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# **Revealing the Hidden Value that the Federal Investment Tax Credit and Treasury Cash Grant Provide To Community Wind Projects**

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## Executive Summary

Although the global financial crisis of 2008/2009 has slowed wind power development in general, the crisis has, in several respects, been a blessing in disguise for community wind project development in the United States.<sup>1</sup> For example, the crisis-induced slowdown in the broader commercial wind market has, for the first time since 2004, created slack in the supply chain, creating an opportunity for shovel-ready community wind projects to finally proceed towards construction. Many such projects had been forced to wait on the sidelines as the commercial wind boom of 2005-2008 consumed virtually all available resources needed to complete a wind project (e.g., turbines, cranes, contractors).

More importantly and to the point of this report, the financial crisis spawned two major stimulus packages in the U.S. that, in combination, have fundamentally reshaped the federal policy landscape for wind power in general, and for community wind projects in particular. Most notably, qualifying wind projects can now, for a limited time only, choose either a 30% investment tax credit (ITC) or a 30% cash grant in lieu of the production tax credit (PTC) that wind has historically received. To qualify for the 30% ITC, projects must be placed in service by the end of 2012. To qualify for the 30% cash grant, projects must either be operational by the end of 2010, or else must begin construction by then and be placed in service by the end of 2012.

It stands to reason that community wind, which has had more difficulty using the PTC than has commercial wind, may benefit disproportionately from this newfound ability to choose among these federal incentives. This report confirms this hypothesis. On the basis of face value alone, the 30% ITC or cash grant – both of which depend on the size of the investment rather than on the quantity of power produced – will be worth more than the PTC to most community wind projects, which on average may cost more or generate less than their commercial counterparts.

Just as importantly, however, and not to be overlooked, are a handful of ancillary benefits that accompany the 30% ITC and/or cash grant, but not the PTC. These ancillary benefits, many of which circumvent barriers that have plagued community wind projects in the United States for years, are summarized in Table ES-1. The first six apply equally to the 30% ITC or cash grant, the seventh applies equally to the PTC or grant, while the last two only apply to the grant.

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<sup>i</sup> In this report, “community wind” power development refers to wind projects that are locally owned (meaning that one or more members of the local community have a significant and direct financial stake in the project, other than through land lease or property tax revenue), consist of utility-scale turbines (generally 100 kW or larger), and are interconnected on either the customer or utility side of the electric meter (i.e., either displacing power purchased from the grid, or selling power directly to the grid, respectively). Though relatively common historically in certain European countries such as Denmark and Germany, community wind is still very much a niche market in the United States, accounting for just 2% of total installed wind capacity at the end of 2008 (a contribution that has remained more or less constant since 2004).

**Table ES-1. Overview of Ancillary Benefits of Choosing the ITC or Grant Over the PTC**

	PTC	30% ITC	30% Cash Grant
<b>Alternative Minimum Tax (AMT)</b>	The PTC is exempt from the AMT for just the first 4 (of 10) years	The 30% ITC is fully exempt from the AMT; The AMT is not applicable to 30% cash grant	
<b>Haircut for Government Grants</b>	The PTC is reduced by government grants applied to capital costs	The 30% ITC/grant is reduced only by government grants that are <i>not</i> taxed as income (most grants are taxable)	
<b>Haircut for Subsidized Financing</b>	The PTC is reduced by government-subsidized low-interest loans	The Recovery Act eliminated this haircut for the 30% ITC/grant (but not for the PTC)	
<b>Owner/Operator Requirement</b>	The owner must also operate the project	No such requirement – enables leasing	
<b>Power Sale Requirement</b>	Power must be sold to an unrelated person	No power sales requirement for the ITC/grant (this benefits behind-the-meter projects)	
<b>Performance Risk</b>	Underperformance reduces cash <i>and</i> PTCs	Underperformance only reduces cash revenue (does not impact the 30% ITC/grant)	
<b>At-Risk Rules</b>	Not applicable	ITC based on amount “at risk”	Not applicable
<b>Passive Credit/Loss Limitations</b>	Individuals who are passive investors can only apply the PTC, ITC, and losses against passive income	30% cash grant not subject to passive credit limitations	
<b>Securities Regulation</b>	PTC and ITC do not provide cash with which to capitalize the project	Grant may reduce number of investors needed	

This report demonstrates that these ancillary benefits could, in aggregate, be worth even more to a typical community wind project than the greater face value provided by the 30% ITC or cash grant relative to the PTC. For example, Chapter 4 presents modeling results for a hypothetical 10.5 MW community wind project that benefits by roughly \$40/MWh from electing the 30% cash grant over the PTC. Only about \$15/MWh of this \$40/MWh benefit is attributable to the 30% ITC or cash grant’s incremental face value relative to the PTC; the remaining \$25/MWh flows from just four of the nine ancillary benefits listed in Table ES-1.

Quantitative analysis of these ancillary benefits may also inform the development of a policy agenda for community wind, by revealing which of these benefits are most valuable to the sector. For example, further analysis of the 10.5 MW project highlights the importance of the 30% cash grant – and especially the relief that it provides from passive credit limitations – for passive investors in community wind projects. Specifically, choosing the 30% ITC over the PTC does not provide much value to passive investors, because the passive credit limitations require all tax benefits (including the PTC or ITC and depreciation deductions) to be carried forward – potentially for many years – until they can be fully applied against the project’s own tax obligations. This delay reduces the present value of these tax benefits. Only if the project elects

the 30% cash grant, which is not subject to the passive credit limitations, does it realize the full potential of wind's temporary ability to choose among these incentives.

Passive investors have not played a significant role in most community wind projects built in the United States to date – perhaps precisely because of the negative impact of the passive credit limitations on the value of the PTC. But if community wind is going to penetrate the broader wind market to any significant degree going forward, it may need to increasingly look to passive investors to finance that expansion. In this light, seeking to extend the very limited window of opportunity for the 30% cash grant – which singlehandedly removes the largest impediment to the participation of passive investors in community wind projects – may be a logical top policy priority for the community wind sector. Alternatively, exempting the PTC and ITC from the passive credit limitations could provide similar relief, though without the other benefits provided by the receipt of cash rather than a tax credit.

# 1. Introduction

Despite being one of the earliest development models for wind power, community wind power development (“community wind”) is surprisingly hard to pin down and define. Broadly speaking, community wind can include several different turbine applications (e.g., projects supplying power to the grid as well as projects displacing power purchased from the grid), a range of turbine and project sizes (e.g., from a single 100 kW turbine up to a wind “farm” consisting of numerous MW-class turbines), and a variety of project participants (e.g., from individual farmers to municipalities) using an assortment of financing and ownership structures (e.g., from simple project finance to complicated tax structures).

With a nod to this diversity, one broad definition of community wind that has held up over the years – perhaps precisely because it is so broad – includes projects that:

- Are locally owned, meaning that one or more members of the local community have a direct financial stake in the project (as distinct from land lease or property tax revenue);
- Consist of utility-scale turbines (generally 100 kW or larger); and
- Are interconnected on either the customer or utility side of the electric meter (i.e., either displacing power purchased from the grid, or selling power directly to the grid, respectively).

Given the vague nature of this definition, however, it is perhaps just as instructive to define community wind by what it is not. At least for the purposes of this report, the following types of wind projects *are not* considered to be community wind:

- Private “commercial wind” projects developed by professional wind developers and owned exclusively by commercial or institutional entities that may not be local to the area;
- “Utility-owned wind” projects, including not only projects owned by investor-owned utilities, but also those owned by publicly owned utilities (i.e., municipal utilities and rural electric cooperatives);<sup>1</sup> and
- “Small wind” projects involving wind turbines of less than 100 kW.

However defined, most community wind projects share in common the fact that they can be particularly challenging to develop and finance. Not only do they face the same challenges confronting all wind projects – e.g., finding a suitable site, negotiating turbine supply agreements and power purchase agreements, managing project construction, interconnecting to the grid – but they must typically face these challenges on tighter budgets and with less-experienced staff, while developing smaller projects that have difficulty attracting the attention of turbine vendors and capturing economies of scale.

Just as important, and more to the point of this report, community wind projects have historically had more difficulty than commercial wind projects in using the federal tax incentives that are provided to wind power in the U.S. Historically, these have included the 10-year production tax

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<sup>1</sup> Though it should be obvious, the author notes that this definition of community wind is just one among many, and that some definitions consider wind projects owned by publicly owned utilities to be community wind projects.

credit (“PTC”) and accelerated tax depreciation deductions (which together, along with the investment tax credit described later, will be referred to as a project’s “Tax Benefits”). On a present value basis, these Tax Benefits amount to more than one-third of the installed cost of a wind project, and therefore represent a significant incentive to wind power development (and conversely, a significant barrier to those projects that cannot make good use of them).

In recent years, analysts and community wind proponents alike have highlighted the relative difficulty that community wind projects have in utilizing wind power’s Tax Benefits (Bolinger et al., 2004; Farrell, 2008). This difficulty stems both from the nature of most community wind investors – which tend to be individuals (or partnerships or limited liability companies comprised of individuals) – as well as the way in which some of the tax rules surrounding wind power’s Tax Benefits apply to individuals (more details on these tax rules are provided in Chapter 3).

With community wind accounting for just 2% (or 4% if one defines community wind to include projects owned by publicly owned utilities) of total installed wind capacity in the U.S. at the end of 2008 (Wiser and Bolinger, 2009), however, and with the overall U.S. wind market growing in excess of 30% per year since 2004, there has been little urgency at the federal level to address any real or perceived discrimination against community wind. In other words, the strength of the commercial wind market from 2005-2008 largely undermined any notion that federal incentives toward wind power are overly burdensome.

The shortcomings of using the federal tax code to stimulate any type of wind project development – commercial or community – became quite clear, however, with the onset of the global financial crisis in the fall of 2008. As the supply of tax equity dried up, wind project finance ground to a halt. As a result, the interests of commercial and community wind came into sharp alignment regarding the limitations of using the tax code to stimulate wind power development. Behind this united front, the wind industry was able to shepherd through the passage of important, though only temporary, policy changes as part of *The Energy Improvement and Extension Act of 2008* (“the Extension Act”) and, more importantly, *The American Recovery and Reinvestment Act of 2009* (“the Recovery Act”). Perhaps the most notable of these changes, stemming from the Recovery Act, provides wind projects with a choice of the existing PTC, a 30% investment tax credit (“ITC”), or a 30% cash grant.

