

**Wind Power Demonstration Project Report  
for  
Oberlin, Ohio  
and Other AMP-Member Ohio Communities**



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# Wind Power Development

In recent years, both the State of Ohio and the federal government have offered unprecedented support and financial incentives for the development of renewable energy technologies. This support has given rise to a variety of installations across the State that range from small residential photovoltaic arrays and wind turbines to utility scale solar and wind farms. This is the first of three reports that will evaluate the issues and opportunities facing renewable energy development in the 9<sup>th</sup> Congressional District. This report focuses on wind energy development, while the second report will review building-mounted solar installations and the third will consider solar farms. Each of these reports will focus on renewable energy development through the lens of a model project in Oberlin, Ohio. In this report, we will outline the applicable subsidies and financing mechanisms that can be utilized by wind developers as well as the regulations that may impact a potential project. We will also review the technical, design and environmental considerations that can be applied to any prospective wind project. Furthermore, we will provide an overview of the various ways that wind installations can and are being structured and how communities across the district can evaluate these projects. Lastly we will highlight several America Municipal Power (AMP) cities within the district that could adapt the proposed Oberlin model.

## STATE OF OHIO SUPPORT OF WIND ENERGY

### Ohio Air Quality Development Authority

The majority of Ohio's renewable energy programs are administered through the Ohio Air Quality Development Authority (OAQDA) which has financed 393 projects totaling more than \$7.1 billion since its inception in 1970. The OAQDA is able to support the construction and acquisition of renewable energy projects through issuing bonds, making loans and grants to local governments, and providing loans to businesses.

For large businesses (100+ employees) that are developing renewable energy technologies, OAQDA can provide a 100 percent exemption from the tangible personal property tax (on property purchased as part of a renewable energy project), real property tax (on real property comprising a renewable energy project), a portion of the corporate franchise tax, and sales and use tax (on the personal property purchased specifically for the renewable energy project only) as long as the bond or note issued by OAQDA is outstanding. Additionally, interest income on bonds and notes issued by OAQDA is exempt from state income tax and may be exempt in certain cases from the federal income tax.<sup>1</sup>

### Advanced Energy Job Stimulus Fund

The OAQDA administers \$84 million through the Advanced Energy Job Stimulus Fund set aside for non-coal-related energy projects. Awards are based on creating new full-time jobs, attracting significant investment and a project's ability to make a major impact on the advanced energy

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<sup>1</sup> Ohio Air Quality Development Authority: [http://www.ohioairquality.org/oaqda/about\\_oaqda.asp](http://www.ohioairquality.org/oaqda/about_oaqda.asp) March 1, 2011

sector in the State of Ohio. This program provides forgivable and non-forgivable loans with awards ranging from \$50,000 to \$2 million with five percent of the fund targeted toward small awards. Loans can be structured a number of ways including below market rates, subordinate collateralized positions with participating financial institutions, and/or varying principal payments for a specified period of time.

### **Qualified Energy Property Tax Exemption**

This critical State initiative allows for 100 percent exemption of tangible personal property tax and real estate taxes. Originally, a renewable energy facility in Ohio that sold electricity to a third-party was considered a “public utility” for tax purposes and therefore subject to public utility tangible personal property tax and real property taxes. Recently, Ohio has adopted legislation that allows energy facilities with nameplate capacity of 250 kilowatts (kW) or less (AC) to receive a complete exemption from public utility tangible personal property tax and real property taxes. Energy facilities are defined as interconnected solar, wind, or other facilities that use renewable energy to generate electricity for the purpose of sale to a third party. This recent legislation includes interconnection equipment, cables, devices, and the land (limited to up to 1/2 acre per wind turbine) in the exemption.

If the project is 250 kW or greater then it is also provided a 100 percent property tax exemption but a payment in lieu of tax is required. In lieu of taxes, the county where the renewable energy facility is located is entitled to receive the following payments:

- All other qualified facilities employing at least 75 percent Ohio-based employees during construction: \$6,000/megawatt (MW)
- All other qualified facilities employing at least 60 percent Ohio-based employees during construction: \$7,000/MW
- All other qualified facilities employing at least 50 percent Ohio-based employees during construction: \$8,000/MW

If the project is 5MW or larger, the property tax exemption must be approved by local county commissioners. Local county commissioners are allowed to require an additional payment but total payments are not to exceed \$9,000/MW. In addition, the law requires that (1) the renewable energy facility meets certain jobs-creation criteria, (2) provides for road repairs (for projects 5MW or more), (3) provides training and equipment to local first responders (for projects 5MW or more), (4) establishes partnerships with universities (for projects 2MW or more), and (5) makes offers to sell the renewable energy credits to Ohio utilities seeking to buy them.<sup>2</sup>

### **A Renewable Portfolio Standard (RPS)**

In 2008, Ohio established an alternative energy portfolio standard (AEPS). The law mandates that by 2025, at least 25 percent of all electricity sold in the State come from alternative energy resources. At least half of the standard, or 12.5 percent of electricity sold must be generated by renewable sources such as wind, solar (which must account for at least 0.5 percent of electricity use by 2025), hydropower, geothermal, or biomass. In addition, at least half of this renewable

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<sup>2</sup> Ohio Department of Development – Business and Industry  
<http://development.ohio.gov/Business/AlternativeEnergyTaxExemption.htm> March 1, 2011

energy must be generated in-state. The bill establishes a renewable energy credit (REC) tracking system, where utilities are able to buy, sell, and trade credits to comply with the renewable energy and solar energy requirements. The hope is that by mandating in-state renewable energy consumption and financially penalizing the utilities for not meeting this minimum, the State will create a tool for financing production, namely through the sale of the RECs.

### **Ohio Advanced Energy Fund and ARRA-Related Programs**

The Ohio Department of Development administers the Advanced Energy Fund to support investments in renewable energy projects in the industrial, agricultural, public, and residential sectors. The Fund has provided more than \$21 million in incentives to deploy both large and small-scale energy projects and has leveraged a total investment of more than \$305 million. The fund was created in 1999 from the proceeds of a 9¢ annual assessment on the utility bills of Ohio consumers. The utility rider was limited to investor-owned utilities and therefore municipal electrics were excluded from participation in the grant program. The Ohio Advanced Energy Fund was allowed to expire at the end of 2010 and re-authorization of the fund is unclear. This program along with various funds like the State Energy Program and those based on American Recovery and Reinvestment Act of 2009 (ARRA) funding have been critical to the recent progress that Ohio has made in attracting renewable energy projects. Their longevity and renewal is in considerable doubt.

