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An Analysis of the Costs, Benefits, and Implications of Different Approaches to Capturing the Value of Renewable Energy Tax Incentives

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Disclaimer

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Executive Summary

In the United States, Federal incentives for the deployment of wind and solar power projects are delivered primarily through the tax code, in the form of accelerated tax depreciation and tax credits that are based on either investment or production. Both wind and solar projects are equally eligible for accelerated tax depreciation, but tax credit eligibility varies by technology: solar is currently eligible for the investment tax credit ("ITC"), while wind is eligible for either the ITC or the production tax credit ("PTC"), though wind project sponsors typically choose the PTC.

For either technology, and with either the PTC or ITC, the combined value of tax deductions and credits (in combination, referred to as a project's "tax benefits") generally exceeds a project's internal ability to use them in each of the first five (or more) years of the project's life. Some project sponsors, said to have "tax appetite," are able to efficiently (i.e., in the years in which they are generated) apply these excess tax benefits against other sources of taxable income external to the project in question. This is the best possible outcome for the sponsor. Other project sponsors that lack tax appetite can carry forward excess tax benefits to future years until they can eventually be used internally by the project itself, but this strategy sacrifices some of the incentives' value, due to the time value of money. A third option is to bring in – at a cost – a third-party "tax equity" investor who is able to efficiently use the project's tax benefits, and who invests in the project in exchange for being allocated most or all of its tax benefits; this is known as "monetizing" the tax benefits (i.e., converting their value into money that can be used to finance the project).

This report compares the relative costs, benefits, and implications of capturing the value of renewable energy tax benefits in these three different ways – applying them against outside income (labeled as "Tax Appetite from Sponsor" in Figure ES-1), carrying them forward in time until they can be fully absorbed internally (labeled as "No Tax Appetite"), or monetizing them through third-party tax equity investors ("Tax Appetite from Tax Equity") – to see which method is most competitive under various scenarios. As summarized in Figure ES-1, it finds that under current law and late-2013 market conditions (denoted by the two green-shaded columns – one for wind, one for solar – in Figure ES-1), monetization makes sense for all but the most tax-efficient project sponsors. In other words, for most project sponsors (i.e., those without much tax appetite), bringing in third-party tax equity currently provides net benefits to a project.[1]

Under a variety of plausible future scenarios relevant to utility-scale wind and solar projects (and summarized in Figure ES-1), however, the benefit of monetization is found to no longer outweigh the incremental cost, and it makes more sense for sponsors – even those without tax appetite – to use the benefits internally rather than seek out third-party tax equity. A permanent expiration of the PTC ("0% PTC" in Figure ES-1) is one obvious example of such a scenario, but

[1] Notably, the size of the net benefit is diminished by the fact that tax equity is currently *twice as expensive* (on a comparable after-tax basis) as the project-level term debt that might otherwise be used in its place. Modeling results presented in the full report suggest that, based on this cost of capital difference alone, project sponsors forfeit one-third or more of the economic value of a project's tax benefits when they bring in tax equity investors to monetize those benefits; these results are roughly in line with other estimates in the literature. With such a high price being exacted, tax equity's position in the marketplace should not be taken for granted.

even just a reduction in the size of the PTC (e.g., "50% PTC" in Figure ES-1) could still render monetization uncompetitive. Similarly, monetization is likely to become much less critical for solar projects if the ITC reverts to 10% at the end of 2016 (as is currently scheduled), and is also found to not be competitive under a *refundable* ITC (at any level), [2] a solar PTC (either refundable or nonrefundable), or tax reform (as recently proposed by the Senate Finance Committee).

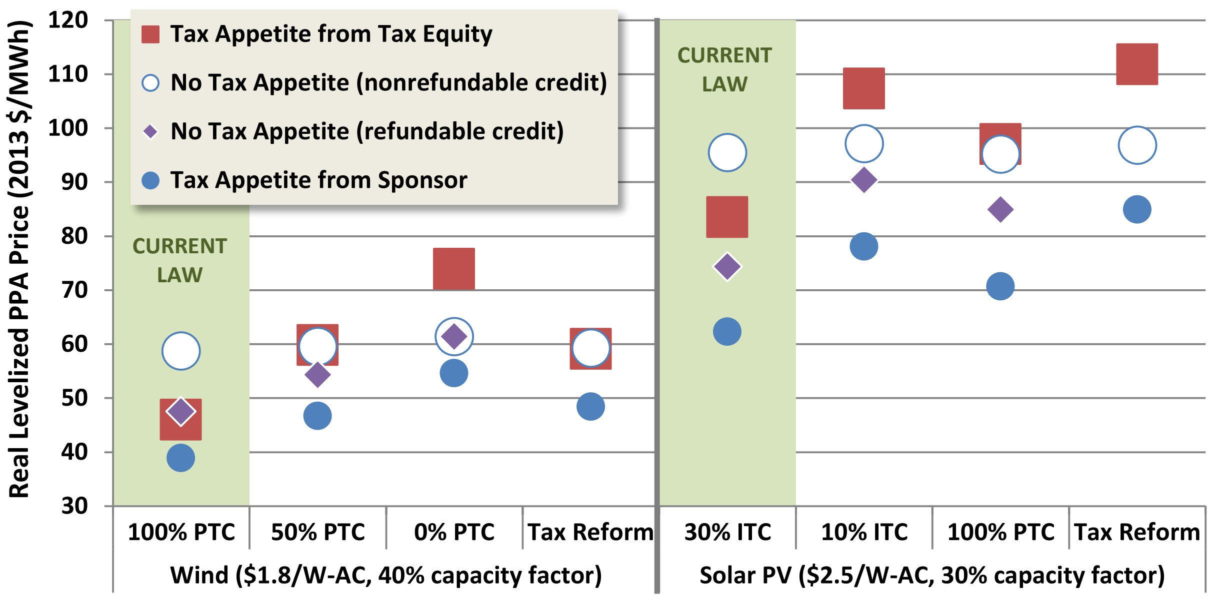


Figure ES-1. Summary of Selected Modeling Results

These and other findings highlighted in the full report have implications for how wind and solar projects are likely to be financed in the future, which, in turn, influences their levelized cost of energy. In the event of a PTC expiration, for example, the conclusion that a wind project sponsor without tax appetite will likely find it more advantageous to finance with debt and carry forward depreciation deductions as necessary rather than to partner with third-party tax equity means that the impact of a PTC expiration on PPA prices might not be as severe as one might otherwise assume under a static financing structure. In other words, the shift from third-party tax equity to project-level debt with a lower cost of capital helps to mitigate – though only to a degree, and certainly not fully – the loss of the credit. The same is true for the scheduled reversion of the solar ITC to 10% at the end of 2016: for many sponsors, the negative impact of the reversion is likely to be partially mitigated by a shift away from tax equity and to a lower cost of capital based on project-level term debt. In all scenarios, this beneficial shift to a lower cost of capital could be both heightened and hastened – and at no incremental cost to taxpayers – by making renewable energy tax credits refundable.

[2] When a tax credit is *refundable*, the recipient uses as much of the available credit as possible (given tax liability) in tax credit form, and then is refunded the balance in cash. In contrast, a *nonrefundable* tax credit can only be taken in tax credit form, either in the year it is first generated (given sufficient tax liability) or in future years (if insufficient tax liability, and if the unused portion can be carried forward). Under current law, the PTC and ITC are both nonrefundable credits.

Notably, the lower costs of capital realized under the "no tax equity" structures modeled in this report are *not* dependent on renewable energy projects having access to new capital formation vehicles like master limited partnerships ("MLPs") or real estate investment trusts ("REITs"). Although MLPs and REITs could, in the future, potentially muster important *new sources* of low-cost capital, project-level debt from both bank and institutional lenders (not to mention the bond market) is already widely available to utility-scale wind and solar projects, and at costs that are competitive with what MLPs and REITs are likely to deliver.[3] Capitalizing on this ready and willing debt market simply requires tweaking Federal incentives in a way that makes it more advantageous for project sponsors to finance their projects with low-cost debt rather than expensive tax equity. Moreover, any such tweaks (e.g., making renewable energy tax credits refundable) would, in turn, enhance the potential usefulness of MLPs and REITs – neither of which is particularly compatible with tax equity.

The scenarios examined in this report are all modeled on an "all else equal" basis, assuming most notably that tax equity hurdle rates do not change in response to any of the scenarios. But it is entirely possible that tax equity investors may be willing to lower their required rates of return under various scenarios, in order to remain competitive with the "backstop" of foregoing tax equity in favor of lower-cost debt. Indeed, there is already some evidence of this responsiveness, as certain tax equity investors reportedly differentiate between deals involving the ITC and the Section 1603 cash grant by charging a premium for the former.

Even if tax equity investors were to actively compete with financing structures involving just sponsor equity and debt under the scenarios modeled in this report, however, only those conclusions about *how* wind and solar projects are likely to be financed under those scenarios – i.e., with or without third-party tax equity – would be impacted. The resulting levelized PPA prices, which are of most importance to this analysis, would *not* be affected. In this light, if tax equity investors are willing to reduce hurdle rates in order to compete with alternative financing structures, so much the better, as project sponsors will then be able to achieve the same low PPA prices through a variety of financing options.

This thought experiment highlights the importance of the debt market (in combination with a sponsor's ability to carry forward unused tax benefits) as a backstop against which tax equity must ultimately compete in order to remain relevant in the renewable energy marketplace. It also highlights the usefulness of the tools and methodology developed in this report as a way to place bounds on the likely range of market impacts stemming from future policy changes. In fact, given current policy uncertainty impacting the wind and solar markets, the methodology and capabilities developed in this report are likely just as important as, if not more important than, the results presented. The policy environment over the next few years is likely to remain fluid, spawning a variety of possible future scenarios – including not only those modeled in this report, but also various combinations and permutations thereof, along with others not yet envisioned. The methodology and capabilities developed within this report will enable more-refined and -targeted policy analyses of these scenarios as they arise.

[3] For example, testimony before the U.S. House of Representatives during a 2013 hearing on the PTC quoted the wind (and solar) developer First Wind as anticipating a 6-8% cost of capital through MLPs, and went on to note that a 7% yield was the mid-range among a sample of energy MLPs (Reicher 2013). This 6%-8% estimated cost of capital under renewable energy MLPs is higher than the 5.5%-6% interest rates that quality wind and solar projects can currently access in the debt markets.

1. Introduction

In the United States, Federal incentives for the deployment of renewable energy, such as wind and solar projects, have historically been (and are currently) delivered primarily through the tax code in the form of accelerated tax depreciation, as well as tax credits that are based on either renewable energy investment or production. As explained later in Section 2, however, the combined value of these deductions and credits (in combination, referred to as a project's "tax benefits") often exceeds the project's internal ability to use them in the years in which they are generated.

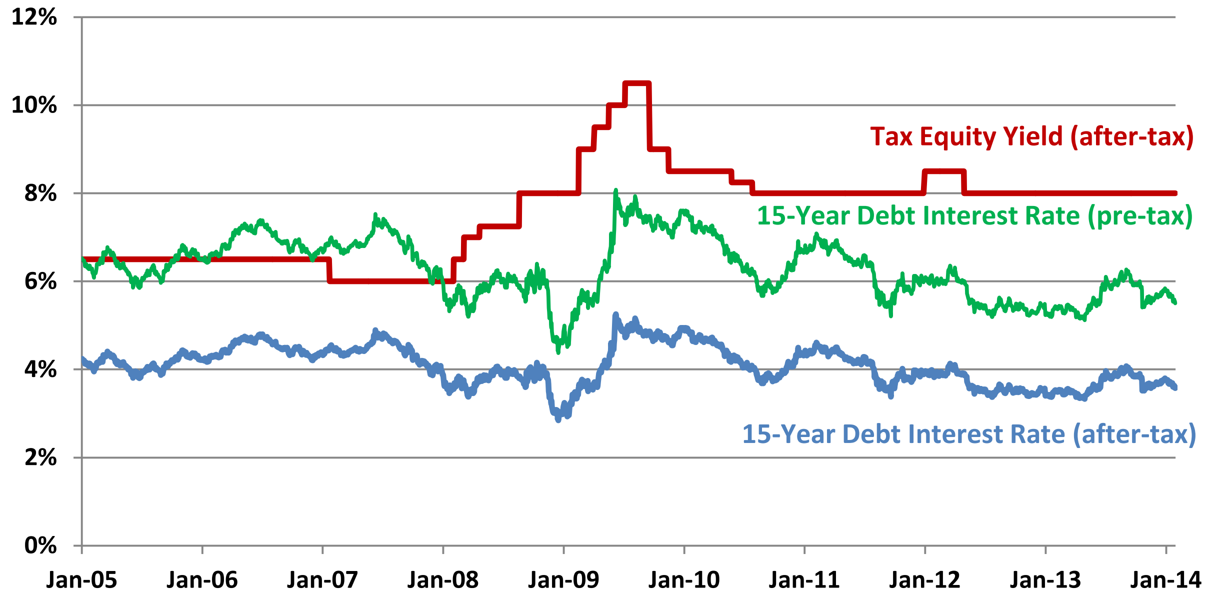
Some project sponsors, said to have "tax appetite," are able to efficiently (i.e., in the years in which they are generated) apply excess tax benefits against other sources of taxable income external to the project in question. Other project sponsors that lack tax appetite can carry forward excess tax benefits to future years until they can eventually be absorbed by the project itself, but this strategy sacrifices some of the incentives' value, due to the time value of money. A third option is to bring in a third-party "tax equity" investor who is able to efficiently use the project's tax benefits, and who invests in the project in exchange for being allocated most or all of its tax benefits. To date, most project sponsors with little tax appetite have found it advantageous to pursue this tax benefit "monetization" strategy involving third-party tax equity investors, rather than carrying forward the tax benefits on their own over time.

Third-party monetization clearly provides a benefit to the project – i.e., tax benefits are efficiently used in the years in which they are generated rather than being carried forward and devalued by the time value of money – but also comes at a cost, as tax equity is an expensive form of capital. In fact, tax equity is the second-most-expensive of six sources of capital commonly tapped by renewable energy project sponsors in the United States. In order of least-to-most expensive, these are: government grants, government-guaranteed project-level term debt, regular project-level term debt, back-levered debt, tax equity, and sponsor equity (adapted from Chadbourne & Parke 2013b). With the primary government grant (Section 1603) and loan guarantee (Section 1705) programs having recently sunset, however, sponsors of new wind and solar projects are left with just the four most-expensive capital sources. And given that third-party tax equity investors will often not tolerate project-level debt (and the accompanying risk of foreclosure), the pool of capital is effectively even more limited in a monetization structure, to just the three most expensive sources.

Were tax benefits not so crucial to a project's competitiveness, project sponsors would likely replace expensive tax equity with cheaper project-level term debt (or, perhaps in the future, with other forms of low-cost capital, such as master limited partnership ("MLPs") or real estate investment trusts ("REITs") – neither of which are currently available to renewable energy projects). The resulting reduction in the project's weighted average cost of capital ("WACC") could be considerable. As shown in Figure 1, adapted from Bloomberg New Energy Finance (2014), tax equity is currently *more than twice as expensive* as 15-year term debt on an after-tax basis.[4] Assuming that tax equity (with an after-tax cost of 8%, per Figure 1) makes up 60% of

[4] The returns of equity investors in renewable energy projects are most often expressed on an after-tax basis, because of the significant value that Federal tax benefits provide to such projects (e.g., after-tax returns can be higher than

the capital stack while sponsor equity (with an assumed after-tax cost of 12%) makes up the remaining 40%, replacing tax equity one-for-one[5] with project-level term debt (with an after-tax cost of 4%, per Figure 1) would reduce a project's after-tax WACC by 240 basis points, which in turn could have a significant impact on levelized cost of energy ("LCOE").



Adapted from Bloomberg New Energy Finance 2014

Figure 1. Cost of 15-Year Debt vs. Tax Equity Over Time

This report develops tools and methods to quantify both the costs and benefits of different approaches to capturing the value of the tax benefits generated by representative utility-scale wind and solar projects.[6] It then uses these methods to analyze a variety of plausible future scenarios in which these costs and benefits, and in particular the costs and benefits of tax equity monetization, could change significantly. For example, increasing demand for tax equity might increase the relative cost of monetization, while making tax credits refundable, or reducing or even eliminating them, will decrease the benefits of monetization. To the extent that any of the scenarios examined – either alone or in combination – shift the economic balance away from tax equity and towards lower cost sources of capital, or vice versa, they could have significant implications for how (and at what cost) wind and solar power projects are financed, which, in turn, could impact the levelized cost of wind and solar energy.

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pre-tax returns). In order to accurately compare the cost of debt (which is quoted on a pre-tax basis) to tax equity (described in after-tax terms), one must first convert the pre-tax debt interest rate to its after-tax equivalent (to reflect the tax-deductibility of interest payments) by multiplying it by 65%, or 100% minus an assumed marginal tax rate of 35%.

[5] The one-for-one debt-for-tax equity exchange assumed in Figure 1 is merely illustrative and a simplifying assumption. That said, modeling results presented later suggest that it is not too far off the mark; in large measure, debt can generally replace tax equity when monetization is not necessary.

[6] This report's focus is restricted to utility-scale projects mostly for the sake of convenience. Many of the fundamental concepts presented herein are also applicable to residential and commercial projects, even though some of the specific project-level and policy details would be different.

This report proceeds as follows. Section 2 describes the primary Federal tax incentives for utility-scale wind and solar project deployment and introduces three different approaches that a project sponsor can use to capture some or perhaps all of the value of those incentives. Section 3 describes three pro forma financial models (as well as the input assumptions to those three models) developed to explore and quantify the impact of these different approaches to capturing the value of tax benefits. Section 4 uses the models to analyze a variety of future scenarios relevant to wind power and in which either the costs or benefits of monetization could change significantly, in order to gauge the resulting impact on wind's levelized cost of energy (as proxied by levelized prices for long-term power purchase agreements, or PPAs). Section 5 does the same for solar projects, while Section 6 concludes. An appendix provides more details (e.g. capital structures) from each modeling run. Guideposts are located at various points throughout the report, directing advanced readers to skip certain sections if they wish.

Ultimately, this report demonstrates that, because of their impact on project finance, nonrefundable tax incentives are an inefficient way to encourage renewable energy deployment – at least relative to refundable tax credits or cash incentives, either of which would likely lead to a lower cost of capital, thereby helping to move wind and solar power closer to achieving LCOE goals (and at no additional taxpayer expense). It is worth emphasizing, here and elsewhere, that driving down the cost of capital does ***not*** require granting utility-scale renewable energy projects access to new capital formation vehicles like MLPs or REITs (though having access to such vehicles could certainly help – particularly if tax equity becomes less crucial). Nor does it require courting investors to make them more comfortable with the risks entailed in utility-scale renewable energy projects. Instead, it simply requires providing incentives in a way that makes it more advantageous for project sponsors to finance their projects using low-cost debt – which is already widely available to utility-scale renewable energy projects – rather than more-expensive tax equity. This realization highlights a number of key policy implications for Federal policymakers in particular that will be drawn out throughout this report.

2. Federal Tax Incentives and How to Capture Them

This three-part chapter begins with a brief discussion of the possible rationale for providing government incentives for renewable energy deployment. It then reviews the primary Federal tax incentives for utility-scale wind and solar deployment, along with brief mention of other Federal incentives that are also relevant. Finally, it reviews, with the aid of visual examples, three different approaches to capturing the value of these Federal tax benefits. Readers familiar with Federal incentives for wind and solar power may choose to skip at least Sections 2.1 and 2.2, if not also Section 2.3, though Section 2.3 covers important fundamental concepts that influence the methodology employed in the rest of this report.

State-level cash and tax incentives for wind and solar power are not discussed in this chapter (or anywhere else in this report) because they vary considerably from state to state, and in many cases are not available to utility-scale projects. Similarly, renewables portfolio standards, which are arguably the most important state-level policies in support of utility-scale renewable generation projects, are also excluded from consideration, as their impact on project finance is unrelated to the incentive design issues examined herein.

2.1 Rationale for Federal Incentives

Although there is debate on the motivations for government support of renewable energy, as well as the most appropriate form of support (e.g., IPCC 2011, Borenstein 2012, Edenhofer et al. 2013, Green and Yatchew 2012, Gillingham and Sweeney 2010, Kalkuhl et al. 2012), it is nevertheless generally accepted that some type of government intervention is justified in order to remedy a market failure. Within the electricity sector, some of the societal costs of fossil generation – such as air pollution, greenhouse gas emissions, water usage, and fuel supply risk (i.e., fuel price volatility as well as geopolitical risk) – are, arguably, not fully reflected in market prices, leading to inefficient choices for energy supply. Though addressing these market failures directly through policies that are specifically intended to internalize external costs is generally expected to be more cost-effective (e.g., Fell and Linn 2013, Fischer and Newell 2008), governments instead often use incentives for the deployment of renewable generation to pursue similar societal objectives: reduced air emissions, mitigation of climate change impacts, reduced water usage, and a more-balanced electricity supply portfolio (IPCC 2011).

Moreover, government incentives that are directed at renewable energy deployment are sometimes justified by the benefits associated with "learning by doing." Although challenges exist in identifying learning effects (e.g., Nordhaus 2009), to the extent that the deployment of emerging renewable energy technologies leads to cost reductions that are not appropriable by private firms, there are conditions in which government intervention is appropriate in order to drive these cost reductions by pushing technology down the learning curve (e.g., Edenhofer et al. 2013).

Advocates for renewable energy often also point to the ancillary benefits of job creation and economic development as further justification for government support. Though care is needed before claiming a "net" increase in jobs or economic development, or that these ancillary effects serve as an economic justification for government policy (e.g., Edenhofer et al. 2013), there is little doubt that wind and solar deployment (and related manufacturing, installation, and operations) do create jobs in the renewable energy sector. As a result, the U.S. government has looked to renewable energy as a source of domestic manufacturing jobs (U.S. Department of Energy 2013), while state governments have often pointed to construction and operations jobs in their support for renewable energy.

2.2 Federal Tax Incentives for Wind and Solar Deployment

The primary Federal tax incentives to encourage wind and solar deployment are accelerated tax depreciation (for both wind and solar), the production tax credit (currently for wind but not solar), and the investment tax credit (currently available to both wind – in lieu of the production tax credit – and solar). In addition, several other notable Federal incentives – including the Section 1603 cash grant and the Section 1705 loan guarantee program – have come and gone in recent years (these two incentives are not tax-based, but are nevertheless relevant to the topic at hand). Each of these incentives is described below.

Accelerated Tax Depreciation

Depreciation is a fundamental accounting principle that businesses use to reflect, over time, the declining value of long-lived assets on their balance sheets. Depreciation is also the way in which businesses expense, on their tax returns, the cost of those long-lived assets. Because most long-lived assets are depreciated in one way or another for tax purposes, depreciation itself is not a tax incentive that is provided preferentially to wind and solar projects. The *accelerated* tax depreciation schedule available to wind and solar projects, however, does provide a preferential incentive, due to the time value of money.

For example, although wind and solar power projects are designed to operate for twenty years or longer, the vast majority – as much as 95% or more – of an investment in a wind or solar project can be depreciated for tax purposes over an accelerated five- to six-year period, using the 5-year Modified Accelerated Cost-Recovery System ("MACRS") schedule. While 5-year MACRS eligibility is "permanent" within the U.S. tax code, in recent years projects that have been placed in service within certain windows of time have also been eligible for an even-more-attractive depreciation schedule based on either 50% or 100% "bonus" depreciation, as a means to further encourage investment. Wind and solar projects also have the option (again, "permanently") to elect a 12-year straight-line depreciation schedule in lieu of 5-year MACRS. Table 1 on the next page lays out these four depreciation schedules, their respective eligibility windows, and – for comparison purposes only – their present values.

