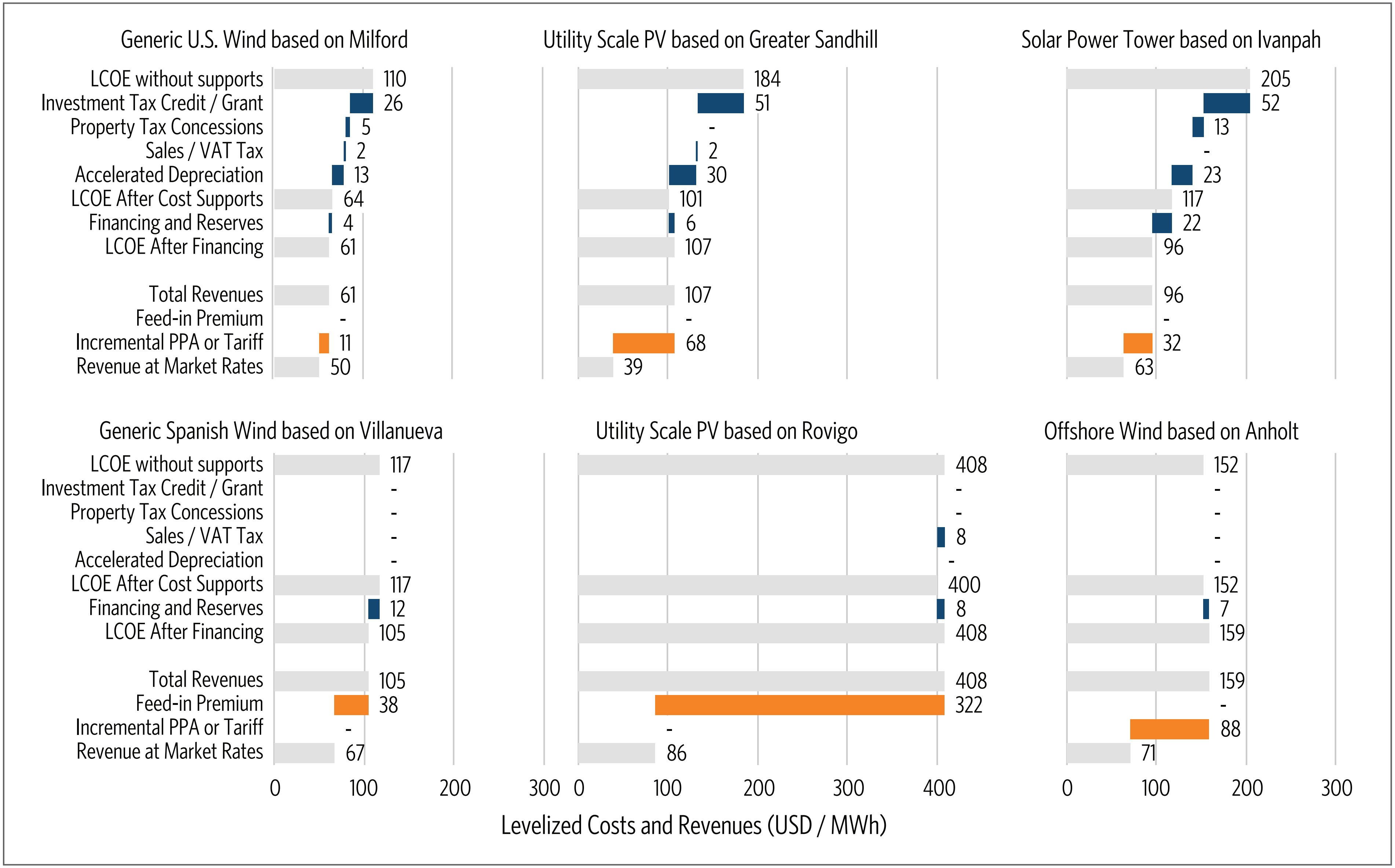
- Up-front, cost-based incentives such as the tax grant and accelerated depreciation policies reduce levelized project costs for U.S. projects by 41-45%.
- The primary form of support for European projects has been on the revenue side through Feed-in Premia (FiPs) and Feed-in Tariffs (FiTs), which provide between 36-79% of levelized revenues. These incentives are atop (or in place of) market prices for electricity that are generally higher than that of our U.S. cases.
- Each of the U.S. projects benefit from the revenue support of a PPA offered by a load-serving utility to meet a state-level RPS, and whose price level is above market prices. This premium above market prices covers 10-37% of project costs.
- With the exception of the U.S. Solar Power Tower, the financing component of the cost of electricity is very close to what it would be if the project were financed by a local utility. The loan guarantee for the U.S. Solar Power Tower case reduces levelized project costs by 11%.
- Overall project costs for the Italian utility-scale PV (based on Rovigo) appear to be much higher than the U.S. utility-scale PV case, and fall on the very high end of levelized cost estimates for PV plants. Greater Sandhill was awarded its PPA as the lowest cost bidder and most attractive among 23 proposed projects, 16 of which met the RFP submission criteria. On the other hand, the significant FiP was available to all projects in Italy which could be built by the end of 2010, enabling high returns to investors in Italian PV, even with high project costs.

Market Price and PPA Price Assumptions

EIA's Annual Energy Outlook 2011 provides an electric power price projection for generation in the Western Electricity Coordinating Council (WECC), as well as the WECC-Rockies region. We use the former as a proxy for expected future wholesale electricity market prices for Ivanpah (adjusted for time-of-day factors) and Milford, and the latter for Greater Sandhill. Furthermore, for our two cases that sell power to California utilities, we assumed that PPA prices were consistent with the appropriate California Public Utility Commission (CPUC) Market Price Referent (MPR). The CPUC publishes an MPR each year, which provides a benchmark (an "avoided cost") used for judging the reasonability of PPAs signed by California's major Investor Owned Utilities in attempting to meet their requirements under California's RPS. The MPR is calculated by assuming that generation needs would be otherwise met by a new 500 MW combined-cycle gas turbine built in the same year as the proposed renewable facility. The calculation assumes an increasing carbon price consistent with California's implementation of a cap and trade regime for carbon emissions.

The basis for market prices forecasts of the European cases are: national power markets data and simple linear growth rate for Spain, two-stage growth for Italy, and a specific price path projection for Denmark.