#### **Why Community Wind Matters**

Given that community wind makes up just 2% of the overall U.S. wind market (or 4% if one defines community wind to include projects owned by publicly owned utilities), one might reasonably ask why this alternative form of development holds any import to the broader industry. The answer is that, in several ways, the impact of community wind may extend well beyond its modest market penetration. For example, a number of studies have found that, through local ownership and greater use of local contractors, community wind provides greater local economic development benefits than does the more-common commercial wind development model (Lantz and Tegen, 2008). Greater local benefits, in turn, lead to increased public acceptance of wind power (Bolinger, 2001) – a critical benefit as siting and permitting challenges increasingly threaten the expansion of the industry in certain parts of the U.S. Finally, by appealing to a broader investor base, community wind has the potential to tap into a heretofore largely untapped pool of capital held by individual investors. With tax equity investors reeling under the strain of the financial crisis, this new source of capital may be important to the long-term expansion of the industry. In these ways, the current modest market penetration of community wind belies its potential significance to the overall wind sector.



Earlier work has already established the relative benefits of the Recovery Act to wind power in general, based on both quantitative and qualitative considerations surrounding the ability to elect a 30% ITC or cash grant in lieu of the PTC (Bolinger et al., 2009; Karcher, 2009). Not surprisingly, the early award announcements from the U.S. Treasury confirm strong interest in the grant program, at least among commercial wind projects.<sup>2</sup>

This report builds on the earlier work by taking a more-detailed look at both the Extension Act and the Recovery Act, specifically with community wind in mind. It explores the notion that the stimulus-related changes to U.S. wind power policy are especially favorable to community wind projects – i.e., likely even more favorable than they are to commercial wind projects. To facilitate the examination of this hypothesis, the report focuses on just one segment of the community wind market – projects owned by private rather than public entities.

Following this introduction, Section 2 provides an overview of federal policy towards community wind, both pre- and post-stimulus. Section 3 describes numerous policy-related barriers to community wind that exist under the PTC, and how policy changes in the Extension Act and the Recovery Act help to overcome these barriers. Section 4 uses a financial pro forma model to quantify the benefits of these stimulus-induced policy changes to two hypothetical community wind projects. Section 5 concludes with a discussion of the analysis results, and what they imply for a community wind policy agenda in the United States.

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<sup>2</sup> As of December 11, 2009, the Treasury had allocated more than \$1.724 billion in cash grants under this program, with more than \$1.535 billion of that total going to “large wind” facilities (and another \$223,000 going to “small wind” projects). Only two of these “large wind” projects – each a single 600 kW turbine interconnected on the customer side of the meter – fall under the definition of community wind used in this report. These two projects received grants that total nearly \$1.2 million, representing less than 0.1% of the total amount awarded to wind power at that time.

## **2. Overview of Federal Policy Incentives for Community Wind**

For the most part, the federal policies and incentives that are of potential benefit to community wind are the same as those available to commercial wind. That is, with a few exceptions, the federal government does not explicitly distinguish between commercial and community wind power development.<sup>3</sup> This section describes the federal incentives for wind power – and by extension, for community wind power – both prior to and after the passage of the Extension Act in late 2008 and the Recovery Act in early 2009.

### **2.1 Pre-Stimulus**

Prior to the financial crisis of 2008 and the two economic stimulus packages that followed, the primary federal incentives for wind power in the U.S. were the 10-year PTC and accelerated tax depreciation. Smaller in magnitude, but nevertheless of potential importance to some community wind projects, were grants from the United States Department of Agriculture (“USDA grants”) and Clean Renewable Energy Bonds (“CREBs”).

#### **2.1.1 The PTC**

As authorized by the Energy Policy Act of 1992 and amended over time, Section 45 of the Internal Revenue Code (“the Code”) provides a production tax credit for power generated by certain types of renewable energy projects. For wind power, the PTC provides an inflation-adjusted \$15 per MegaWatt-hour (“MWh”) credit for a 10-year period (the credit amounts vary for other renewable power technologies). For 2009, the inflation-adjusted PTC stands at \$21/MWh. To receive the credit, a qualifying project must demonstrate that its turbines have been placed in service by the current deadline. Since its original expiration in mid-1999, the PTC has subsequently expired and/or been extended (seldom for more than a year or two) on seven different occasions – most recently by the Recovery Act, which extended the in-service deadline through the end of 2012. For more information on the PTC and the impact of its short-term extensions on the growth of the wind power industry in the U.S., see Wisner et al. (2007).

Assuming an installed project cost of \$2,000/kW and a capacity factor of 35%,<sup>4</sup> the value of the PTC on a present value basis (assuming a 10% nominal discount rate) comes to roughly 22% of installed project costs. As such, the PTC provides a significant incentive for wind power development.

#### **2.1.2 Accelerated Tax Depreciation**

Section 168 of the Code provides a Modified Accelerated Cost Recovery System (“MACRS”) through which certain investments in wind (and other types of) projects can be recovered through

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<sup>3</sup> This is, in part, a definitional issue – as noted in Chapter 1, community wind is not well-defined, which makes it difficult to craft specific policies in support of it.

<sup>4</sup> Both of these parameters approximate the nationwide average in 2008, as reported in Wisner and Bolinger (2009).

accelerated income tax deductions for depreciation. Under this provision, which has no expiration date, certain wind project equipment – including the turbines, generators, power conditioning equipment, transfer equipment, and related parts up to the electrical transmission stage – may qualify for 5-year, 200 percent (i.e., double) declining-balance depreciation. A typical rule of thumb is that 90% to 95% of the total costs of a wind project qualify for 5-year MACRS depreciation, with much of the remaining amount depreciated over 15 years or longer (or not at all).

Depreciating such a large portion of the project using an accelerated schedule creates a taxable loss for the project in its early years, which can be used by investors in the project to offset income from other business activities (i.e., apart from the project) in the same year. Alternatively, if the investor has no other taxable income to shelter, depreciation deductions in excess of net income generated by a project can be carried forward to future years under certain circumstances. However, due to the time value of money and the fact that a significant share of overall wind project returns come from accelerated tax depreciation (and PTCs), it is important for an investor to be able to utilize such Tax Benefits in the years in which they are generated.

Assuming that 90% of a project's installed cost is eligible for 5-year MACRS depreciation, 5% is eligible for a 15-year MACRS schedule, and the remaining 5% is not depreciable at all, the tax benefit provided by accelerated depreciation comes to 29% of total installed costs on a present value basis. Only 13% of this 29%, however, is attributable to the acceleration of the depreciation schedule; the remaining 16% would be realized even if the project were instead depreciated using a less-advantageous 20-year straight-line schedule (which more closely matches the project's expected life).

Thus, in combination, the PTC and accelerated tax depreciation – i.e., the project's Tax Benefits – provide a subsidy that, on a present value basis, equates to roughly 35% (22% for the PTC plus 13% for the acceleration of tax depreciation) of the installed cost of a typical wind project. This is obviously a substantial benefit, and notably a benefit delivered entirely through the tax code.

### **2.1.3 USDA Grants and Clean Renewable Energy Bonds**

Although the PTC and accelerated tax depreciation have historically been the primary federal incentives for both commercial and community wind projects that are owned by taxable entities, since 2003 the federal government has also offered grants to such projects that are located in rural areas. Specifically, Section 9006 of Title IX of *The Farm Security and Rural Investment Act of 2002* established *The Renewable Energy Systems and Energy Efficiency Improvements Program* (the “Section 9006 program”). Administered by the USDA, the Section 9006 program provided grants and loan guarantees to farmers, ranchers, and rural small businesses for assistance with purchasing renewable energy systems and making energy efficiency improvements.

In May 2008, the Section 9006 program was converted to the *Rural Energy for America Program* (the “REAP”) by *The Food, Conservation, and Energy Act of 2008*. The REAP is little changed from the Section 9006 program – i.e., the REAP still targets agricultural producers and rural small businesses (including special purpose project companies set up specifically to own

wind projects) with grants and loan guarantees to encourage the installation of renewable energy systems and energy efficient upgrades. Grants are limited to the lesser of 25% of the project's cost or \$500,000, while loan guarantees may not exceed \$25 million (the combined amount of a grant and loan guarantee may not exceed 75% of a project's cost).

Meanwhile, certain tax-exempt owners of wind projects are eligible to finance their projects using Clean Renewable Energy Bonds ("CREBs"). First conceived under *The Energy Policy Act of 2005* ("EPAct 2005"), CREBs are a financing tool for tax-exempt entities unable to directly use the federal Tax Benefits provided to wind and other renewable energy projects. CREBs are "tax credit bonds," which means that the bond purchaser receives a federal income tax credit in lieu of interest payments. From the borrower's perspective, therefore, CREBs are – at least in theory – the equivalent of a zero-interest loan. In practice, however, CREBs issuers have often had to issue the bonds with a small supplemental interest payment – in addition to the federal income tax credit – in order to entice buyers.

EPAct 2005 authorized \$800 million of CREB funding, which was allocated through a smallest-to-largest solicitation/auction process in early 2006. Another \$400 million was authorized in late 2006, and allocated in February 2008. Collectively, these \$1.2 billion in allocations are now referred to as "old CREBs," to distinguish them from the \$2.4 billion in "new CREBs" authorizations contained in the late 2008 and early 2009 federal stimulus bills (see Section 2.2). This old/new distinction is pertinent because "new CREBs" must follow a different set of rules – largely aimed at increasing the bonds' effectiveness – than existed under the "old CREBs."

## **2.2 Changes Resulting From the 2008 and 2009 Stimulus Packages**

The first stimulus package – the Extension Act, which became law in October 2008 – contained what at the time seemed like only two changes related to federal wind power incentives. First, it extended the PTC's "in-service deadline" (i.e., the date by which the project must be operational in order to qualify for the PTC) by one year, through 2009. Second, it authorized an additional \$800 million in CREB allocations (CREBs are not limited to wind projects, but can be used to finance wind).

The rest of the Extension Act's changes to federal incentives for renewable energy were targeted primarily at solar power. For example, it extended the Section 48 investment tax credit (ITC) for eight years, through 2016, and removed the utility prohibition on using the ITC. It also fully exempted the ITC from the alternative minimum tax. At the time, these changes were considered a major policy victory for the solar industry, but held little import for the wind industry.

