PROJECT FINANCE ALERT	Deacon Harbor FINANCIAL

The American Recovery and Reinvestment Act:
ITC vs. PTC for Wind Projects

February 23, 2009

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OVERVIEW

The American Recovery and Reinvestment Act of 2009 (the "Act") has multiple incentives for renewable energy projects. Some are extensions of previous benefits, while others will allow project owners to choose between the timing and even nature (i.e. cash vs. tax credit) of an incentive. Below is a table outlining the notable provisions of the Act[1].

Table 1: Notable Provisions of the Act

Provision Summary	Detail
Production Tax Credit ("PTC") extension	Placed in service dates are extended to the end of 2012 for wind and the end of 2013 for closed-loop biomass, open-loop biomass, geothermal, landfill gas, trash, qualified hydropower, and marine and hydrokinetic renewable energy facilities.
Investment Tax Credit ("ITC") in lieu of PTC:	A project owner can elect to receive the ITC, generally equal to 30% of qualifying costs, instead of a PTC. Technologies covered are wind, closed-loop biomass, open-loop biomass, geothermal, landfill gas, trash, qualified hydropower, and marine and hydrokinetic.
Cash Grant in Lieu of ITC:	Instead of claiming the ITC as a tax credit, a project owner can elect to receive a cash grant for the same amount. The grant payment would be made by the U.S. Treasury the later of 60 days from the placed in service date or 60 days from the application date. The grant essentially functions as a refundable tax credit and will not be included in project income.
Bonus Depreciation Extension:	Projects placed in service by the end of 2009 are eligible for 50% first year bonus depreciation. Fifty percent of the project's depreciable basis can be deducted in the first year of operation, while the remaining basis is depreciated over the applicable schedule.

[1] Table 1 is not meant to be all inclusive. For additional details on tax provisions in the Act it is recommended that your tax counsel be contacted.

This Alert will touch on a few of the major provisions as relates to renewable energy projects, however the primary focus is to analyze the difference in value between the ITC and the PTC as pertains to wind projects. It is this provision that may have a significant impact on overall project economics, and necessitates a decision from both project developers and the investment community. The choice regarding whether to take the ITC as a cash grant or tax credit will be an important consideration, but the total value of the incentive will not change, just the method of realization. Extension of first-year bonus depreciation will be a benefit to those projects on-line in 2009, assuming tax equity financing is available. The following will briefly discuss the impact of bonus depreciation, but it is available regardless of which incentive is chosen, so this part of the analysis will be done at a high level.

ANALYSIS

Moving the placed in service deadline for PTC qualification through 2012 will help alleviate the stop-start nature of the industry that was caused by historical short-term extensions. This will provide a greater degree of certainty for developers, equipment suppliers and investors, and should result in more projects under development and an increased commitment to establishing domestic manufacturing facilities. However, growth in the wind industry will continue to be driven by project financing from the debt and tax equity markets. Even with a cash grant now available to project owners, additional financing will be required to monetize the full value of the accelerated depreciation benefits. To the extent the current financing crisis continues and capital remains scarce, growth in the wind sector will be slowed[2].

The PTC is a tax credit based on the amount of energy generated by a project over the first ten years of operation. Rather than being realized over time the ITC can be taken in the first year of operation and is based on cost rather than production. Therefore, the principal question revolves around the impact on project returns given the different recovery time and magnitude of the incentives. There may be other extrinsic considerations, such as the preference of investors that will impact which incentive is chosen by a project. However, those considerations were not included in the analysis.

To assess the impact of the ITC vs. PTC a template 100 megawatt wind project was modeled using Deacon Harbor's project financing pro forma model. The template project is based on a set of assumptions intended to reflect a generic wind project and includes items such as capital costs, net capacity factor ("NCF"), revenues, operating costs, energy production, tax rates, and cash flows. The two variables examined were total capital cost and NCF as they directly impact ITC and PTC values, respectively.