Figure 1 – Levelized Costs and Revenues for U.S. and European Cases



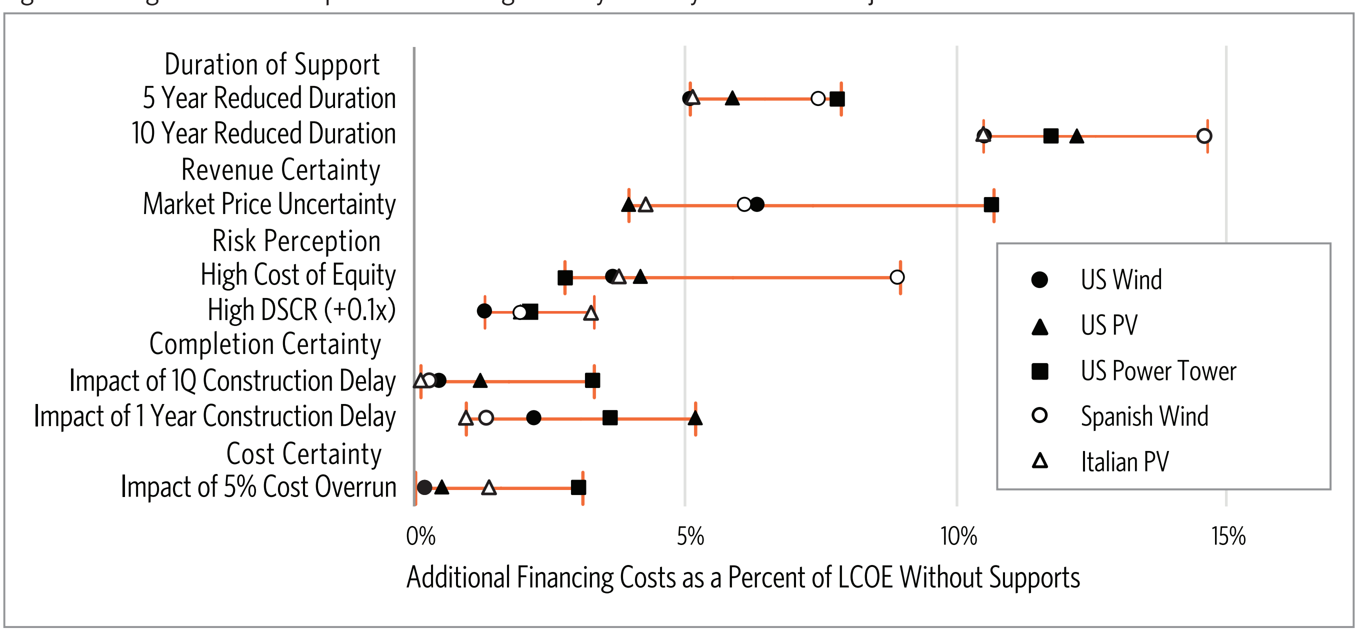
4.4 How can policy impact the cost of financing these projects?

In this section, our goal is to assess the potential importance of each policy impact pathway on financing costs in each of our cases. We do this by comparing the modeled financing costs of the project in various hypothetical scenarios, reflecting changes in the policy regime and project circumstances associated with a given pathway. The results of this analysis are summarized in Figure 2, and described in greater detail in Table 11.

Key Findings

- *The duration of revenue support delivered the greatest reductions on financing costs.* Debt providers match debt repayments to the expected cash flows over the life of the project. Reducing the duration of revenue support and the term of long-term debt by 10 years (and increasing the level of support as needed to keep equity returns fixed) increases financing costs by 11-15% of project electricity costs in the absence of cost or revenue supports (the LCOE without supports described in the previous section).
- *Revenue certainty is next in importance. Policies such as a FiT or an RPS implemented through long-term PPAs, eliminate electricity market price risks which would otherwise be the dominant source of revenue uncertainty.* In all our cases, variability of future expected market prices would have been a larger source of revenue uncertainty than expected variability of the renewable resource or technology availability. Thus, revenue support policies which mitigate or eliminate these risks significantly increase revenue certainty. A shift from a fixed-price revenue support such as a FiT to a premium over market prices (and increasing the level of support as needed to keep equity returns fixed) increases financing costs by 4-11% of LCOE without supports. Including a price-collar in the Spanish wind case reduces this impact from 6% to 1%. The incremental benefit from fixed-price revenue support is also small in projects such as Rovigo, which have premia significantly above market prices.
- *Equity investor perceptions of risk and construction certainty also significantly impact project financing costs.* Increasing required equity returns to the top of the appropriate benchmark range increases financing costs by 3-9% of LCOE without supports. A one year delay in construction increases financing costs by 1-5% of LCOE without

Figure 2 – Range of Potential Impacts on Financing Costs by Pathway Observed in Projects



supports.

- ***Protection against losses from project failure is critical for less mature or innovative projects.*** Debt providers will not lend to a less mature or innovative project unless there are protections in place which can shield them from losses associated with project failure. We use the availability of long-term or construction debt as a proxy for such protections. As described in Table 9, without long-term debt, the additional expense of financing the solar projects using equity alone would increase financing costs by 12-56% of LCOE without supports. As equity costs without debt for wind are comparable to debt costs, this increases the financing costs of the wind projects by only up to 2% of LCOE without supports. If the project could only get debt after construction, the high cost of equity financing during construction can increase financing costs by 8-23% of LCOE without supports. A loan guarantee can directly enable debt financing by shifting the burden of catastrophic failure to the government. Stable, long term revenue supports and streamlining regulatory processes can indirectly affect debt availability by changing debt provider risk perceptions.

Table 9 – Additional Financing Costs without Debt

Additional Financing Costs as % of LCOE w/o Support	US Wind	Greater Sandhill	Ivanpah	Spanish Wind	Rovigo
No long-term debt	2%	12%	38%	-2%*	56%
No construction debt	10%	15%	22%**	8%	23%**

For U.S. Wind, Greater Sandhill and Spanish Wind, construction debt figures are based on an assumed 80% of project costs covered by construction debt.

* As the debt and support duration (20 years) is less than the operating life of the project (25 years), unlevered equity provided at the low benchmark IRR (~7%) for European wind projects over the full operating life has comparable financing costs to the base case financing with 20-year debt.