## **FEDERAL SUPPORT IN WIND PROJECT FINANCING**

The majority of federal financial support for renewable energy projects has taken the form of federal tax credits which enables project developers to partner with “tax equity investors” (typically large investment banks and insurance companies) who can take advantage of the federally provided tax credits and accelerated depreciation deductions in exchange for up-front capital to fund the project. The largest renewable energy tax credit programs are the Federal Production Tax Credit (PTC) and the Federal Investment Tax Credit (ITC).<sup>3</sup>

### **Renewable Energy Incentives (ITC, PTC, REPI, Section 1603, Bonus Depreciation)**

#### Production Tax Credit (PTC)

Section 45 of the Internal Revenue Code provides a 10-year, inflation-adjusted per-kWh tax credit for power generated by certain types of renewable energy projects, including wind. The PTC allows a wind project to claim a 2.2¢ per kilowatt-hour (kWh) tax credit on income for 10 years. Unused credits may be carried forward for up to 20 years following the year they were generated.

#### Investment Tax Credit (ITC)

While the PTC provides an ongoing subsidy to a wind project, the ITC provides a source of up-front capital. This investment tax credit is equal to 30 percent of the cost of development, with no maximum credit limit. The ITC is generated at the time the wind project is placed in service. Financial benefit to a project is derived from the tax credit and accelerated depreciation. The ITC has been expanded to allow wind energy system of all sizes and is no longer targeted specifically

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<sup>3</sup> Mark Bolinger et al. *PTC, ITC, or Cash Grant? An Analysis of the Choice Facing Renewable Power Projects in the United States*: Lawrence Berkeley National Laboratory. March 2009. <http://eetd.lbl.gov/ea/emp/reports/lbnl-1642e.pdf> March 1, 2011

to systems of 100 kW or less.

It is important to note that projects can pursue either the PTC or the ITC but not both, and the PTC and ITC are available only to businesses that pay federal corporate taxes. The Department of Energy's Renewable Energy Production Incentive (REPI) is the version of the PTC that applies to local governments, municipal electrics or rural electric cooperatives. It is also scaled at 2.2¢ per kWh for wind projects over a 10 year period.

For renewable energy projects that are proposed in the near term and whose construction will begin before December 31, 2011, the ARRA and its recent expansions and extensions provide several important financing tools, namely the Section 1603 grant program and the Modified Accelerated Cost-Recovery System (MACRS) + Bonus.

Essentially the 1603 program allow projects that are eligible for the ITC or the PTC to receive a cash grant of 30% of the eligible cost of the project from the U.S. Treasury Department instead of taking the tax credits for new installations. Additionally, wind projects that are eligible for the ITC or PTC also qualify for 100 percent first-year bonus depreciation. After 2011, bonus depreciation is still available, but the allowable deduction reverts from 100 percent to 50 percent of the eligible basis.

Because neither the ITC nor the 1603 grant program requires the project owner to also operate the project-- as required by the PTC-- wind projects replacing the PTC with ITC or 1603 are now able to pursue third party ownership models such as lease financing for the first time.

## **Other Federal Tax Credit Incentives**

### New Markets Tax Credits

Other federal programs, such as New Markets Tax Credits (NMTC), are not specifically targeted at renewable energy projects, but can be used for such if investments are made into qualifying low-income communities. The NMTC is a program run through the U.S. Treasury Department and provides a credit against federal income taxes in exchange for making qualified equity investments in designated Community Development Entities (CDEs), which must make investments in low-income communities. The credit equals 39 percent of the cost of the investment and is claimed over a seven year period. NMTCs can be used successfully as a funding source for renewable energy projects as long as they are located within a qualifying census tract.<sup>4</sup> While credits from any CDE can be used for renewable projects, in 2006, for the first time four CDEs (Midwest Minnesota Community Development Corporation, Detroit Lakes, MN; Rural Development Partners, LLC, Harlontown, IA; Dakotas America, LLC, Sioux Falls, SD; American Community Renewable Energy Fund, LLC, New Orleans, LA) received \$232 million in tax credit allocations for the express purpose of directly supporting the financing of renewable energy projects.

Another encouraging development for the financing of wind projects has been the successful combination or "twinning" of NMTC and ITC/PTC subsidies, as well as the ability to substitute the PTC for the ITC.<sup>5</sup> Through the combination of NMTC and ITC/1603, the Coastal Community

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<sup>4</sup> For census tract mapping tool, see [www.novoco.com/new\\_markets/resources/ct/](http://www.novoco.com/new_markets/resources/ct/)

<sup>5</sup> Novogradac Journal of Tax Credits, March 2010, Volume I, Issue III

Action Program of Aberdeen, Washington, a nonprofit community assistance organization, was able to develop the Coastal Energy Project, a 6MW wind development near the Washington coastline in Grayland, Washington. The project was able to bring in \$8 million in NMTC through ShoreBank Enterprise Cascadia and \$7 million through the 1603 program that allows the project to receive the PTC in cash grant form in lieu of the ongoing tax credit. “Coastal Energy Project is one of the first deals to use the NMTC and the Section 1603 provision that allows ITCs to be claimed for traditional PTC facilities, according to Tony Grappone, Novogradac & Company partner, and CCAP’s Dublanko.”<sup>6</sup>

## **Bonds**

In addition to extending the 1603 program and allowing the ITC and the PTC to be interchangeable, the ARRA also provided up to \$3.2 billion in bonding authority to each state and its local governments to finance renewable energy projects like wind turbines through Qualified Energy Conservation Bonds (QECCBs). QECCBs allow the state or a city to issue bonds and pay back only the principal of the bond, while the bondholder receives federal tax credits in lieu of the traditional bond interest. Moreover recent legislation has provided the option of allowing issuers of QECCBs to recoup part of the interest they pay on a qualified bond through a direct subsidy from the Department of Treasury. QECCBs differ from more traditional tax-exempt bonds in that the tax credits issued through the program are treated as taxable income for the bondholder. The advantage of either option is that it creates a lower effective interest rate for the issuer because the federal government subsidizes a portion of the interest costs.<sup>7</sup>

## **Loan Guarantees**

One of the significant obstacles to both small and large-scale wind developers is the financing guarantees that are required. In order to leverage private investment through banks and facilitate renewable energy projects, the federal government offers several loan guarantee programs:

### U.S. Department of Energy (DOE) - Loan Guarantee Program

Full repayment is required over a period not to exceed the lesser of 30 years or 90 percent of the projected useful life of the physical asset to be financed. The DOE loan guarantees focus largely on projects that exceed \$25 million.

