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Discussion Papers

Impact of Renewable Energy Act Reform on Wind Project Finance

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Impact of Renewable Energy Act Reform

on Wind Project Finance

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June 2014

Abstract:

The 2014 reform of the German Renewable Energy Act introduces a mandatory shift from a fixed feed-in tariff to a floating premium system. This is envisaged to create additional incentives for project developers, but also impacts revenues and costs for new investments in wind generation. Thus uncertainties for example about balancing costs and the impact of the location specific generation profile on the average price received by a wind project are allocated to renewable projects. We first estimate the magnitude of the impacts on wind projects based on historic and cross-country comparison. We then apply a cash-flow model for project finance to illustrate to what extent the impact of the uncertainty for project investors reduces the scale of debt that can be accessed by projects and thus increases financing costs.

Key words: Feed in tariff, financing renewables, project finance

JEL: G32, L51, L94

Introduction

Reaching Germany's renewable energy targets will require the development of between 6 and 7 GW per year until 2020 and consequently, new capital commitments from lenders and equity investors. In recent history, Germany has successfully minimized its cost of capital through an allocation of risk that investors found attractive (De Jager 2008, Rathmann 2011). This trend will need to continue for Germany to achieve the goals of the new legislation without raising costs of capital.

The German cabinet has proposed amendments to the country's Renewable Energy Act (Erneuerbare-Energien-Gesetz, EEG 2014). As proposed, EEG 2014 would expose wind generators to revenue uncertainty through changes to the law's remuneration scheme. These changes are likely to increase the cost of capital needed to finance new wind generation.

The following analysis evaluates how EEG 2014 may impact investment in Germany's future wind generation by analyzing the proposals impact on earnings and cost of capital. In particular, three proposed changes are considered First, EEG 2014 allocates balancing costs to the generator, creating an incremental and uncertain operating cost. Second, EEG 2014 compensates the generator at the market price, plus a premium, the combination of which may be less than under EEG 2012. Finally the third change amends the Reference Model, a system used to mitigate the risk linked to inaccurate assessments of wind conditions at the time of site selection. The first two of these changes were already introduced in 2012 with the option of moving to direct marketing. While the option has been well subscribed the impact on financing was muted as generators retained the option to return to the fixed feed-in tariff.

By reducing earnings, EEG 2014 is likely to create less favorable investment opportunities. By modeling an average wind generator's cash flow to evaluate the impact of EEG 2014 on lending and pre-tax project yield, we estimate that project capital structures could be substantially altered, shrinking debt share by 2,3% to 10,7%. Second, IRRs may decrease by between 29% and 100%.[1] Further, changes to the Reference Model would reduce the duration of premium compensation, intended to mitigate the risk of underproduction, by on average 36% and as much as 88%.

The following sections present the analysis supporting these conclusions:
- Section 2 introduces project finance, the process by which large scale (>1 MW) renewable electricity generators secure the debt and equity needed to build the generation facility.
- Section 3 reviews recent literature on the impact of relevant risks and public policies on project finance.
- Section 4 profiles the impact of EEG 2014 on wind generator revenues and operating costs.
- Section 5 shows the results of cash flow model simulations testing the impact of new risk on debt sizing, equity returns, and overall costs of capital.
- Section 6 analyzes potential investor responses to debt and equity changes.
- Section 7 draws conclusions about whether EEG 2014 is likely to be effective in attracting needed new investment.

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[1] *The results presented by this study are relative to one another (rather than absolute) and presented in nominal terms.*

The research is supported by a literature review, interviews with industry experts, financial cash flow modeling, and market data analysis. Each of these components is explained in further detail below.

To make the scope of this analysis manageable, we focus on large-scale (>1MW), onshore wind generation facilities that use project finance to fund their construction. This scope excludes a considerable share of Germany's historic renewable electric generator market, namely projects which are financed entirely through corporate finance or equity provided by the project sponsor or owner (KNi 2011). Nevertheless, installations larger than 1 MW have and will continue to play a significant role in Germany's renewable energy future (Juergens et al., 2012). This analysis will be most relevant to this important market segment.

We understand that the effects on project finance of new cost and risk allocation implicated by the EEG 2014 direct marketing requirements have not been studied in detail. This study proposes a methodology to better understand the impacts of two potential revenue risks. As the relative results reported here show, the proposed changes could have a substantial impact on project finance for new wind generators suggesting further evaluation and refinement of the methodology used here would be beneficial.

Background: An Introduction to Project Finance

Overview

Project finance allows the sponsors of renewable electricity generation facilities to secure the debt and equity needed to build the generator. The limited rights of the lender makes this method of finance distinct from alternative (i.e., corporate) finance methods: the lenders to a project have either no recourse or only limited recourse to the assets of a project's sponsor. Instead of recourse to the assets of the sponsor, lenders rely on the project assets and anticipated revenues from the sale of the completed project, or from the sale of the project's output, to secure the loan (Groobey 2010, Chatham House 2009).

But how does project finance work? The availability, size, and cost of loans and equity investments depends on a generator's forecasted ability to service the debt - to repay the principal and any accrued interest on time - and to provide equity investors an acceptable return on their capital. Lenders lend and investors invest when they are confident that the forecasts of revenues and costs will be met and when the difference provides an adequate return.

Key Financial Metrics

In project finance, lenders take a senior position in the capital structure, giving them priority rights to cash earned. Their seniority implies a lower return (Return on Debt, ROD). Returns on debt, or cost of debt, is reflected in interest rates charged by the lender. The formula for return on debt is:

$$R_d = \frac{NI_d}{MV_d}$$

$$R_d = Cost\ of\ Debt$$
$$NI_d = Net\ Income\ of\ Debt$$
$$MV_d = Market\ Value\ of\ Debt$$

In contrast, equity investors, either developers or third-party investors, are subordinate to the lenders, only having rights to cash flow after obligations to the lender have been met. Equity investors expect, and when the project is successful, receive, a higher rate of return (Return on Equity, ROE), reflecting their riskier position. The cost of equity is reflected by two financial metrics: ROE and Internal Rate of Return (IRR). The formula for Return on Equity is:

$$R_e = \frac{NI_e}{MV_e}$$

$$R_e = Cost\ of\ Equity$$
$$NI_e = Net\ Income\ of\ Equity$$
$$MV_e = Market\ Value\ of\ Equity$$

The second metric used to assess the attractiveness of equity investments is the Internal Rate of Return (IRR). The IRR is the interest rate (or discount rate) that will bring future cash flows to a Net Present Value of zero. IRR is frequently used by investors comparing two investment opportunities: the opportunity with the higher IRR will, if the investment performs as forecasted, yield a higher return. The IRR formula can be very complex depending on the timing and variances in cash flow amounts. Without a computer or financial calculator, IRR can only be computed by trial and error. (IRR calculations for this analysis were calculated using Microsoft Excel's IRR Function.)

The shares of debt and equity making up a project's capital contributions are organized to ensure all partners to the project receive an acceptable share of the project's risk and reward. The apportionment of shares to debt and equity, with their respective returns, are referred to as a project's capital structure and the Weight Average Cost of Capital (WACC) is a commonly used metric of how much the financing of a project costs. The formula for WACC[2] is:

$$WACC = \frac{MV_e}{MV_d + MV_e} \times R_e + \frac{MV_d}{MV_d + MV_e} \times R_d * (1 - ET)$$

$$MV_e = Market\ Value\ of\ Equity$$
$$MV_d = Market\ Value\ of\ Debt$$
$$R_e = Cost\ of\ Equity$$
$$R_d = Cost\ of\ Debt$$
$$ET = Effective\ Corporate\ Tax\ Rate$$

Determining Debt Size

Given the seniority of lending in capital structures and the importance of debt to past and future renewable energy development in Germany, this analysis relies heavily on lending metrics to assess the potential impact of proposed policy changes. As such, the remainder of this section focuses on explaining key lending metrics and how they affect

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[2] *We present here a standard formula for WACC that takes into account tax effects. However, the results of this study are presented on a pre-tax basis.*

lending behavior by banks. The logic will be illustrated by the following example. The assumptions and calculations behind this example are explained below.

	Table 1: Illustrating Lending Metrics in Debt Sizing			Year 1	Year 2
1	Revenue (EUR)			100	100
2	Operating Costs (EUR)			25	25
3	Cash Flow Available for Debt Service	(CFADS)		75	75
4	Debt Service Coverage Ratio	(DSCR)		1,2	1,2
5	Debt Service Obligation	(DSO)		62,50	62,50
6	-Principal Payment			56,69	59,52
7	-Interest Payment			5,81	2,98
8	Loan Balance		*116,21*	59,52	0
9	Free Cash Flow			12,50	12,50

The attractiveness of a generator to a lender depends on the generator's ability to service debt on time, which in turn depends on its future earnings. Future earnings equal revenue through sales, minus operating costs. This first lending metric is referred to as Cash Flow Available for Debt Service (CFADS). In the example, revenues (Row 1) and operating costs (Row 2) are assumed to be 100 and 25 EUR per year, respectively. CFADS (Row 3) equals the difference, 75 EUR per year.