** Ivanpah and Rovigo involved construction debt in actual financing, and this cost was avoided by these projects.

Methods

We primarily use the following metric to measure policy impacts on financing costs:

- **Financing Component of LCOE:** This is the contribution of cash and tax flows to and from investors and debt providers to the project's LCOE. We present the change in this component as a percentage of the LCOE without supports.[8]

To model the potential size of the impact a particular pathway would have on a given project, we start by simplifying and optimizing our model of the project's financing:

- We fix expected equity returns to the midpoint of benchmark range described in Section 3.2, and adjust the level of revenue support provided to the project as needed to achieve that return (leaving all other policy and project features fixed). This is intended to remove any dependence on the particular risk and reward profile of the specific investors involved in the project.
- We assume that equity investors make decisions on expected returns using annual revenues which are likely to be met or exceeded 50% of the time for each year (the P50 revenues).
- We assume that debt is provided at a cost consistent with the actual project, but that the amount of debt is optimized and the payment schedule sculpted to meet the requirement of a fixed DSCR appropriate to the technology (1.3 for onshore wind and 1.4 for other technologies, the midpoint of the ranges published by ratings agencies as needed to achieve investment grade for renewable projects [see, for ex-

8 We also present results for an additional metric, the cost of capital, in Appendix B. By cost of capital, we mean the IRR of all project cash and tax flows to and from investors and debt providers.

ample, Moody's (2008) or S&P (2009)]).

- We assume that debt providers decide on the level of debt using annual revenue levels which are likely to be met or exceeded 90% of the time for each year (the P90 revenues), a practice noted in our conversations with rating agency staff. Thus, the impact of production[9] or market price uncertainty[10] (when applicable) on financing is captured through debt providers' use of more conservative P90 estimates of annual revenues as compared to the P50 revenues used by equity investors.

This process results in an optimized base project financing, summarized in Table 10.

We repeat the same steps in the alternate scenario relevant to the impact pathway, and compare the financing cost metrics described above in the two cases.

The change in financing cost metrics between the optimized base case and the alternative scenario is entirely driven by a change in the achievable leverage – the amount of capital a debt provider is willing to commit to this project (with the exception of the scenario we consider reflecting high equity returns driven by risk perceptions). Thus, we are making the approximation that the achievable leverage is the driving force behind the cost of capital, and we are neglecting further impacts a modified scenario would have on expected equity returns or debt characteristics (such as spreads or minimum required DSCR). The prominent role of leverage in driving the cost of financing was emphasized to us in interviews with renewable project stakeholders, and it is consistent with modeling results in the absence of debt which generally result in much higher costs (due to the high cost of unlevered equity relative to debt in the tables in Section 3.2).

For example, in the case of the Generic U.S. Wind project, we test revenue certainty by comparing the optimized financing with a fixed-price 20 year PPA (which allows for 77% leverage) to a case where it has a 20 year fixed-price contract for renewable energy credits, at a price sufficient to deliver the same benchmark equity return (12.5%). Because energy sales are now subject to market price uncertainty, the P90 revenues for the project are much lower and the project can now only support 59% leverage (at the same assumed debt interest rate). This leads to an increase in the financing component of LCOE of 7 USD / MWh, which is roughly 6% of the LCOE without Supports for the project (110 USD / MWh). Thus, we say that moving from fixed-price to the fixed-premium policy increased financing costs by 6% of the LCOE without Supports.

Note that as of the time of our analysis, the Offshore Wind case was financed by institutional investors through an equity arrangement with DONG energy, and did not have debt at the project level. As we have not been able to analyze an offshore wind case with debt financing, we chose not to include Anholt in our quantitative analysis for this section. However, after our analysis was completed, we learned that DONG had recently arranged construction debt financing for Anholt.

Scenarios and Discussion of Results

The alternative scenarios used to address the impact of each pathway on financing costs, as well as the results obtained, are described below by pathway. The results of this analysis are shown in Table 11 at the end of the section, and summarized in Figure 2.

9 Annual production uncertainties for each of the solar cases were estimated using 12-month moving averages of monthly historical NASA insolation data and the NREL SAM model, leading to estimated P90 values between 2.5-6.5% lower than the base production. We were not able to find project specific historical wind data and assumed a P90 value of 11% below base production for all wind projects (a value roughly consistent with the range of published values, for example in EWEA (2009)).

10 Using daily electricity market data from Bloomberg, we calculated 12-month moving averages in quarterly increments, which we used to evaluate market price variation. For a range of pricing locations in the U.S. and Europe, one standard deviation was consistently close to 25% of the mean. Based on this figure, we estimated a P90 low market price 32% (25% multiplied by 1.28 standard deviations) lower than the base market price estimate.

Table 10 – Financial Metrics for Optimized Base Project Financing

Optimized Base Case Financing	US Wind	Greater Sandhill	Ivanpah	Spanish Wind	Rovigo
Assumed Benchmark Equity IRR (%)	12.5%	15.6%	17.5%	12%	21.5%
Assumed Interest Rate on Debt (%)	7.0%	7.0%	4.7%	5.1%	6.5-7%
LCOE Without Supports ($ / MWh)	110	184	205	117	408
LCOE After Cost Supports and Financing ($ / MWh)	63	98	89	110	392
Optimized Leverage (%)	77%	77%	76%	82%	82%
Total Cost of Capital (%)	10%	10%	6%	8%	9%

Duration

The duration of the revenue support policy relevant to each of the projects (such as a FiT, FiP, or PPA offered in response to a state RPS / RES) is correlated with the duration of long-term debt financing that the project was able to secure.[11] A reduction in support and debt duration of 10 years increases financing costs by 11-15% of LCOE without supports.

Revenue certainty

For each of our projects, we found that annual variability of electricity market prices is a larger potential risk to revenues than resource variability or technology availability. Our U.S. cases all have RPS-driven long-term PPA contracts which eliminate market price risk during the contract term. If PPAs were replaced by long-term contracts for fixed premiums above market rates with the same expected revenues (such as long-term, fixed-price REC contracts) the uncertainty in market prices would lower the projected revenue levels which are exceeded 90% of the time. Thus, debt providers would be willing to provide less debt than with a PPA, resulting in higher financing costs of 4-11% of LCOE without supports. The modeled European wind and solar PV cases rely on feed-in premiums, which expose debt investors to market price risks. Were these cases to receive fixed prices instead of a premium, financing costs would be reduced by 1-4% of LCOE without supports (the lower end is due to the impact of a price collar in the Spanish wind case, without which costs could have been 6% higher than with fixed-price contract).

Furthermore, note that a FiP leaves the investor with some risk related to underlying commodity price fluctuations, creating a possible comparative advantage for developers who can manage the commodity risks or have offsetting risks, such as large incumbent utilities. The effect of creating this advantage is also an important area for further investigation.