### U.S. Department of Agriculture (USDA) Rural Development

As shown in the map below, nearly 80 percent of the land area of the 9<sup>th</sup> Congressional District is considered “rural” and therefore may be eligible for renewable energy development support through USDA Rural Development programs. The two major sources of funds are the Rural Energy for America Program (REAP) grants and loan guarantees programs and the Business and Industry loan program.

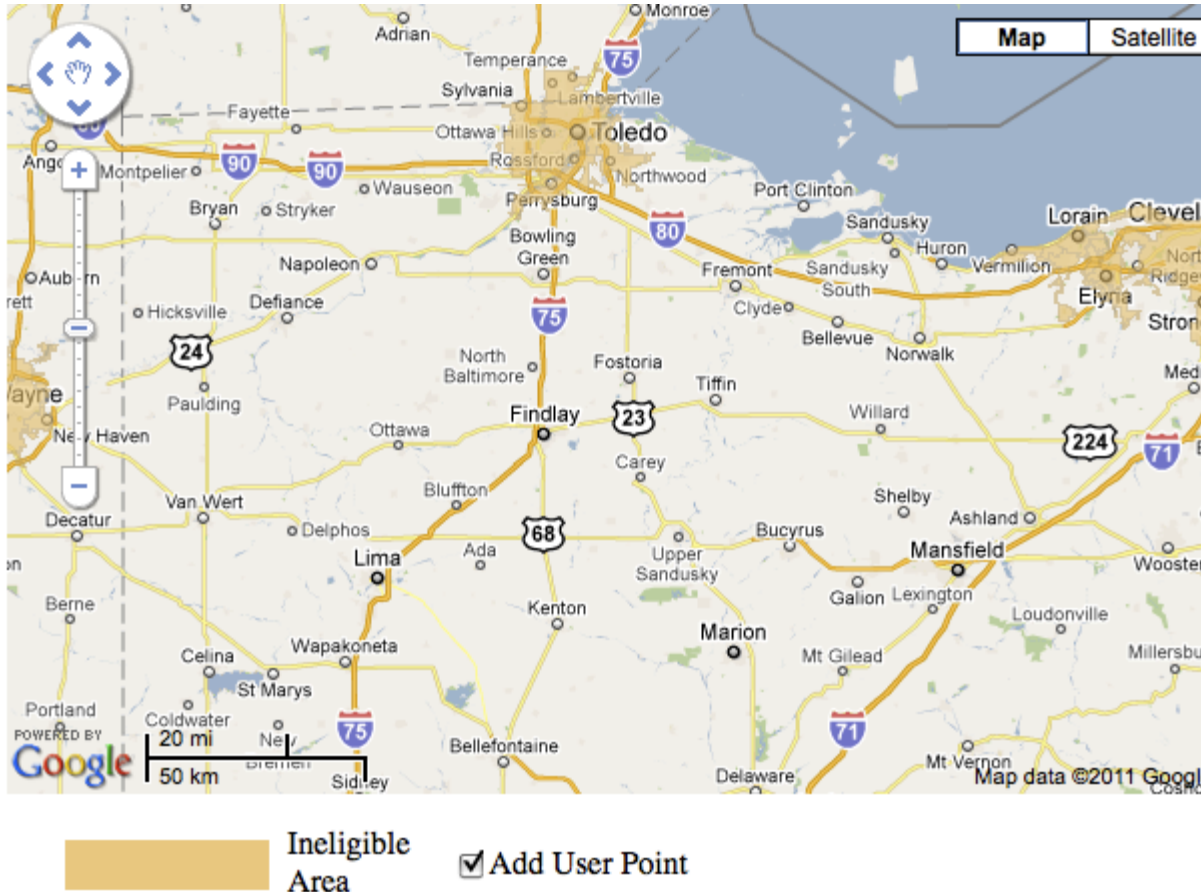
REAP promotes energy efficiency and renewable energy for agricultural producers and rural small businesses through the use of (1) grants and loan guarantees for energy efficiency improvements

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<sup>6</sup> Novogradac Journal of Tax Credits, April 2010, Volume I, Issue IV

<sup>7</sup> Internal Revenue Service. Internal Revenue Bulletin: 2009-16, April 20, 2009 [http://www.irs.gov/irb/2009-16\\_irb/ar10.html](http://www.irs.gov/irb/2009-16_irb/ar10.html) March 1, 2011

and renewable energy systems (systems that may be used to produce and sell electricity), and (2) grants for energy audits and renewable energy development assistance. The REAP grants are limited to 25 percent of a proposed project’s cost, and a loan guarantee may not exceed \$25 million. The combined amount of a grant and loan guarantee may not exceed 75 percent of the project’s cost. In general, a minimum of 20 percent of the funds available for these incentives will be dedicated to grants of \$20,000 or less.



*The map above indicates in gray the areas in Northwest Ohio and the 9th U.S. Congressional District that qualify for business assistance under USDA programs.*

**Business & Industry Loan Guarantees (B&I)**

The B&I program provides loan guarantees for businesses that contribute to the expansion of jobs and the preservation of the environment in rural areas. These guarantees are given to commercial lenders who make credit available to establish or maintain rural businesses. An individual, cooperative or a corporation that seeks to “reduce reliance on nonrenewable energy resources by encouraging the development and construction of solar energy systems and other renewable energy systems” is eligible under the B&I loan program.<sup>8</sup> The B&I program provides guarantees not to exceed 80 percent for loans of \$5 million or less, 70 percent for loans between \$5 and \$10 million, and 60 percent for loans exceeding \$10 million.

<sup>8</sup> US Department of Agriculture. Business and Cooperative Programs. Business and Industry Guaranteed Loans [http://www.rurdev.usda.gov/rbs/busp/b&i\\_gar.htm](http://www.rurdev.usda.gov/rbs/busp/b&i_gar.htm) March 1, 2011



It is important to note that given the USDA requirement that it lend directly to a project, B&I and REAP loan guarantees cannot be used within the New Markets Tax Credit structure. Both funding sources remain viable tools for wind energy finance on their own but wind developers must elect to use one or the other.