Because a bank anticipates uncertainty in its forecast of CFADS, it applies a Debt Service Coverage Ratio (DSCR) for added protection. This second lending metric creates a cushion between expected CFADS and the Debt Service Obligation (DSO).
The following formula illustrates this logic:

$$DSCR = \frac{CFADS}{DSO}$$

The lender must make two principle judgments concerning DSCR; each reflects the lenders risk profile. First, how large (conservative) should the DSCR be?
A DSCR of 1,0 would assume 100% of CFADS will be used to service debt; levels greater than 1,0 provide the bank greater security that its debt will be serviced on time. The higher the DSCR required by a bank, the more secure the loan. The example above assumes a DSCR of 1.2 (Row 4).

The second judgment the lender must make: should the DSCR be applied to every period (e.g., monthly), be spread over time (e.g., quarterly, yearly, or more), or applied to the project's CFADS nadir. If the lender applies the DSCR to every period, the loan has been "sculpted" to CFADS. This implies the DSO may rise and fall in proportion to expected CFADS. This method takes the most liberal approach. Spreading it over time implies a similar sculpting, but allows the borrower a longer period in which to meet its DSO. In contrast, a bank may identify the nadir, the point at which the generator is least able to service debt, and apply the DSCR to this period. This method takes the most conservative approach. The obligation of every period equals the obligation of the weakest period, creating additional security that no payments will be missed. This approach is referred to as "straight-line" or "annuity." The example above uses this straight-line approach, applying the DSCR to every period creating a DSO of 62,50 EUR per period.

As noted above, the DSO comprises both debt and interest payments. Interest payments are the product of the interest rate multiplied by the debt size (principal). As such, they represent a larger portion of the debt service obligation at the beginning of the loan. As the borrower pays down the principal, interest payments become smaller and principal payments become a larger share of the DSO. The example above assumes an interest rate of 5%, fixed over the two periods, resulting in the interest payments seen in Row 7. The size of the principal payments (Row 6) are the difference between the total DSO and interest payments. The schedule of repaying the principal through principal payments is referred to as amortization.

The last lending metric we introduce is tenor. This is simply the length of the loan. The example above uses a two year period.

While there are many more inputs a lender may use to optimize its loan offering, these are the critical factors. In sizing the loan, the lender must determine what size loan could be repaid in full, plus interest, within the given tenor. This question is answered using an optimization, which tests possibilities to arrive at the optimal debt size for the defined situation. (Optimization calculations for this analysis were calculated using Microsoft Excel's Goal Seek Function, which tests possible inputs which produce defined outputs.) An optimization of our example loan determines that, under these circumstances, a principal of 116,21 (Row 8) could be repaid on time.

This example also begins to illustrate the equity investor's return. Due to the 1,2 DSCR (as opposed to 1,0), 100% of the plant's forecasted earnings are not dedicated to debt service. The cash difference between CFADS and the DSO is available to the generator to meet other obligations such as funding reserve accounts, paying taxes, and providing returns to equity. Cash returned to equity investors after obligations are met, divided by the equity contributed, equals the investor's return on equity (ROE). In the above example, Row 9 represents cash free to meet these remaining obligations.

Contrasting Forecast and Actual Debt Service

Of course actual revenue and operating costs may be higher or lower than forecasts – this is the central challenge of project finance. When revenues exceed the forecast, the generator has more free cash flow; when they are less than the forecast, the generators have less free cash flow. The inverse is true for operating costs. Lenders and investors view these possibilities as risks; higher risk leads to higher expected returns and in some cases, effectively excludes risk adverse investors.

Risks to the lender can be mitigated with a debt service reserve fund, a fund which can be drawn on to meet obligations when actual CFADS is less than debt service obligations. However, lenders do not account for the availability of this fund in debt sizing; instead, this fund supports the project only under extreme financial pressure. Furthermore, committing equity to this fund comes at its own cost of capital, with larger funds offering more security coming at a higher price. The plant reaches insolvency if and when it cannot service debt with CFADS or funds held in reserve. In sum, while debt service funds can mitigate risk to lenders, they are costly and have limits. As such, they provide only limited protection against unpredictable revenues and operating costs: these remain a primary driver in the availability of project finance.

Project Finance in Germany

Big Picture

In considering the role of project finance in Germany's renewable energy market, it helps to begin with a big picture. Juergens et al. (2012) provide such a snapshot, assessing how much money is being invested in German renewable energy generation, including the source and recipient sector of the funds. Several findings from this study are particularly relevant to this analysis, especially:

- In 2010 renewable energy investment, which totaled 26.1 Billion EUR, came from a variety of sources: households (37%), utilities, banks, financial investors (25%), farmers (20%), and industry and commerce (17%);
- Small-scale solar photovoltaic installations accounted for 75% of all investment in renewable energy, while the remaining 25% went to large-scale projects;
- Concessionary loans provided a 43% share of total investment in renewable energy.

KNi and Trend:Research (2011) confirm the first and second bullets from above; investors and owners of renewable generation in Germany come from a wide variety of sources, creating considerable diversity in the market. The second finding, the large market share of equity funded roof-top solar PV systems is also documented by Grau (2014).

From this literature we infer two conclusions relevant to our analysis: first, much of Germany's renewable generation is small-scale solar which does not use project finance. Nevertheless, a large number of projects are using debt instruments, especially concessionary loans, to secure a substantial amount of financial support. Therefore, the perspective of debt providers– how they profile, mitigate, and price risk –remains very relevant.

Moving beyond the big picture, two unique factors warrant further explanation: the role of concessionary loans (or "soft loans") and "Bürger" (citizen) investors.

Concessionary Loans

Concessionary loans are debt instruments which provide the borrower more attractive terms and conditions than may otherwise be commercially available. In Germany, concessionary loans are primarily backed by the Kreditanstalt für Wiederaufbau (KfW), a publically-backed German lender. KfW's Standard (270/274) program offer loans with the following characteristics:

- Loan tenors ranging from 5 years to 20 years;
- Fixed interest rates for 5 to 20 years;
- Interest rates between 1,40% and 7,55%;[3]
- Interest-only (no principal payment required) periods up to 3 years.

Borrowers can secure these terms and conditions through their lenders of choice who act as intermediaries implementing the KfW programs.

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[3] *KfW program 270 serves wind generators. Current interest rates in program 270 range between 1.4% and 7.55%, depending on 9 different price categories. Through interviews of market participants, we understand three categories (B, C, and D) are most relevant to wind generators, with corresponding interest rates range between 1.65% and 4.15%.*

Interviews with lenders conducted for this analysis suggest more than 80% of wind generators in Germany have used a KfW debt instrument. This scale is confirmed by the following data showing the number and gross volume KfW loans in 2012 and 2013:

Table 2: KfW Lending to Renewables 2012-2013				
	2012		2013	
	Number	Volume (Million EUR)	Number	Volume (Million EUR)
Standard	25.663	7.574	13.374	4.399

Interviews conducted for this research suggest the market for KfW loans is a "buyers market." Competition among lenders to retain market share keeps the offered interest rates between 3 and 4% and loan tenors 15 years or more.

However two noteworthy constraints do exist: first, according to interview responses from active lenders, KfW loans require straight-line amortization; lenders do not have the flexibility to structure loans based on a profile of forecasted CFADS. Second, loans may not be greater than 25 Million EUR.

"Bürger" Investors

The second unique characteristic of project finance in Germany: active equity investment by individual, private citizens. Citizens engage in three primary ways: through ownership of generation facilities on or near their home, taking partner-level positions in local for-profit and non-profit ventures, or becoming limited-partners in renewable energy funds.

Recent studies conclude this class has sponsored 34 GW of renewable electric generation, more than 47% of Germany's total 73 GW in 2012. Focusing on onshore wind, citizen investors have sponsored 15,5 GW, more than 50% of the total. Estimates of the total market value of this investment range up to 5,1 Billion EUR in 2012, 30,6% of the total 16,7 Billion EUR invested (Trend:Research 2013).

This class of investors stands in contrast to their counterparts, professional equity investors, developers, or institutional equity investors. Their motivations are not primarily financial. Instead, they also consider contributing to Germany's Energiewende, mitigating climate change, and supporting their local economy, more important than financial returns (Trend:Research 2013).