Risk perception

Investor or debt provider perceptions of risk associated with a project can be influenced by the policy regime in place. At the most basic level, debt provider perceptions of risk associated with, for example, the technology a project employs or the policy regime in place can determine if they are willing to provide any construction or term debt at all to a class of projects. At a finer level, these perceptions influence financing costs by, for example, altering the returns required by an equity investor or the minimum DSCR required by a debt provider. Increasing the required DSCR and equity returns to the higher end of the ranges identified in Section 3.2 increase financing costs by 1-3% and 3-9% of LCOE without supports, respectively.

In the U.S., the dependence of projects on multiple incentives exposes the project to potential regulatory uncertainty (application processes and/or changing rules) and policy uncertainty (sustainability of incentives in severely constrained fiscal environments) associated with each incentive. The extent to which the existence of multiple incentives

11 A shorter term of debt than the support policy term leaves less revenue to support equity returns and hence increases financing costs, while a longer term of debt will depend on generally lower and less certain revenues after the support term has ended, also increasing financing costs.

increases risk perceptions and financing costs remains unclear, but deserves further investigation.

On the other hand, the substantial size of revenue support required to render a solar project viable in Europe can lead to policy uncertainty and increased perceptions of regulatory or policy risks, which can increase financing costs. We note that in response to problems in setting FiTs, governments have been forced to change policies, and in some cases changed tariffs retroactively. Numerous interviewees expressed concern over heightened risk and lack of future investability, although this view was not universally shared. The impact of these changes will be an area of CPI investigation as time progresses and the full impact can be observed.

Risk distribution

Construction Debt: As renewable generation projects have high up-front costs, inexpensive short term debt to cover a significant fraction of construction costs (which would otherwise need to be covered by more expensive equity funding) can be critical to reducing financing costs. The U.S. Power Tower and the Italian Utility-Scale PV cases both utilized construction debt, without which their financing costs would have increased by 22% and 23% of LCOE without supports respectively. Similarly, construction debt would have lowered the financing costs of other projects by 8-15% of LCOE without supports.

Inflation Risks: Revenue and cost support policies either implicitly or explicitly impact the distribution of inflation risks among stakeholders by changing the allocation of a fixed fraction of project costs or revenues. A number of recent studies of bond markets (see, for example Hordahl and Tristani (2010)) suggest that the cost of bearing these risks can be measured, and has a value of between 0-50 basis points in the U.S. and European regions, increasing with the tenor of the bond. This provides a rough estimate of the pathway's potential impact on financing costs.

Cost certainty and completion certainty

The management of cost and completion risks can often be handled through contractual rather than policy arrangements. However, this is often not possible for innovative, first-of-a kind projects, where the uncertainty associated with the possibility of catastrophic failures could make a project impossible to finance in the private sector at any reasonable expected return. In the case of Ivanpah, a loan guarantee shifted some of the burden of a catastrophic failure of a project to government.

More generally, uncertainty regarding regulatory or permitting processes can lead to uncertainty in total project costs or completion schedules. If the risks of delays or additional costs are assumed in the baseline financing used by debt providers to determine the amount they are willing to lend to the project, this can increase financing costs. A one year delay can increase financing costs by 1-5% of LCOE without supports, while a 5% cost overrun can increase financing costs by up to 3% of LCOE without supports.

Development risk

Increased risk of project failures at the development stage increases costs and reduces the attractiveness of clean energy investment in general. Since development makes up roughly 5% of project costs (in the U.S. solar power tower and wind cases, where this information was available), direct policy impacts modeled as changes to development costs or timing do not significantly impact financial metrics such as equity returns. However, the most interesting ways in which policy impact project financing through development risks are not captured by this modeling approach. The development process for the U.S. solar power tower, for example, was intimately tied to regulatory processes, as the project was being undertaken on federal lands and dependent upon meeting incentive deadlines (tax grant, loan guarantee, PPA) to achieve returns in line with expectations.

As the first at-scale facility of its kind, this process was complex (roughly 50 required permits from local, state, and federal regulators), and dealt with substantial issues – for example, Ivanpah is sited on federal lands and is expected to disturb a number of threatened desert tortoises, a number equivalent to roughly 1% of the species' remaining population. As a result of these interactions, the project itself was significantly modified (from two 100MW phases and one 200MW phase with several towers to one 126MW and two 135MW towers), the timeline for development and construction was extended, and the financial structure of the project (the requirement of a roughly 20% equity stake in the project) was largely determined. The uncertainty associated with such extensive regulatory and policy interactions required for this project may have impacted the availability and cost of financing for this and future projects. In future work, we hope to better assess the existence

Table 11 – Change in Financing Costs as a Percent of LCOE without Supports

	US Wind	Greater Sandhill	Ivanpah	Spanish Wind	Rovigo
LCOE Without Supports (USD/MWh)	110	184	205	117	408
*Revenue Certainty (Relative to Fixed Price Base Cases)**					
Market Price Uncertainty	6%	4%	11%	1%	4%
Without Price Collar				6%	
Risk Perception					
No Term Debt	2%	12%	38%	−2%	56%
Low DSCR (−0.1x)	−1%	−2%	−2%	−2%	−4%
High DSCR (+0.1x)	1%	2%	2%	2%	3%
Low Cost of Equity	−4%	−4%	−2%	−11%	−5%
High Cost of Equity	4%	4%	3%	9%	4%
Risk Distribution					
Construction Debt On/Off	−10%	−15%	22%	−8%	23%
Duration of Revenue Support					
2 Year Reduced Duration	2%	2%	5%		2%
5 Year Reduced Duration	5%	6%	8%	3%	5%
10 Year Reduced Duration	11%	12%	12%	7%	11%
*Cost and Completion Certainty***					
5% Cost Overrun	0%	1%	3%	0%	1%
1 Quarter Construction Delay	1%	1%	3%	0%	0%
1 Year Construction Delay	2%	5%	4%	1%	1%

* Spanish Wind and Rovigo both have revenue support through FiPs rather than FiTs – to assess the impact of revenue certainty, we use the fixed-price, or FiT as a base case and compare financing costs with the optimized base case with the FiP.

** The impact of cost and completion certainty in the U.S. solar power tower and Italian PV cases would have been higher without construction financing.

and/or extent of such impacts in this and related cases.

More generally, increased failure rates or costs during development can result in lower competition and can drive up the returns required to attract investors. Policy impacts through the development process can be important, but are best understood through analysis at the portfolio rather than project level. We are currently investigating these impacts.