The relevance of the Extension Act to the wind sector increased significantly, however, once the second stimulus package – the Recovery Act, which became law in February 2009 – gave wind access to the ITC. Specifically, the Recovery Act made three important changes to federal policy towards wind power. First, it extended the "in-service" deadline for the PTC through the end of 2012, which is the longest extension in the history of that credit. Second, during that same time period it gave qualifying wind projects the option to elect the 30% ITC in lieu of the PTC. Third, and perhaps most significantly for community wind projects, the Recovery Act

allows projects using wind and other qualifying renewable energy technologies to exchange the 30% ITC for a cash grant of equal value. This cash grant option is only temporary, however. To qualify, eligible projects must either be placed in service in 2009 or 2010, or else construction must have started prior to 2011, with the project placed in service by the end of 2012.

In addition to providing access to either the ITC or an equivalent cash grant, the Recovery Act also eliminated the ITC's anti-double-dipping (or "haircut") provision for subsidized energy financing. Previously, an ITC-eligible project that was financed by a government-subsidized loan would need to reduce the "basis" to which the ITC applies by an amount equal to the amount of subsidized financing. The Recovery Act eliminated this haircut for the ITC, but not for the PTC.<sup>5</sup>

Finally, the Recovery Act also authorized an additional \$1.6 billion in CREB allocations,<sup>6</sup> and modified and expanded a federal loan guarantee program that had been created under EPAct 2005. Although the loan guarantee program in particular has attracted much attention, neither of these two Recovery Act changes is directly relevant to this report, and therefore will not be described or analyzed further.

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<sup>5</sup> Again, this change was targeted primarily at the solar industry, and is in response to lobbying by the City of Berkeley and other municipalities. These local governments were concerned that the ITC's subsidized energy financing haircut would otherwise limit the effectiveness of new municipal programs being developed in Berkeley and elsewhere to help residents finance the installation of rooftop photovoltaic systems through property tax assessments (Bolinger, 2008a).

<sup>6</sup> Applications for the \$2.4 billion in "new CREBs" authorized by the Extension Act (\$800 million) and Recovery Act (\$1.6 billion) were due on August 4, 2009. On October 27, 2009, \$2.2 billion in CREB allocations were awarded, with more than \$70 million going to wind projects owned by governmental entities (excluding publicly owned utilities such as municipal utilities and rural electric cooperatives). The \$800 million authorization reserved for rural electric cooperatives was undersubscribed by \$200 million, which is why only \$2.2 billion was allocated (rather than the \$2.4 billion authorized).

### **3. Ancillary Benefits of Electing the 30% ITC or Cash Grant Over the PTC**

As demonstrated by a number of analysts (Bolinger et al., 2009; Karcher, 2009), the option granted by the Recovery Act to elect the 30% ITC in lieu of the PTC will favor those wind projects with above-average installed costs and below-average energy production, because the ITC is based on the size of the investment rather than on the amount of energy generated. Since many community wind projects may fall into this category – i.e., relatively high-cost due to small size and inability to capitalize on wind’s economies of scale, and relatively low-production due to possible site limitations – the option to elect the ITC is undoubtedly a positive development for community wind.

Even more important, though, is the option to convert that 30% ITC into a cash grant of equivalent value. By receiving the incentive in cash rather than as a tax credit, the project is less-dependent on third-party tax equity investors, and can rely more heavily on conventional forms of finance that are more readily available to community wind power investors.

Beyond these rather obvious direct benefits of choosing the ITC or cash grant over the PTC, however, lie a number of less-obvious indirect or ancillary benefits that, despite their relative obscurity, may be no less important. Specifically, a community wind project that elects the ITC or cash grant will also capture a handful of ancillary benefits that are tied, purely by virtue of association, to the ITC and/or cash grant. In many cases, these ancillary benefits overcome or circumvent policy barriers that have plagued community wind projects in the U.S. for years. As such, choosing the ITC or cash grant can, by capturing these ancillary benefits, provide significant value to a community wind project, above and beyond the direct or face value of the ITC or grant relative to the PTC.

Table 1 provides a high-level overview of nine such ancillary benefits of choosing the 30% ITC or 30% cash grant. The first six apply equally to the ITC or grant, the seventh applies equally to the PTC or grant, while the last two only accrue to the grant. The rest of this chapter describes each of these ancillary benefits in more detail, while Chapter 4 analyzes the value that a number of these benefits provide to a hypothetical community wind project.

**Table 1. Overview of Ancillary Benefits of Choosing the ITC or Grant Over the PTC**

	PTC	30% ITC	30% Cash Grant
<b>Alternative Minimum Tax (AMT)</b>	The PTC is exempt from the AMT for just the first 4 (of 10) years	The 30% ITC is fully exempt from the AMT; The AMT is not applicable to 30% cash grant	
<b>Haircut for Government Grants</b>	The PTC is reduced by government grants applied to capital costs	The 30% ITC/grant is reduced only by government grants that are <i>not</i> taxed as income (most grants are taxable)	
<b>Haircut for Subsidized Financing</b>	The PTC is reduced by government-subsidized low-interest loans	The Recovery Act eliminated this haircut for the 30% ITC/grant (but not for the PTC)	
<b>Owner/Operator Requirement</b>	The owner must also operate the project	No such requirement – enables leasing	
<b>Power Sale Requirement</b>	Power must be sold to an unrelated person	No power sales requirement for the ITC/grant (this benefits behind-the-meter projects)	
<b>Performance Risk</b>	Underperformance reduces cash <i>and</i> PTCs	Underperformance only reduces cash revenue (does not impact the 30% ITC/grant)	
<b>At-Risk Rules</b>	Not applicable	ITC based on amount “at risk”	Not applicable
<b>Passive Credit/Loss Limitations</b>	Individuals who are passive investors can only apply the PTC, ITC, and losses against passive income	30% cash grant not subject to passive credit limitations	
<b>Securities Regulation</b>	PTC and ITC do not provide cash with which to capitalize the project	Grant may reduce number of investors needed	

### **3.1 The Alternative Minimum Tax**

The alternative minimum tax (“AMT”) is, in effect, a parallel system of taxation enacted to ensure that taxpayers who make extensive use of tax credits still pay their fair share of income tax. Though originally designed to target only the wealthiest taxpayers, the AMT has not been regularly adjusted for inflation over time, and as a result an increasing number of middle-class taxpayers have become subject to the AMT in recent years.

Any taxpayer subject to the AMT will likely not be able to make efficient use of federal tax incentives for renewable energy. This has increasingly been an issue for wind and solar projects. In recognition of this issue, Congress included provisions in *The American Jobs Creation Act of 2004* to exempt the PTC from the AMT, but only for the first four years of the PTC’s ten-year period. No similar exemption existed for the ITC until the Recovery Act of 2009, which provided the ITC with a *full* exemption from the AMT. The 30% cash grant established by the Recovery Act and intended to provide the same value as the ITC (except in cash) is similarly not impacted by the AMT.

Hence, by electing the 30% ITC or equivalent cash grant instead of the PTC, a community wind project can avoid the AMT entirely, rather than only partially under the PTC.

### **3.2 The PTC's Anti-Double Dipping Provisions**

Section 45(b)(3) of the Code requires that the value of the PTC be reduced (though not by more than 50%) if a project makes use of any of the following: government grants applied toward capital or construction costs (e.g., USDA REAP grants), tax-exempt bonds, subsidized energy financing (e.g., government-subsidized low-interest loans), or other federal tax credits. In contrast, Section 48 of the Code, which pertains to the 30% ITC (for business taxpayers), includes fewer of these restrictions. Whether pertaining to the PTC or ITC, the purpose of these “haircut” provisions is to prevent projects from “double-dipping” among multiple government incentives, and thereby perhaps relying too heavily on government support.

The PTC's anti-double-dipping provisions have historically hindered community wind projects from taking full advantage of the various government incentives available to them. This section explores this issue by examining differences between the PTC and ITC with respect to two of the four haircut provisions listed in Section 45 of the Code –government grants and subsidized energy financing – both of which could be important to community wind projects.

#### **3.2.1 Haircut for Government Grants**

The value of the PTC is reduced by the receipt of any government grant that is applied towards the project's capital or construction costs, regardless of whether or not that grant is taxed as income. Such grants, however, only trigger an ITC haircut (by reducing the project's basis to which the ITC applies) if they are *not* taxed as income to the recipient.<sup>7</sup> Grants that are considered to be taxable income do not negatively interact with the ITC or, by extension, the 30% cash grant. In other words, the purpose to which the grant is applied has no bearing under the 30% ITC or equivalent 30% cash grant; all that matters is whether or not the grant is taxed as income.

The importance of this issue for community wind is demonstrated by the different treatment of USDA REAP grants under the PTC and ITC (or equivalent cash grant). As a program designed to encourage the development of renewable generation in rural areas with the intent of strengthening rural economies, the REAP is a good fit for community wind. Yet, under the PTC, much of the value of the REAP grant is effectively forfeited to the PTC haircut.

According to a 2006 Berkeley Lab report (Bolinger, 2006), Section 9006 grants (the precursor to REAP grants) lose between 11% and 46% of their face value (depending on the wind project's capital cost and capacity factor) to PTC haircuts. And because Section 9006 grants are most

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<sup>7</sup> Government grants that are not taxed as income also reduce the project's depreciable basis (i.e., the dollar amount that can be depreciated for tax purposes), regardless of whether the project elects the PTC, 30% ITC, or 30% cash grant. One notable exception to this general rule is the 30% cash grant itself; even though the 30% cash grant is not taxed, the Recovery Act requires that the project's depreciable basis be reduced by only half of the grant's value. This 15% basis reduction (i.e., half of 30%) mirrors that required under the 30% ITC.



likely considered taxable income, an additional 20%-37% (depending on tax bracket) is lost to income tax payments on the grant. In combination, depending on the specific tax bracket, capital cost, and capacity factor that pertain to a given wind project, the percentage of a Section 9006 grant lost to both income tax payments and the PTC haircut can range from 31% to 83% of the dollar value of the grant.

In contrast, because REAP grants are most likely considered taxable income, they will not negatively interact with the 30% ITC or equivalent cash grant. Recipients will need to pay income tax on the REAP grant, but will not have to reduce the basis of the project to which the 30% ITC or equivalent cash grant apply. In this way, electing the ITC or equivalent cash grant instead of the PTC provides extra value – above and beyond the relative face value of the incentives themselves – to a community wind project that has also received a REAP grant or other similar government grant.

### **3.2.2 Haircut for Subsidized Energy Financing**

The value of the PTC is also reduced by the proportion of a project's overall cost (capped at 50%) that is financed by "subsidized energy financing," which is defined in Section 48(a)(4)(C) to mean "...financing provided under a Federal, State, or local program a principal purpose of which is to provide subsidized financing for projects designed to conserve or produce energy." The instructions to IRS Form 6497 ("Information Return of Nontaxable Energy Grants or Subsidized Energy Financing") expand upon the Section 48 definition, noting that "Financing is subsidized if the terms of the financing provided to the recipient in connection with the program or used to raise funds for the program are more favorable than terms generally available commercially." Moreover, "The source of the funds for a program is not a factor in determining whether the financing is subsidized."