According to recent studies (Kost et al., 2013; Hern, 2013) and interviews conducted for this study, Bürger investors accept lower returns on their equity than traditional equity investors. We estimate traditional profit-driven equity investors have an equity hurdle rate of 7-9%, whereas Bürger investors may be satisfied with 4-6%.

Accounting for the role of concessionary loans and Bürger investors, project finance in Germany has some unique characteristics. In the following literature we summarize how relevant studies characterize the role of the EEG in creating Germany's unique investing environment.

Literature Review
Overview
The preceding section was supported by the referenced literature, including general introductions to project finance and the state of investment in German renewables. Having established this context and with an eye toward our goal of assessing the potential impacts of EEG 2014 on earnings potential and capital structures for wind generators, we turn now to a second category of literature: studies of risk facing renewable energy investors (General Risk Profile) and the role of public policy in mitigating and/or allocating those risks (Policy and Risk). The following section focuses on this category of literature, zeroing in on aspects most relevant to this analysis.

General Risk Profile
In 2013 Bloomberg New Energy Finance (Bloomberg) and Swiss RE identified key risks facing investors in wind generation and where relevant, characterizing that risk for investors in German renewables with a feed-in tariff (Turner et al., 2013). Four categories of risks are identified: construction, operation, market, and policy. The following table from Bloomberg provides more detail on each category.

Table 3: Risks facing renewable energy projects

Risks facing renewable energy projects

Category	Risk type	Description
Construction	Loss or damage	Breakage/theft in transit or during installation
	Start-up delays	Revenue losses arising from delays in project construction
Operation	Loss, damage & failure	Accident, theft, fire, natural catastrophe; equipment performs worse than anticipated; manufacturer unable to honour O&M agreements
	Business interruption	Revenue loss arising from failure, damage or extreme weather
Market	Weather	Variability in revenue due to variability in output, sometimes incurring additional balancing charges
	Curtailment	Regional grid oversupply where power output cannot be sold
	Power price	Variation in revenue due to wholesale price volatility
	Counterparty	Default of counterparty in power purchase agreement
Policy		Retroactive support cuts

Source: Turner et al., 2013

In detailing weather risk, Turner, et al. state revenues can vary year over year by around 15-20% for wind. This volatility puts reliable debt service at risk. In addition, balancing charges, which are incurred when variable renewable output creates imbalances on the grid that require short term balancing by dispatching additional power and transmission service, add volatility to a generator's operating costs. Both factors combine to undermine the reliability of CFADS forecasts.

According to Turner, et al. power price risk is particularly challenging for wind and solar generators because they cannot control when they produce. Furthermore, the challenge of price risk increases as wind and solar penetration increase. This is due to further complexity in market behavior.

In considering the applicability of these risks to Germany, Turner et al. find that, under the feed-in tariff, balancing costs and price risk have not been allocated to the generator. Therefore the feed-in tariff eliminates these risks and associated risk premiums effecting cost of capital.

Publications by Rathmann (2011), Brodies (2013), and Hern, R. (2013) independently confirm Bloomberg's et al. characterization of weather, balancing, and power price risks. All sources confirm that long-term power purchase agreements are the customary way for a generator to mitigate balancing cost risk and power price risk and acknowledge that absent such contracts, financing for wind and solar becomes more costly.

Policy and Risk

The impacts of public policy on project finance are well documented by de Jager and Rathmann (2008), Rathmann et al. (2011), and Giebel and Breitschopf (2011). Each source identifies risks to investors in renewable energy generation consistent with references listed above. These sources then take the additional step of evaluating how various policy options impact those risks. For this analysis, we focus on a narrow scope of risk and related policy options: namely, remuneration schemes and market integration requirements.

Rathmann et al. (2011) compare fixed price tariffs with sliding premium tariffs. The former pay generators a fixed price for every unit of output over the life of the tariff, equivalent to Germany's feed-in tariff from 2000 to present. The latter compensate generators at the market price at the time the generation occurs, plus a premium, equivalent to the proposed EEG 2014. The "sliding" component implies that the premium goes up when market prices are down, while the inverse is true when market prices are up. Rathmann et al. (2011) conclude that these two options are from a risk perspective roughly equivalent. The one exception is that a fixed system which obliges a third party to absorb balancing costs could lead to 1-2,0% reductions in levelized costs of power. This difference is a result of the increased operating costs shouldered by the generators in a feed-in premium system.

Giebel and Breitschopf (2011) compared the same policy options. Their study concludes financing costs (WACC) under a sliding premium would be 1,85% higher than a fixed price tariff. This study also tests an additional element: quantity balancing. Quantity balancing, which mirrors the "weather" risk identified by Turner, et al., compensates the generator at a higher level to guard against underperformance due to weather. The study concludes that quantity balancing reduces WACC by 0,6%.

In summary, the literature review informs our understanding of project finance in Germany, risks to investors, how policies affect risk, and the risk profile and expected returns of different investor classes. Our analysis aims to add to the literature by profiling new investment risks resulting from the proposed EEG 2014, quantifying those risks to assess their significance, and analyzing the impact of those risks on cost of capital. The following section advances toward this objective by comparing the risk profile of generation under Germany's current fixed feed-in tariff and the proposed EEG 2014.

Earnings Potential: EEG 2012 vs. EEG 2014

Based on this literature review, we conclude the transition from EEG 2012 to the proposed EEG 2014 would alter the risk profile of investments in renewables. The

following table shows whether, in our judgment, the risks defined by Turner et al. would increase, decrease or stay the same.

Table 4: Risks to Investors under EEG 2014 Relative to EEG 2012		
Risk	Description	Increase (+), decrease (-), or static (=) relative to EEG 2012
Construction	Loss or damage	**=**
	Start-up delays	**+**
Operation	Loss, Damage & Failure	**=**
	Business Interruption	**=**
Market	Weather, including balancing cost and volume risk	**+**
	Curtailment	**=**
	Power Price	**+**
	Counterparty	**=**
Policy	Retroactive Support Cuts	**=**

The following description explains our assessment.

EEG 2012

The existing EEG has led to low capital costs and in doing so, enabled substantial investment in renewable generation. This has been possible in large part due to the predictability of revenues and earnings provided by the EEG since 2000. The EEG provides four guarantees, which provide investors this predictability:

- guaranteed off-take of all electricity produced through a 20 year contract, eliminating off-take risk completely;

- guaranteed creditworthiness of off-take parties as cost off-take contracts with Transmission System Operators (TSOs) are backed by the German government;

- guaranteed market integration through allocation of balancing responsibility and costs to applicable TSOs; and

- technology-specific and guaranteed price per unit of output for 20 years (tariffs are vintaged, new tariffs will only apply to new projects), reducing significantly risk that output will be paid a price lower than expectations.

Further, the EEG partially mitigates volume risk, which we define as the risk that electric output over the life of the asset will be lower than projected based on ex-ante site estimates. The EEG's Reference Model, a two-stage compensation mechanism that accounts for the volume of power produced over first five years when determining duration for which higher tariff level will be applied, accomplishes this.

In addition to these assurances provided directly through the EEG, German wind generators also benefit from the previously summarized KfW lending, active Bürger investor class, and a stable regulatory environment.

EEG 2014

The proposed EEG 2014 would preserve many components of the EEG 2012 while requiring some changes that may affect the earnings.

- First, EEG 2014 allocates balancing costs to the generator, creating an incremental and uncertain operating cost. (New Balancing Costs)
- Second, EEG 2014 compensates the generator at the market price, plus a premium, the combination of which may be less than under EEG 2012. (Location Specific Remuneration Uncertainty)
- Third, EEG 2014 amends the Reference Model, a system used to mitigate the risk linked to errors in site-specific wind assessment of expected annual full-load hours. (Shorter Premium Tariffs)

We explain each of these changes in greater detail below. However, before that it should be noted that Germany currently has a voluntary direct marketing remuneration scheme in place. It has been well subscribed for wind deliveries in 2013. Why then should the direct marketing requirement proposed by EEG 2014 effect earning potential for new generators or capital structures? Under the current direct marketing scheme, the generator has the option of reverting back to the fixed feed-in tariff within one month. The fall back option assures lenders and investors predictable prices through the end of their contract. With EEG 2014, generators may revert to a fixed feed-in tariff only in the event of insolvency of the company they have contracted to market their electricity. Furthermore, in this unfortunate scenario, the generator will earn only 80% of the most recently determined, technology specific reference price. This fallback is not being viewed as a bankable revenue stream by lenders and investors interviewed for this research.