Total project after-tax internal rate of return ("IRR") was used as the measure to quantify the relative impact of the PTC and the ITC (see Tables A-1 through A-4 in Appendix A). Other than incentive type, total project cost and NCF, all other assumptions for the template project were held constant. At varying production and

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[2] For a further discussion on tax equity financing see the Deacon Harbor Financial Project Alert, "The Financial Crisis and Renewable Energy", October 17, 2008, at http://www.deaconharbor.com/files/DHF_-_The_Financial_Crisis_and_Renewable_Energy.pdf

cost levels the resulting IRRs were recorded and the ITC IRR was subtracted from corresponding PTC scenario IRR (see Tables 2 and 3). Therefore, a negative number indicates that the ITC yielded a higher return and had greater value to a project. Using the difference between the IRRs allows for a direct comparison of the incentives.

For this analysis, it was assumed that roughly 93% of the project cost qualified for the 5-year Modified Accelerated Cost Recovery System ("MACRS") depreciation schedule. The ITC scenarios were modeled with virtually all of the 5-year MACRS costs qualifying and an ITC amount of 30%. An all-equity capital structure was assumed, which is consistent with how a majority of projects were structured prior to the financial crisis and the Act. The IRRs recorded in the analysis are total project returns (i.e. the combined returns of developer and tax investor).

Table 2: 10-Year Project IRR Deltas

		Total Project Cost ($/kilowatt)									
		1,600	1,650	1,700	1,750	1,800	1,850	1,900	1,950	2,000	2,050
Net Capacity Factor	26%	203	196	189	183	176	170	165	159	154	149
	27%	207	199	192	185	179	173	167	162	156	151
	28%	210	202	195	189	182	176	170	164	159	154
	29%	214	206	199	192	185	179	173	167	162	156
	30%	217	210	202	195	189	182	176	170	165	159
	31%	221	213	206	199	192	186	179	173	168	162
	32%	226	217	210	203	196	189	183	177	171	166
	33%	230	222	214	206	199	193	186	180	174	169
	34%	234	226	218	210	203	196	190	184	178	172
	35%	239	230	222	214	207	200	194	187	181	176

The difference between the IRRs is represented in number of basis points[3]. As seen in Table 2, all of the scenarios had a higher 10-year return with PTCs as opposed to an ITC (i.e. all numbers are positive). The 10-year return was chosen because it corresponds to the term of the PTC and has historically been used as a benchmark for tax equity financing. Returns for the PTC cases ranged from 149 to 239 basis points higher. As total project cost grew larger (ITC increase) and NCF declined (PTC decrease), the IRRs converged but in all cases the template project realized a higher return by selecting the PTC. Over this 10-year period the magnitude and timing of the ITC was not sufficient to offset the forgone PTC value and depreciation[4]. If project cost was increased and NCF decreased it is possible that a point would be reached where the ITC yielded a higher return, but such a scenario was not in the scope of this analysis.

The 10-year IRR differences must be considered in the context of relative risk. Because the PTC is based on actual project production, subject to operating variability, and realized over a 10-year period it must be considered riskier than the ITC, which is realized in year one and based on cost. In addition to this operating uncertainty tax equity investors are subject to the ambiguity of future tax liability, potentiality

[3] A basis point is equal to .01% (e.g. the different between 5.00% and 4.75% is 25 basis points).
[4] Half the value of the ITC can not be depreciated. For example, a 100% project with all costs qualifying for the ITC yields and ITC value of $30, but a depreciable basis of $85 (100- (30*.5)).

impacting ability to utilize credits. For these perceived risks, investors may demand a "PTC Risk Premium" on projects opting for this type of incentive. If the increased return from using PTCs is insufficient relative to the PTC Risk Premium, as determined by the market, then a developer and/or investor may choose an ITC and a lower project return.

As the data in Table 3 indicate, over a 20-year horizon project returns converged and there were situations where the ITC created more value than the PTC (see yellow shaded area). Indeed, given the assumptions used in this analysis, the ITC begins to yield a higher IRR at $1,750kW and a NCF of 26%. After year ten when the PTCs have expired and there is no depreciation difference between the scenarios, the project generates the same after-tax benefits under both incentives, which results in a higher IRR for certain ITC cases.