Table 1. Relevant Depreciation Schedules (Mid-Year Convention)

	5-Year MACRS	5-Year MACRS +50% Bonus	100% Bonus	12-Year Straight-Line
Eligibility Window	Permanent	1/1/2008-9/8/2010 & 1/1/2012-12/31/2013	9/9/2010-12/31/2011	Permanent
Present Value at 10% Discount Rate	77%	84%	91%	54%
Year 1	20%	60%	100%	4.17%
Year 2	32%	16%		8.33%
Year 3	19.2%	9.6%		8.33%
Year 4	11.52%	5.76%		8.33%
Year 5	11.52%	5.76%		8.33%
Year 6	5.76%	2.88%		8.33%
Year 7				8.33%
Year 8				8.33%
Year 9				8.33%
Year 10				8.33%
Year 11				8.33%
Year 12				8.33%
Year 13				4.17%
Total	**100%**	**100%**	**100%**	**100%**

Depreciation is treated as a deduction from taxable income. As such, it serves to reduce or even eliminate annual income tax expense. The ability of wind and solar projects to accelerate these deductions (compared to the useful life of the project) leads to greater tax savings earlier in time (at the expense of lesser tax savings in later years), which, in turn, increases the benefit and incentive to invest, due to the time value of money. The 5-year MACRS schedule (not to mention the two "bonus" schedules) available to wind and solar projects, however, is accelerated enough that it actually creates net operating losses in the early years of most wind and solar projects. In other words, the 5-year MACRS deductions typically more-than-eliminate a project's taxable income over this period. The implications of these net operating losses, in terms of what they mean for the realization of depreciation deductions and tax credits, are discussed later in Section 2.3.

The Production Tax Credit ("PTC")

Section 45 of the U.S. internal revenue code provides a 10-year production tax credit or PTC to certain types of projects (including wind projects, but not at present solar projects) that generate electricity. First enacted by the Energy Policy Act of 1992, the PTC has, since 1994, provided a $15/MWh inflation-adjusted income tax credit over the first ten years of a qualifying project's life. In 2013, after adjustment for inflation, the PTC stood at $23/MWh.

As shown in Table 2, there have so far been nine PTC expiration dates in the PTC's 20-year history, with the ninth reached at the end of 2013.[7] So far, five of these nine expiration dates

[7] Projects that had already qualified for the PTC prior to the end of 2013 deadline are not affected by its expiration and will receive the PTC as planned for 10 years.

have resulted in lapses of varying durations, the longest to date being nine months when the PTC expired at the end of 2003 and was not reinstated (retroactively) until early October 2004, and the shortest being just a day or two after the PTC expired at the end of 2012. The other four expiration dates were preceded by a pre-emptive extension of the credit for some additional period. The PTC is currently still available to projects that started construction before the end of 2013,[8] and that maintain continuous effort to bring the project online thereafter. In response to lingering uncertainty over what "continuous effort" entails, the IRS issued a clarification in September 2013 providing safe harbor to any project that meets the end-of-2013 construction start deadline and is placed in service prior to the end of 2015 (Internal Revenue Service 2013), effectively providing a 2-year construction window (or potentially even longer, if properly documented).

Table 2. Legislative History of the PTC

Legislation	Date Enacted	Start of PTC Window	End of PTC Window	Effective PTC Planning Window (considering lapses and early extensions)
Energy Policy Act of 1992	10/24/1992	1/1/1994	6/30/1999	80 months
Ticket to Work and Work Incentives Improvement Act of 1999	**12/19/1999** ***(> 5-month lapse)***	7/1/1999	12/31/2001	24 months
Job Creation and Worker Assistance Act	**3/9/2002** ***(> 2-month lapse)***	1/1/2002	12/31/2003	22 months
The Working Families Tax Relief Act	**10/4/2004** ***(> 9-month lapse)***	1/1/2004	12/31/2005	15 months
Energy Policy Act of 2005	8/8/2005	1/1/2006	12/31/2007	29 months
Tax Relief and Healthcare Act of 2006	12/20/2006	1/1/2008	12/31/2008	24 months
Emergency Economic Stabilization Act of 2008	10/3/2008	1/1/2009	12/31/2009	15 months
The American Recovery and Reinvestment Act of 2009	2/17/2009	1/1/2010	12/31/2012	46 months
American Taxpayer Relief Act of 2012	**1/2/2013** ***(2-day lapse)***	1/1/2013	Start construction by 12/31/2013	12+ months*

*12+ months because the deadline was changed to a "start of construction" deadline, as opposed to a "placed in service" deadline, which affords some additional planning window (as long as the project meets the minimum "start of construction" criteria).

As a tax credit, the PTC reduces or eliminates the amount of income tax owed by a project. But if a project does not owe any income taxes in a given year – e.g., during a period of net operating losses caused by accelerated tax depreciation – then it cannot use PTCs for that intended purpose. The implications of not being able to use PTCs in the years they are generated to reduce taxes owed by the project in question are discussed below in Section 2.3.

[8] This "start construction" deadline is a departure from previous PTC expiration deadlines, which required a project to be "placed in service." The shift to a "start construction" deadline was a tacit acknowledgment that (A) the 1-year extension came too late – i.e., a few days *after* the PTC had expired at the end of 2012 – to drive much deployment in 2013 if projects were required to be fully online (rather than merely under construction) by the end of the year, and (B) it might be difficult for Congress to extend the credit again beyond the 2013 expiration date, given mounting budgetary challenges and increasing calls for comprehensive tax reform.

The Investment Tax Credit ("ITC")

The business energy investment tax credit, or ITC, in Section 48 of the U.S. tax code has been available to solar projects for many years.[9] Though originally a 10% credit, the *Energy Policy Act of 2005* temporarily increased the size of the credit to 30% starting in 2006, and this 30% level was later extended by the *Emergency Economic Stabilization Act of 2008* through the end of 2016, at which point it is scheduled to revert back to 10%. Although the ITC has historically been considered solar's tax credit (while wind has the PTC), the *American Recovery and Reinvestment Act of 2009* gave utility-scale wind projects the option to elect the 30% ITC in lieu of the PTC, and wind projects that were under construction by the end of 2013 still have this choice.

Unlike the PTC, which is based on the *production* of electricity, the ITC is based on *investment* in a qualifying project that generates electricity. The amount of investment or "basis" to which the 30% credit applies is effectively equivalent to the amount that qualifies for depreciation, which generally comes to 95% or more of a project's total installed cost (though any project that claims the ITC must then reduce the depreciable basis of the project by half the amount of the credit – i.e., by 15%). The ITC is realized in the year in which the project begins commercial operations, but vests linearly over a 5-year period. Thus, if the project ceases to qualify for the credit over this initial 5-year period (e.g., if the project owner sells the project before the end of its fifth year of operations), then the unvested portion of the credit will be recaptured by the Internal Revenue Service ("IRS").

Other Relevant Federal Incentives

Among many other things, the *American Recovery and Reinvestment Act of 2009* created the Section 1603 grant program, which gave projects that were eligible for either the PTC or ITC the ability, starting in 2009, to elect a 30% non-taxable cash grant in lieu of either the PTC or ITC. The 1603 grant was designed to provide the same amount of face value as the 30% ITC (which is why the grant was deemed non-taxable), but delivered in the form of highly fungible cash rather than as a harder-to-use tax credit. The program was enacted as a temporary response to a severe shortage of tax equity investors following the near-collapse of the financial system in late 2008 and early 2009. As such, any project hoping to elect the grant had to originally be under construction by the end of 2010 (later extended to the end of 2011) and, in the case of wind projects, fully online by the end of 2012 (while solar projects theoretically have up until the end of 2016 to finish construction, be placed in service, and receive the grant).

The *American Recovery and Reinvestment Act of 2009* also amended a pre-existing DOE loan guarantee program to make it more sponsor-friendly. Though now closed to new renewable energy applicants (qualifying renewable energy projects had to have commenced construction

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[9] In contrast, the *residential* ITC contained in Section 25D of the tax code has only been available since 2006, and is not a "permanent" part of the tax code – i.e., rather than reverting to 10% at the close of 2016 like the Section 48 business ITC, the Section 25D residential ITC will simply expire. Although this report focuses principally on utility-scale projects, many of the issues discussed in relation to the Section 48 business ITC are also relevant for the Section 25D residential ITC.

prior to October 1, 2011),[10] the Section 1705 loan guarantee program has provided partial loan guarantees to a total of four utility-scale wind projects and twelve utility-scale solar projects (in addition to a variety of other types of projects). The government guarantee allows these projects to access debt capital at reduced interest rates.

2.3 Three Approaches to Capturing the Value of Federal Tax Incentives

Of the various Federal incentives described in the preceding section, the tax incentives in particular have significant implications that are important to understand. For example, as noted above, accelerated depreciation deductions cause most wind and solar projects (unless earning supra-normal revenue) to generate net operating losses during the first five years of their lives. In other words, some portion of the depreciation benefit – i.e., the amount of the deduction that exceeds the project's taxable income – potentially goes unused each year. Furthermore, a project that is generating net losses as a result of accelerated depreciation does not owe any income tax, which means that earned PTCs and ITCs also potentially go unused. As a result, even though the Federal tax benefits provided to wind and solar projects might seem generous at face value, in practice it is difficult for many project sponsors to realize this full face value. Accelerated depreciation schedules are out of synch with most projects' taxable income profile, which not only potentially erodes the benefit of accelerating depreciation deductions, but also in turn potentially renders tax credits less valuable than they could be.

There are, however, three ways in which a project sponsor can still get some value – and potentially even full value – out of any excess deductions or credits generated by a wind or solar project in a given year:

1) **Apply the deductions and credits against outside income:** If the sponsor has a sufficient amount of *outside* taxable income that it has earned from *other* operating projects or certain *other* business activities, then it can apply net operating losses from a wind or solar project against that outside income, thereby reducing or even eliminating it for tax purposes. Afterwards, presuming additional outside taxable income (i.e., tax appetite) still remains, the sponsor can proceed to apply PTCs or ITCs against the tax owed on that remaining income. This is the best possible outcome from the sponsor's perspective, and could result in the sponsor extracting the full face value from the wind or solar project's combined tax benefits.
2) **Carry the tax benefits forward over time:** If the sponsor does not have outside tax appetite (or at least not in sufficient amounts), then it can carry forward net operating losses (for up to twenty years)[11] until they can be absorbed internally by the project in later years. Once the balance of net operating losses has been fully absorbed and the project starts paying taxes, the balance of PTCs or ITCs that have been carried forward

[10] The DOE loan guarantee program was re-opened in late 2013, but only for advanced fossil energy projects.
[11] Because net operating losses can be carried forward for up to 20 years, there is seemingly little incentive for a project sponsor to elect the 12-year straight-line depreciation schedule in lieu of the 5-year MACRS schedule – even though the 12-year schedule is typically a better match with the distribution of the project's taxable income over time.

(also for up to twenty years following the year in which they were generated)[12] can start to be used to reduce or eliminate tax payments. Depending on how long the losses and credits need to be carried forward, as well as the investor's discount rate, this strategy can severely erode the present value of these tax incentives.

3) **Monetize through tax equity:** If the sponsor does not have outside tax appetite and is not interested in carrying forward the tax benefits over time, then it can seek out a third-party tax equity investor to "monetize" the tax benefits by investing in the project in exchange for being allocated the vast majority of losses and credits.

Figure 2 shows the time profile of depreciation deductions and PTCs generated by a generic wind project, compared to that same project's income tax liability *prior to* applying these losses and credits.[13] Depreciation deductions (expressed here in terms of the resulting tax benefit that they provide – i.e., deductions are multiplied by an assumed 35% Federal tax rate before being expressed as a percentage of total capital expenses) exceed the project's annual tax liability in each of the first five years of the project's life, while PTCs compound the excess. In the sixth year, depreciation plus PTCs still exceed the project's own tax liability in that year, as do just the PTCs in the seventh through tenth year once the project has been fully depreciated.

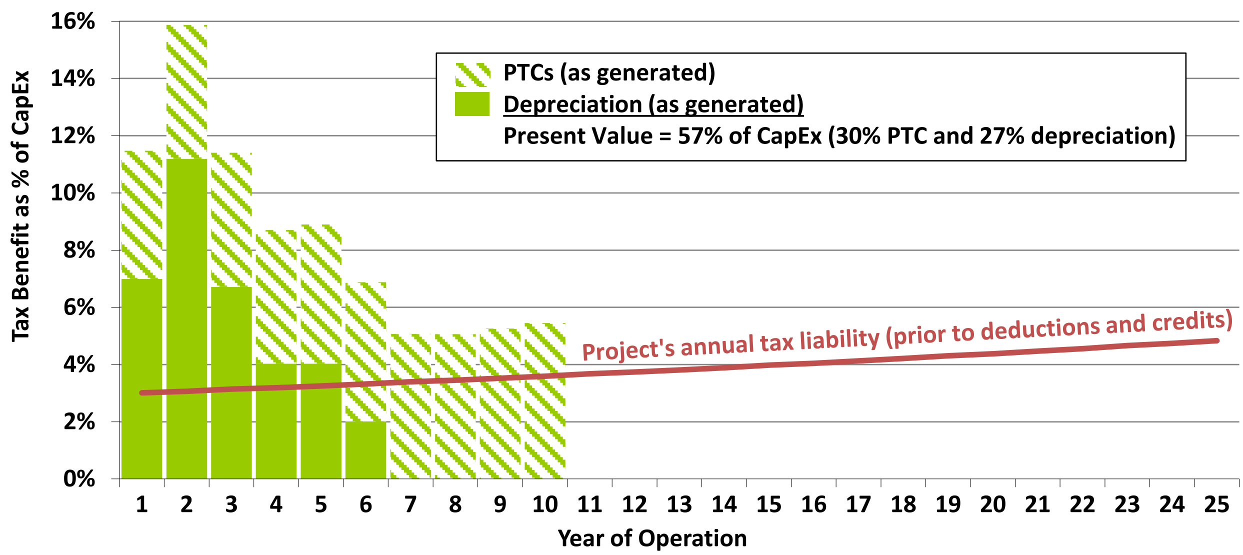

Figure 2. The Time Profile of Tax Benefits Generated by a Wind Project

[12] Any balance of unused PTCs or ITCs that remains at the end of 20 years may be deducted from taxable income in year 21 (see the instructions for IRS Form 3800, on which the credits are ultimately claimed). Deductions are generally worth less than credits, however, because deductions merely reduce taxable income, while credits reduce the tax itself. That said, the present value of either a deduction or a credit taken 20 years in the future will be quite small, perhaps rendering this distinction between the two somewhat less important than it might otherwise be.

[13] The underlying concepts presented in Figures 2 and 3 are similar for a solar project taking the ITC. The most notable difference is that solar receives a large ITC in the first year, rather than a smaller amount of PTCs in each of the first ten years. Depreciation deductions (plus the first-year ITC) exceed the solar project's own tax liability in much the same way as is shown in Figure 2, and the excess deductions and credits can be carried forward in much the same way as is shown in Figure 3 (absorbing depreciation losses first before starting to apply the ITC against income tax in later years).

In the first and third options described above, the amount of depreciation deduction plus PTCs that fall above the project's tax liability line in each year is either applied against outside tax appetite (the first option described above) or monetized by a third-party tax equity investor (the third option described above). In either case, the project can be thought of as realizing the tax benefits as they are generated, according to the time profile shown in Figure 2.

Alternatively, the project sponsor can carry forward the excess losses and credits; this is the second option described above, and is illustrated below in Figure 3. In this case, the sponsor can only use losses and credits to reduce the project's own tax liability, which means that excess losses must be carried forward until they can eventually be absorbed internally. In this illustrative example, this means that the depreciation deductions generated over the project's first six years in Figure 2 are not fully realized until year 11 in Figure 3. Only *after* these losses have been fully absorbed in year 11 can the balance of PTCs start to be applied. In this illustrative example, this means that PTCs earned during the project's first ten years do not actually provide any tax benefit until years 11 through 23. As a result of carrying forward these losses and credits, this hypothetical project would not pay any income tax until its twenty-third year of operations.

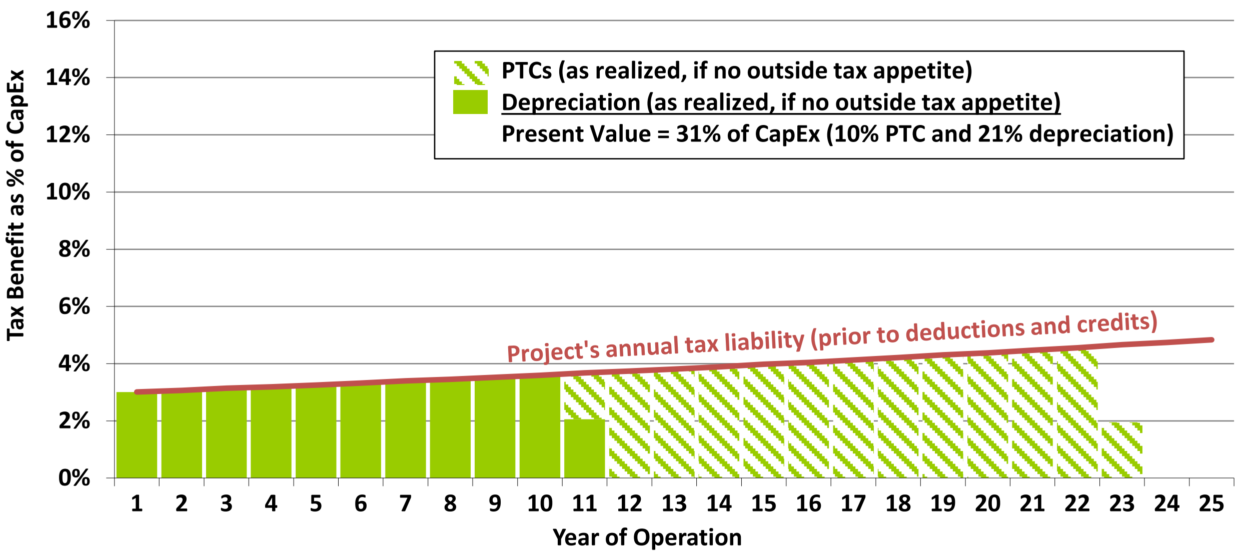

Figure 3. The Time Profile of Tax Benefits Realized by a Wind Project (assuming no tax appetite)

Figures 2 and 3 show the exact same amount of depreciation deductions, tax credits, and tax liabilities. Only the timing of when those deductions and credits are claimed is different. This difference in timing, in turn, has a significant impact on the present value of the tax benefits. In Figure 2, assuming a 10% nominal discount rate, the present value of tax benefits equals 57% of the installed project cost, with 27% from depreciation and 30% from the PTC.[14] In Figure 3,

[14] The 27% depreciation benefit is an *absolute* benefit, and should not be considered the size of the depreciation *subsidy* provided to wind projects. Because all income-generating assets are depreciated (or even expensed) for tax purposes in one way or another, the size of the depreciation subsidy provided to wind and solar projects should be calculated as the present value benefit of *accelerating* tax depreciation relative to whatever schedule would have been used absent access to the 5-year MACRS schedule. As noted above in Table 1, a 12-year straight-line schedule would seem to be the most applicable benchmark. Comparing the present value of the 5-year MACRS schedule

however, these same tax benefits have a present value of just 31% of installed costs, with 21% attributable to depreciation and 10% to the PTC.

Granted, both Figures 2 and 3 represent extreme cases, which in turn maximize the difference in net present value between the two. Specifically, Figure 2 represents a best-case scenario, in which all deductions and credits are used in the year generated, while Figure 3 represents a worst-case scenario, in which *all* tax benefits must be carried forward until they can eventually be absorbed by the project itself. In reality, it is possible, or even likely, that many projects will fall somewhere in between these two extremes. For example, not all tax equity investors or sponsors with tax appetite will always, in every year, be able to use all losses and credits in the years in which they are generated.[15] Similarly, sponsors who carry forward tax benefits over time will often have at least some limited outside tax appetite, thereby allowing losses (and then later credits) to be absorbed a bit earlier in time.[16]

In addition, though not shown in Figure 2 (which, like Figure 3, depicts only tax *benefits*), third-party tax equity monetization comes *at a cost*, in the form of a higher cost of capital than the project-level term debt that it likely supplants. At present, the monetization benefit that tax equity provides must outweigh this cost in most instances, otherwise more sponsors would presumably carry forward tax benefits instead. This has not always been the case, however. For example, back in mid-2008 when the cost of tax equity spiked in response to growing financial turmoil (see Figure 1, earlier), Iberdrola – a Spanish wind developer that is active in the United States but that has only some outside tax appetite – noted that the cost of tax equity had almost risen to the point where it made sense to forego tax equity and carry forward tax benefits instead (Chadbourne & Parke LLP 2008). And once the Section 1603 grant program was implemented in late 2009, thereby suppressing the benefits of tax equity (because tax credits no longer needed to be monetized), at least half of all projects in the market chose to carry forward excess depreciation deductions rather than seek out tax equity (Chadbourne & Parke LLP 2010a). As such, though often overlooked in policy discussions, it is by no means a foregone conclusion that high-cost, third-party tax equity will always be necessary or even relevant to renewable energy project finance.

(27%) to the present value of the 12-year straight-line schedule (22%) yields a 5% subsidy that is provided via accelerated depreciation. Again, though, this calculation assumes that the project has (or can access) sufficient tax appetite to actually realize the benefit of acceleration – if not, then the subsidy provided by accelerated depreciation may actually be closer to 0%.

[15] For example, NextEra Energy Resources is one of the largest wind and solar project sponsors in the United States, a position that was achieved (at least historically) in part through its ability to apply tax benefits against the earnings of its affiliates, including Florida's largest utility, Florida Power & Light. In recent years, however, NextEra's fast growth, in combination with stimulus-related bonus depreciation provisions and hurricane-related losses at Florida Power & Light, has placed the company in a net operating loss position, forcing it to turn to third-party tax equity to monetize tax losses and credits from new investments (Lotano 2012). Edison Mission Energy is another example of a wind project sponsor that historically had tax appetite from affiliates, but lost it in recent years.

[16] It is worth emphasizing, however, that if any amount of depreciation deductions – no matter how small – must be carried forward as a net operating loss during the 5-year MACRS period, then PTCs or ITCs will still need to be carried forward until *after* those losses have been fully absorbed (i.e., for at least five years in this example), at which time the credits can start to be claimed. In other words, just because a sponsor has some limited outside tax appetite does not necessarily mean that a portion of PTCs or ITCs can be absorbed starting in the project's first year. Instead, credits can only start to be applied once all net operating losses have been completely absorbed and the project is generating taxable income.

Using the underlying concepts laid out in this section, the rest of this report develops and uses financial pro forma cash flow models to more accurately estimate both the costs and benefits of third-party tax equity (relative to the other two approaches to capturing the value of tax benefits), to estimate how those costs and benefits might change under a variety of plausible future scenarios, and to assess the likely impact of those changes not only on how wind and solar projects are financed, but also – and more importantly – on their levelized cost of energy ("LCOE").

3. Model Descriptions and Assumptions

This two-part chapter describes the pro forma financial cash flow models and the assumptions that go into them. Readers well-versed in the intricacies of renewable energy finance in the United States, or else more interested in modeling results rather than the models (and assumptions) themselves, may choose to skip ahead to Chapter 4.

3.1 Description of Pro Forma Financial Models

The analysis conducted in Chapters 4 and 5 draws upon three different pro forma financial models built expressly for this purpose. Two of these – the Partnership Flip and Sale-Leaseback models – represent different financial structures involving third-party tax equity investors. Two such models are needed because the solar market has tended to rely heavily on Sale-Leaseback structures (but has also used Partnership Flip structures), while the wind market favors Partnership Flip structures (in part because, as noted below, leasing structures are not compatible with the PTC).[17] The third pro forma model – the Sponsor Equity/Debt model – does not involve third-party tax equity, and instead has the sponsor finance the project through a combination of sponsor equity and project-level term debt, carrying forward tax benefits as needed depending on the sponsor's tax appetite.