New Balancing Costs

Generators incur balancing costs when their output deviates from their last nomination of output which typically occurs one hour or more before gate closure. In order to minimize such 'direct' balancing costs, generators (or the direct marketers they have contracted) engage in the intraday market to adjust their position based on recent wind forecast. In the remainder of the text we refer to both the real-time balancing costs and the intraday adjustment costs as balancing costs. Balancing costs can be particularly high if a generator delivers less than forecasted at times of relative scarcity. (Conversely, balancing rewards may be provided when a generator exceeds forecast during times of scarcity, but as our analysis in the following shows, balancing costs exceed balancing rewards on average).

Balancing costs are a new and not easily predictable cost. Since balancing costs are subtracted from revenues, the predictability of CFADS will correlate with the predictability of balancing costs. In the following section, we evaluate historic market activities of wind generators to determine the potential significance of new balancing costs.

Location Specific Remuneration Uncertainty

Under the proposed feed-in premium system, a generator's revenue comprises a market price, which depends on market conditions at the time of production, and a premium, which equals the difference between the reference price and the monthly average market price weighted with the average production volume wind or solar. Dependent on the correlation of the production at a specific site with the average production in Germany, the average price realized by wind turbines at specific locations can deviate

from the German average. This creates the risk that earnings are below the reference price. Since price paid per unit of output is a driving factor in revenues, the predictability of CFADS will correlate with the predictability of prices. In the following section, we show historic trends in wind deliveries to depict what they may have earned relative to the market average for all wind deliveries.

Shorter Premium Tariffs

Finally, EEG 2014 amends the Reference Model, a system used to mitigate the risk of underproduction resulting from unfavorable weather conditions. To understand this potential impact on earning, further explanation of the Reference Model follows.

Under the Reference Model, every wind generator begins with a first-stage tariff that last 5 years and pays a higher price. After five years the generator begins to earn less, unless it receives an extension of it first-stage tariff.

Extension of the generator's first-stage tariff depends on how much power it has produced relative to an administratively determined Reference Yield (RY). Before commissioning, each generator receives an official RY, calculated by an independent third party, based on a formula defined in the EEG. If the generator's actual output falls short of 150% of the RY, an extension may be granted.

The length of a generator's extension depends on the level of its production relative to its unique RY. For EEG 2012, a generator that produces less than 150% of the RY over 5 years receives a two month extension until it reaches 150% of its RY. Under EEG 2012, extensions would be calculated as follows:

$$T_{2012} = \frac{150 - x}{0,75} + 60$$

$$T_{2012} = Total\ Duration\ of\ Stage\ 1\ Tariff\ in\ Months\ under\ EEG\ 2012$$
$$x = Actual\ Production\ as\ percent\ of\ Reference\ Yield$$

The EEG 2014 would continue to use the Reference Model, however some significant changes have been proposed. First, extensions would be month-to-month, rather than two months. Second, the formula for calculating extensions would be changed to the following:

$$T_{m2014} = \frac{130 - x}{0,36} + \frac{100 - x}{0,48} + 60$$

$$T_m = Total\ Duration\ of\ Stage\ 1\ Tariff\ in\ Months\ under\ EEG\ 2014$$
$$x = Actual\ production\ as\ percent\ of\ Reference\ Yield$$

The following table compares the duration of first stage tariff compensation for generators with a range of production levels relative to RYs.

Table 5: Duration of Stage 1 Tariffs under 2012 and 2014 Reference Model			
	Duration Of Stage 1 Tariff (Years)		
Output Relative to Reference Yield (%)	EEG 2012	EEG 2014	% Change
150	5,0	5,0	0
140	7,2	5,0	44
130	9,4	5,0	88
120	11,7	7,3	60
110	13,9	9,6	45
100	16,1	11,9	35
90	18,3	16,0	14
80	20,0	20,0	0
		Average	35,8

The EEG 2012 and 2014 tariffs last 20 years. Therefore, as we see in the final row of this column, 80% of RY becomes an effective minimum.

As Table 5 shows, the proposed amendment would result in shorter premium tariffs across the board. Only very strong and very weak yields relative to the reference yield would be indifferent. Projects yielding 130% of reference yield would face the largest cut, 88%.[4]

The following section provides a range of potential quantitative impacts on the revenue and costs of wind generators resulting from new balancing costs, potentially lower prices, and less weather protection. In addition, we model the effect of these impacts on debt size and expected capital structures for representative projects.

Impact of EEG 2014 on Capital Structure
This analysis takes two methodological steps to project the impact of new balancing costs and potentially lower prices on wind and solar plant capital structures. First, the risks are quantified, including a point estimate and a range of possibilities around the point estimate. Second, the quantified risks are used as inputs in a cash flow model. Using these inputs as independent variables, the model returns a maximum potential debt size, equity share, IRR, and WACC. Each of these two steps is now described in further detail.

Quantifying New Balancing Costs
To quantify potential new balancing costs that may be attributed to wind generators under EEG 2014, the historic power production by wind generators was compared to the respective day-ahead forecasts. Deviations were deduced. If the deviation was positive, meaning the generator produced more than forecast at a time of market scarcity, a value was attributed to the deviation. Conversely, if the deviation was

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[4] *This study does not model the impact of the proposed changes to the reference yield, but rather assumes the generator will receive a 20-year Feed-in Premium contract. We view this area as worthy of further analysis but beyond the scope of this study.*

negative, meaning the generator produced less than forecast at a time of market scarcity, a cost was attributed to the deviation. The magnitude of the value or cost reflects the magnitude of the scarcity in the market, as measured by the difference between day-ahead and intraday power prices. Figure 1 illustrates this logic.

Figure 1: Hourly wind energy feed-in deviations and differences between day-ahead and intraday power prices, 50Hertz in 2010
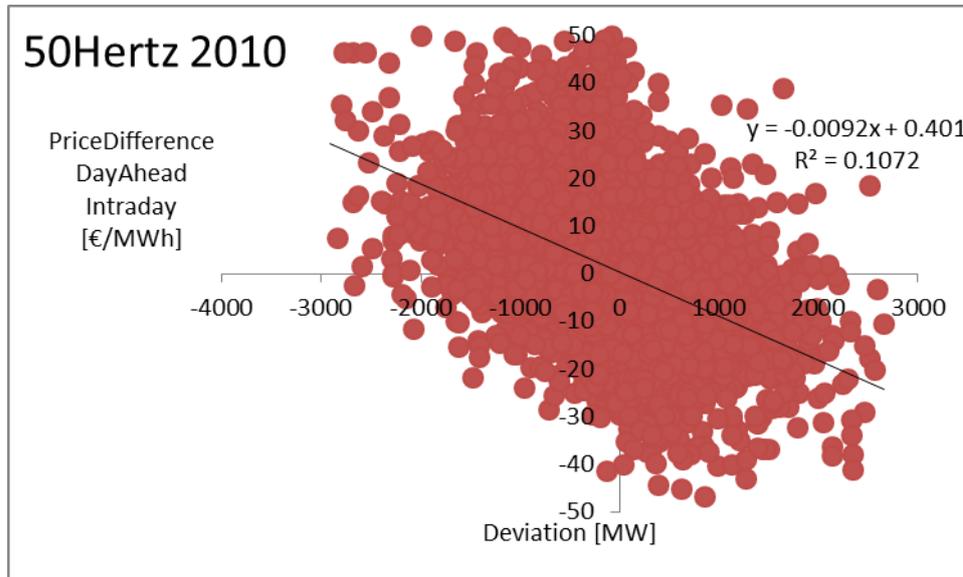
This graphic shows data from wind generators operating in the service territory of 50Hertz during 2010. Each red dot represents two dimensions on hourly basis: first, the difference between the actual wind energy feed-in and the day ahead forecast (x-axis) and second, the difference between the day-ahead power price and the intraday last price (y-axis). Together these factors show the market conditions when deviations between actual and forecasted generation occur.

The trend line and associated equations show a correlation between these factors. Consistent with economic and market theory, which suggests that increases in supply result in decreases in prices, this figure shows that when deliveries exceed forecasts, intraday market prices are lower than day-ahead prices. Lastly, this data set shows more often than not, costs outweigh value, resulting in a cost to the system on aggregate.

From this data, and comparable sets for other service territories and years an average balancing cost is quantified. The average balancing cost, which will be referred to as the Greek symbol epsilon ("ε"), is calculated using the following formula:

$$\varepsilon = \frac{-(\sum Imbalance\ Cost_y)}{\sum Energy\ Revenues_y}$$

$$y = year\ in\ question\ (e.\,g.,\,2010)$$

Therefore, ε represents the portion of revenues dedicated to balancing costs for the total system and year. Table 6 shows these results.