4.5 How could policy help attract capital?

Key Findings

- **Institutional investors:** The significant and stable revenues afforded by revenue support policies, as seen in Feed-in-Tariffs or above-market PPAs, can enable equity participation by institutional investors, if project sponsors are willing to insulate them from completion and policy risks.
- **Loan guarantees, risk of project failure, and innovative projects:** In the case of Ivanpah, the DOE loan guarantee shares the risk of project failure with government (substantial delays, excessive cost overruns, failure of a phase of the plant to operate, etc.) by covering loan payments in the event of a default. The role played by this shift in the risk of project failure in enabling investment by relatively new investors in this space (Google) is a question for future research.

Policy and Institutional Investors – Greater Sandhill and Anholt

Two of the cases we studied, Greater Sandhill and Anholt, were able to derive a substantial fraction of their financing from institutional investors. These investors control large amounts of capital and are often interested in time horizons close to the life of a renewable project, but until recently, have been unwilling to take on the policy and revenue risks of renewable projects in the U.S. Greater Sandhill and Anholt share the following key characteristics of interest to institutional investors:

- Greater Sandhill's PPA and Anholt's FiT eliminate revenue risks associated with market variability and provide a sufficiently large premium over a term long enough for the institutional investors to reach their return targets even under adverse production circumstances.
- Cost and completion risks for both projects are borne by the project sponsors or developers. In the case of Greater Sandhill, the developer sold the project to institutional investors only after completion, while in the case of Anholt, DONG Energy has assumed these risks through performance guarantees.
- In both cases, the institutional investors involved have themselves developed significant internal capacity focused on management of renewable investments.

Our conversations with project stakeholders suggested that each of these three characteristics – revenue certainty, arrangements to insulate investors from cost and completion risks, and investor capacity specifically focused on renewable projects – was important for mobilizing institutional investor capital in this space. Policy clearly influences revenue certainty, but can influence the distribution of risks among project stakeholders and the incentive for investors to develop capacity as well. We hope to return to the latter influences in greater detail in future work.

Ivanpah, Loan Guarantees, and Equity Investment in Innovative Projects

As Ivanpah is five times larger than any other solar power tower built to date, this case provides an example of how government policies can catalyze scale-up. Very few investors are willing to bear renewable scale-up risks—which include getting a first-of-a-kind project up and running on-time and on-budget, revenues dependent on the weather, regular and reliable operation of a first-at-scale technology, and a cost of electricity so far above market rates as to lead to dependence on government incentives. And when they do invest, they demand a premium to do it. Yet, Ivanpah has attracted commitments for nearly $600 million in equity, including an investment from a relatively new, tax motivated investor (Google). Several policy features and contractual arrangements may have helped enable this investment:

- **Cost supports enabling equity returns consistent with first-of-a-kind project risks:** The combined returns for all equity investors (17%) for the project are consistent with expectations for CSP projects (a range of 15-20% in Mintz Levin), and rely on the sum total of the subsidies provided.
- **Government debt-reducing financing costs:** The financing structure, enabled by the low cost government loan covered by the loan guarantee, reduces the levelized cost by roughly 22 USD/MWh, or 11%, relative to utility financing. This is comparable to the amount set aside by the government to cover the cost of the guarantee – on average roughly 15% of loan volume, or 12% of total project costs for the loan guarantee program [Credit Supplement to the President's Budget for 2012].
- **Strong debt contract provisions to cover cost and completion risks:** Based upon materials provided in BrightSource's S-1 filing, we note that the DOE loan guarantee and equity participation agreements require equity funding of a 3% overrun reserve and a commitment by the developer to cover any further cost increases. A fixed-price contract for the bulk of construction with a large engineering contractor in turn mitigates cost uncertainty risks to investors. Thus, the primary cost risk remaining for project investors as well as the government as a debt provider is related to the developer's ability to honor its commitment to cover costs not related to the engineering contractor's scope.
- **Sharing the risk of failure with government through the loan guarantee:** The risk of project failure (substantial delays, excessive cost overruns, failure of a phase of the plant to operate, etc.) is shared with the federal government through the loan guarantee. For example, in the event of a failure leading to default of a PPA (production more than 20% below expectations) or inability to meet a regulatory deadline (such as for a permit or tax grant), the project would not be able to make a scheduled payment of its government loan, thereby triggering a guarantee payment by the DOE to cover the payment.

We hope to return to the question of determining which of these mechanisms was most important for attracting outside equity investment in an innovative project, and to assess the costs and benefits of the supports provided – in particular the guarantee – to various stakeholders.

5 So what does this tell us about renewable policy effectiveness?

How did policy affect project costs, revenues, and returns?

With the exception of Rovigo, financing and project costs do not show evidence of overpayment. Equity returns, debt spreads, and project costs in each case are in line with expectations based upon recent surveys and cost assumptions such as those used by EIA for its Annual Energy Outlook.

Rovigo shows some evidence of higher costs associated with a rush to secure a high FiP by the end of 2010. Base case equity returns for Rovigo are above expectations and the levelized cost of electricity is double that of Greater Sandhill. Both returns and costs appear to have risen because of the high incentive level, perhaps in part due to supply pressures associated with the rush to take advantage of the incentive before it began to be wound down in 2011.

All the projects still rely on cost or revenue supports to provide equity returns currently demanded by investors to bear project risks. None of the projects would have been able to provide equity investors returns commensurate to the risks borne without revenue or cost incentives. However, reductions in some incentives would still have provided adequate returns in some cases. For example, Rovigo would have easily been viable with a reduced incentive, and may have been deployed at lower cost, if not for the rush to grab the high premium before the end of 2010 On the other hand, for a scale-up project like Ivanpah, low-cost government debt enabled equity returns, while absorbing some of risk of project failure. This alignment of risk and return attracted equity investors to the project.

U.S. projects make use of multiple, smaller incentives, each with their own political and regulatory risks while European projects generally rely on a single larger incentive with more focused political and regulatory risks. In light of the significant pressure at all levels of government in the U.S. and Europe to reduce spending, we hope to return to the issue of how this difference in political risk structure influences investors' perceptions of political risk – and the premium they require to bear such risk – in future work.

How can policy impact the cost of financing these projects?

For all of the projects, three factors stood out (see Figure 2 for a summary of these results):

- **The duration of revenue support had the largest impact on financing costs.** Debt providers match debt repayments to the expected cash flows over the life of the project. When revenue supports end early, projects must pay down debt faster to adjust for lower cash flows in later years. This effect increased financing costs by 11-15% of the cost of electricity when revenue support was reduced by 10 years (while increasing the level of support to reach required debt and equity returns).
- **Revenue certainty is the second most important factor.** In all six cases, the uncertainty of electricity prices is a much greater source of revenue risk than the uncertainty surrounding the wind or solar resource. A shift from fixed electricity prices - such as through a Feed-in-Tariff (FiT) or power purchase agreement (PPA) - to a combination of a FiP plus market prices (normalized to maintain equity returns) leads to additional financing costs of 4-11% of the cost of electricity. Revenue certainty is more important to projects that require the lowest premium, as market prices impact a greater share of revenues, and to projects with either high equity costs or low-cost debt, as revenue certainty enables an increase in the low-cost debt. Fixed prices are not the only way to address revenue certainty. Since debt investors are concerned about downside risk, including a collar or minimum price can achieve nearly the same benefit as the fixed electricity price. In our

Spanish Wind case, the FiP penalty was reduced from 6% to 1% by a collar.