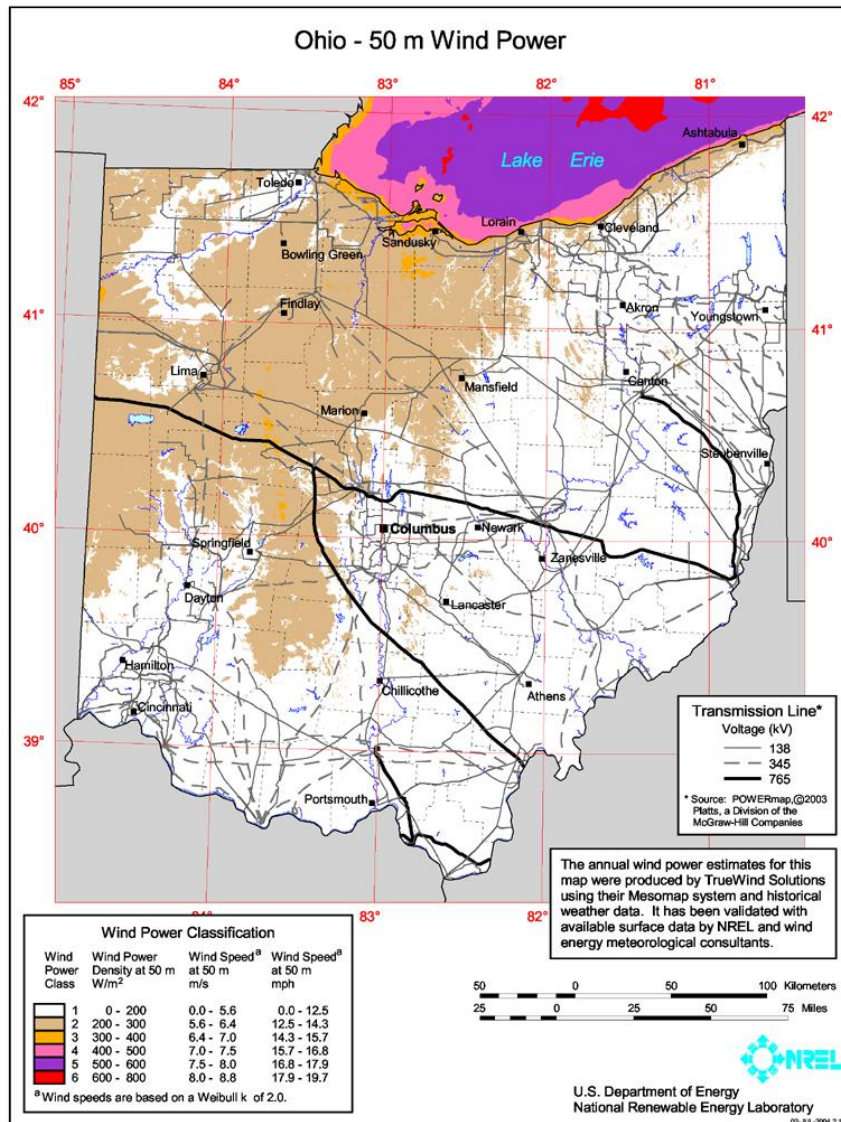
## **WIND POWER: CRITICAL FACTORS AND CASE STUDY** **(Community-Scale Wind Project in Oberlin)**

As the resources outlined above indicate, there are significant federal and state incentives for the development of both utility scale and consumer scale wind energy projects. The following section outlines how some of those resources can be utilized in a model project and outlines the other factors that can impact the successful development of wind power. Our model project occurs in Oberlin, OH, a town of less than 10,000 inhabitants that is served by a municipally owned utility and AMP member. As mentioned above, the analysis here is applicable to any potential wind development. For purposes of this paper, Oberlin has been used as an example. Please see *Appendix A* for the case study financial model.

### **Review of Local Conditions: Wind Resources, Site Selection**

We begin by first reviewing the local conditions, including wind resources and potential locations. This will help familiarize the reader with some of the first considerations that must be balanced in the model and any potential wind project.

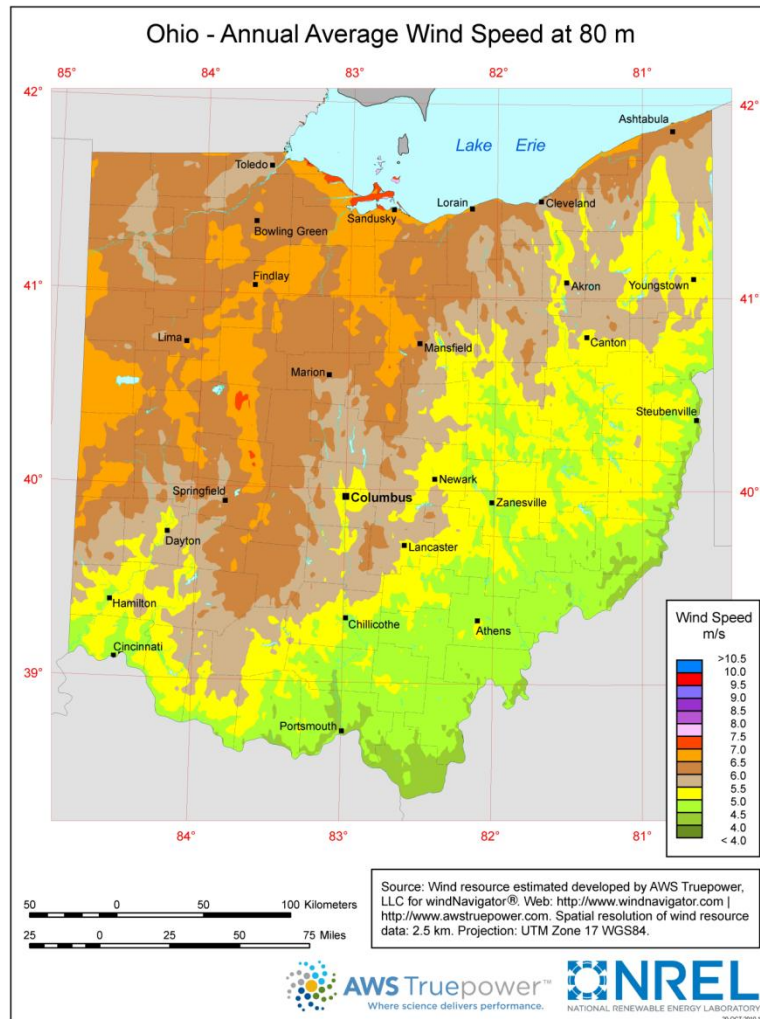
The baseline resource for estimating wind resources, prior to any detailed study, is a map series published by the National Renewable Energy Laboratory (NREL) that shows average wind speeds at a height of 50 meters (a fairly typical hub height for utility-scale wind turbines). See map below.



At first glance, this map does not paint an encouraging picture of the wind resources available in Oberlin. The Oberlin area straddles the line between Class 1 wind power resources (below 5.6 meters per second, which is usually considered not viable for wind power generation, at least not on an economical basis) and Class 2 wind power resources, which have average wind speeds of 5.6-6.4 meters per second, and are marginally viable. As a reference point, most utility-scale wind turbines have a “cut-in speed” (the wind speed at which the turbine begins generating electricity) of 3.5 to 4 meters per second, and need wind speeds of 12-15 meters per second before they will produce their full rated capacity. Good average wind speeds are considered to be in the range of 7 to 8 meters per second.