Hence, most government-sponsored low-interest loan programs will likely be considered subsidized energy financing, and will therefore cut the value of the PTC in half (presuming that more than 50% of the project is financed through the program). In contrast, the Recovery Act eliminated the ITC haircut for subsidized energy financing. As such, electing the ITC or equivalent cash grant instead of the PTC provides extra value – above and beyond the relative face value of the incentives themselves – to a community wind project that hopes to take advantage of a government-sponsored low-interest loan program.

### **3.3 Owner/Operator Requirement**

Section 45(a)(2)(A) of the Code requires that electricity must be "produced by the taxpayer" in order to be eligible for the PTC. In other words, the project owner (i.e., the taxpayer) must also operate the project and produce the electricity. This requirement effectively rules out the use of leasing as a financial tool, since by definition a lease requires a lessor (who owns the project) and a lessee (who operates the project) who are separate entities.

The 30% ITC and cash grant do not have any such owner/operator requirement (perhaps in part because the ITC and grant are not dependent on electricity being produced). As such, lease financing is now available to wind projects that elect the ITC or cash grant in lieu of the PTC.

Relative to the other third-party-finance structures that have traditionally been used in the wind industry (e.g., “partnership flip structures” – see Section 4.1.1), lease financing offers a number of potential advantages to community wind projects. For example, a lease can provide 100% project financing, and therefore 100% monetization of the project’s Tax Benefits. Furthermore, because leases are a familiar financing mechanism to banks and leasing companies (i.e., more so than the “partnership flip structures” that have been the norm), wind’s newfound ability to lease may serve to attract new tax equity investors into the wind sector, thereby broadening the pool of potential investors.<sup>8</sup>

On the other hand, it will be more expensive for local investors to buy out the tax equity investor’s interest in the project under a lease than it is under a partnership flip structure. In the latter, the buyout typically occurs after the tax equity investor’s interest has flipped down to a substantially reduced allocation of cash and tax flows, which greatly reduces the fair market value of the tax equity investor’s interest. A lease has no such flip in allocations, which means that the fair market value buyout price is based on the tax equity investor’s undiluted interest in the full project.

Although it is difficult to quantify the value created by having the ability to use lease financing, electing the 30% ITC or cash grant instead of the PTC nevertheless provides added flexibility or option value to a community wind project that is exploring a variety of financing structures and has an interest in lease financing.

### **3.4 Power Sales Requirement**

Section 45(a)(2)(B) of the Code requires that power must be sold to an unrelated person in order to qualify for the PTC. This requirement has been a nuisance for behind-the-meter community wind projects, where the wind power that is generated is consumed on site rather than sold elsewhere. The primary way that such projects have been able to use the PTC is through a third-party ownership arrangement, whereby a taxable entity owns the project and sells the power to the site host, presumably at a rate that reflects receipt of the PTC.<sup>9</sup> These types of arrangements, however, can be rather complicated from a legal perspective, and the expense of setting up such a structure may be prohibitive for what are typically small (single-turbine) projects.

Unlike the PTC, the 30% ITC and 30% cash grant do not require that the project’s power be sold (indeed, they do not really even require that the project generates much power). In this way,

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<sup>8</sup> Although leases are new to the wind sector (at least since the early 1990s when the PTC first became available), operating leases and sale/leaseback structures have been used on numerous occasions in recent years to finance solar projects (Bolinger, 2009), so there is precedence for the use of leasing structures in the renewable energy sector.

<sup>9</sup> In these types of arrangements, the site host effectively earns the applicable retail rate for all power produced (assuming net metering, or else a large enough load to absorb 100% of the turbine’s output) and pays the project owner a price that is presumably below the applicable retail rate. The project owner earns the project’s Tax Benefits (the PTC and accelerated tax depreciation), as well as cash revenue from power sales to the site host. The site host typically has an option to buy the project once the Tax Benefits have run their course (i.e., at the end of 10 years). Such third-party arrangements have become quite common in the non-residential solar photovoltaic market, where they are known as solar service contracts or PPAs (Bolinger, 2009), but remain relatively rare for community wind projects.

electing the 30% ITC or cash grant instead of the PTC provides extra value – above and beyond the relative face value of the incentives themselves – to a community wind project that is interconnected on the ratepayer side of the meter to offset power that would otherwise be purchased from a utility.

Moreover, this extra value comes at a time when net metering policies are becoming increasingly aggressive in terms of allowing larger systems to net meter. As shown in Figure 1, forty-two states plus Washington, DC have adopted net metering policies; more than half of these policies (those shaded in green in Figure 1) feature individual system capacity limits of 500 kW or greater, and could therefore accommodate a utility-scale turbine.

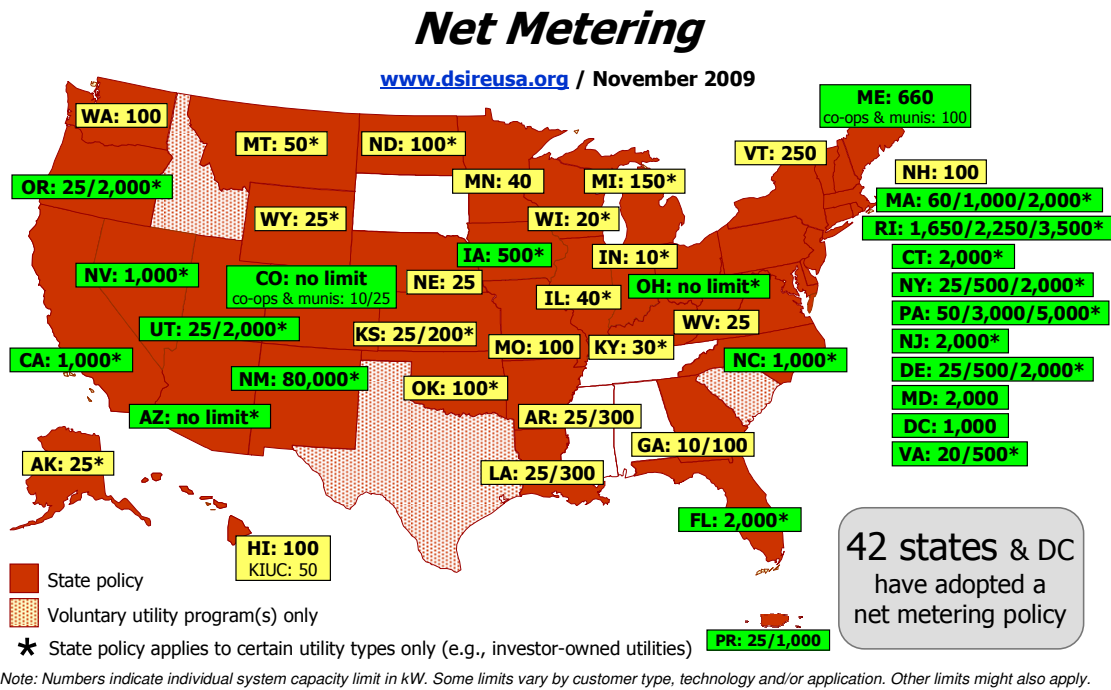


Figure 1. Net Metering Policies and System Size Limits

### 3.5 Performance Risk

If a community wind project that has elected the PTC generates less power than expected, it will not only receive less cash revenue from the sale of power and renewable energy certificates (RECs), but will also earn fewer PTCs. If that same project had instead elected the 30% ITC or cash grant – neither of which are tied to the amount of power generated – the only negative impact would be less cash revenue from power and REC sales. In this way, electing the 30% ITC or cash grant instead of the PTC reduces the amount of performance or technology risk that a project must incur. Though difficult to quantify economically (particularly in advance), this reduced risk profile nevertheless provides value to a wind project, above and beyond the relative face value of the incentives themselves.

### **3.6 At-Risk Rules**

Individuals (including partners and S corporation shareholders), estates, trusts, and certain closely held corporations (other than S corporations) are subject to what are known as the “at-risk” rules. These rules limit the basis to which the 30% ITC (Section 49 of the Code) and depreciation deductions (Section 465 of the Code) are applied to only the amount for which the investor is considered to be personally at risk. An investor is not considered to be personally at risk for any “nonqualified nonrecourse financing” – e.g., a loan from a relative, or from the project sponsor – that is used to capitalize the project, and therefore must reduce both the project’s ITC basis and depreciable basis by the amount of any such loan. As the loan is repaid over time, the investor can correspondingly increase the basis that is at risk, and thereby gradually reclaim the foregone credits and deductions. This delay, however, will negatively impact the present value of these credits and deductions.

Not all forms of nonrecourse financing trigger the at-risk rules. Investors are considered to be at risk for what is known as “qualified commercial financing” in Section 49 of the Code. Qualified commercial financing generally refers to loans that are borrowed on commercial terms from an unrelated person who is regularly engaged in the business of lending money. In other words, as long as a nonrecourse loan is obtained from a traditional lender (e.g., a bank) in an arms-length transaction, then the borrower will likely be considered at risk for repaying the loan, and will therefore not need to reduce the ITC under the at-risk rules in Section 49 of the Code.

The 30% cash grant is not subject to the Section 49 at-risk rules, in the sense that the basis to which the 30% grant applies need not be reduced for amounts not considered to be at risk. A related issue, however, is whether the investor is considered to be at risk for the 30% grant itself under Section 465 of the Code. If not, then an individual investor might conceivably need to reduce the project’s depreciable basis by the full amount of the grant. In fact, given that the 30% cash grant is not considered to be taxable income, one might even presume that the project’s depreciable basis must be reduced by the full amount of the grant regardless of the at-risk rules, since a project’s depreciable basis must typically be reduced by the amount of any non-taxable grants. However, as mentioned earlier in footnote 7, the Recovery Act requires that the project’s depreciable basis be reduced by only *half* of the grant’s value; this statutory requirement trumps all other considerations – e.g., both the at-risk rules and the general rule for non-taxable grants – in this case.

In summary, the at-risk rules in Section 49 of the Code apply to the 30% ITC, but not to the 30% cash grant or the PTC. However, because most projects can qualify for exemptions from these rules simply by seeking debt on commercial terms from qualified sources, the at-risk rules have not been a major barrier to community wind development to date. Therefore, in this case, even though the at-risk rules apply differently to the PTC, ITC, and cash grant, there does not seem to be any significant advantage to electing one over another.