- **Investors' perceptions of risk also significantly impact project financing costs.** Higher risk perceptions lead equity and debt investors to require increased returns or demand greater margins of error. The upper range of investor requirements would increase financing costs by 3-9% of the cost of electricity.

For less mature or more innovative projects, protection against losses is critical due to generally higher risks of project failure. The risk of default – a project being unable to meet debt payments – discourages debt investors. Meanwhile, these projects often require higher equity returns to compensate for perceived risks, so the importance of debt in lowering financing costs is greater. Policies that offer investors some level of protection against default – or absorb the default risk by providing debt directly – can have a significant impact. For example, if the U.S. solar power tower were financed without debt (which was made possible by a loan guarantee and low-cost government loan) the project would have incurred additional financing costs of 38% of the cost of electricity.

Construction and completion risk can be covered through commercial arrangements, as in two of our cases where contracts with the constructors absorb this risk. In other cases, the sponsoring developer was also the constructor, earning higher returns, in part, to compensate for the elevated risks during construction. Because the financial cost of absorbing these risks can be high, policies or commercial guarantees that enable debt financing during construction can significantly reduce project financing costs (by 8-23% of the cost of electricity in the six cases). The length of the expected construction period also has a large influence on the benefit of guarantees or policies.

Institutional investors with the expertise to evaluate renewable projects will invest in renewable projects with revenue certainty and arrangements to insulate them from policy and completion risks (such as through policy support or private contracts). This was the case in both the U.S. PV and the offshore wind projects. To develop this capacity, investors are likely to require greater industry scale to justify investing in the expertise, training, and analytical support.

Next Steps

Our aim is to further extend these analyses to explore the impact of policy design options on renewable policy effectiveness more generally and to apply the lessons to policy options currently under consideration by policymakers. Several areas of immediate interest include:

- Extending the analysis to other geographies. In particular, we are interested in whether these insights apply to emerging economies and why or why not.
- Exploring a greater set of policy design options – for instance, extending the revenue certainty analysis to evaluate the impact of support incentives that are variable, such as renewable energy credits (U.S., India), renewable obligation certificates (UK) or green certificates, or assessing the impact of cost versus revenue supports.
- Evaluating the impact of changes in design features – for example, how sensitive are financing costs to the level of a price collar or whether tapered incentives have the same duration impact?
- Analyzing the tradeoffs with lower financing costs – for example, do the lower financing costs on offer through FiTs justify the additional risk that may be absorbed by government or ratepayers?
- Understanding how financiers and developers will alter their financial requirements when investing in portfolios of projects – for example, how does the cost of increasing development uncertainty impact willingness to invest in renewable projects?

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Appendix A - Case Study Methodology and Financial Model

A.1 Case Selection

CPI selected projects to study for this work using the following criteria:

Technology and geographic coverage
In each region, at least one case was selected involving a mature renewable technology (on-shore wind), an emerging renewable technology (solar photovoltaic), and a developing renewable technology (solar thermal electricity generation in the U.S. and off-shore wind in Europe).

Policy interest
The projects chosen were tailored to enable the analysis of policies that had been identified by policymakers or other key stakeholders to be of interest (such as FITs and FiPs in Europe and loan guarantees and tax grants / credits in the U.S.).

Availability of project financial and technical data and cooperation of case stakeholders
The public availability of information regarding the financing arrangements and basic technical features of the project and the cooperation of case stakeholders was a necessary condition of case selection. The resulting selection bias can impact the extent to which conclusions motivated by this analysis can be generalized without further study.

Diversity of types and sources of financing
The cases were also chosen in an attempt to cover the range of financial sources (debt, equity, mezzanine, venture capital) and the types of financing available, with a view towards projects employing project finance structures with some long-term debt.

Stage of completion
Projects must have closed their financing and were ideally either in construction or in operation.

A.2 Financial Model

The primary analytical tool used in this analysis is a project cash flow model, which CPI developed to examine policy impacts on key financial metrics. The model requires a range of inputs that describe project cost, revenue, policy, and financing characteristics. These inputs are used to calculate cash flows over the development, construction, and operational life of a project. Using these cash flows the model calculates a project internal rate of return (IRR), debt service coverage and whether debt is fully repaid, and returns of project equity investors, as well as the contribution to levelized costs or revenues of each policy. The types of inputs used and outputs generated by the model are described in more detail below.

Model Inputs

- **Project characteristics such as project capacity,** capacity factor, and length and timing of development, construction and operations periods;
- **Capital expenses and investment-based incentives,** including project costs during development and construction, investment-based incentives (grants or tax credits), and sales tax or value-added tax (VAT) on capital expenditures;
- **Operating revenue and production-based incentives**, including power purchase agreement (PPA) or tariff rate and duration, underlying market prices, renewable energy certificates (RECs), production-based incentives, production tax credits, and recovery of VAT from energy sales;
- **Operating expenses,** such as property taxes and concessions, annual expenses, and fixed or variable O&M;
- **Tax and depreciation inputs,** such as national and local tax rates, depreciation schedules, and bonus depreciation;
- **Reserve accounts,** including reserves for construction cost overrun, senior debt service, major equipment replacement, O&M and working capital, and PPA performance security; and

- **Financing,** with inputs for construction debt, senior term debt and subordinate debt (with choices in amortization method), outside equity investors, and project developers.

Model Outputs

- **Project metrics,** including project IRR and levelized cost of energy (LCOE) before and after incentives and financing;
- **Debt investor metrics,** including debt service coverage ratio and proportion of debt repaid;
- **Equity investor metrics,** particularly IRRs for developer, outside, and combined equity investors.

Key Modeling Assumptions

CPI's project cash flow model uses a range of assumptions about the categorization and nature of certain cash flows. These can broadly be categorized as assumptions about the "waterfall" of cash flows, assumptions about tax and depreciation treatment, and assumptions about capitalization vs. expensing of various costs.