Table 3: 20-Year Project IRR Deltas

		Total Project Cost ($/kilowatt)									
		1,600	1,650	1,700	1,750	1,800	1,850	1,900	1,950	2,000	2,050
Net Capacity Factor	26%	18	11	4	(2)	(8)	(14)	(19)	(24)	(29)	(34)
	27%	24	17	10	3	(3)	(9)	(14)	(20)	(25)	(29)
	28%	31	23	16	9	3	(4)	(9)	(15)	(20)	(25)
	29%	37	29	22	15	8	2	(4)	(10)	(15)	(20)
	30%	44	35	28	20	14	7	1	(5)	(10)	(15)
	31%	50	42	34	26	19	13	6	1	(5)	(10)
	32%	57	48	40	32	25	18	12	6	(0)	(5)
	33%	63	55	46	38	31	24	17	11	5	(0)
	34%	70	61	53	44	37	30	23	16	10	5
	35%	77	68	59	51	43	35	28	22	16	10

It should be noted that the range of relative difference in IRRs is fairly tight, from 77 basis points in favor of the PTC to 34 basis points in favor of the ITC. Over a 20-year period this difference is not large, even on the extremes. The same discussion of a PTC Risk Premium, as outlined earlier, applies to the 20-year return as well. For long-term investors the difference between the two incentives as shown above may be insignificant, but that will be determined by the market.

It is interesting to note that this analysis utilized a flat power purchase agreement ("PPA") price for twenty years. Scenarios were run with an escalating PPA price sized to yield a similar 10-year return. As expected, the 10-year IRR deltas were consistent with a flat PPA price. However, since additional value was added to years 11-20 via an escalating price, the convergence in IRRs was more pronounced. There were a number of additional cases where the ITC provided more value than the PTC. In brief, the type of PPA secured by the project will have an impact on the long-term value of the incentives.

The timing of the project also seems to have an impact on the analysis. The value of the PTC is indexed to inflation and increases over time, so the later a project starts the higher the nominal value of the incentive. Therefore, running this analysis assuming a later commercial operations date actually increased the relative difference between the PTC and the ITC. In reality, a later online date would mean a slightly higher cost via inflation and a larger ITC. However, it is unclear how large the cost increase must be to offset PTC value gains. This point serves to underscore the value of the PTC as relates to project timing.

Table 4: Impact of Bonus Depreciation

	$1,600kW – 35% NCF	
	10-Yr IRR	20-Yr IRR
PTC	9.74%	13.21%
PTC w/bonus	10.65%	14.09%
Delta	0.90%	0.88%
ITC	7.35%	12.44%
ITC w/Bonus	8.22%	13.32%
Delta	0.87%	0.88%

To ascertain the relative maximum impact of the 2009 fifty percent bonus depreciation, the low cost ($1,600kW) and high NCF (35%) case was examined. The results were fairly consistent between the two incentives and across the project time horizon, with bonus depreciation adding 87 to 90 basis points of return. The analysis also shows that as project cost increases and NCF decreases, the gain from bonus depreciation declines. This is consistent with expectations because the increase in bonus depreciation is outweighed by the higher required investment and the declining production. As previously discussed, half of the ITC value can not be depreciated so there is an impact on the effect of the bonus depreciation with this type of incentive. Results indicate that the increase in return due to bonus depreciation is muted slightly for ITC projects as the costs increase and NCF decreases.

SUMMARY

Overall, extension of the PTC deadline removes short-term regulatory uncertainty and benefits the wind sector. This should increase the number projects in development and lead to more domestic equipment manufacturing. However, growth resulting from a longer-term PTC period may be tempered by a continuation of the larger financial crisis and a restricted supply of capital if this increased certainty fails to attract new investors.

The cash grant ITC provision of the Act provides additional flexibility for project developers and investors. However, it does not appear to be sufficient to do away with the need for tax equity investing. Prior to the current financial slowdown projects were unable to secure 70% debt, which would be required for cash grant projects to forgo tax-based investors. The current lending environment is even more restrictive.