Most financial models can be run in two directions: either assuming a fixed amount of revenue (e.g., the "going rate" available through PPAs) and solving for the financial return provided by that fixed amount of revenue, or alternatively assuming that investors require a certain financial return and then solving for the amount of revenue (i.e., the PPA price) required to provide that return. The analysis in this report adopts the latter approach: all three models solve for the minimum levelized PPA price that satisfies all modeling constraints, which include recouping the initial capital expense (including repayment of any debt), meeting all operating expenses, and providing all investors with their targeted rates of return. The models use Excel's "Solver" function (a linear programming tool) to iterate and converge on the minimum levelized PPA price that satisfies all of these constraints.

By intention, all three models are relatively simple – particularly in terms of the number of inputs required – yet try to be as accurate as possible methodologically. For example, rather than include separate line items for each individual component of operating costs (e.g., scheduled and unscheduled maintenance, insurance, royalties, land lease, etc.), the model simply requires a single input for *total* operating expenses. Because the analysis is comparative in nature, more emphasis is placed on understanding differences between structures and scenarios, rather than on the resulting PPA prices themselves.

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[17] A third structure involving third-party tax equity – a so-called "lease passthrough" or "inverted lease" – has more recently become popular in the solar market because it enables the sponsor to retain full ownership of the project, thereby avoiding the need to buy out the tax equity investor's stake at the end of the lease. The relative complexity of this structure, however, is beyond the scope of this report, and likely outweighs any incremental insights to be gained from including it (i.e., the Sale-Leaseback structure is likely sufficiently representative and instructive for the purpose of this report).

Sponsor Equity/Debt

The Sponsor Equity/Debt model is the simplest of the three models, largely because it does *not* involve third-party tax equity investors. Instead, this model finances the project with a mix of sponsor equity and project-level term debt, with the exact amount of each determined endogenously by the model (based on specified debt service coverage ratios and other constraints), and reported in the appendix.[18] Depending on its degree of tax appetite (which is an input to the model), the sponsor either uses the project's tax benefits as they are generated or else carries them forward as needed. The model solves for the minimum levelized PPA price that satisfies all modeling constraints, which include paying operating costs, meeting debt service coverage ratios, and meeting the sponsor's equity return target or "hurdle rate."

Sale-Leaseback

The Sale-Leaseback model is somewhat more complex, in that it involves both the sponsor (acting as lessee) and a third-party tax equity investor (acting as lessor). No debt is employed – this is what's known as a "single-investor lease" rather than a "leveraged lease." In this model, the sponsor develops and constructs the project, sells the equipment or hard assets to a tax equity investor, and then leases it back. As the sole owner (and lessor) of the project equipment, the tax equity investor retains 100% of the project's tax benefits, and also receives ongoing lease payments from the sponsor (lessee) that are sized as necessary in order for the tax equity investor to reach its target rate of return. Meanwhile, the sponsor (lessee) operates the project, covers normal operating expenses, makes lease payments to the lessor, and receives revenue from the sale of electricity through a PPA, with the PPA price set at a level necessary for the sponsor to meet its obligations and to reach its own target rate of return. Hence, running this model involves a two-step process: first the lease payments are sized as needed (taking into account the project's tax benefits) in order to reach the tax equity investor's hurdle rate, and then the PPA price is set as needed (taking into account operating expenses – including ongoing lease payments) in order to reach the sponsor's hurdle rate.

Although Sale-Leaseback structures can theoretically provide 100% financing to the sponsor (through the sale of the project's hard assets), in practice the tax equity lessor often requires some up-front prepayment of rent, which is analogous to a sponsor capital contribution. Based on White (2011) and Chadbourne & Parke LLP (2011), the Sale-Leaseback modeling runs conducted for this report assume that 85% financing is achieved; in other words, the sponsor must contribute 15% of the project's installed cost as pre-paid rent. Though exchanged up-front at the start of commercial operations, this pre-payment is (somewhat simplistically) accounted for in a proportional, deferred manner over the term of the lease. For example, over the course of a 20-year lease, the tax equity lessor books 1/20th or 5% of the pre-payment amount as income in each year, while the sponsor expenses that same amount each year.

Because Section 45 of the U.S. tax code (pertaining to the production tax credit) requires that the owner also operate the project, lease financing (which by definition involves a separate owner and operator) has historically not been viable for wind power projects in the United States. This

[18] Should they become eligible for wind and solar projects in the future, master limited partnerships (MLPs) could potentially supplement or even replace project-level term debt as a relatively cheap source of capital.

limitation was lifted in 2009, however, when the *American Recovery and Reinvestment Act* gave wind power projects access to either the Section 48 ITC or the Section 1603 cash grant, neither of which has any such owner/operator provision. In the years since, a handful (or more) of wind projects have pursued Sale-Leaseback structures. For the most part, however, Sale-Leaseback financing has been dominated by solar projects, with most wind projects opting instead for Partnership Flip structures.

Partnership Flip

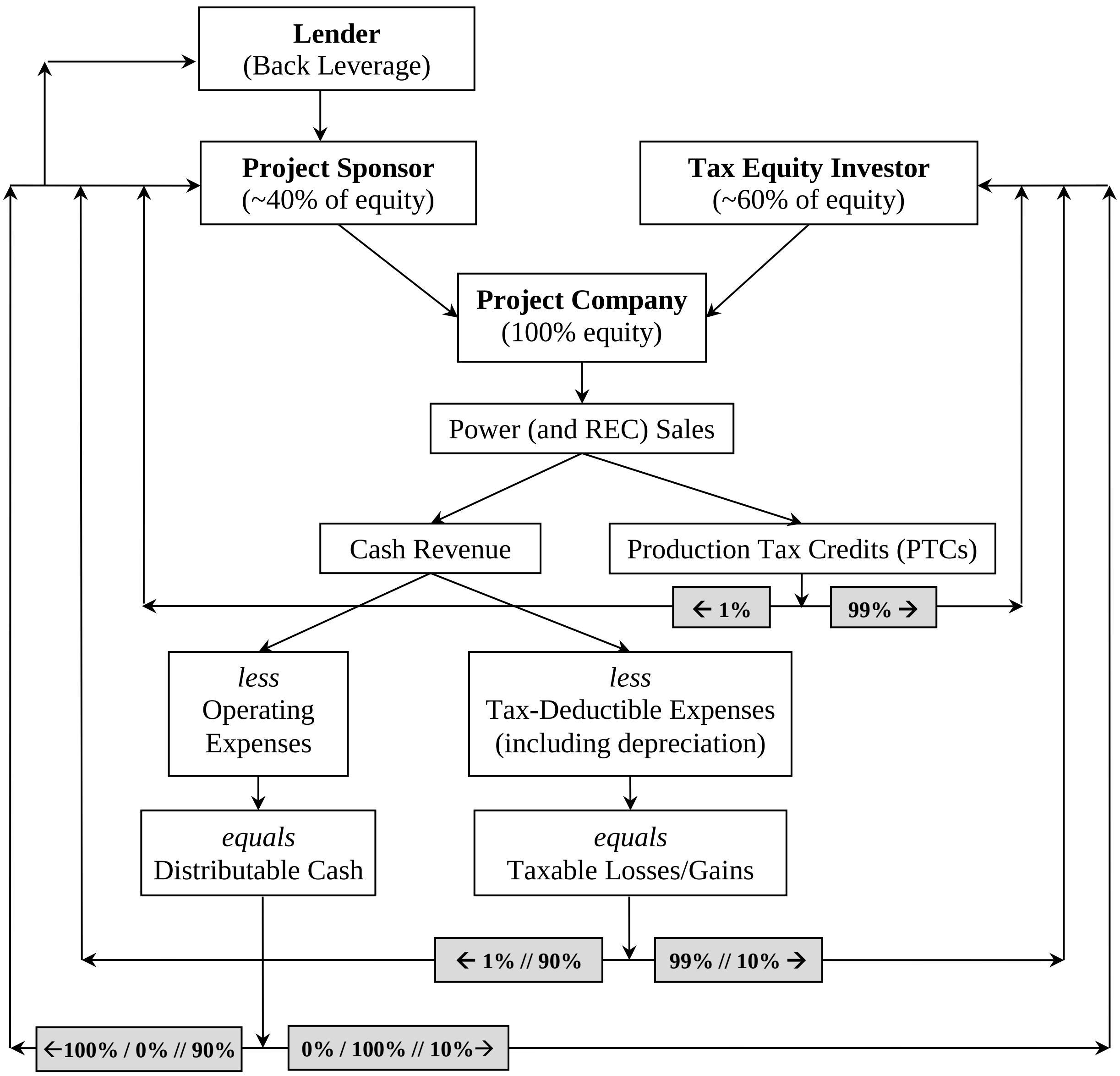
The Partnership Flip model is the most complex of the three models employed here. Like the Sale-Leaseback model, a Partnership Flip involves both a sponsor and a tax equity investor. But unlike the Sale-Leaseback model, a Partnership Flip does not involve a clean sale of the project from the sponsor to the tax equity investor, with each having clearly defined roles and responsibilities as lessee and lessor, respectively. Instead, in a Partnership Flip structure, the sponsor and tax equity investor partner together to finance and own the project, and to share in both its risks and rewards.

The rewards include distributable cash as well as tax losses and credits (i.e., tax benefits). Distributable cash is simply the revenue earned from selling energy (and capacity and RECs) through a PPA, less operating expenses. Tax losses stem from accelerated tax depreciation, while tax credits are either the PTC or ITC (or, for a period of time, the Section 1603 cash grant – even though not technically a tax credit).

In order to help facilitate understanding of this relatively complex structure, Figure 4 (adapted from Bolinger et al. 2009) shows a schematic of a Partnership Flip structure involving the PTC. Though the amount of equity contributed to the project company by the project sponsor (shown as ~40%) and tax equity investor (shown as ~60%) will vary by modeling run (and is determined endogenously by the model, and reported later in the appendix), the cash and tax benefit allocation ratios shown in the shaded boxes of Figure 4 are fixed within the model as shown.

Distributable cash is allocated among the two partners in the following manner. Initially, and for the first few years of the project's life (usually until the sponsor recovers its full investment in the project, or up until a fixed date agreed upon by the two partners – whichever comes first), 100% of distributable cash goes to the sponsor. Thereafter, 100% of distributable cash goes to the tax equity investor until it reaches its target rate of return, which triggers the return-based flip. After the flip, and for the rest of the project's life, a large percentage – often 90% or more – of distributable cash flows to the project sponsor.

Tax benefits – losses and credits – are distributed a bit differently. Per the safe harbor guidance provided by the IRS in Revenue Procedure 2007-65, the sponsor must maintain at least a 1% interest in all losses and credits over the life of the partnership. Thus, prior to the flip, the sponsor is allocated 1% of the project's tax benefits, with the other 99% allocated to the tax equity investor. After the return-based flip, as much as 95% of taxable *income* (since both losses and credits will likely have been exhausted by this time) is allocated to the sponsor. After the flip, the sponsor also often has the right to buy out the tax equity investor's interest in the project – typically at a favorable market-based price given the tax equity investor's greatly reduced cash allocations post-flip.



Note: The single slash in the shaded boxes indicating the allocation of distributable cash signifies the end of the sponsor's initial investment recovery period, while the double slash in those same boxes, as well as in shaded the boxes indicating the allocation of taxable losses and gains, represents the return-based flip in allocations.

Figure adapted from Bolinger et al. 2009

Figure 4. Schematic of the Partnership Flip Structure (with Back Leverage)

Project-level debt is not included in the Partnership Flip model. Typically, tax equity investors in Partnership Flip transactions actively discourage – either through outright prohibition or by stipulating higher hurdle rates[19] – the use of project-level debt, because it gives the lender a first

[19] Prior to the financial crisis of 2008-2009, tax equity investors reportedly charged a premium of 250-300 basis points in deals involving project-level debt (Chadbourne & Parke LLP 2012d, Bolinger et al. 2009). In the wake of the crisis, this premium has reportedly risen to 500-800 basis points (Chadbourne & Parke LLP 2013c, Chadbourne & Parke LLP 2014). This inflated premium essentially cancels out the advantage of adding low-cost debt to the structure, leaving the overall WACC largely unchanged. As a result, very few projects are financed using both tax equity and project-level term debt; for example, the most prominent tax equity investor active in the renewable

lien on the project (Chadbourne & Parke LLP 2014). Their concern is that, in the event of default, a lender might foreclose on the project, potentially leading to the loss of their investment, and perhaps also triggering the recapture of already claimed tax deductions and credits.

The model does, however, allow the sponsor to borrow against or "back-leverage" its own equity stake in the project company. Back leverage is not as risky to the tax equity investor, because in the event of foreclosure, only the sponsor's equity stake is at risk – the tax equity investor will continue to receive the tax and cash benefits to which it is entitled. Given that the sponsor most often operates and maintains the project as well (and is presumably more qualified to do so than most lenders), back leverage is not completely without risk to the tax equity investor, but most are nevertheless willing to work with sponsors who wish to back-lever their equity positions. Given that sponsor equity is typically the most expensive source of capital available to renewable energy projects, back leverage can be an effective means of raising capital at a lower cost, thereby lowering the project's overall WACC.[20]

Partnership Flip structures were first developed in the wind sector more than a decade ago, and are how the majority of wind projects in the United States – particularly those with independent power producers that lack tax appetite as sponsors – are financed. More recently, some solar project sponsors have started to use this model in conjunction with the ITC (rather than PTC). In general, sponsors who desire long-term ownership of the project like this model because it allows them to buy out the tax equity investor's interest in the project at an advantageous price post-flip. As mentioned earlier in footnote 17, lease passthroughs or inverted leases (whose complexity is beyond the scope of this report) are popular with solar projects for a similar reason – i.e., there is no need to buy out the tax equity investor at the end of the lease.

3.2 Modeling Input Assumptions

This section describes the input assumptions to the three models described above. Many assumptions are common to all three models, but may nevertheless vary depending on whether a wind or solar power project is being modeled – these assumptions are shown in Table 3, with details on select assumptions described in the text.

Project Capacity: Though the analysis in this report is more broadly applicable than to just utility-scale projects, utility-scale projects are, in some ways, easiest to consider and represent in the models. The 20 MW_{AC} solar PV project size is roughly consistent with recently proposed projects in the western United States (Bolinger and Weaver 2013), which tend to be smaller than the very large (i.e., several hundred MW) projects that are currently coming online. The 50 MW

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energy market recently estimated that less than 10% of the tax equity deals that it has done over the past ten years involve project-level debt (Chadbourne & Parke LLP 2014).

[20] For example, in 2011, the prominent wind (and now solar) developer/sponsor First Wind completed a high-yield seven-year note offering at a 10.25% interest rate, and used the funds raised as equity (back leverage) in its projects built in 2011 and 2012 (Chadbourne & Parke LLP 2012a). Though 10.25% might seem costly, it is cheaper than the 12% *after-tax* return target attributed to sponsors in this report (particularly when converted to its after-tax equivalent of ~6.7%, assuming a 35% tax rate).

wind project is also moderately sized. Because installed project costs are expressed on a $/kW basis, however, project size does not materially impact the analysis.

Total Capital Expense: The total capital expense ("CapEx") represents an "all-in" installed project cost, inclusive of all costs incurred to place the project in service (including the capitalized cost of construction financing). Wind's CapEx of $1800/kW is largely consistent with empirical cost data presented in Wiser and Bolinger (2013) for projects installed in the U.S. interior region. Utility-scale PV's CapEx is initially modeled at both $3000/kW$_{AC}$ (consistent with the low end of the range for PV projects with tracking presented in Bolinger and Weaver (2013)) and $2000/kW$_{AC}$ (reportedly achievable by the lowest cost projects in 2013, but perhaps unlikely to reflect average CapEx until several years from now when most of the solar scenarios modeled herein would go into effect) before settling in on the midpoint of that range, or $2500/kW$_{AC}$ (which is essentially where GTM/SEIA (2014) pegged average utility-scale PV prices in the fourth quarter of 2013 – i.e., at $1960/kW$_{DC}$, which roughly translates into $2500/kW$_{AC}$).

Table 3. Project Parameters (Input Assumptions) That Do Not Vary By Model

	Wind	**Solar (PV)**
Project Capacity (MW)	50	20
Total Capital Expense ($/kW$_{AC}$)	1800	3000 / 2500 / 2000
Net Capacity Factor (%)	40%	30%
Annual Degradation Rate (%/year)	0.0%	0.5%
Total Operating Expense ($/kW-year)	50	30
Applicable Federal Incentive	PTC	ITC
Depreciation Schedule	100% 5-Year MACRS	
PPA Term (years)	25 years	
PPA Escalation Rate (%/year)	2%	
Federal Income Tax Rate	35%	
State Income Tax Rate	8%	
Nominal Discount Rate	10%	
Inflation Rate (%/year)	2%	

Net Capacity Factor: A 40% net capacity factor for wind is consistent with newer wind turbine technology operating in a class 4 wind resource (or even a class 3 resource, using a low wind speed turbine). Solar PV's net capacity factor of 30% is consistent with projects in the western United States that use tracking (Bolinger and Weaver 2013).

Degradation: Although the output of a properly maintained wind turbine is not typically expected to degrade substantially over time, PV generation is typically assumed to decline by 0.5%/year. This assumed degradation rate is at the low end of the range pulled from a sample of solar PPAs, as discussed in Bolinger and Weaver (2013).

Total Operating Expense: Total operating expenses ("OpEx") represent a single line item for *all* operating costs (not just O&M). Wind's assumed OpEx of $50/kW-year is based on Lantz (2013) and Wiser and Bolinger (2013), while solar's $30/kW-year is based on Bolinger and Weaver (2013). OpEx is assumed to escalate at the rate of inflation (i.e., it is assumed to remain flat in real dollar terms).

Depreciation Schedule: For the sake of simplicity, all three models assume that 100% of CapEx (i.e., 100% of wind CapEx, but just 85% of solar CapEx, given that a project claiming the 30% ITC must reduce the depreciable basis of that project by half the amount of the ITC, or 15%) is depreciated using 5-year MACRS depreciation. In reality, slightly less than 100% of CapEx (maybe 90-95%) would qualify for 5-year MACRS depreciation. Bonus depreciation is not modeled, primarily because there seems to be consensus among tax equity investors – some of whom even opt out of it – that it is not all that useful (Chadbourne & Parke LLP 2011); in addition, bonus depreciation is not currently available, having expired at the end of 2013.

PPA Term: The average PPA term for wind projects cited in Wiser and Bolinger (2013) is 20 years, compared to more than 23 years for utility-scale solar projects (Bolinger and Weaver 2013). For this analysis, however, the PPA term is assumed to be 25 years for both wind and solar. Even though 25 years is longer than the average PPA term in the market (though there are numerous 25-year PPAs for both wind and solar projects within the two PPA samples cited above), a 25-year PPA makes analytical sense for two reasons. First, under certain scenarios involving the PTC, carried-forward PTCs are still being absorbed through year 25 (or even slightly beyond),[21] and although the present value of these long-delayed PTCs is negligible, truncating the analysis at 25 years assigns them no value at all – a shortcoming that would be exacerbated over shorter PPA terms. Second, the closer the PPA term is to the project's assumed life (i.e., the longer the PPA), the more representative the levelized PPA price is of a project's (post-incentive) LCOE.

Nominal Discount Rate and Inflation: The nominal discount rate is fixed at 10% and is used only to calculate standardized net present values. It is not tied to return hurdle rates or the project's WACC. With inflation assumed to be 2%/year, the real discount rate comes to 7.84%.

A few additional assumptions about how wind and solar projects are financed do vary by model (and technology); these are shown in Table 4 and are discussed below.

Table 4. Financing Assumptions

<table>
<tr><th rowspan="2"></th><th colspan="2">Sponsor Equity/Debt</th><th colspan="2">Sale-Leaseback</th><th colspan="2">Partnership Flip</th></tr>
<tr><th>Wind</th><th>Solar</th><th>Wind</th><th>Solar</th><th>Wind</th><th>Solar</th></tr>
<tr><td colspan="7">Equity After-Tax Internal Rate of Return ("IRR") Target</td></tr>
<tr><td>Sponsor</td><td colspan="2">12%</td><td colspan="2">12%</td><td colspan="2">12%</td></tr>
<tr><td>Tax Equity</td><td colspan="2">Not Applicable</td><td>8.50%</td><td>8.25%</td><td>8.50%</td><td>8.25%</td></tr>
<tr><td colspan="7">Project-Level Term Debt</td></tr>
<tr><td>Interest Rate</td><td>6%</td><td>5.5%</td><td colspan="4" rowspan="3">Project-level debt is not modeled for the Sale-Leaseback and Partnership Flip structures.</td></tr>
<tr><td>Tenor</td><td colspan="2">15</td></tr>
<tr><td>DSCR</td><td>1.45</td><td>1.35</td></tr>
<tr><td colspan="7">Back Leverage</td></tr>
<tr><td>Interest Rate</td><td colspan="4" rowspan="3">Back leverage is not modeled for the Sponsor Equity/Debt or Sale-Leaseback models.</td><td colspan="2">10%</td></tr>
<tr><td>Tenor</td><td colspan="2">1-year less than capital recovery period</td></tr>
<tr><td>DSCR</td><td colspan="2">1.45</td></tr>
</table>

[21] Recall from Section 2.3 that unused PTCs can be carried forward for up to 20 years (per the instructions for IRS Form 3800). Since the PTC is a 10-year credit, PTCs generated in years 5 through 10 could potentially be carried forward to years 25 through 30.

Equity After-Tax Internal Rate of Return ("IRR") Target: As mentioned at the start of this chapter, all three models start with assumptions about the rates of return required by sponsors and tax equity investors, and then solve for the minimum levelized PPA price that achieves those returns (while also satisfying all other modeling constraints). The sponsor return target is held at 12% (after-tax) across all three models. This might be thought of as a levered return target, with the "leverage" coming from either project-level debt (in the case of the Sponsor Equity/Debt model) or tax equity (in the Partnership Flip and Sale-Leaseback models).

The tax equity's return target varies slightly by technology – 8.5% for wind and 8.25% for solar – but not by structure. Although one prominent tax equity investor has stated that for quality projects, there is no "significant" difference between the cost of tax equity for utility-scale wind and solar (Chadbourne & Parke LLP 2013c), others have stated that tax equity is slightly cheaper for utility-scale solar, due to less resource (and therefore revenue) risk and more-defensible pro formas in terms of operating costs and expected generation (Chadbourne & Parke LLP 2010b, Chadbourne & Parke LLP 2014).[22] The 25 basis point difference between wind and solar assumed here is minor and – even if unwarranted – probably does not matter too much given that the analysis does not place the two technologies in competition. Instead the analysis is more focused across financing structures, and here the return targets do not vary (Chadbourne & Parke LLP 2012b).[23]

The only way to minimize levelized PPA prices while holding return targets for *both* the sponsor *and* the tax equity investor constant across all models and scenarios is to allow the project's capital structure – i.e., the proportion of the project financed by sponsor equity, tax equity, and/or project-level term debt – to shift. For example, were the PTC reduced to 80% of its current value, PPA prices would – all else equal – need to increase in order to compensate investors (and particularly tax equity investors) for the decline in the credit. Without a commensurate shift in capital structure, the PPA price would rise to a level that satisfies the tax equity investor's (unchanged) hurdle rate. But this new, higher PPA price would generate an above-normal return for the project sponsor (whose return is almost entirely cash-based), which means that the PPA price would be higher than it needs to be to encourage investment. The way to fix this sub-optimal outcome is to shift the capital structure away from tax equity in favor of sponsor equity. As the amount of tax equity decreases, the tax equity investor's return increases, which, in turn, enables the PPA price to decline to a level at which the tax equity investor's return once again matches its hurdle rate. Meanwhile, as the amount of sponsor equity increases (and the PPA price declines), the sponsor's above-normal return reverts back down to its target rate. See the appendix for more details on the capital structure resulting from each modeling run.