Table 6: ε (balancing costs as percent of market price)		
	Tennet	50 Hertz
2010	3,5%	4,3%
2011	2,7%	2,9%
2012	1,5%	3,8%

Figure 2 shows the same calculations for the same regions, but by month rather than year.

Figure 2: Monthly epsilons for Tennet and 50Hertz between 2010 and 2012
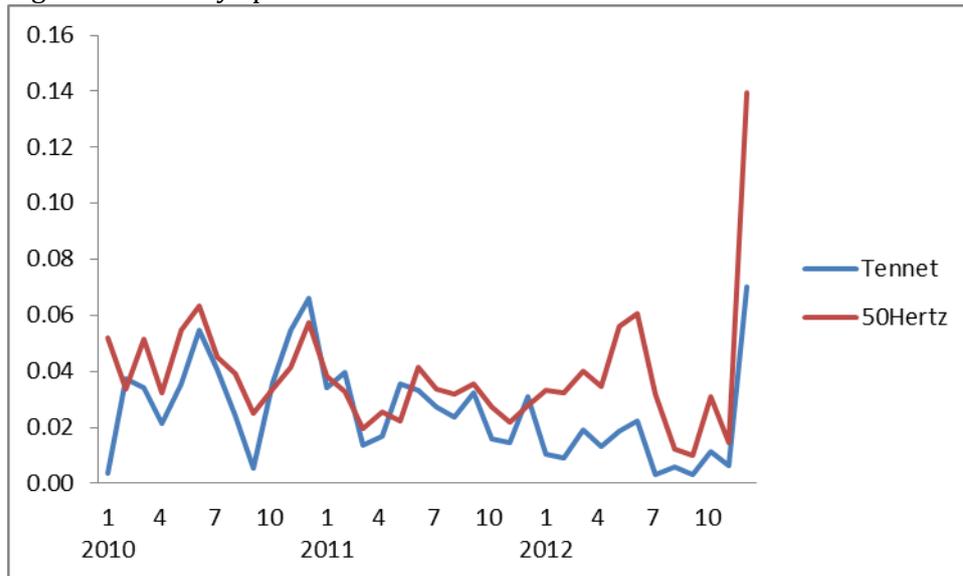
This figure shows that ε is not seasonal. Rather, the imbalance of the system appears to be randomly spread across the year. The outlying data point of 50Hertz at the end of 2012 is the result of relatively large imbalance cost in December 2012.

Finally, Figure 3 presents the distribution of monthly ε factors.

Figure 3: Distribution of monthly epsilons.
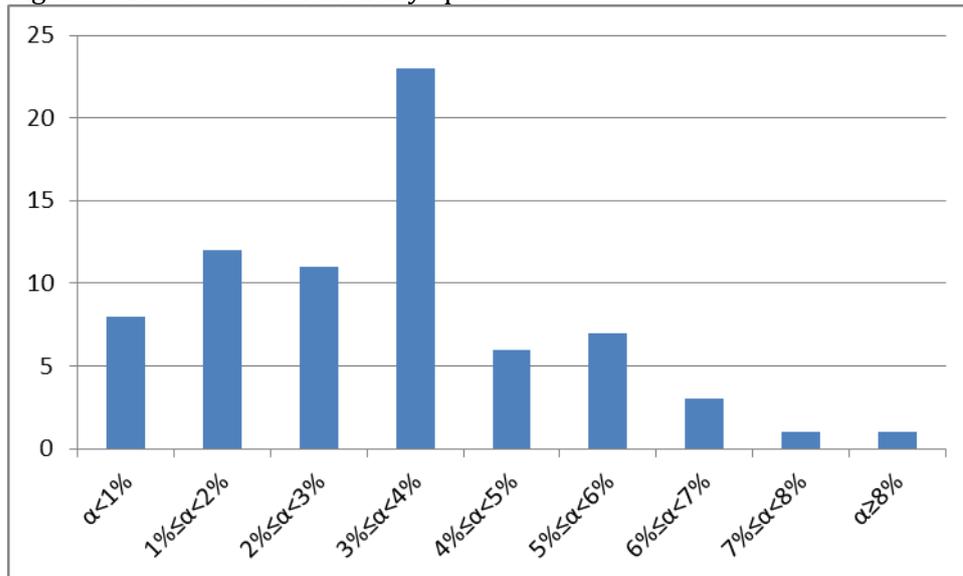
The average of the monthly epsilons is 3,2%.

We infer from these final results that balancing costs range from 0 to more than 8% of revenues. The final step of this methodology is an assumption: the ε of the total system is assumed to be representative of a generator within that system and therefore ε represents the balancing cost that a random, but distinct generator might face. More specifically, to date the balancing costs of a randomly selected generator are likely to be between 3% and 4%, but may range between 0 and more than 8%. Later in this section we show how these ε factors may impact a project's capital structure.

This relatively simplified estimation of balancing costs assumes any deviations from day-ahead forecasts and real-time output of wind generators would be balanced based on the last price paid in the intra-day market. The costs can be (i) reduced where earlier intraday forecasts allow for adjustments at lower costs (ii) increase where multiple adjustments intraday to match recent forecasts create additional costs (iii) increase if real-time balancing is required and faces higher prices than the last intraday price. The EEG2012 created the opportunity for market participants to voluntarily move to direct marketing and benefit from a premium of 0,45 Euro/MWh, which corresponds to roughly 1% of the market price of the period. The premium encouraged large scale switching to direct marketing, suggesting that realized balancing costs where less than the management premium.

In the following, we describe international experiences on balancing costs at the examples of the UK and Spain. In the UK, imbalance opportunity costs for out of balance producers are currently around 1 pound/MWh and might rise to 5 pounds/MWh in 2020, and 10 pounds/MWh in 2030 (Baringa, 2013).

We illustrate the Spanish experience at the example of February 2013. In this month, forecasted wind energy feed-in (hour by hour) amounted to 5.731 GWh, while actual feed-in accounted only for 5.341 GWh. Absolute deviations amounted to 497 GWh, equivalent to 9% of forecasted feed-in, with the overall costs of these generation deviations accounting for 7,2 m€, i.e. 1,35 €/MWh actually produced (data from Red Eléctrica de Espana).

Location Specific Remuneration Uncertainty

As explained above, some generators who produce at times of excess supply will earn below the market average, thereby reducing their total compensation to a level below the reference price. The following methodology was used to quantify this potential, which we refer to as zeta ("ζ")..

Calculation of wind power production

To calculate wind power generation at different locations, we use a characteristic power production curve of a typical wind turbine with 2 MW capacity, as shown in Figure 4. This curve has a cut-in wind speed of 3 m/s (speed at which the wind turbine starts to produce electricity), a rated output wind speed of 15 m/s (at which the maximum power level is reached), and a cut-out speed of 25 m/s.

Figure 4: Power production curve of typical wind turbine
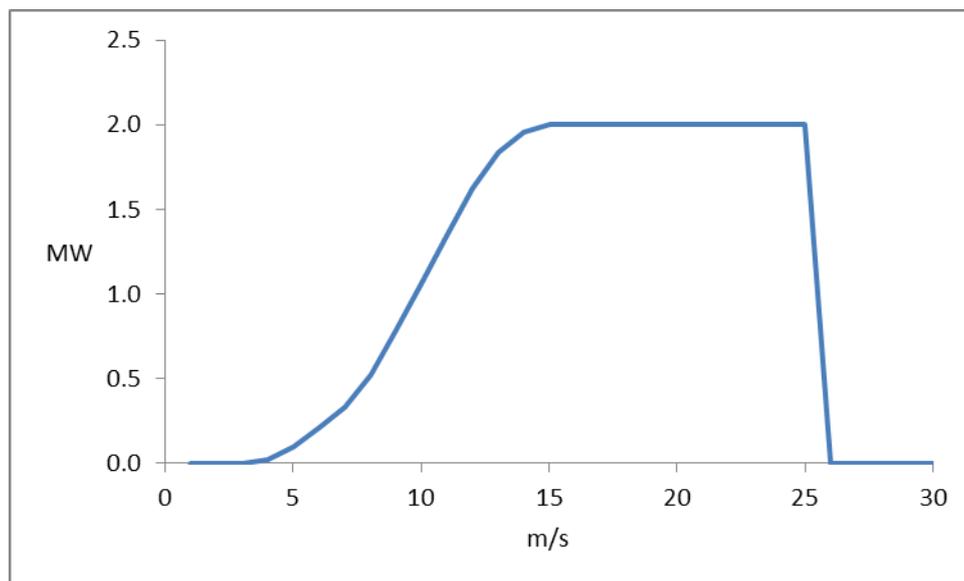
The web database from Deutscher Wetterdienst[5] provides hourly means of wind speed data (in m/s) for around 70 locations with specific sensor heights in Germany. Wind speeds for different hub heights can be calculated using the following formula

$$v_h = v_s * \left(\frac{h}{s}\right)^g$$

with hub height h, sensor height s, and wind speed in sensor height v_s. The exponent g depends on the type of terrain, being 0,16 for open areas (e.g. coast), 0,28 for areas with barriers up to 15m (e.g. forest), and 0,40 for areas with large barriers (e.g. big city). We use a typical hub height h of 90m and a typical exponent g of 0,23.