Results of this analysis show that the 10-year after-tax project returns are higher with a PTC-based incentive by 149 to 239 basis points, depending on project cost and NCF. However, the 20-year IRRs converge and in some cases show a higher project return with the ITC. Given the operating and utilization uncertainty associated with the PTC, the difference in returns will need to be examined in the framework of a PTC Risk

Premium. The 10-year returns especially, which have historically been used as a tax equity investor benchmark, will be reviewed by the market to see if the increased IRR is sufficient compensation for the added risk. Finally, the data show that the increase in returns due to bonus depreciation is fairly consistent across the incentives. The positive impact is muted slightly in the ITC cases given the forgone asset basis.

Multiple partnership "flip" structures have evolved for the financing of new utility-scale wind projects[5]. These structures were derived to allocate risk and tax benefits to the parties that can most efficiently utilize them. They were also developed as a result of the limitations associated with the PTC, specifically the restrictions that excluded leasing as a financing option. The ability for a project to now utilize the ITC may very well lead to the use of leasing structures for wind projects, as has been done in the solar sector. The current utility-scale solar financing markets are not as mature as those for wind, but both leasing and partnership flip structures have been utilized. If nothing else, the availability of an ITC provides additional financing options to wind project developers and investors.

Overall, the data indicate a relative difference in the value to a project of the PTC and ITC. Indeed, in both the short and long-term there are situations where one incentive provides greater value. Results also show that a number of factors can influence the impact of the incentives, such as project timing and PPA structure. Another factor not considered here, which may have an impact, is the addition of debt to the capital structure. The calculations used were based on assumptions regarding the portion of the assets that qualify for the ITC and other factors, which may be different for specific projects. This analysis serves to underscore the need for developers and investors to carefully evaluate each project individually, based on its unique characteristics, to determine the relative values of the PTC and the ITC.

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[5] For further information see Harper et al., "Wind Project Financing Structures: A Review and Comparative Analysis", September 2007.
http://www.deaconharbor.com/files/Wind_Financing_Structures_Report.pdf

Appendix A:

Project After-Tax IRR

Table A-1: 10-Year Project IRR

PTC

Net Capacity Factor	Total Project Cost ($/kilowatt)									
	1,600	1,650	1,700	1,750	1,800	1,850	1,900	1,950	2,000	2,050
26%	3.1%	2.5%	2.0%	1.5%	1.1%	0.6%	0.2%	-0.2%	-0.6%	-1.0%
27%	3.9%	3.3%	2.8%	2.3%	1.8%	1.3%	0.9%	0.5%	0.1%	-0.3%
28%	4.6%	4.1%	3.5%	3.0%	2.5%	2.1%	1.6%	1.2%	0.8%	0.4%
29%	5.4%	4.8%	4.3%	3.8%	3.3%	2.8%	2.3%	1.9%	1.5%	1.0%
30%	6.2%	5.6%	5.0%	4.5%	4.0%	3.5%	3.0%	2.6%	2.1%	1.7%
31%	6.9%	6.3%	5.7%	5.2%	4.7%	4.2%	3.7%	3.2%	2.8%	2.3%
32%	7.6%	7.0%	6.4%	5.9%	5.3%	4.8%	4.3%	3.9%	3.4%	3.0%
33%	8.3%	7.7%	7.1%	6.6%	6.0%	5.5%	5.0%	4.5%	4.1%	3.6%
34%	9.0%	8.4%	7.8%	7.2%	6.7%	6.1%	5.6%	5.1%	4.7%	4.2%
35%	9.7%	9.1%	8.5%	7.9%	7.3%	6.8%	6.3%	5.8%	5.3%	4.8%