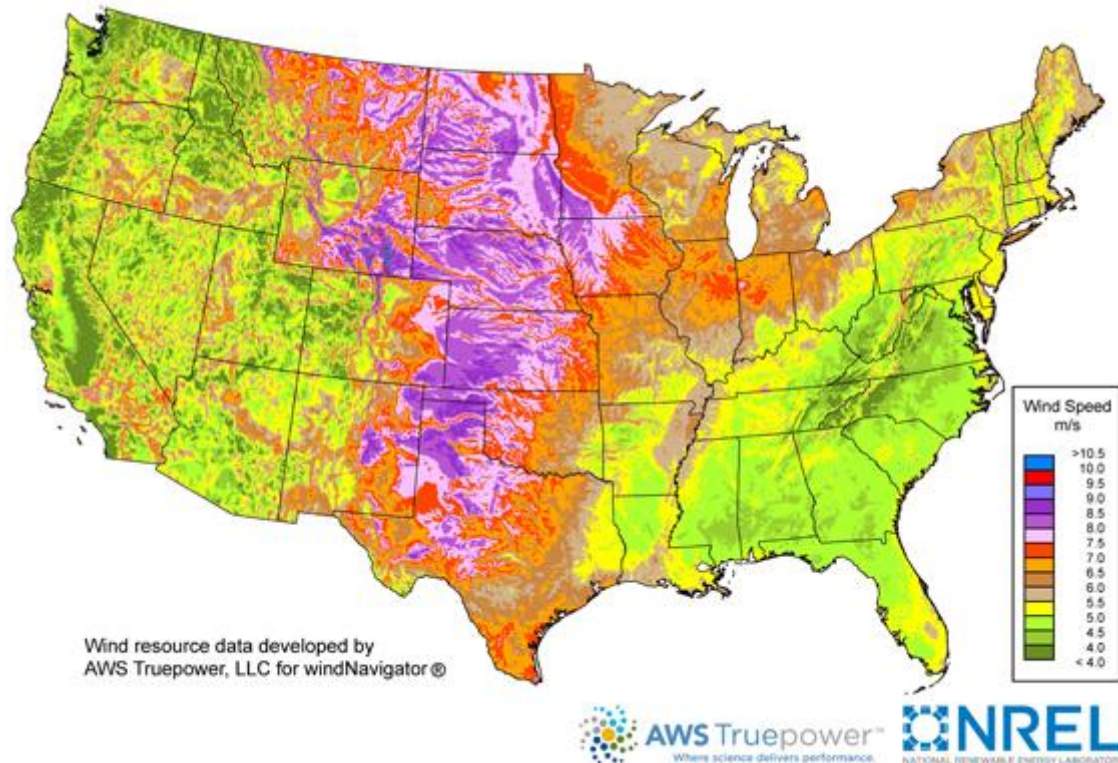
NREL published an updated version (below) of the Ohio wind map in October 2010, reflecting additional data that has been gathered around the State since the above shown 2004 edition, and providing finer gradations at lower wind speeds. This map shows average wind speeds at 80 meters, which is becoming a more typical hub height for new wind installations. The picture is

only slightly more encouraging, indicating likely average wind speeds between 5.5 and 6.5 meters per second.



This type of state-level average data is only useful for a general overview. Wind resources are variable from site to site, and the only way to truly assess a particular location is to perform a site-specific wind study. Fortunately, John Scofield in the Oberlin College physics department set up a wind monitoring tower in June 2006 and gathered a significant amount of localized data, assessing wind speeds up to the 50-meter height. The average annual wind speed was found to be approximately 4.6 meters per second, confirming the data from the NREL wind maps.

To put the local picture in perspective, the national 80-meter wind map from the NREL data set is below, showing the areas of the country with higher wind speeds and thus more commercial wind development.



There are some noteworthy large-scale wind developments planned in the western parts of Ohio, where the 80-meter wind map shows average wind speeds above 7 meters per second:

- 200 turbine wind farm in Hardin County developed by Chicago-based Invenergy LLC;
- 27 turbine wind farm in Hardin County developed by JW Great Lakes Wind LLC, a subsidiary of German wind developer Juwi GmbH; and
- 50 turbine wind farm in Champaign County developed by New York-based EverPower Wind Holdings, Inc.

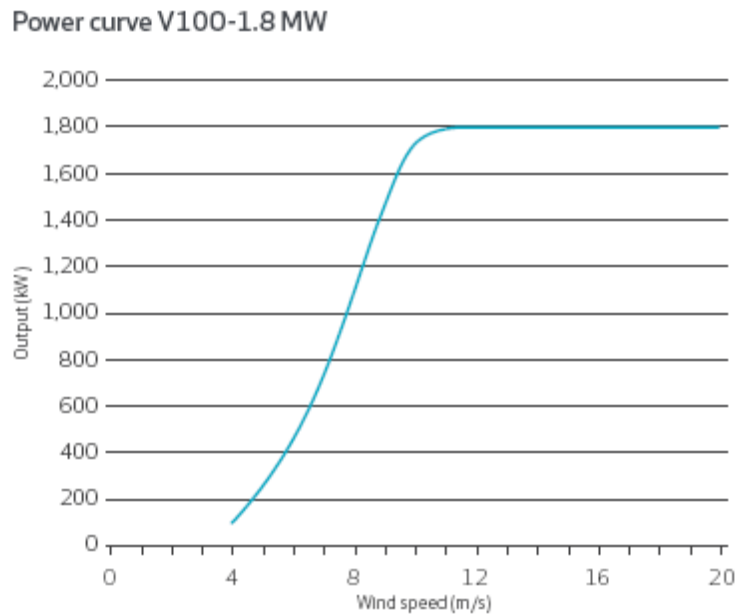
Because the projects have not yet been built, it is not possible to assess their actual performance. But assuming the parties to those developments performed adequate due diligence and made reasonable financial assumptions, we may assume that in those areas and at that scale, these projects are reasonably productive and economically feasible.

### **Brief Introduction to Wind Power Output**

This study is not meant to be a full exploration of the engineering of wind turbine projects and methods for modeling their output, but it is helpful to provide a general overview to put the recommendations in context.