Waterfall assumptions: The priority of various claims on the cash flows of a project is often referred to as the "waterfall" of project cash flows. CPI's model assumes that project cash flows are first used to cover operating expenses, then to service senior debt, followed by subordinate debt service, with the remaining cash flows split proportionally between outside and developer equity investors with respect to their contributions (or in a pre-determined fashion as is sometimes the case in tax-equity arrangements in the US).

Tax and depreciation treatment: CPI's model assumes that capitalized costs, including interest paid during construction, lenders fees, and sales tax or VAT on development and construction expenditures are depreciated over a specified schedule. Costs associated with creating reserve accounts are excluded from the depreciable basis of the project, and the option is available to reduce the depreciable basis using investment-based incentives. Depreciation expenses, as well as interest expenses during operation, are deducted from the project's taxable income, which in some cases yields net tax benefits.

Capitalization vs. expensing of costs: The model also assumes that costs incurred during development and construction of the project can be capitalized, thereby impacting the investment required by the project, as well as the amount that can be depreciated for tax purposes. In addition to hard development and construction expenditures, capitalized costs include interest paid during construction, lenders fees, and sales tax or VAT on development and construction expenditures. Costs that occur during project operation are counted as expenses against project revenues. These costs include property taxes, annual, fixed, and variable O&M costs, and fuel costs (if applicable).

Data

Data was collected for each case study from a range of sources, as is detailed in our References. Subscription services such as Bloomberg, Bloomberg New Energy Finance, and Project Finance Magazine were used for information about financial structure and, where available, terms of financing. Regulatory filings were typically used to fill in additional details about the project, its costs, and financial terms. For U.S. projects, we drew upon regulatory filings with the Securities and Exchange Commission (SEC), Federal Energy Regulatory Commission (FERC), Bureau of Land Management (BLM), and various state environmental and utility regulators. In Europe, regulatory sources included Gestore Servizi Energetici (GSE), Gestore dei Mercati Energetici (GME), and the Danish Energy Agency.

When possible, our team tested available data and modeling assumptions through conversations with stakeholders involved in financing renewable energy projects, including several of the cases presented here.

Where a particular modeling input was not available, we developed a reasonable proxy for the missing data, based on guidelines produced by regulators, market data, or assumptions from other industry models.

Appendix B - Detailed Modeling Results

Table B-1 – Final, After-Tax Cost of Capital – Change in Basis Points

	US Wind	Greater Sandhill	Ivanpah	Spanish Wind	Rovigo
Base Case Cost of Capital (w/ Fixed Price Offtake)	10.34%	10.17%	6.04%	8.21% 8.15%	9.13% 8.67%
Revenue Certainty (Relative to Fixed Price Offtake)					
Market Price Uncertainty	64	53	111	6	45
Without Price Collar				60	
Risk Perception					
No Term Debt	−185	−31	392	−130	485
Low DSCR (−0.1x)	−14	−31	−31	−23	−40
High DSCR (+0.1x)	13	27	30	20	34
Low Cost of Equity	−83	−89	−45	−150	−65
High Cost of Equity	82	92	49	124	52
Risk Distribution					
Cost to Bear Inflation Risk	~50	~50	~50	~50	~50
Construction Debt On/Off	−329	−407	419	−131	323
Duration of Revenue Support					
2 Year Reduced Duration	22	33	27	30	19
5 Year Reduced Duration	59	93	69	78	52
10 Year Reduced Duration	129	226	146	174	124
Cost and Completion Certainty					
5% Cost Overrun	2	8		3	
1 Quarter Construction Delay	6	19		5	
1 Year Construction Delay	21	67		20	

Table B-2 – LCOE After Cost Supports and Financing

	US Wind	Greater Sandhill	Ivanpah	Spanish Wind	Rovigo
Base Case LCOE (w/ Fixed Price Offtake)	63	98	89	110 109	392 375
Revenue Certainty (Relative to Fixed Price Offtake)					
Market Price Uncertainty	70	106	111	110	392
Without Price Collar				116	
Risk Perception					
No Term Debt	66	120	167	107	621
Low DSCR (-0.1x)	62	94	84	107	377
High DSCR (+0.1x)	65	102	94	112	406
Low Cost of Equity	59	91	84	97	373
High Cost of Equity	67	106	95	120	408
Risk Distribution					
Construction Debt On/Off	50	68	139	100	486
Duration of Revenue Support					
2 Year Reduced Duration	66	103	93	113	400
5 Year Reduced Duration	69	109	100	118	413
10 Year Reduced Duration	75	121	113	127	435
Cost and Completion Certainty					
5% Cost Overrun	66	104		115	
1 Quarter Construction Delay	65	103		111	
1 Year Construction Delay	71	116		116	

Table B-3 – Initial Project Leverage (Equity Net of Tax Grant for US Projects)

	US Wind	Greater Sandhill	Ivanpah	Spanish Wind	Rovigo
Base Case Leverage (w/ Fixed Price Offtake)	77%	77%	76%	82% 109	82% 375
Revenue Certainty (Relative to Fixed Price Offtake)					
Market Price Uncertainty	59%	71%	66%	82%	82%
Without Price Collar				72%	
Risk Perception					
No Term Debt	0%	0%	0%	0%	0%
Low DSCR (-0.1x)	82%	81%	79%	87%	85%
High DSCR (+0.1x)	73%	74%	73%	78%	79%
Low Cost of Equity	74%	73%	73%	72%	79%
High Cost of Equity	81%	81%	79%	91%	85%
Risk Distribution					
Construction Debt On/Off	62%	61%	110%	73%	100%
Duration of Revenue Support					
2 Year Reduced Duration	76%	76%	106%	81%	81%
5 Year Reduced Duration	73%	74%	72%	77%	80%
10 Year Reduced Duration	66%	70%	67%	71%	77%
Cost and Completion Certainty					
5% Cost Overrun	76%	76%		82%	
1 Quarter Construction Delay	79%	79%		83%	
1 Year Construction Delay	84%	86%		87%	