Table A-2: 10-Year Project IRR

ITC

Net Capacity Factor	Total Project Cost ($/kilowatt)									
	1,600	1,650	1,700	1,750	1,800	1,850	1,900	1,950	2,000	2,050
26%	1.0%	0.6%	0.1%	-0.3%	-0.7%	-1.1%	-1.5%	-1.8%	-2.2%	-2.5%
27%	1.8%	1.3%	0.9%	0.4%	0.0%	-0.4%	-0.8%	-1.1%	-1.5%	-1.8%
28%	2.5%	2.1%	1.6%	1.1%	0.7%	0.3%	-0.1%	-0.5%	-0.8%	-1.2%
29%	3.3%	2.8%	2.3%	1.8%	1.4%	1.0%	0.6%	0.2%	-0.2%	-0.5%
30%	4.0%	3.5%	3.0%	2.5%	2.1%	1.7%	1.2%	0.9%	0.5%	0.1%
31%	4.7%	4.2%	3.7%	3.2%	2.7%	2.3%	1.9%	1.5%	1.1%	0.7%
32%	5.4%	4.8%	4.3%	3.8%	3.4%	2.9%	2.5%	2.1%	1.7%	1.3%
33%	6.0%	5.5%	5.0%	4.5%	4.0%	3.6%	3.1%	2.7%	2.3%	1.9%
34%	6.7%	6.2%	5.6%	5.1%	4.6%	4.2%	3.7%	3.3%	2.9%	2.5%
35%	7.4%	6.8%	6.3%	5.7%	5.2%	4.8%	4.3%	3.9%	3.5%	3.1%

Table A-3: 20-Year Project IRR
PTC

Net Capacity Factor	Total Project Cost ($/kilowatt): 1,600	1,650	1,700	1,750	1,800	1,850	1,900	1,950	2,000	2,050
26%	7.5%	7.0%	6.6%	6.2%	5.8%	5.5%	5.1%	4.8%	4.5%	4.1%
27%	8.1%	7.7%	7.3%	6.8%	6.5%	6.1%	5.7%	5.4%	5.1%	4.7%
28%	8.8%	8.3%	7.9%	7.5%	7.1%	6.7%	6.3%	6.0%	5.6%	5.3%
29%	9.5%	9.0%	8.5%	8.1%	7.7%	7.3%	6.9%	6.6%	6.2%	5.9%
30%	10.1%	9.6%	9.2%	8.7%	8.3%	7.9%	7.5%	7.1%	6.8%	6.4%
31%	10.7%	10.2%	9.8%	9.3%	8.9%	8.5%	8.1%	7.7%	7.3%	7.0%
32%	11.4%	10.9%	10.4%	9.9%	9.5%	9.0%	8.6%	8.3%	7.9%	7.5%
33%	12.0%	11.5%	11.0%	10.5%	10.0%	9.6%	9.2%	8.8%	8.4%	8.1%
34%	12.6%	12.1%	11.6%	11.1%	10.6%	10.2%	9.7%	9.3%	9.0%	8.6%
35%	13.2%	12.7%	12.1%	11.6%	11.2%	10.7%	10.3%	9.9%	9.5%	9.1%

Table A-3: 20-Year Project IRR
ITC

Net Capacity Factor	Total Project Cost ($/kilowatt): 1,600	1,650	1,700	1,750	1,800	1,850	1,900	1,950	2,000	2,050
26%	7.3%	6.9%	6.6%	6.2%	5.9%	5.6%	5.3%	5.0%	4.7%	4.5%
27%	7.9%	7.5%	7.2%	6.8%	6.5%	6.2%	5.9%	5.6%	5.3%	5.0%
28%	8.5%	8.1%	7.7%	7.4%	7.1%	6.7%	6.4%	6.1%	5.8%	5.6%
29%	9.1%	8.7%	8.3%	8.0%	7.6%	7.3%	7.0%	6.7%	6.4%	6.1%
30%	9.7%	9.3%	8.9%	8.5%	8.2%	7.8%	7.5%	7.2%	6.9%	6.6%
31%	10.2%	9.8%	9.4%	9.1%	8.7%	8.3%	8.0%	7.7%	7.4%	7.1%
32%	10.8%	10.4%	10.0%	9.6%	9.2%	8.9%	8.5%	8.2%	7.9%	7.6%
33%	11.4%	10.9%	10.5%	10.1%	9.7%	9.4%	9.0%	8.7%	8.4%	8.1%
34%	11.9%	11.5%	11.0%	10.6%	10.2%	9.9%	9.5%	9.2%	8.8%	8.5%
35%	12.4%	12.0%	11.5%	11.1%	10.7%	10.4%	10.0%	9.6%	9.3%	9.0%