Every wind turbine type has specific characteristics of power output at a given wind speed. The graph of this characteristic is known as the “power curve” of the turbine. Below is an example of the power curve from a Vestas Model V100. You can see from this curve that the turbine produces no power below 4 meters per second (the “cut-in speed” at which the turbine begins producing electricity), reaches the maximum rated output of 1.8MW at 11 meters per second, and then

maintains maximum rated output up to 20 meters per second, which is its cut-out speed. Above the cut-out speed, it is not safe for the turbine to operate, so the turbine will stop itself.



To estimate the power output of a given turbine at a given site, one would essentially match the power curve to the observed wind speeds. This should be done using short time intervals --1 or 5 minute intervals -- and ideally would be based on a full year of data because wind conditions are variable by season.

This task would not ordinarily be possible within the scope of this report, but we are fortunate that Scofield's report and wind monitoring tower gathered this data, which allowed for a much more robust estimate of power output than would otherwise be possible. To understand why average wind speed as a metric is not sufficient to calculate power output, consider two cases. In the first case, the wind blows at exactly 4.6 meters per second all the time, leading to slow, steady power output for most wind turbines. In the second case, the wind blows at 3 meters per second most of the time (below the cut-in speed for most wind turbines) but from time to time the wind gusts so hard that the turbine reaches its cut-out speed and shuts down because it cannot operate safely. In the second case, the wind turbine would produce power only at those intervals between the cut-in and cut-out conditions, which in our hypothetical occurs only for short periods, making the second case a low power generator even though the average wind speed is the same as in case one. Obviously those two cases are at the extremes, and most sites would fall somewhere in the middle, however, this is just to give an example of the technical challenges of estimating wind output.

Using the data from Scofield's tests, we can put together an economic model that would allow for a feasibility analysis and an assessment of the applicability of financing mechanisms. Scofield takes the observed 50-meter data and extrapolates the average wind speeds at 80 meters from that data. The expected output from several different turbines is modeled below.

<b>Turbine Model</b>	<b>Annual Energy (kWh)</b>	<b>Capacity Factor</b>
General Electric 1.5 xle	2,656,790	20.2%
General Electric 1.5 sle	2,300,430	17.5%
General Electric 2.5 xl	3,703,330	16.9%
Vestas V80-1.80	2,417,670	15.3%
Vestas V82-1.65	2,772,590	18.8%
Mitsubishi MWT92- 2.4	3,322,510	15.8%

The chart above shows the gross output in the center column, unadjusted for turbine size. Larger turbines such as the Mitsubishi MWT92 (with a rated output of 2.4MW) produce more energy annually, but are operating at full capacity less of the time. Capacity factor, shown in the right hand column, is a better indicator of a given turbine’s suitability for a given site. Capacity factor is calculated by dividing the theoretical maximum amount of energy the turbine could produce in a year (rated capacity x 24 hours a day x 365 days per year) by the actual amount it is modeled to produce. By this metric, the General Electric 1.5xle turbine appears to be the frontrunner for turbines available in this market, and these output assumptions will be used for modeling purposes in the remainder of the report. (Whether or not a proposed project would actually be able to place such a small order with General Electric is a separate question.) As an additional caveat, please note that the monitoring site is over a mile from one of the proposed locations below, and wind data can be highly site-specific. It is recommended for any project that a wind study be conducted at the potential site.

Each 1.5xle turbine is estimated to produce 2,656,790 kWh annually under optimal conditions (assuming no losses due to turbine downtime and no losses in transformers or site wiring). The three turbine installation recommended below would have an ideal annual output of 7,970,370 kWh, or enough to power about 750 homes for a year.

### **Site Selection: Four Characteristics**

A prospective site for a wind installation in Oberlin has to consider several factors:

- **Ownership:** We limited our selections to existing Oberlin College-owned property on the assumption that Oberlin College would want the installation on its land for public relations purposes, but would not want the additional expense of purchasing land that would be used only for a wind installation.
- **Proximity to existing infrastructure:** The site should be accessible to roads. Equipment is delivered by truck, and each tower location should be reasonably close to an existing road (while still obviously obeying setback restrictions) and vehicles should not need to cross obstacles such as wetlands. Installation costs will be controlled by minimizing the

amount of site access work to be done. The site should also be accessible to the power transmission infrastructure.

- **No wind-disrupting obstacles:** The site should not have tall, wind-disrupting obstacles such as large buildings upwind from the turbines. Even though the towers are significantly taller than local trees, ideally they would not be located immediately downwind of trees. This would help to minimize wind shear (that is, when looking at the area swept by the rotor, the difference in wind speeds between the upper area and the lower area) which affects turbine performance. The site should also be laid out such that the turbines have proper spacing between them. The dominant wind direction in Oberlin is from the west/southwest. A good rule of thumb is that turbines should be spaced no less than 5 rotor diameters apart in the direction perpendicular to the prevailing winds, and no less than 10 rotor diameters apart in the direction parallel to the prevailing winds. The GE 1.5xle has a rotor diameter of 82.5 meters, so ideally the turbines would be at least 400-500 meters apart (along a line running perpendicular to the prevailing wind direction).
- **Compatibility with existing uses:** Wind facilities should also be compatible with current land uses and neighbor sensitivities. A minimum 1000-foot setback from all residential structures is assumed to minimize complaints from neighbors and potential disputes during zoning and approval hearings. Of course, depending on the characteristics of the neighborhood, greater setbacks or other requirements may be required. Ideally, the site would have a low-impact existing use such as farming that would be able to continue after the turbines were installed.

### **Two Potential Locations Identified for Oberlin College**

The balance of the four characteristics described above led us to two sites of interest: (1) the fields on the southwest corner of Butternut Ridge Road and North Professor Street, and (2) the George Jones Memorial Farm on State Route 511 west of Oberlin.

Advantages/Disadvantages of Location 1: The available site has several beneficial factors.

- It is several hundred acres and provides ample space for three wind turbines (the system size recommended below).
- There is an existing OMLPS substation on Butternut Ridge Road, with a 69KV line running from the substation into town.
- The location provides for ample setbacks between turbine sites and adjacent residential property, with a minimum of 1000 feet from residential structures.
- Most of the site is currently devoted to agricultural use. After construction, farming could resume on the vast majority of the site that is not needed for operations.
- The site is close to State Route 58, and access raises no large logistical concerns. There is even an existing access road which could be expanded and improved to help minimize costs and site disturbance.
- The site is adjacent to the site where the Scofield wind monitoring station was set up, increasing the reliability of that data.

One of the main disadvantages of Location 1 is that it is in Census Tract 602, which does not qualify for the New Markets Tax Credit (see discussion of the NMTC in the *Federal Support*

section above). Only Census Tract 601 in Oberlin (essentially, locations east of Main Street) would qualify for this program. While this factor alone would not rule out the location, it does fall outside the model suggested below, which depends in part on the NMTC.