[22] Tax equity investors do reportedly charge a higher IRR hurdle rate for distributed (e.g., residential) solar than for utility-scale solar (Chadbourne & Parke LLP 2013a, Bloomberg New Energy Finance 2013), but since this report focuses on utility-scale projects, this distinction is ignored.

[23] Though target returns do not vary by structure, there is some evidence that they may vary by incentive. Specifically, tax equity investors reportedly charge a premium to take the 30% ITC rather than the 30% cash grant, because the former uses up more "tax capacity." This idea is discussed further in Section 5.2.

This example illustrating the importance of capital structure might give pause to those acquainted with the Modigliani-Miller theorem, which is often referred to as the "capital structure irrelevance principle." The text box below, however, provides an explanation of why the Modigliani-Miller theorem is not directly applicable to renewable energy project finance.

The "Capital Structure Irrelevance Principle" – Irrelevant to Renewable Energy Project Finance

Published in 1958 by future Nobel Prize winners Franco Modigliani and Merton Miller, the Modigliani-Miller theorem holds that in an efficient market with no taxes, no bankruptcy costs, no agency costs or asymmetric information, no transaction costs, and equal borrowing costs, the value of a firm is unaffected by how the firm is financed. In other words, whether the firm is capitalized with equity or with some combination of equity and debt does not matter in a perfect market, because as leverage is added, equity becomes riskier and increases in cost, leaving the overall WACC unchanged (Modigliani and Miller 1958).

Setting aside the obvious fact that few of Modigliani-Miller's assumptions or conditions (e.g., no taxes, no transaction costs, equal borrowing costs, etc.) hold in practice (and particularly with respect to renewable energy project finance), this theorem potentially calls into question the value of focusing on different renewable energy financing structures that employ varying amounts of sponsor equity, tax equity, and debt. If capital structure is, indeed, irrelevant and differences in WACC are just arbitraged away, then perhaps how renewable energy projects are financed doesn't really matter all that much.

A deeper examination of the peculiarities of renewable energy project finance, however, reveals why capital structure is, in fact, still relevant. For example, Modigliani-Miller assumes that different types of capital (namely, equity and debt) are fungible or homogenous in the sense that they can be used for the same purpose and to generate the same basic return. In renewable energy project finance, however, different sources of capital are not fungible, in large part due to taxes (which Modigliani-Miller assumes away): sponsor equity is often much less efficient than tax equity at capturing a project's tax benefits, while debt is unable to capture those benefits at all. Thus, tax equity (which, despite its name, provides debt-like capital) brings a benefit to the project that debt does not, which means that tax equity should be able to command a premium over debt – which it does.

This distinction is perhaps best illustrated using an analogy later crafted by Merton Miller himself to explain the Modigliani-Miller theorem. He writes (in Miller 1991):

> "Think of the firm as a gigantic tub of whole milk. The farmer can sell the whole milk as it is. Or he can separate out the cream, and sell it at a considerably higher price than the whole milk would bring…But, of course, what the farmer would have left would be skim milk, with low butter-fat content, and that would sell for much less than whole milk…The Modigliani Miller proposition says that if there were no cost of separation (and, of course, no government dairy-support programs), the cream plus the skim milk would bring the same price as the whole milk."

Miller was referring, of course, to debt and equity, equating debt to the separated cream, levered equity to the leftover skim milk, and unlevered equity to the whole milk. But one can also apply this analogy to a wind or solar project, to show how it breaks down. Specifically, the cream represents the project's tax benefits that are "skimmed off" by a tax equity investor, the skim milk represents the leftover cash-based return available to the sponsor equity, and the whole milk represents the project as a whole. If there were no "costs of separation" (which there are, of course: though not considered in this report, significant transaction costs are incurred in setting up these tax-advantaged project finance structures), then the sum of the project's tax benefits and cash returns would equal the return of the project as a whole.

For most wind and solar projects, however, this is simply not the case, because the project sponsor lacks sufficient tax appetite to efficiently use the project's tax benefits. A project that is wholly owned by such a sponsor will therefore be *less* valuable as a whole than if the tax benefits are instead stripped out and sold to someone who can actually use them as they are generated. Said another way – and demonstrated in Chapters 4 and 5 of this report – in today's market, a sponsor with little or no tax appetite that has to carry forward tax benefits will most often require a *higher* levelized PPA price than if that same sponsor were to partner with a tax equity investor who can use the tax benefits efficiently.

In other words, when it comes to wind and solar projects, often the whole milk ***is not*** worth as much as the cream and skim milk separated. If it were, this would imply that tax equity provides no net benefit, which is simply not the case – at least in today's market. This in no way discredits the Modigliani-Miller theorem or its contribution, but instead simply highlights that the renewable energy project finance market is far from "perfect," in large part due to the tax-based nature of Federal incentives intended to stimulate deployment.

Project-Level Term Debt: Only the Sponsor Equity/Debt model includes project-level term debt. As mentioned above, some Partnership Flip or Sale-Leaseback structures have included project-level term debt, but typically the steep premium (currently 500-800 basis points) tacked onto tax equity hurdle rates in these cases offset the benefits of adding low-cost debt to a project. As a result, project-level debt is not included here in structures involving tax equity (Chadbourne & Parke LLP 2014).

As with tax equity yields, debt interest rates vary slightly by technology, with solar at 5.5% and wind at 6%. This 50 basis point differential is based on Chadbourne & Parke LLP (2010b), while the general level of interest rates to which the differential is applied is based on Figure 1. Debt service coverage ratios (under P50 generation projections[24]) also favor solar, at 1.35 compared to 1.45 for wind (Chadbourne & Parke LLP 2014, 2013c, 2010b).

The term of the loan is set at 15 years, which is consistent with Figure 1 but nevertheless requires an explanation given the bank market's recent reversion to 7- to 10-year "mini-perms" (Wiser and Bolinger 2013, Chadbourne & Parke LLP 2014).[25] In this light, the assumed 15-year tenor can be thought of as a 7- to 10-year mini-perm that is later refinanced at the same 5.5% or 6% rate out to the full assumed 15-year term. Alternatively, it can be thought of as fully-amortizing debt from an institutional lender (e.g., an insurance company) willing to span the full 15 years; such institutional lenders have been stepping in to fill the void left by banks exiting the long end of the market (Chadbourne & Parke LLP 2014). The amortization schedule is customized (optimized) to achieve the exact debt service coverage ratio in each period.

Back Leverage: The sponsor only takes on back leverage in the Partnership Flip model. The assumed interest rate (10%) is higher than for project-level debt, because the back-levered loan is secured merely by the sponsor's stake in the project rather than by the project itself, and is largely consistent with First Wind's high-yield note offering mentioned in footnote 20. Neither the interest rate nor the debt service coverage ratio (1.45) varies by technology, for much the same reason – the credit assessment is based more on the sponsor than on the underlying technology. The term of the loan is short – nominally a year less than the sponsor's initial 5-6 year capital recovery period (see the description of the Partnership Flip structure, above), but in practice even shorter than that due to a full "cash sweep" (i.e., any extra available cash in each period is used to pay off principal in order to retire the debt more rapidly).

[24] A P50 generation projection is a median projection – there is an equal (i.e., 50%) probability that actual generation will be either above or below the projection.

[25] A "mini-perm" is a relatively short-term (e.g., 7–10 years) loan with an amortization based on a much longer tenor (e.g., 15–17 years), thereby requiring a balloon payment of the outstanding principal upon maturity. In practice, this balloon payment is often funded by refinancing the loan at that time. Thus, a 7-year mini-perm might provide the same amount of leverage as a 15-year fully amortizing loan, but with refinancing risk at the end of 7 years. In contrast, a 15-year fully amortizing loan would be repaid entirely through periodic principal and interest payments over the full tenor of the loan (i.e., no balloon payment required and no refinancing risk).

4. Wind Scenarios

The benefits of tax equity must currently outweigh its high cost of capital, otherwise presumably no projects would bother with it. Looking ahead, however, it is possible to envision a number of plausible future scenarios in which either the benefits of tax equity will decrease (as in three of the scenarios described below), or alternatively the cost of tax equity will increase (as in the fourth scenario). This chapter analyzes the impact of these scenarios on wind projects exclusively; Chapter 5 will take a similar look at the impact of some of these same scenarios, as well as others, on solar projects. Readers interested only in solar projects may choose to skip ahead, but should be aware that certain fundamental concepts are explained as they first arise in this chapter, and as such will not be repeated in the next chapter (where they may also be encountered).

Throughout this chapter, tax equity structures are represented solely by the Partnership Flip structure, which, as mentioned in Chapter 3, has been the dominant tax equity structure used to finance utility-scale wind projects in the United States.

4.1 Permanent PTC Expiration

As noted earlier in Section 2.2, nine scheduled PTC expiration dates have come and gone since the PTC was first enacted back in 1992. The credit was pre-emptively extended prior to four of these, retroactively re-instated following another four, and is currently in limbo following the latest expiration at the end of 2013. The PTC is currently available to projects that started construction in 2013 and are placed in service in 2014, 2015, or perhaps even as far off as 2016. But, with the end-of-2013 construction start deadline having now lapsed, there is uncertainty over whether the PTC will be re-instated (and if so, in what form) going forward. With budget sequestration, government shutdowns, debt ceiling battles, and comprehensive tax reform all frequent topics in the news these days, there appears to be some risk – seemingly greater than in the past – that the PTC may not be re-instated this time around.[26]

If the PTC expires permanently, this would obviously reduce the monetization benefit that third-party tax equity provides. Using the models and assumptions described in the previous chapter, Figure 5 explores how losing the PTC – either gradually or all at once – might impact wind project financing, and in turn levelized wind PPA prices. Specifically, Figure 5 shows levelized PPA prices (in real 2013 $/MWh) generated by three different financing structures in which the project either lacks or has (from either the sponsor or third-party tax equity) tax appetite, and across the full range of PTC levels (from 100% PTC, or the current status quo, down to 0% PTC, which represents a complete expiration) in 10% increments along the x-axis.

[26] That said, in early April 2014, the Senate Finance Committee included a 2-year retroactive extension of the PTC in a "tax extenders" bill that may be taken up by Congress as a whole in the near future. In his opening statement at a session to mark up the bill, Senator Ron Wyden (D-OR), who chairs the Committee, vowed that "this will be the last tax extenders bill the committee takes up as long as I'm chairman" (Wyden 2014), thereby signaling his intent to tackle comprehensive tax reform before another extenders bill is needed.

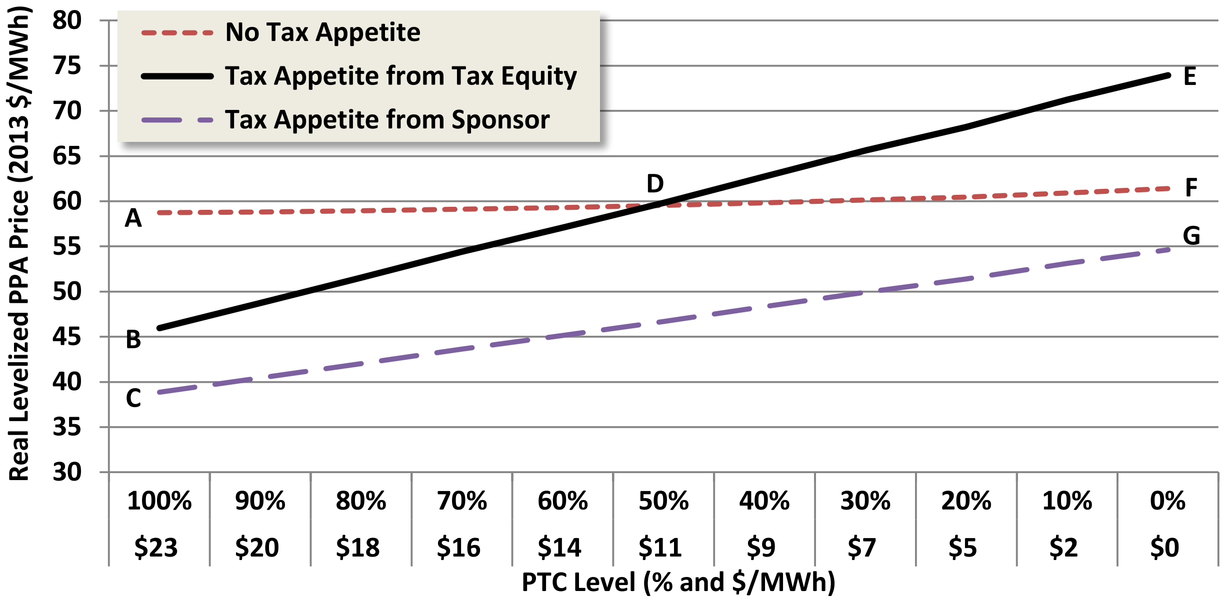

Figure 5. Wind Modeling Results: PTC Expiration

Across all PTC levels, the lowest PPA prices shown in Figure 5 come from a project sponsor with sufficient tax appetite to absorb all tax benefits as they are earned, without having to carry any forward to future years or partner with tax equity investors (see line CG). Other than investor-owned utilities, which owned ~12% of all wind capacity operating in the U.S. at the end of 2013, there are not many project sponsors with this much tax appetite.[27]

Instead, most project sponsors active in the market have limited or no tax appetite. These sponsors will typically find that with the PTC at its current level ($23/MWh), partnering with tax equity will result in a much lower PPA price (point B in Figure 5) than carrying forward losses and credits over time (point A in Figure 5). If the PTC were to permanently expire, however, the reverse would likely be true: sponsors without tax appetite would be able to achieve a lower PPA price by carrying forward excess depreciation deductions (point F in Figure 5) than by partnering with tax equity (point E in Figure 5). In other words, without the PTC, the importance of tax equity will wane, such that a sponsor without tax appetite will be better off foregoing tax equity in favor of lower-cost project-level debt, and carrying forward the project's tax benefits (just depreciation deductions in this case) as necessary.[28]

[27] Examples might include MidAmerican Renewables, Duke Energy Renewables, and NextEra Energy Resources (though, as mentioned earlier, NextEra has been in a net operating loss position in recent years) – all three are unregulated subsidiaries of larger utility holding companies. A few other wind project sponsors in the U.S. are at least somewhat diversified in the U.S. outside of renewables – e.g., Invenergy owns gas-fired generation, while Iberdrola owns electric and gas utilities in New York and Maine – and therefore presumably have at least some limited external U.S. tax appetite (though notably, both Invenergy and Iberdrola regularly partner with third-party tax equity investors on wind projects). In addition, pure-play wind project sponsors who have been in the industry for a while may soon start to build up some limited tax appetite, as wind projects built in 2003 and earlier have now come off of their 10-year PTC (and perhaps also flip) period, while wind and solar projects built in 2009 that elected the Section 1603 cash grant will soon be coming off of their 5-year MACRS depreciation period.

[28] Even though they both reflect a scenario in which there is no PTC, points F and G are not identical because the sponsor without tax appetite (point F) must still carry forward unused depreciation deductions, while the sponsor with tax appetite (point G) can efficiently use all depreciation deductions in the years in which they accrue.

Figure 5 illustrates at what PTC level (between the current $23/MWh and no PTC at all in the event of a permanent expiration) third-party tax equity switches from being more to less advantageous to a sponsor without tax appetite. For a sponsor that needs to carry forward all tax benefits, this crossover point occurs once the PTC falls below roughly 50% of its current level (point D in Figure 5). Once this crossover point is reached, further reductions in the size of the PTC impact the levelized PPA price achievable by such sponsors only marginally, because sponsors that must carry forward the PTC benefit little from it to begin with (due to the time value of money), which, in turn, mitigates the impact of losing it.

This eventual shift from using tax equity to foregoing tax equity in favor of debt as the PTC percentage declines means that when calculating the value that the PTC provides to a sponsor with limited or no tax appetite, one should not necessarily assume a static financing structure or a single value. In other words, in Figure 5, the value of the PTC to a sponsor without tax appetite should be calculated ***not*** as the difference between points E and B (which comes to $28.0/MWh),[29] but rather as the difference between points F and B (or $15.5/MWh). Further, $15.5/MWh (F-B) might be considered the ***maximum*** value that the PTC provides to a sponsor with limited tax appetite, because if the sponsor has any tax appetite at all (which, as noted earlier in footnote 27, an increasing number likely do), then the benefit of third-party monetization will be smaller. On the other hand, sponsors *with* tax appetite receive roughly $15.7/MWh (the difference between points G and C in Figure 5) of value from the PTC. As such, one must be careful in ascribing a single "value" to the PTC, as it depends on both the tax appetite of the sponsor and the financing structure used.

Figure 5 can also be used to estimate how much of a project's tax benefits are forfeited to tax equity investors (in the case of a sponsor without tax appetite that partners with tax equity), rather than going towards their intended purpose of encouraging wind power development by boosting the sponsor's return and/or lowering the PPA price. For example, the maximum benefit that third-party tax equity might possibly provide to a wind project is simply the difference between the two structures that do not use tax equity – i.e., this difference represents what having tax appetite is worth to a project. With a full PTC, this difference (i.e., point A minus point C) comes to $19.8/MWh. Meanwhile, the cost that tax equity imposes on a project is simply the difference between the two structures that realize tax benefits immediately (either through sponsor tax appetite or by partnering with third-party tax equity) – i.e., this difference represents how much more it costs to have tax equity monetize the tax benefits than to have the project sponsor (with tax appetite) use them. With a full PTC, this difference (i.e., point B minus point C) comes to $7.1/MWh. In other words, the ability to use credits efficiently as they are generated (rather than carrying them forward) is worth a ***maximum*** of $19.8/MWh to this

[29] This value – $26.9/MWh – expressed in PPA price terms is larger than the PTC's 2013 notional value of $23/MWh because, as a tax credit, the PTC provides *after-tax* value, while PPA prices represent *pre-tax* revenue. The PTC's $23/MWh after-tax notional value can be converted to pre-tax revenue-equivalent terms by dividing by 60% (i.e., 100%-40% combined state and Federal corporate tax rate), which yields $38.3/MWh. In other words, it takes $38.3/MWh of taxable PPA revenue to generate $23/MWh of after-tax value in 2013, assuming a 40% combined state and Federal corporate tax rate. Further transformations are necessary to express the PTC's value in *levelized* PPA price terms, since the PTC is a 10-year credit, while PPAs commonly extend to twenty years or longer. This levelization process, however, ignores the impact of financing – and in particular of switching to a lower cost of capital – in a PTC expiration scenario.

project, but it costs $7.1/MWh for third-party tax equity to provide that ability. As such, roughly 36% ($7.1/$19.8) or more (e.g., if the sponsor has any tax appetite at all) of the project's tax benefits are forfeited to tax equity investors. This degree of forfeiture *increases* at lower PTC percentages, as the relative benefit of tax equity declines (i.e., as lines AF and CG converge) at the same time as the relative cost of tax equity increases (i.e., as lines BE and CG diverge), until reaching 100% forfeiture at the crossover point D, at which point tax equity no longer makes sense.

For comparison purposes, the text box on the next page compiles other estimates of tax benefit forfeiture – many of which are of similar magnitude to what is estimated here. It should be emphasized, however, that this forfeiture is only applicable to project sponsors that use third-party tax equity. Those projects that do not use third-party tax equity forfeit no tax benefits at all (except perhaps to the erosion of time, if unable to fully use them in the years they are generated).

Of course, Figure 5 (as well as the foregoing discussion surrounding it) was constructed on an "all else equal" basis, assuming that no other changes are sparked by changes to the PTC's status. Instead, it could be that, in order to remain competitive with sponsors that finance with project-level debt and carry forward tax benefits as necessary, tax equity will be willing to reduce its required rate of return if the PTC permanently expires (or is reduced to some lower level that uses up less "tax capacity"). In this case, the line BE in Figure 5 would bend at some point – perhaps at point D, such that it ends up looking a lot like the angle BDF. If this were to happen, however, it would only impact conclusions about *how* wind projects would be financed (e.g., with or without third-party tax equity); it would *not* impact the resulting levelized PPA prices, which are of most importance to this analysis. In other words, if tax equity investors are willing to reduce their hurdle rates to compete with the "No Tax Appetite" structure under a PTC expiration scenario, so much the better, as sponsors will then have more financing options from which to choose, without negatively impacting PPA prices. This hypothetical situation demonstrates why the approach used herein is so useful: the "No Tax Appetite" structure provides a backstop against which tax equity must ultimately compete in order to remain relevant within the renewable energy marketplace.

Other Estimates of the Inefficiency of Tax Incentives

Although tax incentives have been a key driver of renewable energy deployment in the U.S. for two decades, the inefficiency of relying on tax losses and credits (rather than cash-based incentives) to stimulate the deployment of renewable energy has been a topic of discussion and analysis, particularly in the wind industry, going back to at least the fall of 2008 (a time of financial turmoil when the shortcomings of tax incentives became painfully clear):

- **October 2008:** The American Wind Energy Association's ("AWEA") annual finance forum featured a discussion among several prominent wind developers and financiers, two of whom offered widely differing views on how much of a wind project's tax benefits are "lost" to third-party tax equity investors. One financier estimated (based on the difference in the present value of after-tax cash flows between a sponsor who can use the tax benefits itself and one that needs to partner with a tax equity investor) that roughly 15% of a project's tax benefits are lost. Using a different method (similar to that used in this report), a large wind developer countered that the number is more like 50% (Chadbourne & Parke LLP 2008).
- **January 2010:** At the request of the Bipartisan Policy Center, Bloomberg New Energy Finance ("BNEF") looked at this issue specifically, and also found that tax credits are only about 50% efficient – i.e., a cash grant only half as large as the present value of tax benefits would achieve the same results (Bloomberg New Energy Finance 2010).
- **March 2011:** The Bipartisan Policy Center itself issued a follow-up report (Bipartisan Policy Center 2011), noting once again BNEF's finding that "a subsidy financed through tax equity markets is twice as expensive as a cash grant subsidy," but also adding that "some in the renewable energy industry have argued that BNEF's estimate of the cash grant amount needed to achieve an equivalent result is too low."
- **May/June 2011:** In support of this "too low" argument, a representative of private equity firm Hudson Clean Energy Partners opined at AWEA's WINDPOWER 2011 conference in May that the Federal subsidy provided to wind projects could be cut by 30% if awarded as cash rather than as tax benefits (Slamm 2011). A wind developer/sponsor on the same panel thought the reduction in the subsidy could be even greater – maybe 40-50% – if it were awarded as cash (Garland 2011). Less than a month later, a different Hudson representative estimated in Congressional testimony a slightly larger potential reduction of 35%-40% (Auerbach 2011).
- **September 2012:** The Climate Policy Initiative also found that "tax incentives leak money," and that wind project sponsors only realize about two-thirds (i.e., lose one-third) of the value of the incentive, while solar project sponsors lose roughly half of the value (Varadarajan et al. 2012).

Whether the "correct" number is 15% or 50% (or something in between) depends on a variety of factors that are not always clear in the various conjectures and analyses cited above, including:

- whether the "subsidy" being examined refers only to tax credits (e.g., the PTC or ITC) or also accelerated tax depreciation;
- if depreciation is included, whether the counterfactual includes no depreciation at all (which seems extreme), or instead merely a less-advantageous depreciation schedule, like 12-year straight-line;
- whether the estimates are derived from simple net present value analysis or instead a more-thorough pro forma model; and
- the extent to which project-level term debt figures into the analysis.