### 3.7 Passive Credit and Loss Limitations

Any individual who is an investor in a community wind project but is not involved in the day-to-day operations of the project will most likely be considered by the IRS to be a passive investor in that project.<sup>10</sup> As a passive investor, an individual becomes subject to what are known as “passive credit” and “passive loss” limitations. The passive credit limitations require that the PTC or ITC – i.e., passive credits in this case – only be used to offset tax liability from passive income, either from the wind project itself or from other passive investments apart from the wind project. Net operating losses are treated similarly: the “passive loss limitations” require that passive losses only be used to reduce passive income, either from the project itself or from other passive investments outside of the project.

These passive credit and loss limitations typically restrict a passive investor’s ability to make efficient use of a community wind project’s tax benefits, because wind projects generate net operating losses in their early years (due to accelerated depreciation deductions) and because most individuals do not have other forms of passive income outside of the project. Specifically, the two most common types of income – “personal service income” (e.g., wages and salaries) and “portfolio income” (e.g., interest and dividends) – are *not* considered to be passive income (IRS, 2009). Instead, passive income is comprised primarily of certain rental income (other than that earned by real estate professionals), as well as income from other investments in which the investor does not materially participate (e.g., a passive investment in a limited liability company that owns an ethanol production plant).

As a result, most passive investors in community wind projects are only able to use the PTC or ITC, as well as net operating losses resulting from accelerated tax depreciation, to reduce the project’s own income tax obligations. The excess credits and operating losses are then carried forward to future years until they can be fully absorbed by income from the wind project itself. This could take up to 10 years or longer – a delay that severely reduces the present value of these Tax Benefits compared to using them in the years in which they are first generated.

Notably, the 30% cash grant created under the Recovery Act is *not* subject to the passive credit limitations (and, in fact, is not even a “credit”). As such, the grant can be used immediately, rather than having to be carried forward for many years. In this way, electing the 30% cash grant instead of the PTC or ITC provides extra value – above and beyond the relative face value of the incentives themselves – to a community wind project that is capitalized by passive investors.

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<sup>10</sup> IRS Publication 925, “Passive Activity and At-Risk Rules,” notes that “there are two kinds of passive activities: (1) trade or business activities in which you do not materially participate during the year, and (2) rental activities, even if you do materially participate in them, unless you are a real estate professional.” Publication 925 lists seven tests, any of which can be used to substantiate *material participation* in a trade or business activity. While too numerous and lengthy to exhaustively list here, these tests include: working more than 500 hours in the trade or business during the year; working more than 100 hours – and at least as much as any other person – in the trade or business during the year, and; working any amount of time in the trade or business during year, provided that your work represented substantially all of the work by all individuals during the year. For more information on these and additional material participation tests, or for further information on the at-risk and passive credit and loss limitations in general, see IRS Publication 925 (IRS, 2009).

### **3.8 Securities Regulation**

One of the purest and simplest ownership structures for community wind projects involves a group of farmers and/or other local investors pooling sufficient equity capital through the sale of shares to finance a jointly owned wind project. Although such projects are often organized according to cooperative principles, they are typically structured as limited liability companies (LLCs) for tax and legal reasons. As such, this financing/ownership structure is sometimes referred to as the “Cooperative LLC” structure (this structure will be described further in Section 4.1.2).<sup>11</sup>

When raising equity, sponsors of the Cooperative LLC structure (or any similar financing structure) must be cognizant of regulations from the Securities and Exchange Commission (SEC) that govern how one must go about selling shares in a project to the general public. These regulations are intended to protect the public from fraudulent investment schemes. A primary means of protection is a requirement that the shares (or “securities”) be “registered” with the SEC at the federal level (states have similar requirements). Registration requires the offeror to disclose detailed information about the security to the offeree, most commonly through a prospectus.

Registering securities with the SEC and issuing a formal prospectus can be expensive, primarily due to the legal fees involved. In recognition that the registration process can be financially and administratively burdensome for small businesses, however, the SEC has created rules to exempt certain securities and securities transactions from having to register. Some of these exemptions are based on the number (and type) of investors involved (Bolinger et al. 2004, Farrell 2008).

If a community wind project can capitalize 30% of its costs with a cash grant from the Treasury, then it will require less equity capital from the public, which presumably translates into fewer investors than if the project elected the PTC or ITC.<sup>12</sup> With fewer investors, the project may be able to more easily comply with certain exemptions from SEC regulation. Although it is difficult to quantify the value of more easily bypassing expensive securities registration requirements, electing the 30% cash grant instead of the ITC or PTC nevertheless provides added flexibility in how community wind project sponsors capitalize their projects.

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<sup>11</sup> The most well-known (and perhaps only) working examples of this structure in the United States are the nine “Minwind” community wind projects located in southwestern Minnesota.

<sup>12</sup> It is important to note that the 30% cash grant will not be paid until after the project achieves commercial operation. As such, if trying to minimize the number of equity investors, the project will need to find a bank willing to temporarily lend against this 30% grant until it is received.

## **4. Modeling the Benefits that the 30% ITC and Cash Grant Provide to Community Wind Projects**

Chapter 3 described both the direct and indirect benefits provided to community wind projects that elect the 30% ITC or cash grant over the PTC. This chapter uses a financial pro forma model to estimate the value that these benefits provide to several different types of community wind projects. Specifically, this chapter analyzes two hypothetical community wind projects – a 10.5 MW “grid supply” project and a 1.5 MW “behind-the-meter” project – financed under two different ownership structures, and under a variety of different policy scenarios. Section 4.1 describes the two financing structures that are modeled, Section 4.2 briefly describes the pro forma model and project parameters, and Section 4.3 discusses the modeling results.

### ***4.1 Financing Structures Modeled***

The two financing structures analyzed have been the two most common structures used for private sector community wind projects in the United States. The first – the Strategic Investor Partnership Flip structure – requires the participation of a tax equity investor, and therefore closely resembles structures used widely in the commercial wind sector. The second – referred to here as the Cooperative LLC structure – does not require a tax equity investor, and is therefore much simpler.

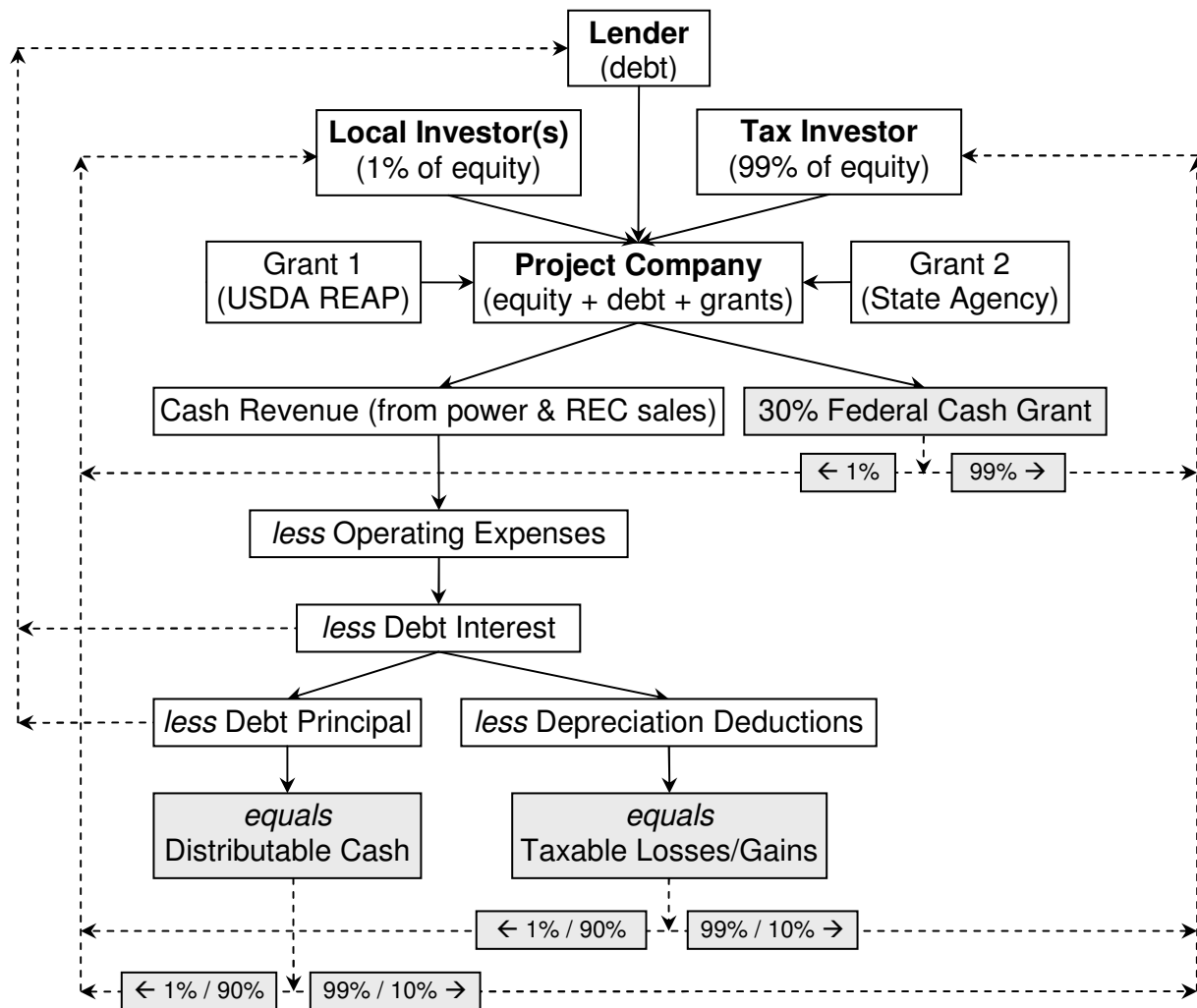
#### **4.1.1 The Strategic Investor Partnership Flip Structure**

In one form or another, “special allocation partnership flip” structures have been used to finance a significant portion of the wind capacity installed in the United States since the early part of this decade. At the most basic level, these are formal legal partnerships involving the project developer (or, in the case of community wind, one or more local investors) and one or more tax equity investors who are brought in to monetize the project’s Tax Benefits. “Special allocation” means that the various benefits created by the project – i.e., cash revenue, tax credits, and tax losses – need not be allocated to the various partners in accordance with their respective ownership stake in the project. Finally, the “flip” refers to the fact that most of the project’s benefits are initially allocated to the tax equity investor until it has achieved a pre-negotiated target rate of return, after which the allocations “flip” in favor of the developer (or local investors).