**Advantages/Disadvantages of Location 2:**

- Location 2 is NMTC qualified.
- Although the site is smaller, at less than 100 acres, it is almost a mile from the north end to the south end. The north/south orientation permits three turbines to take advantage of the prevailing west/southwest winds and be sited at adequate distances from one another without interference, and at adequate distance from residential structures.
- There is programmatic tie-in to the organic farm on the site, which could take advantage of some of the benefits of the energy generated, and could add an important educational component.
- An existing OMLPS 69KV distribution line runs along the south edge of site.
- Road access is good coming off of State Route 511 on the north end of the property, and the site is very close to US Route 20, a major truck route.

The site has the drawback of significant amounts of woods and wetlands on it. The usable areas that are not wooded are in use by the organic farm, which could dampen enthusiasm for the development. The existing site character and uses would be changed significantly by a wind development of this scale. Location 2 is over a mile away from the site where the Scofield wind monitoring station was set up, which will perhaps decrease the applicability of the data from that study.

**Inputs and Key Factors**

The examination of the model for a wind project follows, taking the perspective of the entity that would be hosting the project. Below is a discussion of the key variables and assumptions used in that model.

Project Factor 1: System Size

In assessing system size, economies of scale are a dominant factor. Smaller turbines typically have a higher installed price per watt, and lower tower heights lose out on much of the available wind. Utility-scale wind projects tend to be pushing the boundaries towards larger-capacity turbines and higher towers, and exploring the limits of scale. See chart below for a sense of how wind turbine sizes have advanced recently.

	<b>Years:</b>	<b>1998-99</b>	<b>2000-01</b>	<b>2002-03</b>	<b>2004-05</b>	<b>2006</b>	<b>2007</b>	<b>2008</b>	<b>2009</b>
	<b># MW:</b>	1,016	1,758	2,125	2,803	2,454	5,249	8,350	9,994
	<b># turbines:</b>	1,425	1,987	1,757	1,960	1,536	3,190	5,029	5,734
<b>Turbine Size Range (MW)</b>	<b>0.00-0.5</b>	1.3%	0.4%	0.5%	1.8%	0.7%	0.0%	0.5%	0.2%
	<b>0.51-1.0</b>	98.5%	73.9%	43.4%	18.5%	10.7%	11.2%	10.3%	4.6%
	<b>1.01-1.5</b>	0.0%	25.4%	43.5%	56.0%	54.0%	49.2%	53.5%	49.4%
	<b>1.51-2.0</b>	0.3%	0.4%	12.5%	23.6%	18.4%	23.1%	16.3%	21.2%
	<b>2.01-2.5</b>	0.0%	0.0%	0.0%	0.1%	16.2%	15.2%	16.8%	23.1%
	<b>2.51-3.0</b>	0.0%	0.0%	0.1%	0.0%	0.0%	1.3%	2.5%	1.4%

Source: AWEA project database



These considerations lead to a focus on commercial-scale applications, large enough to achieve some economies of scale, but not utility-scale in scope. The goal would be to have a system large enough to offset a meaningful amount of energy use, but small enough to finance and construct on a reasonable timeline, and not overwhelming to the local utility and grid. There is also the consideration of the Ohio Power Siting Authority, discussed in the *Policy Recommendations* section below. Regulatory cost, uncertainty, and time are greatly expanded for projects over 5MW. For these reasons, we look at 5MW as the maximum system size.

At the same time, especially in an area such as Oberlin with only marginal wind resources, a project will need to realize all available economies of scale on the construction. And the fixed costs associated with designing, permitting, and financing a system should be spread over as large a base as possible. For this reason, in this context we focused on a system of three 1.5MW turbines, for 4.5MW installed nameplate capacity.

### Project Factor 2: Ownership Structure

In deciding on an ownership structure for a wind turbine project, several factors must be balanced: long term value of the asset, and long term costs of owning the asset (including implied costs such as staff time).

#### ***Recommended Structure: Power Purchase Agreement (PPA)***

A Power Purchase Agreement (PPA) is a contractual arrangement with a developer by which Oberlin College can take advantage of wind energy savings while remaining sheltered from the risks of system ownership. It is assumed that Oberlin College is more interested in the green power output of the wind turbines than in actually owning the turbines themselves. A PPA provides a vehicle by which a customer or “host” engages a third-party developer to construct a wind power system on the host’s land. The host, Oberlin College, would sign a PPA with a developer. The developer would be responsible for selecting the equipment, project design, permitting, finance, and installation. Oberlin College would purchase the power output at a predetermined price per kilowatt-hour. For environmental and financial reasons, the host may also want to own the associated RECs, however, this would be a negotiated point with the developer (under a PPA model), as the RECs may be needed to help finance the project. The developer would be responsible for operations, maintenance, and all tasks needed to keep the turbines running properly. If problems with the equipment or the wind resources prevent the project from performing as expected, the developer would not have as much power to sell, but the price per kWh to Oberlin College would remain the same. This type of arrangement is recommended because it transfers risk away from Oberlin College and places it on the developer, while still providing the benefits and price stability.

#### ***Turnkey installation and sale: Not Recommended.***

Another possible structure for the project would involve Oberlin College contracting with a turnkey installer to design and install a system that Oberlin College would own. This structure would give Oberlin College more potential long term benefits along with more long term costs and risks, than a PPA structure or an equipment lease.

The long-term benefits accrue once the system is paid for, at which point every additional kWh of power comes to Oberlin College at a very low marginal cost. Owning the system would

essentially cut out an additional party that needs to derive annual profits from the structure. A developer working in a PPA or equipment lease structure (below) would use relatively conservative assumptions of annual output in order to cover their costs in years when the equipment is down for unscheduled maintenance or the wind conditions are not favorable. The developer would make a profit in most years. If Oberlin College takes on the risks of ownership, then it would also receive the benefits of this profit margin.

The long-term costs to consider are that the turbines will require increasing maintenance after the expiration of the warranty period (typically 3-5 years). Service contracts are available through the installer or third parties, or Oberlin College could train existing maintenance staff to perform most needed task. The cost of annual service/maintenance/parts replacement will increase with the age of the turbine. See discussion of operational costs in Assumption 7, below.