So far we calculated hourly wind power production for three exemplary locations, Frankfurt am Main, Hannover, and Schwerin for the period between January and December 2010.

Calculation of Zeta

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[5] https://werdis.dwd.de/werdis/start_js_JSP.do

We calculate ζ as follows:

$$\zeta = \frac{P_{a,i}}{P_a} - 1,$$

with the average price $P_{a,i}$ at location i being

$$P_{a,i} = \frac{\sum_t Y_{i,t} * P_t}{\sum_t Y_{t,i}},$$

and the average price P_a across locations being

$$P_a = \sum_t \frac{\sum_i Y_{i,t} * P_t}{\sum_i Y_{i,t}}.$$

We use simulated hourly spot prices for 2020, based on renewables feed-in data from 2010, demand assumed to be as in 2010, and two scenarios: (i) with capacities based on the German Netzentwicklungsplan, and (ii) with 90% of these capacities for all conventional power plants (but same renewables feed-in).

Results

Table 6 shows resulting zeta factors, and Figure 5 shows their distribution.

Table 6: Yearly and monthly zetas for different locations

Zeta 2020	Frankfurt		Hannover		Schwerin	
	2020	2020 "-10%"	2020	2020 "-10%"	2020	2020 "-10%"
	0%	0%	-4%	-3%	-6%	-4%

Zeta	Frankfurt		Hannover		Schwerin	
	2020	2020 "-10%"	2020	2020 "-10%"	2020	2020 "-10%"
Jan	4.3%	1.6%	-0.3%	-0.7%	-8.5%	-7.7%
Feb	0.7%	-0.7%	-1.9%	-1.7%	-2.7%	-3.4%
Mar	5.6%	6.9%	-10.5%	-10.1%	-11.7%	-10.6%
Apr	-5.1%	-5.2%	-8.6%	-8.3%	-5.8%	-5.1%
May	0.6%	0.4%	-7.2%	-7.5%	-6.0%	-6.4%
Jun	0.7%	1.0%	1.1%	0.8%	-3.8%	-3.6%
Jul	2.6%	2.7%	0.8%	0.8%	-0.9%	-1.4%
Aug	1.4%	1.1%	-2.0%	-1.9%	-5.9%	-5.6%
Sep	-1.3%	-0.5%	-2.5%	-2.0%	-2.6%	-1.7%
Oct	3.2%	-5.5%	-5.6%	-1.4%	-4.8%	0.2%
Nov	-2.6%	0.3%	-3.4%	1.2%	-3.9%	-0.2%
Dec	-4.5%	-3.0%	-2.4%	-2.6%	-5.7%	-4.7%

Figure 5: Distribution of ζ factors
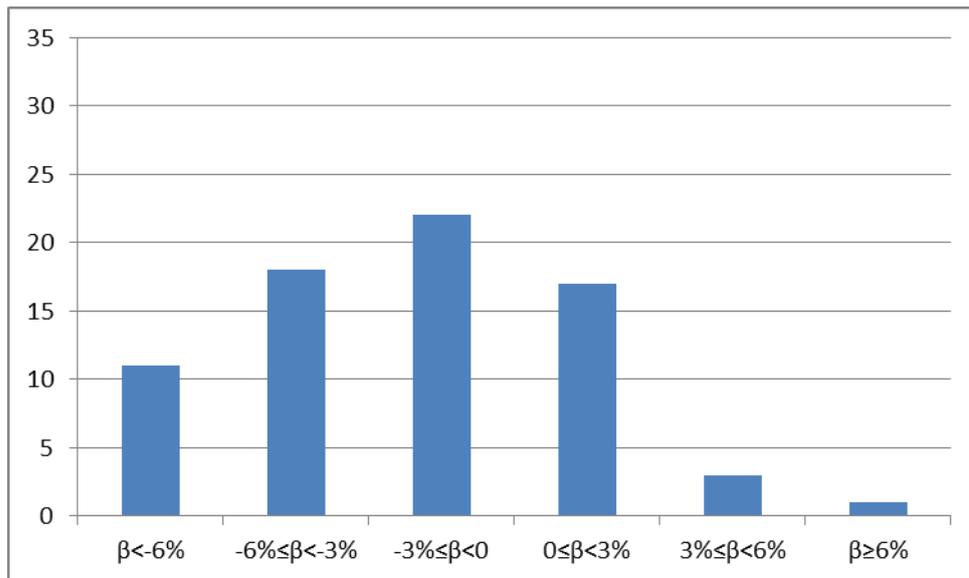
In short, if simulated 2020 market price estimates are correct and wind production continues to be as it has, wind deliveries from Frankfurt would, on average, equal market prices. In Hannover, wind prices would be 4% lower than market prices. In a 2020 scenario with less conventional generation, the difference would be 3%. In Schwerin, wind prices would be 6% and 4% lower than market prices.

We also note that investors who diversity across locations could reduce zeta risk, while project based lending would not allow for such a diversification. As the zeta risk is likely to be persistent over years, it will not be covered by wind insurance contracts that typically provide cover for annual variations of aggregate wind output. Hence we assume that conservative lenders and investors consider a zeta as observed in the wind location with the highest impact (among the three reviewed wind locations)and set zeta to be 7% in the following modeling.

Impact of Epsilon and Zeta on Capital Structure

To analyze the impact of ε and ζ on a project capital structure they are used as inputs in a cash flow model. The model returns a maximum potential debt size based on the quantified values of the new risks, as well as other relevant inputs. The cash flow model used follows the logic presented in Section 2 above.

Drawing on the ε and ζ results above, the following scenarios were modeled:

- Baseline: $\varepsilon = 0$ and $\zeta = 0$
- Average: $\varepsilon = 3,2\%$ and $\zeta = 0$
- Conservative: $\varepsilon = 8\%$ and $\zeta = 7\%$.
- Equity Perspective: this scenario simulates the perspective of an equity investor willing to take more risk than a lender. That investor assumes: $\varepsilon = 3,2\%$ and $\zeta = 0$, but can only leverage the project as if $\varepsilon = 8\%$ and $\zeta = 7\%$.

These scenarios represent a range of plausible outcomes, plus a baseline in which no new balancing costs or price risk occurs. The average scenario represents what our analysis of balancing costs and price risk suggests would be a likely outcome. However, investors wishing to minimize risk as completely as possible may adopt a conservative perspective. Finally the "equity perspective" scenario sizes the debt conservatively, but

assumes earnings consistent with the average scenario. With this arrangement we show a combination of conservative lending and more risky equity investing.

Detailed explanation of key inputs can be found in Appendix A.[6] In general this project is an average wind generator with the following characteristics:

- Capacity factor: 19,0%,
- Installed cost: 1.400/kW,
- Price: 89,00 EUR/MWh,
- DSCR: 1,1
- Loan Tenor: 20 years
- Cost of debt: 3,5%
- Technical Life of Asset: 20 years
- Duration of First-stage tariff: 20 years

Sensitivity analysis is used to test the impact of ε and ζ on capital structure. For the sensitivity analysis, the model is run iteratively, with only ε and ζ changing between iterations. The results of each test shown here include:

- Debt Share: the model returns the largest debt size the generator can afford under the defined conditions. The debt share equals debt size divided by total installed cost.
- IRR: The IRR is the interest rate (or discount rate) that will bring future cash flows to a Net Present Value of zero. The IRR represents the attractiveness of the investment opportunity to equity investors.
- WACC: The WACC represents the weighted, pre-tax cost of capital for the modeled project.

All values are reported as pre-tax.

The following Table shows the results.

Table 7: Impact on Capital Structures			
Scenario (ε,ζ)	Debt Share	IRR	WACC
Baseline (0,0)	85,2%	10,8%	4,6%
Average (3.2, 0)	83,2%	7,7%	4,2%
Conservative (8,7)	76,1%	-0,12%	2,63%
Equity (mix)	76,1%	6,2%	4,1%

In the "Conservative" scenario, which assumes that both equity and debt investors only consider the scenario of $\varepsilon = 8\%$ and $\zeta = 7\%$ the IRR for equity investors is slightly negative. We acknowledge the impossibility of such capital structures; a project would not be financed under these conditions. Nevertheless, we report the data here to consistently illustrate the impact of ε and ζ relative to the other scenarios.