For the most part, commercial wind projects have favored a rather complex partnership flip structure that involves passive “institutional” tax equity investors (i.e., large investment banks and insurance companies) and allocations that are not proportional to each partner’s equity stake in the project. Harper et al. (2007) refer to this structure as the “Institutional Investor Flip” structure, and provide more detail on its mechanics, as well as advantages and disadvantages.

Community wind projects, on the other hand, have tended to use a simpler partnership flip structure – one that involves “strategic” tax equity investors (i.e., subsidiaries of utilities or large manufacturers that have a strategic interest in the wind sector) and allocations of cash and Tax

Benefits that are proportional to each partner’s equity stake. Harper et al. (2007) refer to this structure as the “Strategic Investor Flip” structure.<sup>13</sup>



**Figure 2. Schematic Diagram of Strategic Investor Flip Structure, With Debt**

Figure 2 provides a schematic overview of the Strategic Investor Flip structure. The project company is capitalized by equity from both a strategic tax equity investor (e.g., John Deere or Edison Mission Energy) and one or more local investors, with the former providing the vast majority of the equity (99% in this example). The project company may also benefit from one or more federal or state-level grants (e.g., USDA REAP grants), and may seek debt financing. Presuming the project has elected the 30% cash grant (rather than the 30% ITC or PTC), the grant is received shortly after the start of commercial operations, and is allocated proportional to each partner’s equity stake in the project (99% to 1% in this example). The project also receives cash revenue from the sale of power and RECs; this revenue becomes distributable cash once operating expenses (which may include a management fee paid to the local investor(s)) and debt

<sup>13</sup> For a discussion of the advantages of the Strategic Investor Flip over the Institutional Investor Flip for community wind projects, see Bolinger (2008b) or Bolinger and Karcher (2009).



service have been deducted, and also creates taxable losses (or gains) after accounting for depreciation deductions. Like the 30% cash grant, both distributable cash and taxable losses (or gains) are initially allocated in proportion to each partner's equity stake in the project (i.e., 99% to 1% in this example). Once the tax equity investor has achieved a pre-negotiated internal rate of return (IRR), however, the cash and tax allocations “flip” in favor of the local investor(s), who in this example receive 90% of all allocations thereafter (in Figure 2, the pre- and post-flip allocations are separated by a slash).<sup>14</sup> After the flip has occurred, the local investor(s) may also have an option to buy out the tax equity investor's stake in the project.<sup>15</sup>

The Strategic Investor Flip structure was first used for community wind projects in Minnesota and has since become commonplace in that state. As a result, this structure is sometimes referred to as the “Minnesota Flip” model.

#### **4.1.2 The Cooperative LLC Structure**

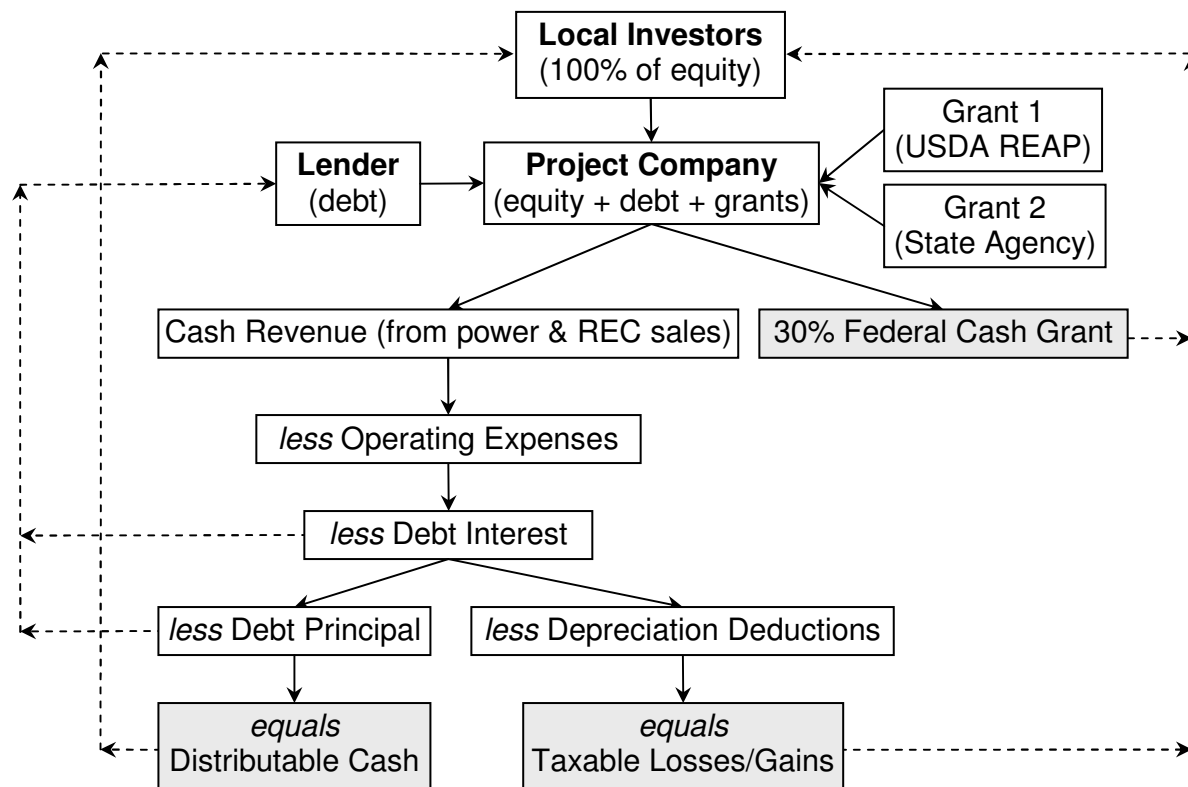
Also originating in Minnesota, where it has been used by the “Minwind” projects,<sup>16</sup> the Cooperative LLC structure is much simpler than the Strategic Investor Partnership Flip, largely because it does not involve any tax equity investors. Instead, this structure features a number of local farmers or other investors pooling their equity capital, utilizing any federal (e.g., from the USDA and/or Treasury) or state grants that are available, and borrowing the remainder of installed costs from local banks or other lenders. The local investors base the size of their individual equity investment on the amount of Tax Benefits that they can absorb – i.e., those with larger tax appetites invest more, while those with smaller tax appetites invest less. With no tax equity investors involved, there is no need to share any of the project's benefits, or for any flip in allocations at any point in time. Instead, the three benefit streams created by the project – i.e., the 30% cash grant, the distributable cash, and the taxable losses (or gains) – flow entirely back to the group of local farmers or investors who have provided all of the equity to the project company. Figure 3 provides a schematic overview of the Cooperative LLC structure, assuming the project has elected the 30% cash grant (rather than the ITC or PTC).

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<sup>14</sup> Under the PTC, this flip in allocations is typically projected to occur at the end of 10 years, once the PTCs are exhausted. Under the 30% ITC or cash grant, the flip may occur earlier, but typically not before the end of six years (since accelerated depreciation deductions often run through year six, and there is also a 5-year recapture period).

<sup>15</sup> To the benefit of the local investor(s), the tax equity investor's stake in the project will be worth significantly less after the flip has occurred, simply because its allocations are greatly reduced.

<sup>16</sup> The Minwind projects are a series of nine wind projects (Minwind I-IX, though developed and constructed as two larger projects – Minwind I & II and Minwind III-IX) located in southwestern Minnesota and owned by a group of local farmers. For background information on the Minwind projects, see <http://www.windustry.org/minwind-iii-ix-luverne-mn-community-wind-project>.



**Figure 3. Schematic Diagram of Cooperative LLC Structure**

The name of the structure alludes to the fact that the project is often envisioned or set up according to cooperative principles (e.g., consumers or producers joining together to more advantageously provide a service for themselves), but for legal reasons and to better access the Tax Benefits, the project entity will typically incorporate as a limited liability company (“LLC”) rather than as a cooperative.

Although this structure is relatively straightforward from a financial perspective, care must be taken to comply with all pertinent SEC regulations when soliciting equity contributions from the general public. As noted earlier in Section 3.8, such regulations can add significant additional legal expense to this structure in particular.<sup>17</sup> The current, but temporary, option to elect a 30% cash grant instead of the ITC or PTC may make it easier to minimize the potential impact of these regulations, by reducing the number of equity investors required to capitalize the project.<sup>18</sup>

## 4.2 Model Description and Project Assumptions

The model is a relatively straightforward financial pro forma model capable of analyzing both of the financing structures described in Section 4.1. All line items (e.g., operating costs and cash

<sup>17</sup> The Minwind projects were able to minimize such expense by restricting the number of “non-accredited” investors in each project to fewer than the SEC threshold that triggers greater regulation.

<sup>18</sup> It is important to note, however, that the cash grant will not be received until *after* the project has been constructed and has commenced commercial operations. Therefore, the project will need to find a bank willing to temporarily lend against this 30% grant until it is received.

and tax flows) are modeled in six-month increments over a period of twenty years. All returns are modeled on an after-tax basis. In general, the model is designed to accept assumptions about investors' target returns and then solve for the amount of revenue required to generate those returns, but it can also be run in the other direction – i.e., starting with revenue assumptions and calculating the returns provided.