Furthermore, there is likely not even a single correct answer, as the impact presumably varies from project to project, as well as over time depending on market conditions. For example, when PPA prices are high (as they were back in 2008/2009), cash revenue from the PPA accounts for a greater proportion of a project's overall return (since tax benefits are largely fixed), thereby enabling a sponsor foregoing tax equity to take on more project-level debt than is possible when PPA prices are lower. Greater leverage reduces the project's WACC, which increases the relative cost of tax equity and therefore the amount of the incentive that is lost to tax equity. For example, the analysis surrounding Figure 5 in the main text finds that 36% of tax benefits are lost to tax equity under the assumptions described in the report, but if the CapEx assumption is increased from $1.8/W to $2.2/W (i.e., more akin to 2008 conditions), then the percentage of the subsidy that is forfeited under a Partnership Flip structure increases to 54%. This is both significantly different from the 36% found under current market conditions, and also very close to the 50% loss estimated by others back in the 2008/2009 timeframe, suggesting that underlying market conditions can have a significant impact on the result.

Regardless of the exact number, there is seemingly widespread consensus that, compared to more-fungible cash-based incentives, tax incentives are an inefficient way to spur deployment of renewable energy. The Federal government could either stimulate the same amount of deployment at reduced taxpayer cost, or alternatively stimulate greater deployment for the same taxpayer cost, if the incentives were provided in a more user-friendly form, such as cash or even refundable credits.

4.2 PTC Made Refundable

President Obama's FY15 budget proposal (Office of Management and Budget 2014) raises another plausible scenario that is almost diametrically opposed to a PTC expiration, but that would nevertheless also reduce the benefit provided by third-party tax equity. Specifically, the administration's budget request proposes to make the PTC both permanent and refundable (and available to solar – see Section 5.3, later). While permanence has little bearing on the analysis in this report,[30] a refundable credit does. When a tax credit is refundable, the eligible taxpayer uses as much of the available credit as possible (given tax liability) in tax credit form, and then is refunded the balance in cash.[31] As a result, there is never an unused balance of credits to carry forward to future years – the credit is always realized as it is generated, either in the form of a tax credit or as a cash refund (or as a combination of both). This flexibility presents significant value to a sponsor that would otherwise be forced to wait a dozen years or more – i.e., until all net operating losses (from accelerated depreciation deductions) have been absorbed – to begin realizing the PTC's value.

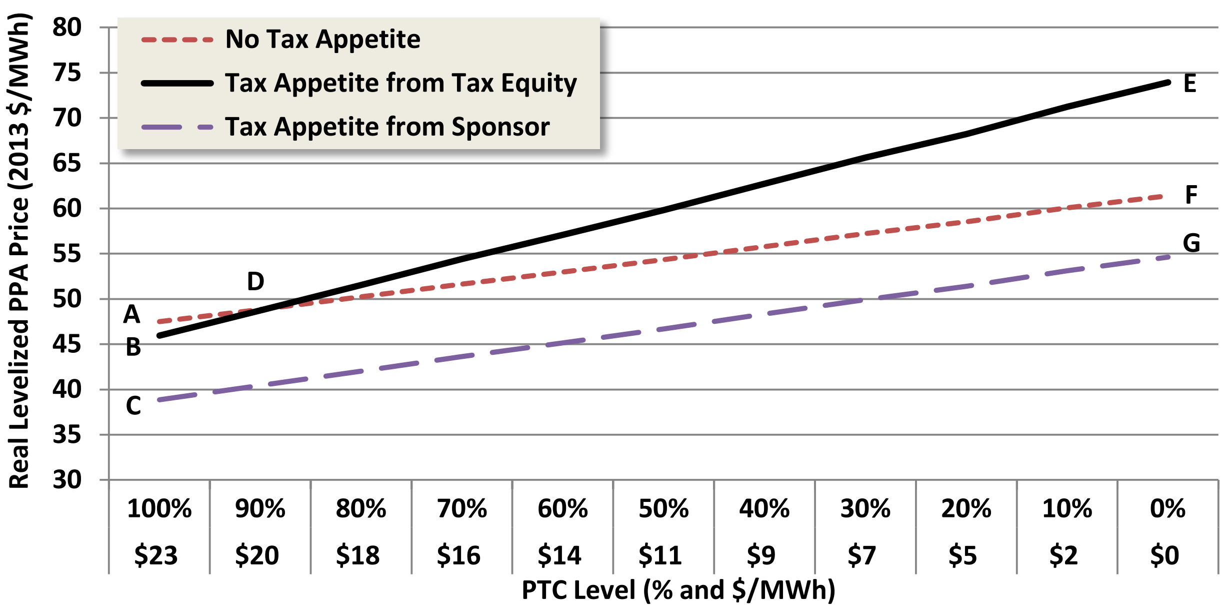

Figure 6. Wind Modeling Results: Refundable PTC

Figure 6 above is similar in structure to Figure 5 in the previous section, but presents results under a refundable PTC. The first (and perhaps most obvious) finding is that a refundable PTC has no impact on the two tax-efficient structures, both of which realize PTCs as they are generated regardless of whether or not those PTCs are refundable. In other words, these two structures (represented by lines CG and BE) are unchanged from Figure 5, and so provide a

[30] Some have speculated that a permanent PTC might induce more tax equity investors to enter the market, given that permanence would presumably help to justify the steep learning curve associated with structuring tax equity deals in a new market. Any such new entrants might help to drive down the cost of tax equity, an important variable that is examined further in Section 4.4.

[31] As such, a refundable PTC (or ITC) presumably uses up just as much of a tax equity investor's "tax capacity" as a nonrefundable PTC or ITC. This stands in contrast to the Section 1603 cash grant, which does not use up tax capacity because it is awarded as cash.

useful benchmark against which to measure the movement of the tax-inefficient structure (line AF).

In contrast, the "No Tax Appetite" structure (line AF) benefits significantly from a refundable PTC, due to its newfound ability to realize PTCs as they are generated rather than having to carry them far into the future. Specifically, the slope of line AF steepens under a refundable PTC, as point F (representing no PTC) remains unchanged, while point A (representing a full PTC) declines by $11/MWh from where it was in Figure 5, thereby making this structure nearly competitive with the tax equity structure (at point B).[32] In addition, with the steeper slope of line AF, the crossover point D occurs much earlier in Figure 6: at roughly 90% PTC, compared to 50% in Figure 5. This earlier crossover point means that making the PTC refundable would partially mitigate the negative impact of reducing the size of the PTC to anything less than 90% of its current level.

The analysis in this section reveals that the two tax-efficient structures are indifferent as to whether or not the PTC is refundable, while the tax-inefficient structure benefits significantly from a refundable PTC. Taxpayers, meanwhile, should presumably also be indifferent as to whether or not the PTC is refundable, as it will cost them the same amount per MWh either way (i.e., assuming no change in the amount of deployment).[33] In short, making the PTC refundable is a policy change that would seemingly hurt no one, while providing significant benefit to project sponsors with limited tax appetite, thereby reducing wind power costs to consumers.

4.3 Comprehensive Tax Reform

Another plausible scenario that could impact wind project financing, and in turn wind's competitiveness, in the future is comprehensive tax reform in the United States. Although many uncertainties remain as to what tax reform might look like (or whether it will even happen), in November and December 2013, the Senate Committee on Finance released two tax reform proposals highly relevant to the energy sector (Joint Committee on Taxation 2013a, 2013b).[34]

[32] Although point A is slightly (i.e., $1.6/MWh) higher than point B in Figure 6, implying that tax equity (and the tax benefit monetization that it brings) is still slightly more competitive than debt (with the sponsor carrying forward unused tax benefits) under a refundable PTC, two factors could negate such a conclusion. First, the modeling does not account for transaction costs; the high cost of structuring a tax equity transaction could potentially overwhelm the small difference between points A and B. Second, point A reflects a sponsor with no tax appetite at all; if instead the sponsor has at least some tax appetite, then the gap between points A and B would shrink, perhaps disappear altogether, or even leave point A *less than* point B (as is point C, which reflects a sponsor with full tax appetite).

[33] In other words, assuming that the level of deployment is the same whether or not the credit is refundable, the foregone tax receipts from a nonrefundable credit will equal the foregone tax receipts plus cash outlays from a refundable credit. As such, from a purely revenue-based perspective, taxpayers (and the U.S. Treasury) should be indifferent between refundable and nonrefundable credits.

[34] More recently, on February 26, 2014, the House Ways and Means Committee released its own comprehensive tax reform proposal. Among other things, this proposal would eliminate accelerated depreciation and replace it with schedules that are more in line with assets' economic lives; would allow the 30% ITC to expire (rather than revert to 10%) at the end of 2016; would eliminate the PTC's annual inflation adjustment for all electricity sold after 2014; and would not extend the now-expired PTC eligibility window. Although this House proposal differs markedly from what the Senate Finance Committee had proposed a few months earlier, it is nevertheless not modeled in this report, for several reasons: (1) the replacement to accelerated depreciation is not clearly specified, and is subject to

First, on November 21, 2013, the Committee released a proposal to reform cost recovery and tax accounting rules that would, among other changes, eliminate accelerated depreciation (for all assets – not just renewable power technologies) and replace it with a simplified system in which assets would be placed into one of five pools, each of which would be depreciated differently. Wind and solar power would fall into the fourth pool, and be depreciated at a rate of 5%/year, using a 100% declining balance method.[35] This is a much slower depreciation schedule than the 5-year MACRS schedule currently available to such projects, and, as such, has important financing implications, as will be discussed below.

Second, on December 18, 2013, the Committee released a proposal to streamline energy tax incentives by consolidating most of them into a single technology-neutral clean energy credit based on the greenhouse gas intensity of the technology. Under the proposal, the current PTC and 30% ITC would be extended (or remain in place) through 2016 and then replaced by the new clean energy credit – available as either a 10-year production tax credit or a 20% investment tax credit, depending on recipient preference – starting in 2017. Zero-emission technologies like wind and solar would be eligible for the full value of the new PTC (set to equal the current PTC, adjusted for inflation) or 20% ITC, while technologies that emit greenhouse gases would receive a reduced credit or no credit at all, depending on their relative greenhouse gas intensity. The proposed clean energy credit would remain in place until the greenhouse gas intensity of the overall U.S. power sector declines by 25% relative to 2013 levels. Thereafter, the credit would be phased out at a rate of 25%/year over a four-year period (i.e., the fourth year of the phaseout would see the credit expire).

Although neither proposal directly addresses changes to the corporate tax rate, the staff discussion draft for each proposal nevertheless notes that the various proposals are intended to be considered as a package (rather than as standalone proposals) that should enable a significant reduction in the corporate tax rate. No specific numbers are mentioned, but previous discussions surrounding tax reform have indicated a bipartisan desire to reduce the maximum corporate income tax rate, from 35% to either 28% (Democrat proposal) or 25% (Republican proposal).

Figure 7 presents the impact of tax reform as proposed to date by the Senate Committee on Finance. The first set of data points on the left show the business-as-usual results for a full PTC,[36] and thus match points A, B, and C in Figure 5. The next set of data points to the right show the impact of switching from 5-year MACRS depreciation to the slower 5%/year, 100% declining balance depreciation schedule. This switch hurts the two tax-efficient structures by

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further review; (2) the proposed PTC change is essentially the same as an outright expiration from a modeling perspective, in the sense that the loss of the inflation adjustment applies only to those projects that have already qualified for the PTC (by starting construction prior to the end-of-2013 deadline), and therefore have presumably also already arranged financing; (3) the expiration of the 30% ITC is simply a more-severe version of the 10% ITC reversion scenario that is modeled in chapter 5, and would not alter the basic findings of that scenario.

[35] The 100% declining balance method means that 5% of the project's cost basis would be depreciated in the first year, 4.75% (5%*95%) in the second year, 4.5125% (5%*90.25%) in the third year, etc. In other words, the 100% declining balance method ensures that the asset will never be fully depreciated: ~40% of the asset would be depreciated over the first 10 years, ~64% over the first 20 years, ~79% over the first 30 years, etc.

[36] Only the PTC, and not the 20% ITC, is modeled in Figure 7, as a 20% ITC is not attractive to wind projects under the assumptions modeled in this report and described in Chapter 3.

$10-$17/MWh, but barely impacts the tax-inefficient structure, which was already carrying forward all depreciation benefits and so is not impacted by switching to a slower schedule. The third set of data points layers on a reduction in the corporate income tax rate from 35% to 25%, which reduces PPA prices by a small amount for all three structures.[37] This step completes the full implementation of tax reform as proposed to date, and leaves sponsors without tax appetite essentially indifferent between carrying forward tax benefits or partnering with tax equity investors to monetize them.

Finally, the last four sets of data points on the right show the impact of eventually phasing out the PTC once the greenhouse gas intensity of the overall power sector has dropped by 25% compared to 2013 levels.[38] As shown, this phaseout renders the tax equity structure progressively uncompetitive with the other two structures. Meanwhile, the tax-inefficient structure is barely impacted by the phaseout (because a carried-forward PTC is not worth much to begin with), such that towards the end of the phaseout, there is little or no distinction between a sponsor with or without tax appetite.

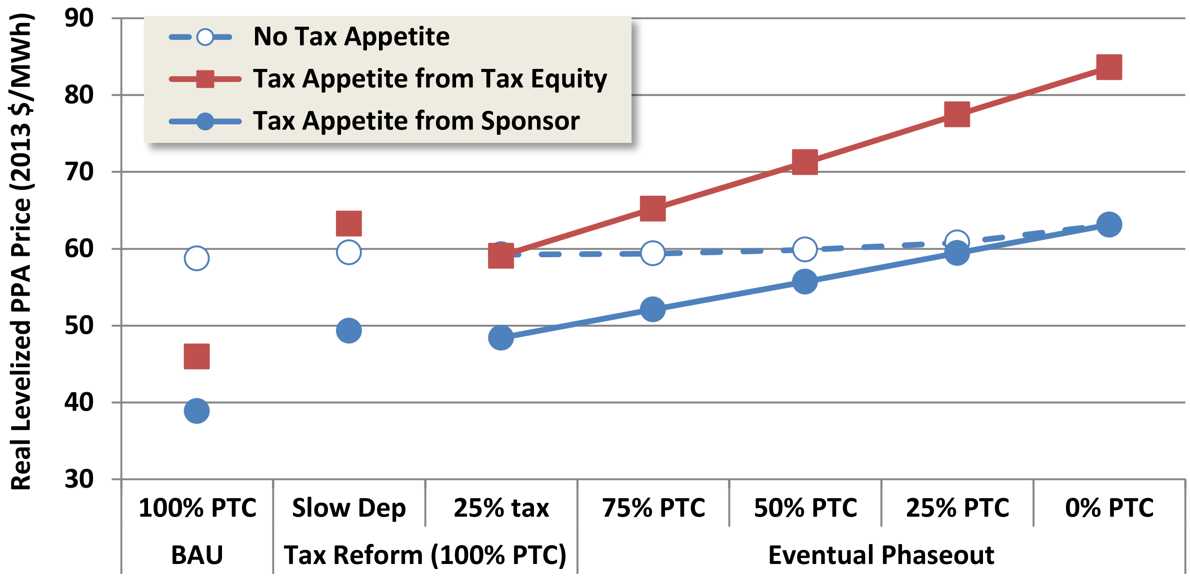

Figure 7. Wind Modeling Results: Tax Reform

4.4 Changes in the Cost of Tax Equity (and Debt)

The yields required by third-party tax equity investors are not tied to, and do not move in concert with, interest rates, although by now it is hopefully obvious to the reader that interest rates do serve as a backstop for how high tax equity yields can go before tax equity investors price

[37] A 25% tax rate is assumed (rather than 28%) in order to more clearly illustrate the potential impact of lowering the rate from 35% (and because the House Ways and Means proposal also specifies a 25% tax rate). Interestingly, if the switch to a much slower depreciation schedule had not already occurred in the modeling process, a lower corporate tax rate would have actually *increased* PPA prices, by reducing the value of accelerated depreciation deductions. Under the much slower 5%/year, 100% declining balance schedule, however, the reverse is the case – reducing the corporate tax rate also reduces PPA prices.

[38] Given the timing contained in the Senate Finance proposal, with the new technology-neutral clean energy credit beginning in 2017, presumably the absolute earliest that this phaseout could occur would be from 2018-2021.

themselves out of the market. Nor are tax equity yields necessarily fully "a reflection of the risk profile of the asset class" (Chadbourne & Parke LLP 2012c),[39] although risk does play a role, for example in this report's assumption that tax equity target yields are slightly lower for solar than for wind. Instead, tax equity yields are primarily (though again, not fully) a function of supply and demand.

Supply can be impacted by the number of tax equity investors in the market and their respective tax appetites, as well as by yields on competing tax equity investments such as low-income housing tax credits or historic preservation tax credits (if yields in these other markets rise above the yields available in wind and solar projects, tax equity will flow out of the renewable power sector). Demand, in turn, can be impacted by the amount of renewable energy development happening, the types of Federal incentives being offered and how much "tax capacity" they use up (e.g., the 1603 cash grant versus the PTC), as well as the relative tax appetites of project sponsors (which determines how much those sponsors need to rely on third-party tax equity). The resulting supply/demand balance can result in significant swings in tax equity yields.

For example, following the collapse of Lehman brothers in late 2008 and the financial turmoil that ensued, many tax equity investors that had previously been active in renewable energy exited the market. Those few that remained were considerably less certain about their likely tax appetite several years into the future. Meanwhile, demand for tax equity did not immediately ease up proportionally – it was not until the Section 1603 grant program was implemented in late 2009 that demand became more elastic. As a result, tax equity yields rose dramatically throughout 2008 and 2009, from as low as 6% (after-tax, unleveraged) prior to the financial crisis to more than 10% in late 2009 (see Figure 1, earlier). At that time, at least one prominent wind developer with only limited tax appetite noted that tax equity yields had risen to a point where foregoing tax equity and carrying tax benefits forward was starting to look attractive (Chadbourne & Parke LLP 2008). This more than 400 basis point increase in after-tax tax equity yields eased up somewhat following implementation of the Section 1603 grant program and the return of some measure of stability, but the increase has not been wholly erased – even today, tax equity yields remain about 200 basis points higher than they were prior to the financial crisis of 2008 and 2009 (see Figure 1, earlier).

Although the 400+ basis point increase in tax equity yields witnessed back in 2009 was the result of an extreme and hopefully isolated event, looking ahead there are nevertheless a number of reasons to believe that the cost of tax equity could increase going forward:

- The Section 1603 grant program is no longer available to wind projects (which had to be operating by the end of 2012 in order to qualify for the grant), and will gradually taper off for solar projects (which had to be under construction by the end of 2011, but have until the end of 2016 to be placed in service). As no new wind projects and progressively fewer solar projects have access to the grant, demand for third-party tax equity to monetize PTCs and ITCs should increase. Sponsors that had previously found it advantageous to carry forward excess depreciation deductions under the Section 1603 grant will instead likely need to pursue tax equity once again, while other sponsors that had continued to use tax equity in conjunction with the grant (i.e., to monetize just

[39] As such, tax equity yields will not necessarily decline materially, like one might expect debt interest rates to, as the wind and solar sectors mature and becomes less risky (Chadbourne & Parke LLP 2012c).

depreciation benefits) will, for future projects, use up more tax capacity in monetizing not just depreciation benefits, but also either PTCs or ITCs. Indeed, anecdotal evidence from several years ago suggests that tax equity investors were charging premiums of roughly 100 basis points for solar deals that elected the ITC rather than the Section 1603 grant (Chadbourne & Parke LLP 2011).

- Some tax equity investors have never been comfortable with PTC risk, and only entered the wind market through Section 1603 grant deals. With the Section 1603 grant's legacy now fading, some of these tax equity investors may drop out of the market, reducing the supply of tax equity.
- The Section 1705 DOE loan guarantee program has also sunset, thereby reducing the availability of ultra-low-cost debt financing. Though only four wind projects (and twelve solar projects) were awarded guarantees under this program, the closure of this source of cheap debt nevertheless might impact tax equity yields, as higher-cost commercial debt reduces the differential to the cost of tax equity, thereby potentially stimulating additional demand for tax equity rather than debt.
- As wind turbines have become more efficient in recent years, higher wind capacity factors are generating more PTCs, which use up more tax capacity. As a result, tax equity dollars allocated to wind projects do not stretch quite as far as they used to.[40]
- As the rapidly growing utility-scale solar market continues to surge through 2016, and as third-party ownership (financed through third-party tax equity) captures more of the residential solar market, there will be increasing competition from solar for tax equity dollars – particularly as the number of grandfathered Section 1603 grant projects tapers off.
- Wind and solar PPA prices have fallen dramatically in recent years (Wiser and Bolinger 2013, Bolinger and Weaver 2013), which has the effect of increasing the relative proportion of a project's after-tax return that is generated by a project's tax benefits, rather than by cash revenue from PPA sales. As a result, projects foregoing tax equity are not able to support as much debt as they can when PPA prices are higher, which inflates their PPA prices relative to the Partnership Flip structure. This effect not only potentially increases demand for third-party tax equity, but also increases the IRR ceiling beyond which tax equity would no longer be competitive, providing more "head room" for tax equity yields to potentially increase.
- Finally, tax equity already currently provides net benefits to most project sponsors.[41] Unless the cost of competing debt makes a concerted move lower, which seems unlikely given market conditions (Chadbourne & Parke LLP 2013c) as well as the history presented earlier in Figure 1, there is little reason for tax equity yields to decline (compared to quite a few reasons listed above for them to increase).

In spite of the numerous influences listed above that could pressure tax equity yields higher in the coming years, it nevertheless remains possible that the cost of tax equity could instead

[40] For example, holding all inputs to the base-case wind project constant except for net capacity factor, tax equity provides 56% of the capital in a Partnership Flip structure at a 35% capacity factor, compared to more than 60% at a 40% capacity factor and nearly 69% at a 50% capacity factor.
[41] For example, earlier in Figure 5, note the significant difference between points A and B.

decrease, for example returning to the 6% levels seen back in 2007 (Figure 1). As such, Figure 8 shows the impact of both a 200 basis point *decrease* and a 300 basis point *increase* in tax equity yields on levelized PPA prices from a tax equity structure under three different scenarios: business-as-usual, a refundable PTC, and tax reform. Somewhat surprisingly, the impact is not all that large – a 300 basis point increase in the cost of tax equity adds just $5-$6/MWh to levelized PPA prices (see the positive error bars), while a 200 basis point decrease in the cost of tax equity subtracts just $4-$5/MWh (see the negative error bars).[42] In acknowledgment of the fact that interest rates are low at present, Figure 8 also shows the impact on the "no tax equity" structures of increasing debt interest rates by 200 basis points (the lower edge of the shaded rectangles represents the base case interest rate of 6%, while the upper edge represents an 8% interest rate). The impact here is also rather muted: just $2-$3/MWh in the case of a sponsor with tax appetite, and $3-$4/MWh in the case of a sponsor without tax appetite.

These shifts in the relative cost of capital are not enough to alter the financing outcome in a business-as-usual scenario (i.e., even if tax equity yields were to increase by 300 basis points, sponsors without tax appetite would still be better offer monetizing tax benefits through a tax equity structure rather than carrying them forward). They are, however, potentially enough of a shift to render the tax equity structure uncompetitive with (or at least no more competitive than) the "no tax appetite" structure under either a refundable PTC or tax reform scenario.