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[6] *The authors also invite review of the cash flow model used in this analysis. Please contact the authors to receive a copy of the model.*

The "Equity" scenario shows the effect of assuming more optimistic conditions than the lender. In this example the lender assumes ε = 8% and ζ =7%. The lender reduces debt size accordingly. But the equity investor considers the average scenario more likely and therefore forecasts a 6,2% return for herself.

Several trends are revealed by this data. First, as risk increases, debt shares are reduced from 85,2% to 76,1%, a drop of 2,3% and 10,7%. Second, IRRs decrease from 10,8% to 0,0%, a drop of 29% to 100%. Third, the decline of IRRs contributes to a reduction in WACC. So long as equity investors are willing to accept lower IRRs, this result is valid. Of course, this is very rarely the case, leading to the conclusion that some adjustment to earnings potential would be needed to retain equity investors.

The following section considers how equity investors may respond to these trends and what changes to model inputs would result in acceptable IRRs for equity investors.

Investor Response
Here we consider whether the investment opportunities summarized above are likely to attract equity investors.

The literature on investment in German renewables suggests there are two active classes of equity investors in Germany: commercial and Bürger. Commercial equity investors have experience investing in energy projects, so they can cope with complexity and risk. Kost et al. (2013) conclude this class of investors expects returns of 8-9% when investing in large-scale wind. Our own interviews of equity investors suggest this conclusion may be too conservative or out of date. Therefore we adopt the low end of their range, 8%.

The second class of equity investors, the so-called Bürger investors, have less experience with energy investing, value simplicity, and have lower returns on expectations. Through a review of literature and interviews, we conclude this class is willing to accept returns of 4-6%. We use 5%.

Comparing target hurdle rates of 8% for commercial equity and 5% for Bürger investors shows what may be the response of equity investors to reduced earnings potential. The average scenario and yields 7,7%, exceeding the Bürger investor hurdle rate but falling just short of commercial investor hurdle rate. The equity scenario, with a yield of 6,2% would have the same appeal. Meanwhile, The profit-less conservative scenario scares away all equity.

Under the Average, Conservative, and Equity scenario the project needs either additional compensation or reductions in cost to achieve equity hurdle rates. Table 8 depicts the additional revenue that would be needed over the life of the asset to achieve an 8% hurdle rate under each scenario.

Table 8: New Revenues Needed to Reach 8% IRR			
	Default IRR	Additional Revenues Needed	% Change
Average	7,7%	10,652	0,1
Conservative	-0,12%	358.200	6,0
Equity	6,2%	99.870	1,6

Alternatively, the project could achieve a target hurdle rate by reducing its installed or operating costs. As an example, we show what reductions in total installed costs would be needed to achieve a 8% IRR

Table 9: Cost Reductions Needed to Reach 8% IRR			
	Default IRR	Cost Reductions Needed	% Change
Average	7,7%	8.000	0,2
Conservative	-0,12%	222.000	7,9
Equity	6,2%	62.000	2,2

Tables 8 and 9 omit a critical factor that supports achieving the target hurdle rate: increased leverage achieved through increased revenue or reduced cost. The following sensitivities show how improvements in key factors – price per unit, capacity factor, and installment cost – affect debt share, thereby making each scenario acceptable to the commercial investor class:

Sensitivity A: Raising Price/MWh					
	Baseline Price = 89,00		Commercial Equity Target IRR = 8%		
	IRR (%)	Debt Share (%)	New Price Needed (EUR/MWh)	Percent Change (%)	New Debt Share (%)
Baseline (0,0)	10,8	85,2	None	0,0	None
Average (3,2, 0)	7,7	83,2	89,16	0,1	83,4
Conservative (8,7)	-0,12%	76,1	94,38	6,0	82,9
Equity (mix)	6,2	76,1	90,50	1,7	78,0

This table shows the change needed in price paid per MWh to achieve a target IRR of 8% under each scenario. The introduction of incremental balancing costs of 3.2% would require only a negligible increase (0,1%) above to the baseline 89,00 EUR; assuming the worst case scenario, requires a 6,0% increase in the price. Lastly, the target IRR can be reached with a modest 1.7% increase under the equity scenario, in which debt is sized conservatively, while earnings are assumed to be average.

Comparing the equity and average scenarios begins to reveal the cost of the uncertainty inherent in balancing costs and price risk. To reach an 8% hurdle rate, the equity scenario requires 1,34 EUR/MWh (1.5%) above the price needed to reach the same hurdle rate in the average scenario (89,16 EUR/MWh). Because the equity scenario sizes debt more conservatively, thereby representing the perspective of a conservative lender, while assuming earnings consistent with the average scenario, the 1,34 can be viewed as an indicator of the investment cost resulting from the new risks. These numbers are still very preliminary and primarily provided to illustrate an effect that might benefit from further attention in the further design of renewable remuneration mechanisms. As the following sensitivities show, other modest changes to the project's cash flow (i.e., greater output, lower installment costs) may achieve the same target.

Sensitivity B: Raising Capacity Factor					
	Baseline Capacity Factor = 19%		Commercial Equity Target IRR = 8%		
	IRR (%)	Debt Share (%)	New Capacity Factor Needed (%)	Percent Change (%)	New Debt Share (%)
Baseline (0,0)	10,8	85,2	None	0,0	None
Average (3.2, 0)	7,7	83,2	19,05	0,2	83,3
Conservative (8,7)	-0,12%	76,1	20,63	8,6	82,6
Equity (mix)	6,2	76,1	19,43	2,3	77,8

Achieving an 8% hurdle rate may also be achieved through greater output, as reflected in the capacity factor. A negligible input of 0,2% achieves a hurdle rate of 8% under the average scenario while increases of 8,6% and 2,3% achieve the same hurdle rate for the conservative and equity scenarios, respectively.

Sensitivity C: Lowering Installment Costs					
	Baseline Installment Costs = 1.400/kW		Commercial Equity Target IRR = 8%		
	IRR (%)	Debt Share (%)	New Installed Cost Needed (%)	Percent Change (%)	New Debt Share (%)
Baseline (0,0)	10,8	85,2	None	None	None
Average (3.2, 0)	7,7	83,2	1.396	0,2	83,4
Conservative (8,7)	-0,12%	76,1	1.289	7,9	82,6
Equity (mix)	6,2	76,1	1.369	2,2	77,8

Achieving an 8% hurdle rate may also be achieved through lower installed costs. A negligible reduction of 0,2% achieves a hurdle rate of 8% under the average scenario while reductions of 7,9% and 2,2% achieve the same hurdle rate for the conservative and equity scenarios, respectively.

From these sensitivities we see the magnitude of increases in price paid per unit of output, capacity factor, or reductions in installed cost that would be necessary to achieve hurdle rates for commercial equity investors.

We consider also how these factors may be changed to achieve to meet a 5% hurdle rate, typical of bürger investors The only case in which a 5% IRR is not achieved with the default assumption is the conservative scenario, which has no yield. In order to reach a 5% IRR in the conservative scenario, one of the following inputs is required:

- Price: 92.73 EUR (4,1% increase), raising debt share to 80,8%.
- Capacity Factor: 20,3% (6,8% increase), raising debt share to 81,3%
- Installed costs/kW: 1.311 EUR (6,3% decrease), raising debt share to 81,2%.

We also note that under EE 2014 bürger investors may achieve their targeted rates of return at lower input levels. For example, a 5% hurdle rate could be reached at a lower price (87,60 EUR) in the average scenario. However, this analysis does not consider in depth the risk appetite of bürger investors. Whether these investors would be willing to shoulder greater risk for lower rate of return is an opportune topic for further research.

Conclusion

As proposed, EEG 2014 would reduce earning opportunities for future wind generators through changes to the law's remuneration scheme. These changes are likely to increase the cost of capital needed to finance new wind generation.

Three proposed changes would have the greatest impact on wind generator earnings and cost of capital. Two of these changes result from the proposal's direct marketing requirement, which was muted under earlier versions of EEG by the option to revert to a fixed feed-in tariff. First, EEG 2014 allocates balancing costs to the generator, creating an incremental and uncertain operating cost. Second, EEG 2014 compensates the generator at the market price, plus a premium, the combination of which may be less than under EEG 2012. Finally the third change amends the Reference Model, a system used to mitigate the risk of underproduction resulting from unfavorable weather conditions.