**Table 2. Major Assumed Parameters for Hypothetical Community Wind Projects**

Commercial Operation Date	January 1, 2011		
Hard Cost	\$2200/kW		
Fixed O&M	\$20/kW-year		
Variable O&M	\$7.5/MWh		
Income Tax Rates	35% federal, 8% state		
Depreciation	90% 5-year MACRS + 5% 15-year MACRS + 5% undepreciable		
Project Type	<b>Grid Supply</b>	<b>Behind-the-Meter</b>	
Project Capacity	10.5 MW	1.5 MW	
Net Capacity Factor	30%	25%	
Construction Financing	50% debt (at 6% interest) for 6-month period		100% equity
Term Debt	10-yr term, 6.5% or 4.0% interest, 1.45 DSCR		No Debt
Grants	Two government grants for \$500k each		One \$500k grant
Total Installed Cost	\$2500/kW		\$2310/kW
Financing Structure	<b>Strategic Investor Flip</b>	<b>Cooperative LLC</b>	Cooperative LLC
After-Tax IRR Target	Tax Investor (TI): 10% over 10 years	Local Investors: 15% over 20 years	Site Host: 12% over 20 years
Cash and Tax Allocations	99% TI / 1% local flips to 10% TI / 90% local	100% to local investors	100% to site host

Table 2 describes the major assumed project parameters that apply to the two hypothetical community wind projects modeled – a 10.5 MW grid supply project and a 1.5 MW behind-the-meter project. Other than rated capacity, major differences between the two projects include the following:

- The behind-the-meter project assumes a lower capacity factor (25% instead of 30%) on the assumption that it will be somewhat site-constrained by the site host's location.
- The behind-the-meter project is assumed to be financed on balance sheet, using no construction or term debt.
- The grid supply project receives two small government grants (e.g., a USDA REAP grant and a grant from a state agency) totaling \$1 million, while the behind-the-meter project receives just one such grant (due to its smaller size) totaling \$500,000. These grants are considered to be taxable income, which means that they will not negatively impact the basis to which the 30% ITC or cash grant apply. They are however, assumed to trigger a PTC haircut.
- For the sake of simplicity, hard costs (e.g., turbine and balance of plant costs) are assumed to be the same for both projects (on a \$/kW basis), but total installed costs end up being higher for the grid supply project, due to more soft costs (e.g., interest during construction, as well as costs and fees related to the use of construction and term debt).
- The grid supply project is modeled under each of the two financing structures described in the previous section, with corresponding differences in target returns and allocations of cash and tax flows by structure. The behind-the-meter project, meanwhile, is modeled under just the Cooperative LLC structure, but assuming just one local investor (rather than a group of local investors) – i.e., the site host that will own and operate the project, as well as serve as power offtaker.

- Finally, for the grid supply project, the Cooperative LLC structure is assumed to be made up entirely of passive investors with no other passive income outside of the project. The implications of this assumption are that the passive credit and loss limitations will apply, requiring any Tax Benefits that cannot be fully applied (in the year that they are earned) against the project’s own income tax obligations to be carried forward to future years until they can be fully used by the project. Though it is difficult to judge just how conservative this assumption is, it nevertheless does represent a worst-case scenario, in that some local investors in the project may have other forms of passive income against which to apply the wind project’s Tax Benefits.

### 4.3 Analysis Results

This section presents the modeling results, first for the 10.5 MW grid supply project, and then for the 1.5 MW behind-the-meter project.

#### 4.3.1 Modeling Results for the Grid Supply Project

Table 3 presents the modeling results from six modeling runs – Steps 1 through 6. The relevant assumptions for each step are shown in the left half of the table, while the results (expressed in terms of 20-year levelized LCOE) for both the Strategic Investor Flip and the Cooperative LLC structures are shown on the right.

**Table 3. Modeling Results for 10.5 MW Grid Supply Project**

Step	AMT	Grant Haircut	PTC	30% ITC	10-Year Debt Interest Rate	30% Cash Grant	Carryforward (for Cooperative LLC)			Results: Strategic Flip		Results: Cooperative LLC	
							PTC/ITC	Federal Loss	State Loss	LCOE (\$/MWh)	Delta (\$/MWh)	LCOE (\$/MWh)	Delta (\$/MWh)
1	✓	✓	✓		6.5%		✓	✓	✓	\$138.5		\$149.1	
2		✓	✓		6.5%		✓	✓	✓	\$122.7	-\$15.8	\$145.2	-\$3.9
3			✓		6.5%		✓	✓	✓	\$121.5	-\$1.2	\$145.1	-\$0.2
4				✓	6.5%		✓	✓	✓	\$107.8	-\$13.6	\$145.8	+\$0.7
5				✓	4.0%		✓	✓	✓	\$100.1	-\$7.7	\$135.4	-\$10.3
6					4.0%	✓		✓	✓	\$98.9	-\$1.2	\$105.5	-\$30.0
<b>Total Reduction in LCOE (\$/MWh):</b>										<b>-\$39.6</b>		<b>-\$43.6</b>	

Step 1 is the starting point or benchmark scenario, intended to represent worst-case market conditions as they existed prior to the Recovery Act of 2009 (i.e., a fully constrained PTC, with no choice of ITC or cash grant). In this scenario, the PTC’s value is assumed to be reduced by the alternative minimum tax (AMT), which is modeled by only allowing PTCs to flow through during the project’s first four years. The PTC is also reduced by a “haircut” for the two small government grants, which is modeled per the formula specified in Section 45 of the Code. The 10-year debt is assumed to be priced at market (6.5% in this case) in order to avoid a PTC haircut for subsidized energy financing. For the Cooperative LLC structure only, the passive credit and loss limitations apply, which means that the PTC (and in later steps, the ITC) and net operating losses at both the federal and state levels must be carried forward until they can be absorbed by the project itself.

Under this constrained benchmark scenario, the Strategic Investor Flip structure requires nearly \$139/MWh of revenue levelized over 20 years, whereas the Cooperative LLC requires more than \$149/MWh.<sup>19</sup> In either case, this hypothetical grid-supply project is clearly not even close to being economically competitive with wholesale power prices, and so would likely never be built under these conditions.

Step 2 removes the AMT constraint,<sup>20</sup> which provides a significant amount of value to the Strategic Investor Flip (almost \$16/MWh), but much less value to the Cooperative LLC. This muted impact reflects the fact that the Cooperative LLC must carry forward all Tax Benefits until they can be absorbed by the project itself, which defers the benefit of eliminating the AMT constraint, thereby diluting its present value.

Step 3 eliminates the PTC haircut for the two small government grants.<sup>21</sup> This provides only modest value (\$1.2/MWh) to the Strategic Flip, due to the small size of the grants relative to total project costs (i.e., the grants, totaling \$1 million, make up only 3.8% of total project costs, and therefore reduce the PTC by just 3.8%).<sup>22</sup> Once again, the value provided to the Cooperative LLC is significantly less, because the PTC is carried forward (until it can be used in years 9 through 15), which defers the benefit.

Step 4 switches from the PTC to the 30% ITC. Relative to the PTC, the ITC provides a significant amount of value to this project under the Strategic Investor Flip structure, reducing the required amount of revenue by nearly \$14/MWh. Somewhat surprisingly, however, the

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<sup>19</sup> In reality, Step 1 results for the Strategic Investor Flip structure are not particularly applicable, since an AMT-constrained tax equity investor is presumably an oxymoron (i.e., if a would-be tax equity investor was constrained by the AMT, there would be little reason for it to invest). As such, a more likely starting point for the Strategic Investor Flip structure would be Step 2. Step 1 results are shown in Table 3, however, purely for the sake of comparison with the Cooperative LLC structure.

<sup>20</sup> The AMT constraint is removed by allowing PTCs to flow through for the full ten years (rather than just the first four years). This approach is slightly troublesome, given that the October 2008 Extension Act fully exempted the ITC – not the PTC – from the AMT. In other words, in reality, an AMT-constrained taxpayer would never have full access to the PTC, as is modeled in Step 2. However, given that the intent here is to isolate the value of removing just the PTC's AMT constraint, this is the most straightforward approach to modeling this particular benefit. The other potential approach – trying to model AMT relief in conjunction with the ITC – would aggregate the value of two distinct benefits: that of AMT relief, and that of switching from the PTC to the ITC.

<sup>21</sup> As noted in Section 3.2, the Recovery Act of 2009 eliminated this haircut for the ITC (and cash grant), but not for the PTC. As such, modeling haircut relief in conjunction with the PTC is somewhat unrealistic. Just as was noted in footnote 20 with respect to the AMT, however, any other approach that tries to combine haircut relief with the ITC would end up aggregating the value of two separate benefits: relief from the haircut, and the greater value of the ITC over the PTC. In other words, one only attains full AMT or haircut relief by electing the ITC over the PTC, but electing the ITC also captures the incremental face value of the ITC relative to the PTC, making it impossible to isolate just the value of AMT or haircut relief. The only way to isolate and value this relief is to model it in conjunction with the incentive that is afflicted by the constraint – the PTC.

<sup>22</sup> It is worth noting that the order in which these constraints are relaxed (i.e., the order of the modeling steps) has an impact on the value of relaxing each individual constraint. For example, if the PTC haircut for government grants were removed *prior to* eliminating the AMT constraint, rather than after, the value of removing the haircut would be smaller than shown in Table 3 because the PTC would still be AMT-constrained (i.e., the benefit of removing the haircut would only apply to the first four, rather than all ten, years of the PTC). In recognition that order does matter, Table 3 takes the approach of relaxing the largest (regardless of order) constraints first, since the value of removing a large constraint will be less-impacted by the existence of a smaller constraint, and vice versa.

amount of revenue required by the Cooperative LLC actually *increases* once the ITC is chosen over the PTC. There are two reasons for this counterintuitive result:

- 1) Just as with the PTC, the ITC must also be carried forward until it can be absorbed by the project itself. This dilutes the incremental value that the ITC would otherwise provide relative to the PTC.
- 2) Once the project elects the ITC, it must also reduce the depreciable basis of the project by half the value of the ITC (i.e., by 15%). With tax losses being carried forward, this basis reduction will be fully absorbed before there is any tax liability against which to claim the ITC. Hence, the negative impact of the basis reduction hits up earlier in time than does the positive impact of the ITC, and this timing differential is sufficient to negate the incremental value that the ITC would otherwise have provided to the project.

Now that the project is claiming the ITC rather than the PTC, it is free to take advantage of any government-subsidized low-interest loan programs that may exist, without fear of triggering a PTC haircut. As such, Step 5 lowers the debt interest rate from 6.5% to 4.0%, which provides roughly \$8-\$10/MWh of value to the project, depending on structure. It is important to note that this value is provided solely by the interest savings from the lower interest rate, and is not reflective of the value provided by eliminating the PTC haircut for subsidized energy financing. The latter is somewhat difficult to gauge, because subsidized energy financing typically causes a net loss of value under the PTC, unless the interest rate is sufficiently low enough to compensate for the lost PTC value (a 4% interest rate would not be sufficient). As such, few projects would presumably ever choose to make use of subsidized energy financing under the PTC, in which case the true cost of the haircut might be best thought of as an opportunity cost (said another way, the true value of removing the haircut might best be thought of as the foregone value of using subsidized energy financing – as is measured here).

Finally, Step 6 switches from the 30% ITC to the 30% cash grant. This provides only a modest amount of value – \$1.2/MWh – to the Strategic Investor Flip, mostly related to the time value of money.<sup>23</sup> The Cooperative LLC, on the other hand, realizes a *tremendous* amount of value from switching to the grant: the amount of revenue required by the project drops by a remarkable \$30/MWh. This sizable drop is attributable to the fact that, unlike the ITC, the 30% cash grant is not subject to the passive credit limitations, which has two implications:

- 1) The 30% cash grant can be used immediately in the project's first year, rather than having to wait 10 or more years into the future (as with the PTC and ITC).
- 2) All of the benefits that were previously deferred under the PTC and ITC – e.g., eliminating the AMT constraint and PTC haircuts back in Steps 2 and 3 – can now be used in the project's first year, rather than many years down the road, which increases their present value.