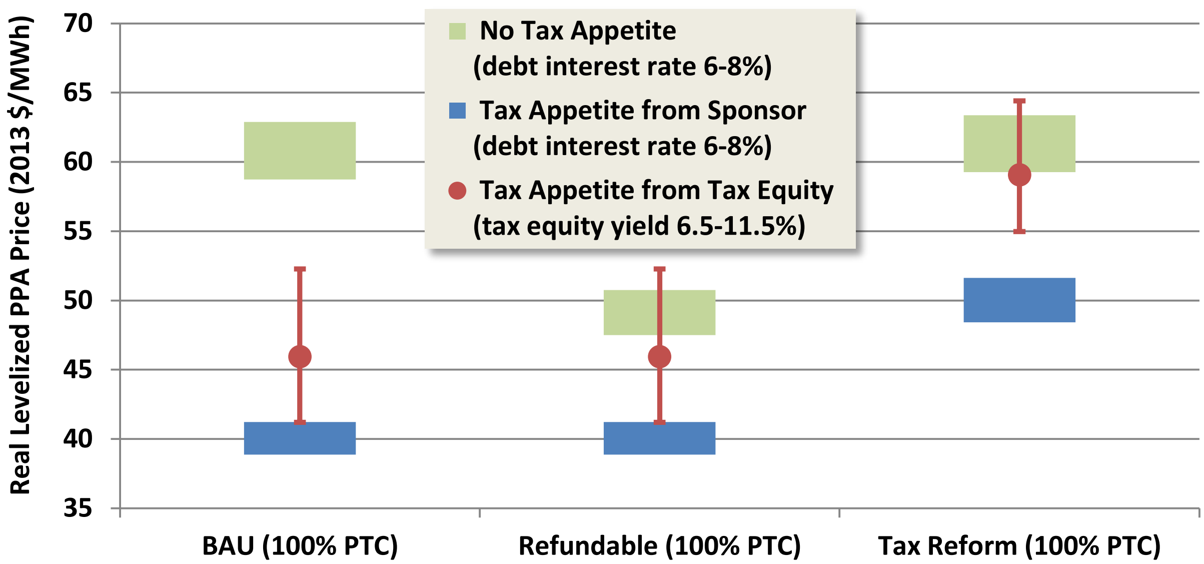

Figure 8. Wind Modeling Results: Changes in the Cost of Tax Equity and Debt

[42] The impact is not larger because tax equity accounts for only 60% or less of the capital stack in all three scenarios.

5. Solar Scenarios

The previous chapter found that continued reliance on third-party tax equity is by no means a foregone conclusion in the wind sector under a variety of plausible future scenarios. This means that wind projects could, in the future, be financed at lower costs of capital that, in turn, enable lower PPA prices than would otherwise be possible. This chapter takes a similar look at a number of scenarios that are more relevant to the solar sector and its primary incentive, the ITC (readers interested only in wind may skip ahead to the conclusions in Chapter 6). These include the scheduled reversion of the 30% ITC to 10% at the end of 2016, making the ITC refundable (or awarding it as a cash grant, as was done under the Section 1603 grant program), giving solar access to the PTC (either refundable – as in President Obama's FY15 budget request – or nonrefundable), comprehensive tax reform, and changes in the cost of both tax equity and debt.

Throughout this chapter, tax equity structures are represented by either a Partnership Flip structure (as in Chapter 4) or a Sale-Leaseback structure – whichever yields a lower levelized PPA price. As described earlier in Section 3.1, Sale-Leaseback structures are not available to projects that elect the PTC (which rules out most wind projects, and is why Sale-Leaseback was not included in Chapter 4), but have been popular among solar projects taking the ITC. In most modeling runs presented in this chapter, the Sale-Leaseback structure yields a slightly lower PPA price than the Partnership Flip structure,[43] and is therefore presented as the relevant tax equity structure. The exceptions to this general rule include any results presented for the PTC (given that Sale-Leaseback is not compatible with the PTC), as well as the high end of the tax equity yield ranges presented later in Figure 12 – in these cases, the results pertaining to a tax equity structure reflect a Partnership Flip rather than a Sale-Leaseback structure.[44]

Figure 9 shows modeling results for the business-as-usual 30% ITC along with three other scenarios: the ITC reversion to 10%, the conversion to a PTC, and making credits refundable. Given that all three of these scenarios are perhaps unlikely to play out for a few years (e.g., the ITC reversion to 10% is not scheduled to happen until 2017), and that most industry observers expect installed project costs to continue to fall, Figure 9 presents levelized PPA prices at two different installed cost assumptions: $3/$W_{AC}$ (intended to be more reflective of today's average prices) and $2/$W_{AC}$ (perhaps more reflective of average pricing in 2017).[45] Results for each of the three scenarios shown in Figure 9 are discussed below within each section of this chapter.

[43] This is the case even assuming that both structures provide the tax equity investor with the same return at the end of the 25-year PPA. The difference is primarily attributable to the relative WACC of these two structures. Recall from Section 3.1 that the tax equity investor provides 85% of the capital in a Sale-Leaseback structure, compared to 55-65% in a Partnership Flip structure. Because tax equity – though expensive – is still cheaper than sponsor equity, the higher degree of tax equity "leverage" in a Sale-Leaseback structure leads to a lower overall WACC, and in turn a lower required PPA price.

[44] For the same reason noted in the previous footnote (i.e., more tax equity in the capital stack), a Sale-Leaseback structure suffers more than a Partnership Flip structure from an assumed 300 basis point increase in tax equity yields, to the point where the Partnership Flip is more competitive than the Sale-Leaseback at those higher yields.

[45] Anecdotal evidence suggests that some utility-scale PV projects in the southwestern U.S. are already being installed for roughly $2/$W_{AC}$ (Bolinger and Weaver 2013).

Before proceeding, however, a brief discussion of the business-as-usual scenario shown in the first column of Figure 9 – i.e., a nonrefundable 30% ITC at an installed cost of $3/W_{AC}$ –is warranted. As was the case with wind, the sponsor with tax appetite is most competitive (at $72.4/MWh), but is similarly a bit of a rarity among solar project sponsors.[46] Sponsors with little or no tax appetite are typically better off partnering with a tax equity investor (at $97.9/MWh) than carrying forward tax benefits over time (at $112.3/MWh). These three data points suggest that the cost of tax equity in this case is $25.4/MWh ($97.9/MWh-$72.4/MWh), while the maximum benefit of tax equity is $39.8/MWh ($112.3/MWh-$72.4/MWh), in which case roughly 64% of tax benefits (i.e., $25.4/$39.8) are forfeited to tax equity investors in the business-as-usual scenario.[47] This degree of forfeiture is higher than the 36% estimated for wind power in Chapter 4, but is similar to the loss found in the one other study reviewed in the text box on page 28 that looked specifically at solar: Varadarajan et al. (2012) found roughly one-third forfeiture for wind power and roughly 50% forfeiture for solar.

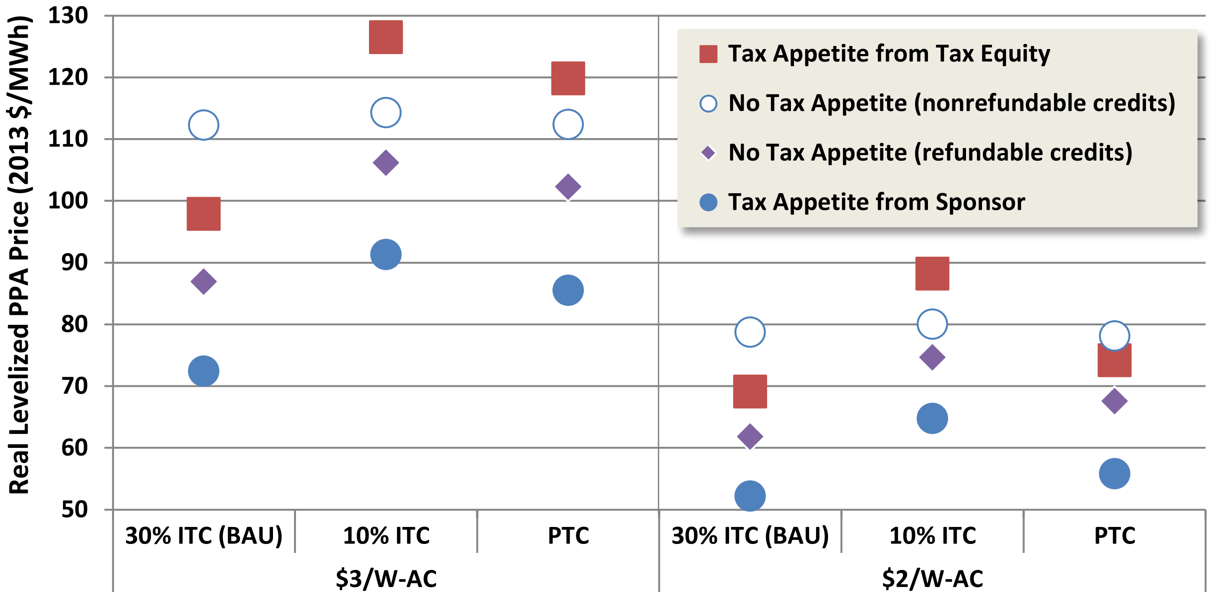

Figure 9. Solar Modeling Results: 30% ITC, 10% ITC, PTC, and Refundable Credits

5.1 Scheduled Reversion of the Nonrefundable ITC from 30% to 10%

As described earlier in Section 2.2, the 30% ITC is currently scheduled to revert back to its "permanent" 10% level at the end of 2016. As shown in Figure 9, this reversion will (all else equal) have a significant negative impact on the two structures with tax appetite (either from the sponsor or from a tax equity investor), whose levelized PPA prices will increase by ~$20/MWh to ~$30/MWh, respectively, at $3/W_{AC}$ (and by less at $2/W_{AC}$). In contrast, the "No Tax

[46] Solar project sponsors with potentially enough tax appetite to fall into this category include MidAmerican Renewables, NRG Energy, Southern Company/Turner Renewables, Duke Energy Renewables, and Sempra Generation, as well as a variety of investor-owned utilities (e.g., Pacific Gas & Electric, Southern California Edison, Arizona Public Service, Public Service Company of New Mexico) that have ventured into solar project ownership.
[47] This degree of forfeiture is the same at a CapEx of $2/W_{AC}$, because both the ITC and depreciation scale directly with installed costs.

Appetite" structure is barely impacted (assuming a nonrefundable credit), because the value of a carried-forward ITC – whether at a 30% or 10% level – is heavily eroded by the time value of money. As a result, tax equity is likely to become much less critical in the wake of the reversion (again, all else equal): even a sponsor with no tax appetite that has to carry forward a nonrefundable credit will be able to compete with tax equity structures under a 10% ITC.

Although levelized PPA prices are clearly higher under a 10% ITC than under a 30% ITC at installed costs of either $\$2/W_{AC}$ or $\$3/W_{AC}$, it is notable that a 10% ITC at $\$2/W_{AC}$ yields a lower PPA price for all structures than does a 30% ITC at $\$3/W_{AC}$. This suggests that, if installed costs continue to decline through 2017, then the ITC's scheduled reversion to 10% could leave solar PPA prices potentially no higher, and perhaps even lower, than they are at present. That said, it is important to acknowledge that the change in the size of the credit will literally happen overnight, while cost declines occur much more gradually over time. As such, even though PPA prices might, as suggested in Figure 9, be lower on January 1, 2017 under a 10% ITC than they are *today* under a 30% ITC, they will nevertheless most certainly be *higher* than they were on December 31, 2016 under a 30% ITC (this is also shown in Figure 9, by comparing the 30% and 10% ITC scenarios at $\$2/W_{AC}$). In other words, the abruptness of the scheduled policy shift is a potential cause for concern, and is a primary reason why the solar industry has advocated changing the nature of the end-of-2016 deadline from a placed-in-service requirement to a start-construction requirement. A similar change to the end-of-2013 PTC deadline has provided the wind industry with a multi-year planning window, of which the solar industry is also hoping to avail itself.

5.2 ITC Made Refundable

Making the ITC refundable (or changing it to a non-taxable grant like under the Section 1603 program) only impacts the "No Tax Appetite" structure; the other two structures are tax-efficient and therefore already use all tax losses and credits in the years in which they are generated, regardless of whether or not they are refundable. As shown in Figure 9, the "No Tax Appetite" structure sees levelized PPA prices decline by \$25.3/MWh under a refundable 30% ITC at $\$3/W_{AC}$ (\$16.9/MWh at $\$2/W_{AC}$), which makes carrying forward depreciation deductions more competitive than bringing in tax equity to monetize them – even if the sponsor has no tax appetite. This finding is consistent with statements from financiers that at least half of all projects (presumably in both the wind and solar markets) opted to carry forward depreciation losses under the Section 1603 cash grant program (Chadbourne & Parke LLP 2010a).[48]

[48] The comparison of a nonrefundable to a refundable ITC (or grant) in this section assumes that the tax equity investor targets the same after-tax IRR hurdle rate in either case. In reality, tax equity investors have reportedly charged a premium in deals involving the ITC instead of the grant, because the ITC uses up more tax capacity, "which is a scarce commodity." (Chadbourne & Parke LLP 2011). One tax equity investor noted that this premium has ranged from 25 to 130 basis points, while a second reportedly charges a 100 basis point premium for ITC (rather than grant) deals, and expected that premium to increase once the eligibility period for the 1603 grant expired, due to supply and demand (Chadbourne & Parke LLP 2011). Were this premium considered in the analysis presented above, then the results for the tax equity structure presented in Figure 9 would, in fact, differ somewhat depending on whether or not the credit was refundable. If the premium is only 100 basis points, however, then the difference would fall within the range of results presented later in Figure 12, which models the impact of changes in the cost of tax equity and debt.

Not surprisingly, making a 10% ITC refundable (e.g., to try and take some of the sting out of the reversion) does not have nearly as large of an impact (\$8.1/MWh at \$3/W_{AC} and \$5.4/MWh at \$2/W_{AC}) as making the 30% ITC refundable. This is because the relatively small size of the 10% ITC reduces the relative benefit of being able to use it immediately rather than carrying it forward. Nevertheless, the "No Tax Appetite" structure was already more competitive than bringing in third-party tax equity under a *nonrefundable* 10% ITC (see Section 5.1, above), and making the credit refundable merely increases the margin. Importantly, all of this benefit comes at no incremental cost to taxpayers (assuming all else equal – e.g., no incremental increase in deployment as a result of making the ITC refundable).

5.3 Solar Gets the PTC (Nonrefundable or Refundable)

President Obama's FY15 budget request not only seeks to make the PTC permanent and refundable, but also to make solar eligible for the (permanent and refundable) PTC. Figure 9 includes both refundable and nonrefundable PTC runs for PV.[49] As noted earlier in Section 3.1, Sale-Leaseback is not a viable structure in conjunction with the PTC,[50] so tax equity is represented solely by the Partnership Flip structure in this case.

Whether at \$3/W_{AC} or \$2/W_{AC}, the tax-inefficient "No Tax Appetite" structure is largely indifferent between a *nonrefundable* 30% ITC, 10% ITC, or PTC. Again, this is because this structure must carry credits forward for many years before they can be absorbed, which greatly erodes their present value and minimizes any differences between credits. In all other cases, however, the PTC results fall somewhere in between the 30% ITC and the 10% ITC results (for both nonrefundable and refundable credits), with the PTC more closely approaching the 30% ITC at \$2/W_{AC} than at \$3/W_{AC}, given the reduced value of the ITC as installed costs decline. In other words, solar's relatively high installed cost and low capacity factor (compared to wind) makes the 30% ITC a more advantageous incentive than the PTC (though less so at \$2/W_{AC}) – even despite the 15% reduction in depreciable basis that accompanies the 30% ITC but not the PTC. But with a 10% ITC (accompanied by a 5% reduction in depreciable basis), the PTC prevails.

Finally, comparing the *nonrefundable* PTC modeling runs at \$3/W_{AC} and \$2/W_{AC} reveals an interesting effect. In the \$3/W_{AC} PTC run, the Partnership Flip structure is less-competitive than all other structures,[51] but in the \$2/W_{AC} PTC run, it is more competitive than the "No Tax

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[49] Though implied by the reference to the FY15 budget request, it is perhaps worth clarifying that this section models the same PTC (in terms of level and duration) that was modeled for wind in Chapter 4.
[50] This is due to the PTC's requirement that the recipient both own and operate the project – functions that are separated between lessor and lessee in a Sale-Leaseback transaction.
[51] Note that this hierarchy stands in contrast to the relative competitiveness of structures for wind projects, where the Partnership Flip structure beats the "No Tax Appetite" structure. The reason for this discrepancy across technologies is largely the same as that explained above in the text for differences between solar at \$3/W_{AC} and \$2/W_{AC}. Wind's lower installed cost and higher capacity factor means that PTCs make up a larger percentage of the overall return for wind than for solar, which both reduces the relative cost of tax equity (by restricting the amount of low-cost debt that a project can support) and increases the relative monetization benefit of tax equity (by extending the period over which carried-forward PTCs will be absorbed). See the discussion surrounding solar in the text above for further explanation.

Appetite" structure. This difference is attributable to two factors. First, at $2/W$_{AC}$, the resulting PPA price is lower, which means that the fixed amount of PTCs generated by the project (regardless of its installed cost or PPA price) make up a larger proportion of the project's overall after-tax return, which in turn reduces the amount of cash revenue available to service debt, and therefore also the amount of leverage that a project can support. This reduction in the amount of low-cost debt that can be used to finance the "No Tax Appetite" structure effectively reduces the relative cost of tax equity to the project, making the Partnership Flip structure more competitive. Second (and similarly), an installed cost of $2/W$_{AC}$ results in a lower PPA price, which in turn generates less taxable income against which to apply PTCs. In a carry forward situation, the result is that PTCs must be carried forward for a longer period before they can be fully absorbed, which reduces their present value. This delay in PTC realization effectively increases the relative monetization benefit that tax equity provides to the project, again making the Partnership Flip structure more competitive.

5.4 Comprehensive Tax Reform

As described in Section 4.3, the prospect of comprehensive tax reform has grown in recent years, and preliminary proposals for energy tax reform emerged from the Senate Committee on Finance in November and December 2013 (and, though not modeled here for reasons described earlier in footnote 34, from the House Committee on Ways and Means in late February 2014). To briefly summarize, the Senate Finance Committee proposals would replace 5-year MACRS depreciation with a much slower 5%/year, 100% declining balance depreciation schedule starting in 2015, and in 2017 would replace the current ITC with a technology-neutral clean energy credit that could be taken as either a 20% ITC or a 10-year PTC (set at the same level as the current PTC). As a zero-emission technology, PV would receive the full value of the clean energy credit. The credit would be phased out over four years once the greenhouse gas intensity of the overall electricity sector declines by 25% relative to 2013 levels. These proposed changes (along with others, either not mentioned or yet to come) are intended to be considered as a package that should enable a significant reduction in the corporate income tax rate.

The choice of 20% ITC is interesting, given that Section 5.3 demonstrated that the PTC yields a levelized PPA price that falls somewhere in between that provided by a 30% and a 10% ITC. This revelation suggests that for PV (unlike for wind, for which the PTC is clearly preferable to a 20% ITC), tax reform should be modeled under *both* the 20% ITC *and* the PTC, given that there may not be a clear winner. Figure 10 shows the results for the 20% ITC, while Figure 11 shows the results for the PTC. Both graphs are structured very much like Figure 7 from Section 4.3: the left-most set of data points shows the business-as-usual results (i.e., a 30% nonrefundable ITC at $2.5/W$_{AC}$), followed by the phase-in of tax reform (starting with a switch to the slower depreciation schedule, followed by a change in the level or type of credit, and finally a reduction in the corporate tax rate from 35% to 25%), and finally the four-year phase-out of the relevant credit.

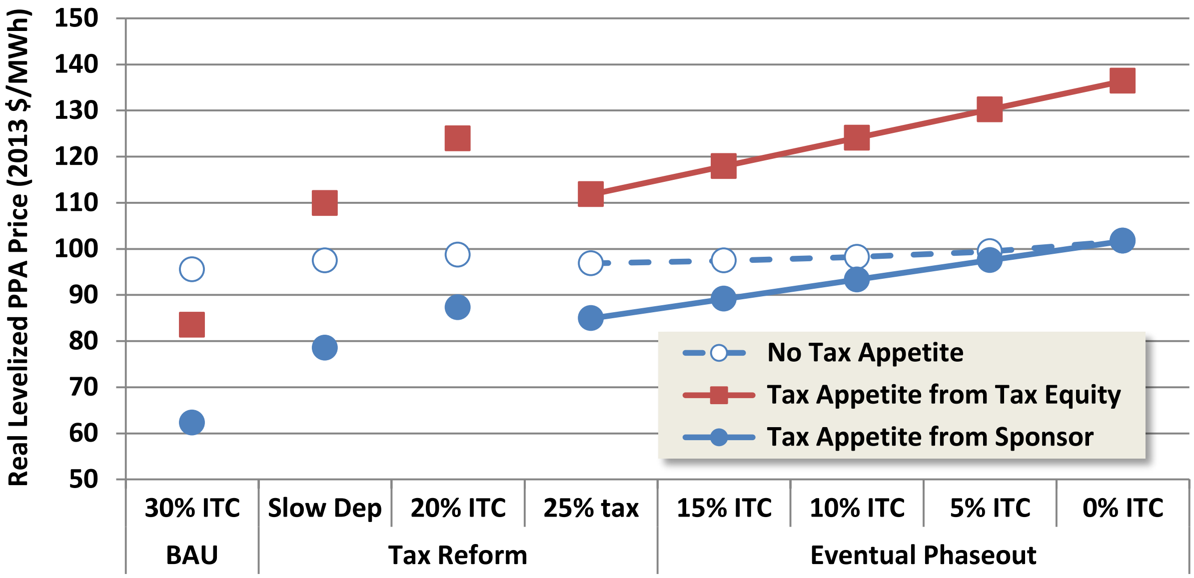

Figure 10. Solar Modeling Results: Tax Reform (20% ITC)

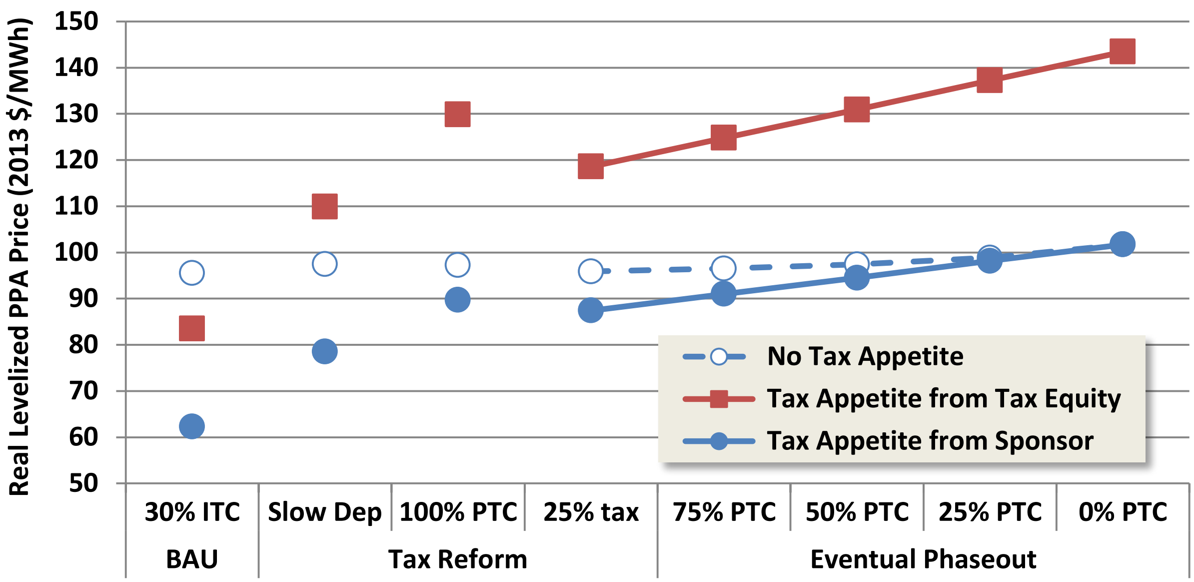

Figure 11. Solar Modeling Results: Tax Reform (PTC)

As shown in Figures 10 and 11, there appear to be only minor differences resulting from a PV project sponsor electing the PTC rather than the 20% ITC version of the proposed clean energy credit. Perhaps the most notable difference is that the gap between a sponsor with and without tax appetite is narrower under the PTC than it is under the 20% ITC. This is because the PTC is generated over a 10-year period (rather than all at once in year one, like the ITC), which makes the PTC easier for a sponsor without tax appetite to absorb in real time (or close to it), particularly in conjunction with the slower depreciation schedule.