By reducing earnings, these changes are likely to create less favorable investment opportunities. We estimate that project capital structures could be substantially altered, shrinking debt share by 2,3% to 10,7%. Second, IRRs may decrease by 29% to 100%. Further, changes to the Reference Model would reduce the duration of premium compensation, intended to mitigate the risk of underproduction, by on average 36% and as much as 88%.

Comparing the equity and average scenarios begins to reveal the cost of the uncertainty inherent in balancing costs and price risk. To reach an 8% hurdle rate, the equity scenario requires 1,34 EUR/MWh (1.5%) above the price needed to reach the same hurdle rate in the average scenario (89,16 EUR/MWh). Because the equity scenario sizes debt more conservatively, thereby representing the perspective of a conservative lender, while assuming earnings consistent with the average scenario, the 1,34 (1.5%) can be viewed as an indicator of the investment cost resulting from the new risks.

These numbers are still very preliminary and primarily provided to illustrate an effect that might benefit from further attention in the further design of renewable remuneration mechanisms. Additional factors that would need to be considered are the potential impact of regional pricing (zonal or nodal) that might be necessary for a secure and cost effective operation of power system with high shares of renewable energy. This can imply that German-wide reference price deviates from the sales revenue that can be achieved at specific locations, and could constitute a further risk for future revenue streams if not appropriately hedged.

We understand that the effects on project finance of new cost and risk allocation implicated by the EEG 2014 direct marketing requirements have not been studied in detail. This study proposes a methodology to better understand the impacts. As the relative results reported here show, the proposed changes could have a substantial

impact on project finance for new wind generators. This potential suggests further evaluation and refinement of the methodology used here would be beneficial.

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Appendix A: Model Inputs and Sources

Unless explicitly noted, all inputs are for renewable generators >1MW, located in Germany.

Input	Value	Source
Capacity Factor (%)	19	Kost, C. 2013 LCOE Study (2013); Note: Range of 15-22% for German wind
Annual Output Degradation (%/year)	0	Kost, C. 2013 LCOE Study (2013)
Technical Useful Life (years)	20	Kost, C. 2013 LCOE Study (2013)
Reference/FiT Price, Year 1 (€/MWh)	89,00	EEG 2014 §47
Stage 2 Wind Price	49,50	EEG 2014 §47
Technology Specific Monthly Average Market Price (TSMAMP) (€/MWh)	45	45,00 EUR/MWh is latest market price from Netztranzparenz.de
Discount to TSMAMP (%)	*Epsilon*	Calculated
Average Spot Market Price (EUR/MWh)	35.00	EEX. Note: March, 2014. Peak= 43.92, Baseload = 34.27
Annual Inflation of Market Price (%/year)	2	Common inflation rate
Installed Cost (€/kW)	1400	Kost, C. 2013 LCOE Study (2013); Note: Range of 1000-1800 for wind
Variable or Fixed O&M (€/Mw-year or €/MWh))	15,00	Kost, C. 2013 LCOE Study (2013); interviews suggest 20-30% of revenues for total O&M, including balancing costs
Balancing Costs (% of revenue)	*Zeta*	Calculated
Minimum DSCR at P90 (Ratio)	1.1	Interviews; Note: Range from 1.1-1.3
Minimum Equity Requirement (% of Total Cost)	15	Interviews; Note: Range from 0 to 30%
Loan Tenor (Years)	20	KfW 270; Interviews; Note:

		Range up to 18 years.
Fixed Debt Rate (%)	3.5	Interviews + KfW 270 Program; Note: KfW rate (2,9-4,0%) is commercial rate
Fixed Debt Rate Term (years)	10	Interviews + KfW 270 Program
Variable Interest Rate (%)	5	Interviews; Note: 250 bps over reference rate.
Variable Debt Rate Term (Years)	5	Interviews
Interest Only Period (Years)	3	KfW 270
Lending Fee (% of Principal)	1	Interviews
Amortization Schedule (Straight-line or Sculpted)	Straight-line	Interviews; Note: KfW requires straight-lined
Depreciation Schedule (Straight-line or Extraordinary)	Straight-line	Interviews; Note: rare exceptions to straight-line required by equity contributors with near-term tax liability.

Eight experts in renewable energy investing in Germany completed this questionnaire. The results are compiled and referenced in Appendix A and throughout the study.

Impact of EEG 2.0 on Renewable Generator Project Finance: A Questionnaire
28.2.2014

Responses requested by April 4, 2014.

Purpose: The purpose of this research is to analyze the impact of the German government's proposed EEG 2.0[7] on project finance for new German onshore wind and solar generators. More specifically, how would the proposal impact the predictability of future revenues, debt sizing, and required equity contributions?

Disclaimer: Information acquired in this survey will only serve academic research. Your answers will be used confidentially and anonymously. In return for your participation in this interview, we will send you the results of the survey.

General

- What is your professional position within your company?
- In which major markets is your company active in project development? (Wind, Solar, etc.)
- In which countries is your company active?
- In which project stages is your company active? (Development, Construction, Operation)
- How many employees does your company have? (1-9, 10-100, >100)
- What is the average size of your realized project? (<100kW, 100-1000kW, >1 MW)
- Is your company a bank, institutional equity investors, a retail equity investor, or other?

Current and Future Project Finance Practice
Your responses to the following statements will help characterize current project finance practices under EEG 1.0 and anticipated future practices under EEG 2.0.

- Are the following statements true for current practice? If not, please provide a "correction" in the space provided. Are the following statements true for anticipated future practice? If not, please provide an
- "estimate" in the space provided.

(See Appendix A)

Follow-up Questions:

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[7] For the sake of this questionnaire, EEG 2.0 implies a) required direct marketing for all generators by the stated deadlines and implies market price risk for electric output, b) additional remuneration through a feed-in premium, calculated as the difference between a reference price and average monthly market price, and c) option to fall back to 80% of most recently available reference price. This definition is derived from the January 21, 2013 "Eckpunkte für die Reform des EEG"

1. Do your responses to statements 1-3 above completely describe your experience complying with lending policies toward DSCR and amortization? If not, please elaborate.

2. Under what circumstances would the debt service reserve fund be used?

3. Could larger Debt Service Reserve Funds be counted as Cash Flow Available for Debt Service in order to increase debt/equity ratios?

4. Have you assessed implications of a shifting from a feed-in premium with feed-in back up to a feed-in premium system without such back up with respect to:

   a. balancing costs in the future;
   b. location and production profile of wind turbine relative to reference price for feed-in premium;
   c. quantity risk in a world without automatic adjustment of time for which high feed-in tariff is available based on realized wind output?

   If so, what do you anticipate will be the potential impact on project finance for new renewable generation projects?

5. Would elimination of the proposed 80% fall back, fixed Feed-in Tariff change your responses to the prior questions?

6. Beyond the topics from above, what new risk or benefits to lenders and equity investors. Would the proposed EEG 2.0 effect your lending, investing, or borrowing in other noteworthy ways?

Thank you very much for your responses. For questions, please contact:

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	***Appendix A***				
#	*Statement*	*True/False*	*Correction*	*Estimate for EEG 2.0*
1	Lenders require a DSCR of 1.1-1.3.			
2	Lenders will allow a DSCR as low as 1.0 for 1 year, if the borrower meets a higher standard over 3 years.			
3	Amortization schedules are sculpted to fit expected Cash Flow Available for Debt Service. Higher debt service obligations will be scheduled for years of higher expected CFADS.			
4	Loan tenors range from 12 to 20 years.			
5	15-17 years are common loan tenors.			
6	Rates on fixed interest loans range from 3 to 6%.			
7	50% of leveraged projects use a KfW loan.			
8	KfW interest rates have ranged from 3 to 4%.			
9	Debt interest rates are fixed for 10 years.			
10	Variable interest rates are 250 bps over the lender's reference rate (i.e. Euribor).			
11	Lenders require borrowers to maintain Debt Service Reserve Funds to cover 6 months of debt service.			
12	Debt Service Reserve Funds are funded through an equity contribution at COD.			
13	Most lenders require at least a 10% equity contribution from the project sponsor.			
14	Equity investors expect a return of 2% premium over the debt rate.			
15	The effective income tax rate on a for-profit renewable generator is 37.5%.			
16	All taxable generators use straight-line depreciation.			
17	Volume risk, whether the generator produces the anticipated amount of electricity (or more), is the largest risk facing investors in renewable energy.			
18	Volume risk is greater for solar than for wind.			
19	Annual operating cost for solar is 30 €/kW.			
20	Variable operating cost for onshore wind is 0,015 €/kWh.			