In aggregate, transitioning this hypothetical community wind project from a worst-case, pre-Recovery Act, constrained-PTC scenario to a post-Recovery Act 30% cash grant scenario has reduced the amount of cash revenue needed to reach investors' target returns by roughly \$40/MWh for both financing structures. In other words, this policy shift provides a substantial

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<sup>23</sup> The model realizes the entire grant in the first six months after commercial operation (since in most cases the grant will be paid within 60 days of achieving commercial operation), while the ITC is split between the first and second six-month periods (to more closely mimic when it is realized through tax filings).

amount of value to this project, transforming it from one that would likely not have been built under the PTC to one that is significantly closer to market under the cash grant.

Moreover, only about \$15/MWh<sup>24</sup> of the total value provided is attributable to the direct or face value of the ITC/grant relative to the PTC. All of the remaining value flows exclusively from the ancillary benefits that accompany the switch to the ITC and cash grant. Though potentially inflated by the “worst-case” nature of Step 1, the value of these ancillary benefits, which total \$25-\$29/MWh, is clearly significant and should not be overlooked by community wind investors.

Finally, it is instructive to note differences between the two structures in the distribution of benefits among the six modeling steps. Specifically, the Strategic Investor Flip structure benefits significantly more from choosing the ITC over the PTC in Step 4 than it does from switching to the 30% cash grant in Step 6. Meanwhile, the opposite is true for the Cooperative LLC structure, which does not benefit much from selecting the ITC over the PTC, but realizes a tremendous amount of value by choosing the 30% cash grant over the ITC. This stark difference between these two structures clearly illustrates the importance of the cash grant – and the relief from the passive credit limitations that it provides – to passive investors in community wind projects. The policy implications of this finding will be discussed further in Chapter 5.

### **4.3.2 Modeling Results for the Behind-the-Meter Project**

As described in Section 3.4, “behind-the-meter” wind projects – i.e., those that are interconnected on the ratepayer (rather than utility) side of the meter to displace power that would otherwise be purchased from the utility – are generally ineligible for the PTC, because there is no power sale. The 30% ITC and cash grant, on the other hand, do not have any such power sales requirement, and can therefore be used by such projects.

Whereas the previous section quantified the value (to a 10.5 MW grid supply project) of four of the nine ancillary benefits described in Chapter 3, the 1.5 MW behind-the-meter project modeled in this section is likely to benefit mostly, if not exclusively, from just this lack of a power sales requirement. In other words, because behind-the-meter projects are ineligible for the PTC, none of the benefits of switching away from the PTC (i.e., full AMT relief, fewer haircuts, ability to lease, and no performance risk) are applicable. Moreover, given the nature and small size of the behind-the-meter project, it is perhaps unlikely that such a project would be subject to the at-risk rules, the passive credit limitations (the site host would most likely be considered an active investor), or securities regulation (presumably this project would just have a single owner).

Table 4 presents modeling results for this project under three scenarios: without the PTC (i.e., reflecting conditions prior to the Recovery Act of 2009), with the 30% ITC, and with the 30% cash grant. Since the passive credit limitations, at-risk rules, and securities regulation are not considered to be applicable, the only difference between the 30% ITC and the 30% cash grant is the timing of the benefit: the model realizes half of the ITC in each of the first and second six-

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<sup>24</sup> Focusing on just the Strategic Investor Flip (because it does not need to carry forward tax impacts), \$13.6/MWh of the total value comes from switching from the PTC to the ITC in Step 4, while another \$1.2/MWh is gained by choosing the cash grant over the ITC in Step 6.

month periods, while it realizes the entire grant’s value in the first six-month period. Because this “time value of money” difference is relatively small, the remainder of this section will focus only on the “no PTC” and “30% cash grant” scenarios, as well as the difference between them.

**Table 4. Modeling Results for 1.5 MW Behind-the-Meter Project**

Step	Scenario	20-Year After-Tax IRR Target of 12%		\$120/MWh First-Year Revenue (with 2% inflation)	
		First-Year Revenue	20-Year Levelized Revenue	20-Year After-Tax IRR	20-Year After-Tax NPV
1	No PTC	\$154.4/MWh	\$176.6/MWh	8.7%	-\$246k
2	30% ITC	\$110.0/MWh	\$125.8/MWh	13.2%	+\$484k
3	30% Cash Grant	\$108.5/MWh	\$124.1/MWh	13.4%	+\$505k
	<b>Step 3-Step 1:</b>	<b>-\$45.9/MWh</b>	<b>-\$52.5/MWh</b>	<b>+4.7%</b>	<b>+\$751k</b>

Presume that the site host requires a 12% after-tax IRR at the end of 20 years. Without access to the PTC, this project must earn a levelized \$176.6/MWh of cash revenue (which equates to a starting revenue of \$154.4/MWh, escalating at 2%/year) over this 20-year period in order to generate the required return. As long as the utility retail rate that is displaced by the wind power meets (or exceeds) these levels, the project will yield at least the target IRR.<sup>25</sup> Under the 30% cash grant, the amount of cash revenue required drops to a levelized \$124.1/MWh (which equates to a starting revenue of \$108.5/MWh, escalating at 2%/year). In other words, having the ability to elect the 30% cash grant is worth roughly \$52/MWh to this project on a levelized basis.

Perhaps a simpler way to think about behind-the-meter projects, however, is to start with revenue assumptions (based on the retail rate that will be displaced) and then calculate the return that the project will generate. Presume that the project will earn cash revenue that starts at \$120/MWh and escalates at 2%/year (which equates to \$137.3/MWh levelized over 20 years). Without access to the PTC, this project will yield a 20-year after-tax IRR of 8.7%, or a 20-year net present value (NPV) of -\$246,000 (using a 10% discount rate). Under the 30% cash grant, the IRR increases to 13.4%, while the NPV increases to +\$505,000. In other words, having the ability to elect the 30% cash grant is worth roughly 4.7% of IRR, or \$751,000 of present value to this 1.5 MW behind-the-meter project.

<sup>25</sup> The results presented in Table 4 reflect the simplifying assumption that the site host will be able to absorb 100% of the wind turbine’s output, either instantaneously or through the benefits of net metering.



## 5. Summary and Conclusions

In several respects, the financial crisis of 2008/2009 has been a blessing in disguise for community wind development in the United States. The crisis-induced slowdown in the broader commercial wind market has, for the first time since 2004, created slack in the supply chain, creating an opportunity for shovel-ready community wind projects – many of which have been forced to wait on the sidelines during the commercial wind boom – to finally proceed towards construction. More importantly, the financial crisis spawned two major stimulus packages that, in combination, have fundamentally reshaped the federal policy landscape for wind power in general, and for community wind power in particular. Most notably, qualifying wind projects can now, for a limited time only, choose either a 30% ITC or a 30% cash grant in lieu of the PTC. It stands to reason that community wind, which has historically had more difficulty using the PTC than has commercial wind, may benefit disproportionately from this newfound ability to choose among available federal incentives.

This report confirms this hypothesis to be true. On the basis of face value alone, the ITC or cash grant – both of which depend on the size of the investment rather than on the quantity of power produced – will be worth more than the PTC to most community wind projects, which on average may cost more or generate less than their commercial counterparts. Just as importantly, however, and not to be overlooked, are the handful of ancillary benefits that accompany the ITC and/or cash grant, but not the PTC. These ancillary benefits, many of which circumvent barriers that have plagued community wind projects in the United States for years, include:

- Full relief from the alternative minimum tax;
- No “haircuts” for certain government grants or subsidized energy financing;
- Relief from the passive credit limitations and at-risk rules (30% cash grant only);
- No power sales requirement (enables behind-the-meter projects to qualify);
- No owner/operator requirement (enables leasing as a viable financing structure);
- Less performance risk (because the ITC/grant do not depend on production); and
- Greater ease in qualifying for exemptions from SEC regulations surrounding securities registration (30% cash grant only).

As demonstrated in this report, these ancillary benefits could, in aggregate, be worth more to a community wind project than the greater face value of the ITC or cash grant relative to the PTC. For example, Chapter 4 presented results for a hypothetical 10.5 MW “grid supply” project that benefitted by roughly \$15/MWh from the cash grant’s incremental face value, and by more than \$25/MWh from just the first three ancillary benefits listed above. Chapter 4 also found that the cash grant could be worth roughly \$50/MWh to a behind-the-meter community wind project that would not otherwise be eligible for the PTC.

The window of opportunity for community wind projects to capture these substantial benefits is short. To qualify for the 30% ITC, projects must be placed in service by the end of 2012. To qualify for the 30% cash grant, projects must either be operational by the end of 2010, or else must begin construction by then and be placed in service by the end of 2012. In other words, the deadline to qualify for the grant in particular is only a year away, unless the Recovery Act provisions are extended.

In this vein, the step-by-step analysis presented in Chapter 4 may also inform the development of a forward-looking policy agenda for community wind, by revealing what recent policy changes have been most valuable to the sector. For example, analysis of the 10.5 MW grid supply project under the Cooperative LLC structure highlights the importance of the 30% cash grant – and especially the relief that it provides from passive credit limitations – for passive investors in community wind projects. In particular, choosing the ITC over the PTC did not provide much value to this project under this structure, because the passive credit limitations required all tax impacts to be carried forward. Only once the project transitioned to the 30% cash grant, which is not subject to the passive credit limitations, did it realize the bulk of the total value provided by the 30% cash grant.

Most community wind projects built in the United States to date have used some form of a partnership flip structure, which, because of the participation of a tax equity investor, is not impacted by the passive credit limitations. But if community wind is going to penetrate the broader wind market to any significant degree going forward, it may need to increasingly look to passive investors to finance that expansion (particularly if the tax equity market remains weak). In this light, seeking to extend the window of opportunity for the 30% cash grant – which singlehandedly removes the largest impediment to the participation of passive investors in community wind projects – would appear to be a logical priority for those supportive of community wind (alternatively, exempting the PTC and ITC from the passive credit limitations could provide similar relief). If the tax equity market eventually returns to its former glory, active investors engaged in partnership flip structures can get by with the 30% ITC (or even the PTC, if it comes to that), but passive investors simply cannot become meaningful investors in community wind projects without relief from the passive credit limitations, which currently only the 30% cash grant provides.

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