The tax equity structure fares a little worse under the PTC than under the 20% ITC, largely because the PTC requires use of the Partnership Flip structure, while a Sale-Leaseback structure can be used in conjunction with the 20% ITC. Under business-as-usual conditions, the percentage of tax equity in the capital stack of a Partnership Flip structure (~55%) is lower than it is in a Sale-Leaseback structure (85%), leading to a higher WACC in the former (since sponsor equity is more expensive than tax equity). This difference is exacerbated under the proposed tax reform scenario, which reduces the combined tax benefits generated by the project and, in turn, the amount that a tax equity investor is willing to invest in a Partnership Flip structure (~35% of the capital stack, compared to ~55% under business-as-usual conditions).

Under either the 20% ITC or the PTC, the tax equity structure is uncompetitive under the proposed tax reform scenario – even sponsors without tax appetite will be better off carrying forward tax benefits rather than bringing in third-party tax equity. Moreover, in both cases, the difference between sponsors with and without tax appetite narrows under tax reform (under either credit), and eventually disappears as the credit is eventually phased out (as the much slower depreciation schedule can be absorbed largely in real time, even by sponsors with no tax appetite).

Finally, although Figures 10 and 11 are modeled assuming an installed cost of $2.5/$W_{AC}$, different elements of the proposed tax reform scenario will not kick in until a number of years down the road, by which time average PV installed costs are expected to have fallen further. For example, the switch to the slow depreciation schedule is proposed for 2015, while the implementation of the technology-neutral clean energy credit is proposed for 2017 (which, in turn, means that the earliest that the phaseout could possibly begin would be in 2018, ending in 2021). Rather than trying to project installed costs that far out, the models can instead be used to back into the installed cost that would be needed at each point in time in order for levelized PPA prices to remain unchanged from the business-as-usual scenario.

Table 5 presents these installed cost "hurdle rates" for both the 20% ITC (from Figure 10) and PTC (from Figure 11) tax reform scenarios, focusing solely on the most-competitive "Tax Appetite from Sponsor" structure. Not surprisingly (in light of Figures 10 and 11), there is not much difference between the installed cost hurdle rates for the 20% ITC and the PTC. By 2015, when the slower depreciation schedule is proposed to kick in, installed costs would need to decline from $2.5/$W_{AC}$ to around $1.9/$W_{AC}$ in order to maintain stable PPA prices. By 2017, when the clean energy credit is implemented, costs would need to decline further to around $1.7-$1.8/W_{AC}. In the first year of the phaseout (2018 at the earliest), costs would need to reach $1.6-$1.7/W_{AC}, and by the last year of the phaseout (2021 at the earliest), costs would need to have fallen to $1.4/$W_{AC}$ (all else equal) in order to provide the same levelized PPA price (of $62.3/MWh) as under the business-as-usual scenario at $2.5/$W_{AC}$.

Table 5. $/$W_{AC}$ Installed Cost Needed To Match BAU Levelized PPA Price of $62.3/MWh

2013 $/$W_{AC}$	BAU	Tax Reform			Eventual Phaseout			
	30% ITC	Slow Dep.	20% ITC or PTC	25% tax rate	75%	50%	25%	0%
Earliest Possible Year	2014	2015	2017	2017	2018	2019	2020	2021
20% ITC (Figure 10)	**$2.50**	**$1.89**	**$1.67**	**$1.73**	**$1.63**	**$1.55**	**$1.47**	**$1.41**
PTC (Figure 11)	**$2.50**	**$1.89**	**$1.77**	**$1.80**	**$1.70**	**$1.61**	**$1.51**	**$1.41**

Given the rapid decline in installed PV project costs in recent years, and that some utility-scale PV projects are already reporting installed costs in the vicinity of $2/$W_{AC}$ (Bolinger and Weaver

2013), a further decline to $1.4/$W_{AC}$ by 2021 (at the earliest) does not seem implausible. As such, one might reasonably conclude that, at least as proposed to date, tax reform will hurt the economics of utility-scale PV,[52] but that further reductions in installed project costs could nevertheless leave PPA prices no higher than they currently are (though still higher than they would have been absent tax reform).

5.5 Changes in the Cost of Tax Equity (and Debt)

Section 4.4 described a number of reasons why the cost of tax equity could increase in the coming years, including the expiration of the Section 1603 grant and Section 1705 loan guarantee programs, as well as increasing competition for tax equity between wind and solar through 2016 (as utility-scale solar expands significantly, as an increasing amount of residential solar is third-party owned and financed through tax equity, and as more-efficient wind turbines generate more PTCs – and therefore take up more tax capacity – per project). In addition, and somewhat more subtly, falling PPA prices for both wind and solar make tax equity relatively more attractive, by decreasing its *relative* cost (because lower PPA prices support less debt in projects foregoing tax equity) and increasing its *relative* benefit (because lower PPA prices generate less taxable income, which extends the length of time for which a sponsor with little or no tax appetite must carry forward fixed tax losses and credits). This somewhat subtle impact presumably not only increases demand for tax equity, but also provides tax equity investors with additional leeway to increase target yields without pricing themselves out of the market.

As with Figure 8 earlier (pertaining to wind), Figure 12 (which models a PV CapEx of $2.5/$W_{AC}$) shows the impact of both a higher (+300 basis points) and lower (-200 basis points) cost of tax equity, as well as a higher (+200 basis points) cost of debt in the structures that forego tax equity. A sponsor with tax appetite indisputably remains the most competitive – even if debt interest rates increase by 200 basis points while tax equity yields decrease by the same amount. Meanwhile, if tax credits were made refundable (not applicable to the tax reform scenario), even a sponsor without any tax appetite would outcompete tax equity *except* in the unlikely event that the cost of tax equity were to decline at the same time as the cost of debt were to increase. Finally, even if the ITC and PTC remain nonrefundable, tax equity is generally not competitive with a sponsor without tax appetite under the 10% ITC, PTC, and tax reform scenarios, unless once again the cost of tax equity were to decline at the same time as the cost of debt were to increase.

[52] Although the modeling results presented in Figures 10 and 11 suggest that tax reform would likely hurt the *economics* of utility-scale PV (all else equal), the impact on the relative *competitiveness* of utility-scale PV is less clear. For example, under the proposals released to date by the Senate Committee on Finance, gas-fired power plants would also be depreciated much more slowly (i.e., on a straight-line basis over 43 years) than they currently are, and would likely not be eligible for the new clean energy credit simply by virtue of their greenhouse gas intensity. As such, tax reform is likely to hurt the *economics* of gas-fired generation as well, which would, in turn, have implications for the relative *competitiveness* of utility-scale PV (and wind).

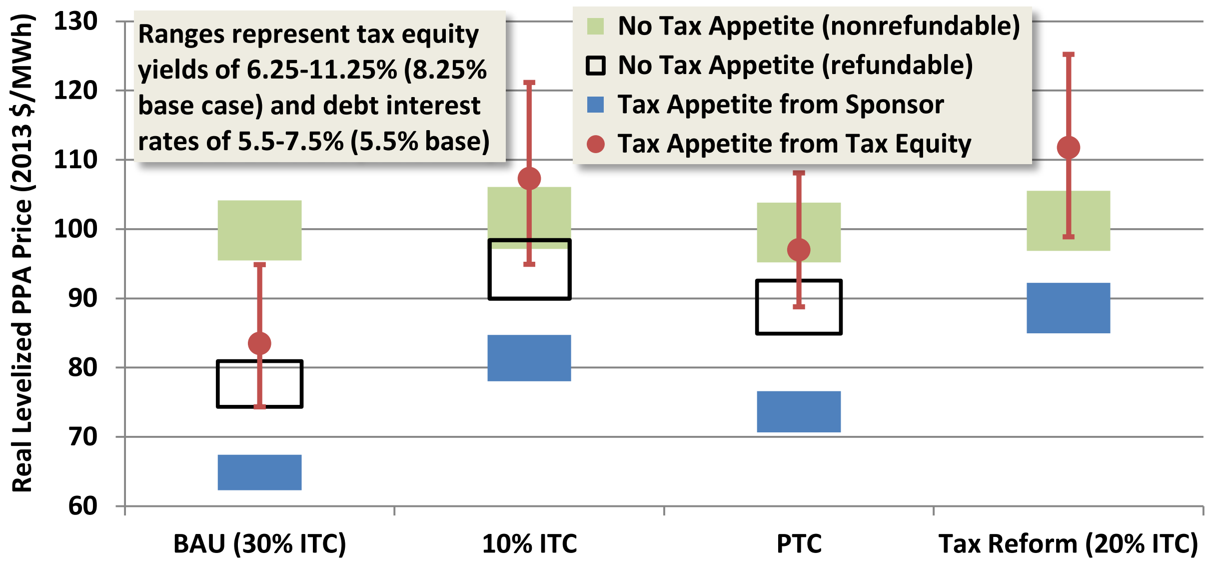

Figure 12. Solar Modeling Results: Changes in the Cost of Tax Equity and Debt

6. Conclusions

This report compares the relative costs, benefits, and implications of capturing the value of renewable energy tax incentives in three different ways – applying them against outside income, carrying them forward in time until they can be fully absorbed internally, or monetizing them through third-party tax equity investors – to see which method is most competitive under various scenarios. It finds that under current law and mid-2013 market conditions, monetization makes sense for all but the most tax-efficient project sponsors. In other words, for most project sponsors (i.e., those without much tax appetite), bringing in third-party tax equity currently provides net benefits to a project, although the size of the net benefit is diminished by the fact that tax equity is currently *twice as expensive* (on a comparable after-tax basis) as the project-level term debt that it likely supplants. Modeling results presented here suggest that project sponsors forfeit one-third or more of the notional value of a project's tax benefits when they bring in tax equity investors to monetize those benefits; these results are roughly in line with previous estimates.

With such a high price being exacted, tax equity's position in the marketplace should not be taken for granted. In fact, under a variety of plausible future scenarios examined in this report and relevant to utility-scale wind and solar projects, the benefit of monetization is found to no longer outweigh the incremental cost, and it makes more sense for sponsors – even those without tax appetite – to use the benefits internally rather than seek out third-party tax equity. A permanent expiration of the PTC is one obvious example of such a scenario, but even just a reduction in the size of the PTC could still render monetization uncompetitive. For example, based on the analysis and assumptions used in this report, reducing the *nonrefundable* PTC to less than 50% of its current level would make third-party tax benefit monetization more costly than other financing structures; this threshold would increase to 90% if the PTC were made *refundable*. Similarly, monetization is likely to become much less critical for solar projects if the ITC reverts to 10% at the end of 2016 (as per current law), and is also found to not be competitive under a refundable ITC (at any level), a solar PTC (either refundable or nonrefundable), or tax reform (as recently proposed by the Senate Finance Committee).

These findings have implications for how wind and solar projects are likely to be financed in the future, which, in turn, influences their levelized cost of energy. In the event of a PTC expiration, for example, the conclusion that a wind project sponsor without tax appetite will likely find it more advantageous to finance with debt and carry forward depreciation deductions as necessary rather than to partner with third-party tax equity means that the impact of a PTC expiration on PPA prices might not be as severe as one might otherwise assume under a static financing structure. In other words, the shift from third-party tax equity to project-level debt with a lower cost of capital helps to mitigate – though only to a degree, and certainly not fully – the loss of the credit. The same is true for the scheduled reversion of the solar ITC to 10% at the end of 2016: for many sponsors, the negative impact of the reversion is likely to be partially mitigated by a shift away from tax equity and to a lower cost of capital based on project-level term debt. In all scenarios, this beneficial shift to a lower cost of capital could be both heightened and hastened – and at no incremental cost to taxpayers – by making renewable energy tax credits refundable.

Notably, the lower costs of capital realized under the "no tax equity" structures modeled in this report are *not* dependent on utility-scale renewable energy projects having access to new capital formation vehicles like master limited partnerships ("MLPs") or real estate investment trusts ("REITs"). Although MLPs and REITs could, in the future, potentially muster important *new sources* of low-cost capital, project-level debt from both bank and institutional lenders (not to mention the bond market) is already widely available to utility-scale wind and solar projects, and at costs that are competitive with what MLPs and REITs are likely to deliver.[53] Capitalizing on this ready and willing debt market simply requires tweaking Federal incentives in a way that makes it more advantageous for project sponsors to finance their projects with low-cost debt rather than expensive tax equity. Moreover, any such tweaks (e.g., making renewable energy tax credits refundable) would, in turn, enhance the potential usefulness of MLPs and REITs – neither of which is particularly compatible with tax equity.

The scenarios examined in this report are all modeled on an "all else equal" basis, assuming most notably that tax equity hurdle rates do not change in response to any of the scenarios. But it is entirely possible that tax equity investors may be willing to lower their required rates of return under various scenarios, in order to remain competitive with the "backstop" of foregoing tax equity in favor of lower-cost debt. Indeed, there is already some evidence of this responsiveness, as certain tax equity investors reportedly differentiate between deals involving the ITC and the Section 1603 cash grant by charging a premium for the former.

Even if tax equity investors were to actively compete with financing structures involving just sponsor equity and debt under the scenarios modeled in this report, however, only those conclusions about *how* wind and solar projects are likely to be financed under those scenarios – i.e., with or without third-party tax equity – would be impacted. The resulting levelized PPA prices, which are of most importance to this analysis, would *not* be affected. In this light, if tax equity investors are willing to reduce hurdle rates in order to compete with alternative financing structures, so much the better, as project sponsors will then be able to achieve the same low PPA prices through a variety of financing options.

This thought experiment highlights the importance of the debt market (and a sponsor's ability to carry forward unused tax benefits) as a backstop against which tax equity must ultimately compete in order to remain relevant. It also highlights the usefulness of the tools and methodology developed in this report as a way to place bounds on the likely range of market impacts stemming from future policy changes. In fact, given current policy uncertainty impacting the wind and solar markets, the methodology and capabilities developed in this report are likely just as important as, if not more important than, the results presented. The policy environment over the next few years is likely to remain fluid, spawning a variety of possible future scenarios – including not only those modeled in this report, but also various combinations and permutations thereof, along with others not yet envisioned. The methodology and capabilities developed within this report will enable more-refined and -targeted policy analyses of these scenarios as they arise.

[53] For example, testimony before the U.S. House of Representatives during a 2013 hearing on the PTC quoted the wind (and solar) developer First Wind as anticipating a 6-8% cost of capital through MLPs, and went on to note that a 7% yield was the mid-range among a sample of energy MLPs (Reicher 2013). This 6%-8% estimated cost of capital under renewable energy MLPs is higher than the 5.5%-6% interest rates that quality wind and solar projects can currently access in the debt markets.

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Appendix: Additional Modeling Results

Notes to tables: All IRR's are expressed in after-tax terms, all interest rates (except the after-tax WACC) are expressed in pre-tax terms, and all prices are expressed in 2013 $/MWh. For Sale-Leaseback structures (used for solar only), 25-year tax equity IRR target rates are arrived at by first running the scenario through the Partnership Flip model with an 8.25% after-tax target IRR at the end of year 10. The resulting 25-year after-tax IRR from the Partnership Flip model is then used as a target IRR within the Sale-Leaseback model (i.e., at least from a 25-year IRR perspective, the tax equity investor should be indifferent between a Partnership Flip or Sale-Leaseback structure).

Tax Appetite from Sponsor (Figure ES-1)								
	Wind ($1.8/W-AC, 40% capacity factor)				Solar PV ($2.5/W-AC, 30% capacity factor)			
	100% PTC	50% PTC	0% PTC	Tax Reform	30% ITC	10% ITC	100% PTC	Tax Reform
1st-Year PPA Price	$39.7	$47.6	$55.7	$49.4	$63.6	$79.6	$72.1	$86.6
Real Levelized PPA Price	$38.9	$46.7	$54.6	$48.4	$62.3	$78.0	$70.6	$84.9
Nominal Levelized PPA Price	$46.3	$55.6	$65.1	$57.7	$74.0	$92.6	$83.9	$100.8
Sponsor Equity %	62.6%	50.9%	39.0%	48.3%	55.6%	41.9%	48.4%	35.9%
Project Debt %	37.4%	49.1%	61.0%	51.7%	44.4%	58.1%	51.6%	64.1%
Sponsor IRR at Year 25	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%
Debt Interest Rate	6.0%	6.0%	6.0%	6.0%	5.5%	5.5%	5.5%	5.5%
After-Tax WACC	8.9%	7.9%	6.9%	7.9%	8.1%	6.9%	7.5%	6.7%

Tax Appetite from Tax Equity (Figure ES-1)								
	Wind ($1.8/W-AC, 40% capacity factor)				Solar PV ($2.5/W-AC, 30% capacity factor)			
	100% PTC	50% PTC	0% PTC	Tax Reform	30% ITC	10% ITC	100% PTC	Tax Reform
1st-Year PPA Price	$46.9	$61.0	$75.4	$60.3	$85.1	$109.5	$98.9	$114.0
Real Levelized PPA Price	$45.9	$59.8	$73.9	$59.1	$83.5	$107.3	$97.0	$111.8
Nominal Levelized PPA Price	$54.8	$71.3	$88.1	$70.4	$99.1	$127.4	$115.1	$132.7
Sponsor Equity %	39.3%	55.7%	72.2%	58.8%	15.0%	15.0%	49.7%	15.0%
Tax Equity %	60.7%	44.3%	27.8%	41.2%	85.0%	85.0%	50.3%	85.0%
Sponsor Back Leverage %	43.8%	44.4%	44.7%	41.3%	N/A	N/A	41.3%	N/A
Sponsor IRR at Year 25	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%
Tax Equity IRR at Year 25	9.2%	9.7%	10.4%	9.7%	9.5%	9.7%	9.2%	10.1%
Tax Equity IRR at Flip	8.5%	8.5%	8.5%	8.5%	N/A	N/A	8.25%	N/A
Back Leverage Interest Rate	10.0%	10.0%	10.0%	10.0%	N/A	N/A	10.0%	N/A
After-Tax WACC	9.3%	9.5%	9.6%	9.8%	9.9%	10.1%	9.4%	10.4%

No Tax Appetite (Figure ES-1)								
	Wind ($1.8/W-AC, 40% capacity factor)				Solar PV ($2.5/W-AC, 30% capacity factor)			
Nonrefundable Credits:	100% PTC	50% PTC	0% PTC	Tax Reform	30% ITC	10% ITC	100% PTC	Tax Reform
1st-Year PPA Price	$59.9	$60.7	$62.6	$60.4	$97.4	$99.1	$97.1	$98.8
Real Levelized PPA Price	$58.7	$59.5	$61.4	$59.3	$95.5	$97.1	$95.2	$96.8
Nominal Levelized PPA Price	$70.0	$71.0	$73.2	$70.6	$113.3	$115.3	$113.0	$115.0
Sponsor Equity %	32.8%	31.6%	28.8%	32.0%	26.7%	25.2%	26.9%	25.5%
Project Debt %	67.2%	68.4%	71.2%	68.0%	73.3%	74.8%	73.1%	74.5%
Sponsor IRR at Year 25	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%
Debt Interest Rate	6.0%	6.0%	6.0%	6.0%	5.5%	5.5%	5.5%	5.5%
After-Tax WACC	6.3%	6.2%	6.0%	6.7%	5.6%	5.5%	5.6%	5.9%

No Tax Appetite (Figure ES-1)						
	Wind ($1.8/W-AC, 40% capacity factor)			Solar PV ($2.5/W-AC, 30% capacity factor)		
Refundable Credits:	100% PTC	50% PTC	0% PTC	30% ITC	10% ITC	100% PTC
1st-Year PPA Price	$48.4	$55.4	$62.6	$75.9	$92.2	$86.6
Real Levelized PPA Price	$47.5	$54.3	$61.4	$74.4	$90.4	$84.9
Nominal Levelized PPA Price	$56.6	$64.8	$73.2	$88.3	$107.3	$100.8
Sponsor Equity %	49.7%	39.4%	28.8%	45.1%	31.1%	35.9%
Project Debt %	50.3%	60.6%	71.2%	54.9%	68.9%	64.1%
Sponsor IRR at Year 25	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%
Debt Interest Rate	6.0%	6.0%	6.0%	5.5%	5.5%	5.5%
After-Tax WACC	7.8%	6.9%	6.0%	7.2%	6.0%	6.4%

Tax Appetite from Sponsor (Figures 5 and 6)											
PTC Level:	100%	90%	80%	70%	60%	50%	40%	30%	20%	10%	0%
1st-Year PPA Price	$39.7	$41.2	$42.9	$44.5	$46.0	$47.6	$49.3	$50.9	$52.4	$54.2	$55.7
Real Levelized PPA Price	$38.9	$40.4	$42.0	$43.6	$45.1	$46.7	$48.3	$49.9	$51.4	$53.1	$54.6
Nominal Levelized PPA Price	$46.3	$48.2	$50.1	$52.0	$53.8	$55.6	$57.6	$59.5	$61.3	$63.3	$65.1
Sponsor Equity %	62.6%	60.3%	57.9%	55.4%	53.2%	50.9%	48.4%	46.0%	43.8%	41.2%	39.0%
Project Debt %	37.4%	39.7%	42.1%	44.6%	46.8%	49.1%	51.6%	54.0%	56.2%	58.8%	61.0%
Sponsor IRR at Year 25	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%
Debt Interest Rate	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%
After-Tax WACC	8.9%	8.7%	8.5%	8.3%	8.1%	7.9%	7.7%	7.5%	7.3%	7.1%	6.9%

Tax Appetite from Tax Equity (Figures 5 and 6)											
PTC Level:	100%	90%	80%	70%	60%	50%	40%	30%	20%	10%	0%
1st-Year PPA Price	$46.9	$49.7	$52.6	$55.5	$58.2	$61.0	$64.0	$66.9	$69.6	$72.7	$75.4
Real Levelized PPA Price	$45.9	$48.7	$51.5	$54.4	$57.1	$59.8	$62.7	$65.6	$68.2	$71.2	$73.9
Nominal Levelized PPA Price	$54.8	$58.1	$61.4	$64.9	$68.0	$71.3	$74.8	$78.2	$81.3	$84.9	$88.1
Sponsor Equity %	39.3%	42.6%	45.9%	49.3%	52.4%	55.7%	59.1%	62.5%	65.5%	69.1%	72.2%
Tax Equity %	60.7%	57.4%	54.1%	50.7%	47.6%	44.3%	40.9%	37.5%	34.5%	30.9%	27.8%
Sponsor Back Leverage %	43.8%	43.9%	44.0%	44.2%	44.3%	44.4%	44.4%	44.5%	44.6%	44.6%	44.7%
Sponsor IRR at Year 25	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%
Tax Equity IRR at Year 25	9.2%	9.3%	9.4%	9.5%	9.6%	9.7%	9.8%	9.9%	10.1%	10.3%	10.4%
Tax Equity IRR at Flip	8.5%	8.5%	8.5%	8.5%	8.5%	8.5%	8.5%	8.5%	8.5%	8.5%	8.5%
Back Leverage Interest Rate	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
After-Tax WACC	9.3%	9.3%	9.4%	9.4%	9.4%	9.5%	9.5%	9.6%	9.6%	9.6%	9.6%