Glossary

Term	Definition
Accelerated Depreciation	For tax purposes, businesses in the U.S. can claim depreciation expenses against their taxable income by assuming that the assets depreciate over a much shorter duration than their lifetime.
Bonus Depreciation	A policy which allows a business to claim a depreciation expense against their taxable income for a fraction of project costs in the year in which the costs were incurred (often 50% or 100%).
Construction	We model the period of construction as beginning when all contractual and legal arrangements needed – including financial close – to start building a project are complete, and ending with the start of operations.
Construction Debt	Debt provided to a project to cover a fraction of its expenses during construction.
Cost of Capital	The internal rate of return of all cash / tax flows to and from the project to all of its financiers, including tax benefits resulting from debt interest expenses. CPI's analysis uses this metric in place of the weighted average cost of capital (WACC).
Cost Support	Any up-front subsidy provided to a project to cover a fraction of project costs.
Debt Amortization	The schedule of repayments of remaining debt principal. This schedule can be customized to reflect expected cash flows, or can be part of a fixed debt service payment, as in a mortgage-style loan.
Debt Service Coverage Ratio (DSCR)	Ratio of cash available for debt service to the amount of debt service payment due.
Debt Term or Tenor	The duration over which a debt instrument must be fully repaid.
Default	Here, the failure of the project to meet the conditions of its financial commitments, for example, to meet required debt payments.
Depreciation Expenses	Business expenditures for assets that are not "used-up" in the year in which they are acquired are accounted for in the companies' books as depreciation expenses – spread out over their useful lifetime. Depreciation expenses are typically tracked separately for tax accounting (where accelerated depreciation policies apply) and book accounting.
Development	The process of site selection, technical planning, and arranging all legal and contractual agreements needed to procure, build, finance, and operate a project.
Duration of Revenue Support	The length of time over which a revenue support (such as a Feed-in-Premium or Power Purchase Agreement) is made available to a project.
Equity IRR	The internal rate of return of all cash / tax flows to and from the project to its equity investors.
EURIBOR	Euro Interbank Offered Rate, a daily measure of the average interest rates that banks in the Eurozone wholesale money market are charging to lend to other banks.
Feed-in-Premium (FiP)	A policy which provides a guaranteed fixed premium above market electricity prices to an electricity generating project.
Feed-in-Tariff (FiT)	A policy which provides a guaranteed fixed price for the electricity generated by a project.
Financing Component of LCOE	The contribution of cash and tax flows to and from investors and debt providers to the project's levelized cost of electricity, discounted at a utility cost of capital.
Hurdle Rate	The rate of return equity investors demand to bear the risks of a particular project.

Term	Definition
Institutional Investor	Class of investors including pension funds and insurance companies who manage a large volume of capital invested in a broad portfolio of financial instruments, and have long investment horizons.
Internal Rate of Return (IRR)	Interest rate at which cash / tax flows to and from a project or investor have zero net present value.
Investment Tax Credit (ITC)	A credit offered to U.S. solar facilities (and to wind facilities until the end of this year) which provides an up-front tax credit for 30% of qualified project costs.
LCOE After Cost Supports and Financing	The levelized cost of electricity after the effects of all cost supports and financing are taken into account.
LCOE without Supports	The levelized cost of electricity of the project calculated by assuming that the project does not receive any cost supports and is financed entirely on balance sheet by a local utility.
Levelized Cost of Electricity (LCOE)	A single measure of the cost per unit of electricity (usually MWh) generated by a project calculated by dividing the discounted sum of all project costs by the total discounted generation. We use the local utility cost of capital as a discount rate for these calculations.
Leverage	Ratio of the amount of long-term debt initially provided to the project to the fraction of total project costs which need to be financed by investors. We exclude the value of a tax grant from total project costs in our calculations of leverage for U.S. projects.
Levered IRR	For our purposes, the equity IRR in the case that a project also has debt financing.
LIBOR	London Interbank Offered Rate, a daily measure of the average interest rates that banks in the London wholesale money market are charging to lend to other banks
Loan Guarantee	A guarantee made by a third-party (government or financial institution) to cover debt service in the event that a debtor is unable to make a payment to a lender.
Market Price Uncertainty	Here, uncertainty in revenues associated with fluctuating wholesale market prices for the electricity generated by a facility. Our project model only considers annual revenues, so we are primarily interested in annual variations in prices.
Megawatt (MW)	A rating reflecting the electric generating power of a facility. A 500 MW facility operating at full capacity for an hour can generate 500 MWh of electricity.
Megawatt Hour (MWh)	Unit of energy roughly equivalent to a month's (three months) worth of household electricity consumption in the U.S. (Europe).
Net Present Value (NPV)	Value of a set of future and past cash flows discounted to the present day
Operations	The period over which a project generates electricity for sale.
Permitting	The process of obtaining all legal permits and documentation required by various governments and agencies to operate a facility.
Power Purchase Agreement (PPA)	A long term contract by a load-serving entity to purchase electricity from a project.
Price Collar	A cap and floor on the price paid for the electricity from a facility. In our Spanish case, this price collar is adjusted annually for inflation.
Production Tax Credit (PTC)	A U.S. tax credit provided to wind facilities of roughly $21 / MWh for the first ten years of production.
Project Finance	A financing structure which is used to isolate the risks and rewards of a specific (often infrastructure) project. The project typically involves a number of investors (known as sponsors) as well as lenders whose loans are backed only by the assets of the project itself, rather than all assets of project sponsors.

Term	Definition
Project Finance Model	A model which captures the financial flows (cash and tax) associated with a specific project as a stand-alone entity.
Project IRR	The IRR associated with all cash / tax flows to and from the project – note that this is equivalent to the Cost of Capital except that it does not include tax benefits resulting from debt interest expenses.
Property Tax	An annual tax levied on the appraised value of a property -- both the land and improvements to land (immovable objects like buildings).
Renewable Energy or Green Tradable Certificate (REC / GTC)	A certificate representing the environmental benefits of the electricity generated which may be sold or traded separately or bundled with the electricity itself. The value of these certificates is driven by an RES / RPS which can be satisfied in part through the surrender of certificates.
Renewable Portfolio or Energy Standard (RES / RPS)	A requirement placed on certain electricity market participants that a fraction of the electricity they purchase or deliver be derived from renewable sources.
Revenue support	Revenue in addition to or in place of wholesale market prices for electricity generated.
Sales Tax	A consumption tax on the purchase price of goods and services at the point of sale.
Tax Equity Investor	An investor with tax liabilities who is interested in a project at least in part monetize tax benefits associated with a project. In the U.S., these tax benefits can be the ITC, PTC, or accelerated depreciation.
Tax Grant / Investment-Based Grant	A grant in lieu of the ITC for a project.
Term Debt	Debt for a project that is to be repaid by a project's revenues over its operational life.
Value-Added Tax (VAT)	A consumption tax that is a tax on the purchase price from the point of view of the buyer but is only levied on the net "value-added" by the seller, who is reimbursed for VAT paid on inputs to the goods or services sold.
VAT Facility	A financing facility aimed at bridging the gap between the timing of VAT due on project inputs and the VAT collected on project electricity sales.