No Tax Appetite (Figure 5)											
PTC Level:	100%	90%	80%	70%	60%	50%	40%	30%	20%	10%	0%
1st-Year PPA Price	$59.9	$60.0	$60.1	$60.3	$60.5	$60.7	$61.0	$61.3	$61.7	$62.1	$62.6
Real Levelized PPA Price	$58.7	$58.8	$58.9	$59.1	$59.3	$59.5	$59.8	$60.1	$60.5	$60.9	$61.4
Nominal Levelized PPA Price	$70.0	$70.1	$70.3	$70.5	$70.7	$71.0	$71.3	$71.7	$72.1	$72.6	$73.2
Sponsor Equity %	32.8%	32.7%	32.5%	32.2%	31.9%	31.6%	31.2%	30.7%	30.2%	29.5%	28.8%
Project Debt %	67.2%	67.3%	67.5%	67.8%	68.1%	68.4%	68.8%	69.3%	69.8%	70.5%	71.2%
Sponsor IRR at Year 25	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%
Debt Interest Rate	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%
After-Tax WACC	6.3%	6.3%	6.3%	6.3%	6.3%	6.2%	6.2%	6.2%	6.1%	6.1%	6.0%

No Tax Appetite (Figure 6)											
Refundable PTC Level:	100%	90%	80%	70%	60%	50%	40%	30%	20%	10%	0%
1st-Year PPA Price	$48.4	$49.8	$51.2	$52.7	$54.0	$55.4	$56.9	$58.4	$59.7	$61.3	$62.6
Real Levelized PPA Price	$47.5	$48.8	$50.2	$51.7	$53.0	$54.3	$55.8	$57.2	$58.5	$60.1	$61.4
Nominal Levelized PPA Price	$56.6	$58.2	$59.9	$61.6	$63.1	$64.8	$66.5	$68.2	$69.8	$71.6	$73.2
Sponsor Equity %	49.7%	47.6%	45.5%	43.4%	41.4%	39.4%	37.2%	35.1%	33.1%	30.8%	28.8%
Project Debt %	50.3%	52.4%	54.5%	56.6%	58.6%	60.6%	62.8%	64.9%	66.9%	69.2%	71.2%
Sponsor IRR at Year 25	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%
Debt Interest Rate	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%
After-Tax WACC	7.8%	7.6%	7.4%	7.2%	7.1%	6.9%	6.7%	6.5%	6.4%	6.2%	6.0%

Tax Appetite from Sponsor (Figure 7)							
	BAU	Tax Reform		Eventual Phaseout			
	100% PTC	Slow Dep	25% tax	75% PTC	50% PTC	25% PTC	0% PTC
1st-Year PPA Price	$39.7	$50.3	$49.4	$53.1	$56.8	$60.6	$64.4
Real Levelized PPA Price	$38.9	$49.3	$48.4	$52.1	$55.7	$59.4	$63.1
Nominal Levelized PPA Price	$46.3	$58.8	$57.7	$62.1	$66.4	$70.9	$75.2
Sponsor Equity %	62.6%	46.9%	48.3%	42.7%	37.3%	31.7%	26.2%
Project Debt %	37.4%	53.1%	51.7%	57.3%	62.7%	68.3%	73.8%
Sponsor IRR at Year 25	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%
Debt Interest Rate	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%
After-Tax WACC	8.9%	7.5%	7.9%	7.5%	7.1%	6.6%	6.2%

Tax Appetite from Tax Equity (Figure 7)							
	BAU	Tax Reform		Eventual Phaseout			
	100% PTC	Slow Dep	25% tax	75% PTC	50% PTC	25% PTC	0% PTC
1st-Year PPA Price	$46.9	$64.5	$60.3	$66.5	$72.7	$79.0	$85.3
Real Levelized PPA Price	$45.9	$63.2	$59.1	$65.2	$71.2	$77.5	$83.6
Nominal Levelized PPA Price	$54.8	$75.4	$70.4	$77.7	$84.9	$92.3	$99.6
Sponsor Equity %	39.3%	62.5%	58.8%	66.5%	74.1%	81.9%	89.6%
Tax Equity %	60.7%	37.5%	41.2%	33.5%	25.9%	18.1%	10.4%
Sponsor Back Leverage %	43.8%	42.4%	41.3%	41.5%	41.6%	41.7%	41.8%
Sponsor IRR at Year 25	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%
Tax Equity IRR at Year 25	9.2%	9.7%	9.7%	9.9%	10.2%	10.6%	11.1%
Tax Equity IRR at Flip	8.5%	8.5%	8.5%	8.5%	8.5%	8.5%	8.5%
Back Leverage Interest Rate	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
After-Tax WACC	9.3%	9.5%	9.8%	9.9%	10.0%	10.0%	10.0%

No Tax Appetite (Figure 7)							
	BAU	Tax Reform		Eventual Phaseout			
	100% PTC	Slow Dep	25% tax	75% PTC	50% PTC	25% PTC	0% PTC
1st-Year PPA Price	$59.9	$60.7	$60.4	$60.6	$61.1	$62.0	$64.4
Real Levelized PPA Price	$58.7	$59.5	$59.3	$59.4	$59.9	$60.8	$63.1
Nominal Levelized PPA Price	$70.0	$70.9	$70.6	$70.8	$71.3	$72.5	$75.2
Sponsor Equity %	32.8%	31.6%	32.0%	31.8%	31.1%	29.7%	26.2%
Project Debt %	67.2%	68.4%	68.0%	68.2%	68.9%	70.3%	73.8%
Sponsor IRR at Year 25	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%
Debt Interest Rate	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%
After-Tax WACC	6.3%	6.2%	6.7%	6.6%	6.6%	6.5%	6.2%

Tax Appetite from Sponsor (Figure 8)						
	BAU (100% PTC)		Refundable (100% PTC)		Tax Reform (100% PTC)	
1st-Year PPA Price	$39.7	$42.1	$39.7	$42.1	$49.4	$52.7
Real Levelized PPA Price	$38.9	$41.2	$38.9	$41.2	$48.4	$51.6
Nominal Levelized PPA Price	$46.3	$49.1	$46.3	$49.1	$57.7	$61.5
Sponsor Equity %	62.6%	64.2%	62.6%	64.2%	48.3%	50.5%
Project Debt %	37.4%	35.8%	37.4%	35.8%	51.7%	49.5%
Sponsor IRR at Year 25	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%
Debt Interest Rate	6.0%	8.0%	6.0%	8.0%	6.0%	8.0%
After-Tax WACC	8.9%	9.4%	8.9%	9.4%	7.9%	8.8%

Tax Appetite from Tax Equity (Figure 8)									
	BAU (100% PTC)			Refundable (100% PTC)			Tax Reform (100% PTC)		
1st-Year PPA Price	$42.0	$46.9	$53.3	$42.0	$46.9	$53.3	$56.1	$60.3	$65.7
Real Levelized PPA Price	$41.2	$45.9	$52.3	$41.2	$45.9	$52.3	$55.0	$59.1	$64.4
Nominal Levelized PPA Price	$49.1	$54.8	$62.3	$49.1	$54.8	$62.3	$65.5	$70.4	$76.8
Sponsor Equity %	33.7%	39.3%	46.9%	33.7%	39.3%	46.9%	53.6%	58.8%	65.6%
Tax Equity %	66.3%	60.7%	53.1%	66.3%	60.7%	53.1%	46.4%	41.2%	34.4%
Sponsor Back Leverage %	43.5%	43.8%	44.0%	43.5%	43.8%	44.0%	41.1%	41.3%	41.4%
Sponsor IRR at Year 25	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%
Tax Equity IRR at Year 25	7.2%	9.2%	12.1%	7.2%	9.2%	12.1%	7.8%	9.7%	12.5%
Tax Equity IRR at Flip	6.5%	8.5%	11.5%	6.5%	8.5%	11.5%	6.5%	8.5%	11.5%
Back Leverage Interest Rate	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
After-Tax WACC	7.9%	9.3%	10.8%	7.9%	9.3%	10.8%	8.9%	9.8%	10.8%

No Tax Appetite (Figure 8)						
	BAU (100% PTC)		Refundable (100% PTC)		Tax Reform (100% PTC)	
1st-Year PPA Price	$59.9	$64.1	$48.4	$51.8	$60.4	$64.6
Real Levelized PPA Price	$58.7	$62.9	$47.5	$50.7	$59.3	$63.4
Nominal Levelized PPA Price	$70.0	$74.9	$56.6	$60.5	$70.6	$75.5
Sponsor Equity %	32.8%	35.7%	49.7%	51.7%	32.0%	35.1%
Project Debt %	67.2%	64.3%	50.3%	48.3%	68.0%	64.9%
Sponsor IRR at Year 25	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%
Debt Interest Rate	6.0%	8.0%	6.0%	8.0%	6.0%	8.0%
After-Tax WACC	6.3%	7.4%	7.8%	8.5%	6.7%	7.8%

Tax Appetite from Sponsor (Figure 9)						
	$3/W-AC			$2/W-AC		
	30% ITC	10% ITC	PTC	30% ITC	10% ITC	PTC
1st-Year PPA Price	$73.9	$93.1	$87.2	$53.2	$66.0	$56.9
Real Levelized PPA Price	$72.4	$91.3	$85.5	$52.2	$64.7	$55.8
Nominal Levelized PPA Price	$86.0	$108.4	$101.5	$61.9	$76.9	$66.2
Sponsor Equity %	55.7%	41.9%	46.2%	55.6%	41.9%	51.7%
Project Debt %	44.3%	58.1%	53.8%	44.4%	58.1%	48.3%
Sponsor IRR at Year 25	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%
Debt Interest Rate	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%
After-Tax WACC	8.1%	6.9%	7.3%	8.1%	6.9%	7.8%

Tax Appetite from Tax Equity (Figure 9)						
	$3/W-AC			$2/W-AC		
	30% ITC	10% ITC	PTC	30% ITC	10% ITC	PTC
1st-Year PPA Price	$99.8	$129.0	$122.2	$70.5	$89.9	$75.7
Real Levelized PPA Price	$97.9	$126.5	$119.8	$69.1	$88.2	$74.2
Nominal Levelized PPA Price	$116.2	$150.1	$142.2	$82.0	$104.7	$88.1
Sponsor Equity %	15.0%	15.0%	52.4%	15.0%	15.0%	45.6%
Tax Equity %	85.0%	85.0%	47.6%	85.0%	85.0%	54.4%
Sponsor Back Leverage %	N/A	N/A	41.3%	N/A	N/A	41.3%
Sponsor IRR at Year 25	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%
Tax Equity IRR at Year 25	9.5%	9.7%	9.3%	9.5%	9.7%	9.1%
Tax Equity IRR at Flip	N/A	N/A	8.25%	N/A	N/A	8.25%
Back Leverage Interest Rate	N/A	N/A	10.0%	N/A	N/A	10.0%
After-Tax WACC	9.9%	10.1%	9.4%	9.9%	10.1%	9.3%

No Tax Appetite (Figure 9)						
	$3/W-AC			$2/W-AC		
Nonrefundable Credits:	30% ITC	10% ITC	PTC	30% ITC	10% ITC	PTC
1st-Year PPA Price	$114.5	$116.5	$114.6	$80.3	$81.6	$79.7
Real Levelized PPA Price	$112.3	$114.3	$112.4	$78.7	$80.0	$78.1
Nominal Levelized PPA Price	$133.3	$135.6	$133.4	$93.4	$95.0	$92.7
Sponsor Equity %	26.7%	25.2%	26.6%	26.7%	25.2%	27.3%
Project Debt %	73.3%	74.8%	73.4%	73.3%	74.8%	72.7%
Sponsor IRR at Year 25	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%
Debt Interest Rate	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%
After-Tax WACC	5.6%	5.5%	5.6%	5.6%	5.5%	5.7%

No Tax Appetite (Figure 9)						
	$3/W-AC			$2/W-AC		
Refundable Credits:	30% ITC	10% ITC	PTC	30% ITC	10% ITC	PTC
1st-Year PPA Price	$88.7	$108.3	$104.3	$63.0	$76.1	$68.9
Real Levelized PPA Price	$86.9	$106.2	$102.3	$61.8	$74.6	$67.6
Nominal Levelized PPA Price	$103.2	$126.0	$121.4	$73.4	$88.6	$80.2
Sponsor Equity %	45.1%	31.1%	34.0%	45.1%	31.1%	38.8%
Project Debt %	54.9%	68.9%	66.0%	54.9%	68.9%	61.2%
Sponsor IRR at Year 25	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%
Debt Interest Rate	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%
After-Tax WACC	7.2%	6.0%	6.2%	7.2%	6.0%	6.7%

Tax Appetite from Sponsor (Figure 10)								
	BAU	Tax Reform			Eventual Phaseout			
	30% ITC	Slow Dep	20% ITC	25% tax	15% ITC	10% ITC	5% ITC	0% ITC
1st-Year PPA Price	$63.6	$80.1	$89.1	$86.6	$90.9	$95.2	$99.5	$103.8
Real Levelized PPA Price	$62.3	$78.5	$87.3	$84.9	$89.1	$93.3	$97.5	$101.7
Nominal Levelized PPA Price	$74.0	$93.2	$103.6	$100.8	$105.8	$110.8	$115.8	$120.7
Sponsor Equity %	55.6%	41.5%	33.8%	35.9%	32.2%	28.5%	24.9%	21.2%
Project Debt %	44.4%	58.5%	66.2%	64.1%	67.8%	71.5%	75.1%	78.8%
Sponsor IRR at Year 25	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%
Debt Interest Rate	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%
After-Tax WACC	8.1%	6.9%	6.2%	6.7%	6.4%	6.1%	5.8%	5.5%

Tax Appetite from Tax Equity (Figure 10)								
	BAU	Tax Reform			Eventual Phaseout			
	30% ITC	Slow Dep	20% ITC	25% tax	15% ITC	10% ITC	5% ITC	0% ITC
1st-Year PPA Price	$85.1	$112.1	$126.4	$114.0	$120.3	$126.5	$132.8	$139.1
Real Levelized PPA Price	$83.5	$109.9	$123.9	$111.8	$117.9	$124.1	$130.2	$136.4
Nominal Levelized PPA Price	$99.1	$130.5	$147.1	$132.7	$140.0	$147.3	$154.6	$161.9
Sponsor Equity %	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%
Tax Equity %	85.0%	85.0%	85.0%	85.0%	85.0%	85.0%	85.0%	85.0%
Sponsor Back Leverage %	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Sponsor IRR at Year 25	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%
Tax Equity IRR at Year 25	9.5%	10.0%	10.2%	10.1%	10.1%	10.2%	10.2%	10.3%
Tax Equity IRR at Flip	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Back Leverage Interest Rate	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
After-Tax WACC	9.9%	10.3%	10.4%	10.4%	10.4%	10.4%	10.5%	10.5%

No Tax Appetite (Figure 10)								
	BAU	Tax Reform			Eventual Phaseout			
	30% ITC	Slow Dep	20% ITC	25% tax	15% ITC	10% ITC	5% ITC	0% ITC
1st-Year PPA Price	$97.4	$99.4	$100.7	$98.8	$99.4	$100.2	$101.4	$103.8
Real Levelized PPA Price	$95.5	$97.5	$98.7	$96.8	$97.4	$98.2	$99.4	$101.7
Nominal Levelized PPA Price	$113.3	$115.7	$117.1	$115.0	$115.7	$116.6	$118.0	$120.7
Sponsor Equity %	26.7%	24.9%	23.9%	25.5%	25.0%	24.3%	23.2%	21.2%
Project Debt %	73.3%	75.1%	76.1%	74.5%	75.0%	75.7%	76.8%	78.8%
Sponsor IRR at Year 25	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%
Debt Interest Rate	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%
After-Tax WACC	5.6%	5.5%	5.4%	5.9%	5.8%	5.8%	5.7%	5.5%

Tax Appetite from Sponsor (Figure 11)								
	BAU	Tax Reform			Eventual Phaseout			
	30% ITC	Slow Dep	100% PTC	25% tax	75% PTC	50% PTC	25% PTC	0% PTC
1st-Year PPA Price	$63.6	$80.1	$91.5	$89.2	$92.8	$96.4	$100.1	$103.8
Real Levelized PPA Price	$62.3	$78.5	$89.7	$87.4	$91.0	$94.5	$98.1	$101.7
Nominal Levelized PPA Price	$74.0	$93.2	$106.5	$103.8	$108.0	$112.2	$116.5	$120.7
Sponsor Equity %	55.6%	41.5%	31.7%	33.7%	30.6%	27.5%	24.3%	21.2%
Project Debt %	44.4%	58.5%	68.3%	66.3%	69.4%	72.5%	75.7%	78.8%
Sponsor IRR at Year 25	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%
Debt Interest Rate	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%
After-Tax WACC	8.1%	6.9%	6.1%	6.6%	6.3%	6.1%	5.8%	5.5%

Tax Appetite from Tax Equity (Figure 11)								
	BAU	Tax Reform			Eventual Phaseout			
	30% ITC	Slow Dep	100% PTC	25% tax	75% PTC	50% PTC	25% PTC	0% PTC
1st-Year PPA Price	$85.1	$112.1	$132.4	$120.9	$127.3	$133.5	$140.0	$146.3
Real Levelized PPA Price	$83.5	$109.9	$129.9	$118.6	$124.8	$130.9	$137.2	$143.5
Nominal Levelized PPA Price	$99.1	$130.5	$154.1	$140.8	$148.2	$155.4	$162.9	$170.3
Sponsor Equity %	15.0%	15.0%	70.3%	65.6%	69.3%	72.9%	76.7%	80.3%
Tax Equity %	85.0%	85.0%	29.7%	34.4%	30.7%	27.1%	23.3%	19.7%
Sponsor Back Leverage %	N/A	N/A	40.4%	39.2%	39.2%	39.3%	39.3%	39.4%
Sponsor IRR at Year 25	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%
Tax Equity IRR at Year 25	9.5%	10.0%	9.7%	9.7%	9.8%	9.9%	10.1%	10.3%
Tax Equity IRR at Flip	N/A	N/A	8.25%	8.25%	8.25%	8.25%	8.25%	8.25%
Back Leverage Interest Rate	N/A	N/A	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
After-Tax WACC	9.9%	10.3%	9.6%	9.9%	9.9%	10.0%	10.0%	10.0%

No Tax Appetite (Figure 11)								
	BAU	Tax Reform			Eventual Phaseout			
	30% ITC	Slow Dep	100% PTC	25% tax	75% PTC	50% PTC	25% PTC	0% PTC
1st-Year PPA Price	$97.4	$99.4	$99.2	$97.8	$98.4	$99.4	$100.8	$103.8
Real Levelized PPA Price	$95.5	$97.5	$97.2	$95.9	$96.5	$97.4	$98.8	$101.7
Nominal Levelized PPA Price	$113.3	$115.7	$115.4	$113.8	$114.6	$115.6	$117.3	$120.7
Sponsor Equity %	26.7%	24.9%	25.1%	26.3%	25.8%	25.0%	23.7%	21.2%
Project Debt %	73.3%	75.1%	74.9%	73.7%	74.2%	75.0%	76.3%	78.8%
Sponsor IRR at Year 25	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%
Debt Interest Rate	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%
After-Tax WACC	5.6%	5.5%	5.5%	6.0%	5.9%	5.8%	5.7%	5.5%

Tax Appetite from Sponsor (Figure 12)								
	BAU (30% ITC)		10% ITC		PTC		Tax Reform (20% ITC)	
1st-Year PPA Price	$63.6	$68.8	$79.6	$86.4	$72.1	$78.1	$86.6	$94.1
Real Levelized PPA Price	$62.3	$67.4	$78.0	$84.7	$70.6	$76.6	$84.9	$92.3
Nominal Levelized PPA Price	$74.0	$80.0	$92.6	$100.6	$83.9	$90.9	$100.8	$109.5
Sponsor Equity %	55.6%	57.3%	41.9%	44.0%	48.4%	50.3%	35.9%	38.3%
Project Debt %	44.4%	42.7%	58.1%	56.0%	51.6%	49.7%	64.1%	61.7%
Sponsor IRR at Year 25	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%
Debt Interest Rate	5.5%	7.5%	5.5%	7.5%	5.5%	7.5%	5.5%	7.5%
After-Tax WACC	8.1%	8.8%	6.9%	7.8%	7.5%	8.3%	6.7%	7.8%

Tax Appetite from Tax Equity (Figure 12)												
	BAU (30% ITC)			10% ITC			PTC			Tax Reform (20% ITC)		
1st-Year PPA Price	$75.8	$85.1	$96.8	$96.8	$109.5	$123.6	$90.5	$98.9	$110.3	$100.9	$114.0	$127.7
Real Levelized PPA Price	$74.4	$83.5	$94.9	$94.9	$107.3	$121.2	$88.8	$97.0	$108.1	$98.9	$111.8	$125.2
Nominal Levelized PPA Price	$88.3	$99.1	$112.6	$112.7	$127.4	$143.8	$105.4	$115.1	$128.4	$117.4	$132.7	$148.7
Sponsor Equity %	15.0%	15.0%	48.5%	15.0%	15.0%	63.5%	44.9%	49.7%	56.1%	15.0%	15.0%	69.5%
Tax Equity %	85.0%	85.0%	51.5%	85.0%	85.0%	36.5%	55.1%	50.3%	43.9%	85.0%	85.0%	30.5%
Sponsor Back Leverage %	N/A	N/A	41.2%	N/A	N/A	41.4%	41.3%	41.3%	41.3%	N/A	N/A	39.3%
Sponsor IRR at Year 25	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%
Tax Equity IRR at Year 25	7.6%	9.5%	12.3%	7.9%	9.7%	12.5%	7.3%	9.2%	12.1%	8.3%	10.1%	12.8%
Tax Equity IRR at Flip	N/A	N/A	11.25%	N/A	N/A	11.25%	6.25%	8.25%	11.25%	N/A	N/A	11.25%
Back Leverage Interest Rate	N/A	N/A	10.0%	N/A	N/A	10.0%	10.0%	10.0%	10.0%	N/A	N/A	10.0%
After-Tax WACC	8.3%	9.9%	10.9%	8.5%	10.1%	10.6%	8.3%	9.4%	10.7%	8.8%	10.4%	10.9%

No Tax Appetite (Figure 12)								
Nonrefundable Credits:	BAU (30% ITC)		10% ITC		PTC		Tax Reform (20% ITC)	
1st-Year PPA Price	$97.4	$106.2	$99.1	$108.2	$97.1	$105.9	$98.8	$107.6
Real Levelized PPA Price	$95.5	$104.1	$97.1	$106.1	$95.2	$103.8	$96.8	$105.5
Nominal Levelized PPA Price	$113.3	$123.6	$115.3	$125.9	$113.0	$123.2	$115.0	$125.3
Sponsor Equity %	26.7%	29.2%	25.2%	27.7%	26.9%	29.4%	25.5%	28.1%
Project Debt %	73.3%	70.8%	74.8%	72.3%	73.1%	70.6%	74.5%	71.9%
Sponsor IRR at Year 25	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%
Debt Interest Rate	5.5%	7.5%	5.5%	7.5%	5.5%	7.5%	5.5%	7.5%
After-Tax WACC	5.6%	6.7%	5.5%	6.6%	5.6%	6.7%	5.9%	7.1%

No Tax Appetite (Figure 12)						
Refundable Credits:	BAU (30% ITC)		10% ITC		PTC	
1st-Year PPA Price	$75.9	$82.5	$92.2	$100.6	$86.6	$94.4
Real Levelized PPA Price	$74.4	$80.9	$90.4	$98.7	$84.9	$92.6
Nominal Levelized PPA Price	$88.3	$96.1	$107.3	$117.1	$100.8	$109.9
Sponsor Equity %	45.1%	46.9%	31.1%	33.4%	35.9%	38.0%
Project Debt %	54.9%	53.1%	68.9%	66.6%	64.1%	62.0%
Sponsor IRR at Year 25	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%
Debt Interest Rate	5.5%	7.5%	5.5%	7.5%	5.5%	7.5%
After-Tax WACC	7.2%	8.0%	6.0%	7.0%	6.4%	7.3%