Disposal of the asset at the end of its useful life. As the turbines begin to approach the end of their design life, additional decisions will have to be made. Continue operations in the face of escalating yearly costs and increased downtime? Rebuild the equipment, either completely or in part? Dismantle and attempt to sell? These questions are not, on their own, a reason to avoid wind turbine ownership. However, the cost and staff time that will be devoted to answering them properly must be incorporated into the analysis as a factor weighing against ownership. Because these questions are not likely to be answered for approximately 20-25 years, it is unlikely that any current decision-makers at Oberlin College will be available for consultation, and the cost and time involved in the decision should be counted as an institutional liability for future administrations to absorb.

In consideration of all these factors, ownership is not recommended for a wind turbine project of this small scale because of the inability to take advantage of economies of scale. Wind turbine operation and ownership, once the investment becomes large enough to be economically significant to the owner, is best approached as a business in and of itself. The scale of this project makes it difficult.

### ***Equipment Lease: Not Recommended***

It is possible to lease wind turbines from manufacturers and some larger installers. Equipment leases have several advantages that make the structure worth considering. Similar to a PPA, an equipment lease would protect Oberlin College from the cost fluctuations and long-term concerns associated with ownership. Lease payments would be fixed, allowing for fairly simple financial planning. The main disadvantage to this type of arrangement is that power output would be variable, while the annual cost remains fixed. So the cost per kWh of output would also remain variable.

An equipment lease would be a more attractive option for Oberlin College if the College had a high level of understanding regarding the likely power output from various wind turbines. In an equipment lease scenario, the lease payments would be negotiated based on factors including upfront costs borne by the lessor, the specific equipment installed, and the length of term over which the lessor would be able to recover those costs. The anticipated power output of the installation would remain a variable, the risk of which would be borne by Oberlin College. Different calculations of anticipated output would result in different implied electricity prices. Unfortunately, there are no comparable wind projects in the area which could be used to help predict output. The nearest large installation is the AMP JV5 installation in Bowling Green, which

is 100 miles away in an area with a different wind classification.

It is also important to note, from an administrative/project evaluation standpoint, that it is likely that evaluating proposals from more than one lessor would require an analysis of different equipment and installations across the proposals. (Similarly, a proposal from a single manufacturer might include options for different turbine models.) This means that in order to properly evaluate an equipment lease proposal, Oberlin College would have to develop internally, or contract for, a reasonably high degree of sophistication in wind project engineering. A PPA structure would take this additional set of variables off the table, and allow planning and negotiation based directly on electricity prices. This allows for easier planning of total Oberlin College electricity expenditures.

While an equipment lease would be more appropriate for Oberlin College than outright ownership, a PPA structure would help to eliminate variables and simplify decision-making.

### Project Factor 3: Regulatory Involvement and OMLPS

One of the critical parties in any scenario is Oberlin Municipal Light and Power Systems (OMLPS), the local utility. OMLPS would have to approve the installation of any new grid-connected power generation equipment within its service area. (We assume that this wind power installation will be connected to the grid, as it would be impractical to try to store and use the power for off-the-grid applications.) OMLPS has permitted customer-owned, behind-the-meter generation systems in the past, under a net metering regime there is something of a precedent for the request, but there are two significant differences here, which bear some examination:<sup>9</sup>

**A) Third Party Ownership:** OMLPS would need to agree to let a third party (that is, an entity which is not its customer, but an independent developer holding a contract with its customer) install and operate power generation equipment connected to the OMLPS grid via a PPA or Lease with the customer. Traditionally, this role is filled only by the utility company, or by the customer under particular conditions.

**B) Remote Net Metering:** OMLPS would need to integrate what is known as “remote net metering” or “virtual net metering.” Standard net metering discussed above involves power generation equipment that is behind the customer’s meter. That is, if there is a building such as the Adam Joseph Lewis Center that installs a solar array on the roof, that array is said to be behind the OMLPS meter. Power generated by that array is essentially “used” first in the building, and only if there is a net surplus of power production is it exported onto the grid. (Depending on the set-up, the “green” electrons may pass the meter to the grid and thus become indistinguishable from the “brown” energy supplied by the grid. Either way, the host site is credited for the energy it produces.) In remote or virtual net metering, the power generation equipment is not connected to the meter that benefits from the generation, and instead a meter at the generation site records the power exported onto the grid, and the customer is given a credit for that power on an existing utility account. As with standard net metering, utilities are wary of certain implications of remote net metering and such terms are evolving, including the price at which a kilowatt-hour of green energy is credited to the customer’s account, the period for which net metering is allowed to carry

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<sup>9</sup> *Appendix C:* OC/OMLPS net metering contract for AJLC array; *Appendix D:* OMLPS net metering regulation; *Appendix E:* Ohio net metering regulation

over, what happens to any net production (over the customer's use) at the end of the relevant period (e.g., is it a "use it or lose it" scenario, can it be allowed to roll-over, or is it paid out to the customer at a pre-determined rate), and whether or not to allow customers to transfer credits, or "sell electricity," to unaffiliated parties across the street or across town. . See *Appendix F* for an example of remote net metering legislation (Pennsylvania).

We assume for the purposes of this report that OMLPS will accept a virtual net metering regime. Discussions between SCA staff and OMLPS staff indicate that OMLPS is not against the idea, and could support it if the proper pricing and regulatory regimes were put in place.

**OMLPS Pricing:** See *Appendix B* for a discussion of OMLPS cost structure and pricing. For the purposes of this model, we assume that OMLPS would offer a credit equal to the Commercial Generation Charge, which is \$0.073 per kWh for 2011.

#### Project Factor 4: PPA Terms

- A) **Price.** For purposes of the case study model, we assume that the price charged to Oberlin College in the PPA would be equal to the credit given by OMLPS (\$0.073 per kWh), plus a premium to reflect the "greenness" of the power. Placing a dollar value on that premium is difficult, since it is highly subjective, but one objective proxy for the value would be the price of Renewable Energy Certificates (RECs). The REC market is highly variable, location-specific, technology specific, and subject to other factors such as future policy decisions. (See *State Support* section above for a discussion of RECs in Ohio). So while no one REC price can stand in for the actual value, two methods seem to offer acceptable proxies. The first is the EcoSmart Choice program run by American Municipal Power (AMP), of which Oberlin is a member. This program allows customers in AMP member communities to purchase the renewable attributes of AMP-operated renewable assets. The price is \$5.00 per REC (or \$0.005 cents per kWh, since a REC is one megawatt hour of electricity). These RECs come from a variety of assets, primarily hydroelectric but with landfill gas and wind included. AMP does not specify the exact mix of sources for RECs available through the EcoSmart Choice program, and it is likely not a fixed percentage, but variable depending on the assets in place at a given time and AMP's other existing REC sale contracts. Many environmentalists consider hydroelectric power to be less "green" than other renewable energy due to ecological damage caused by hydroelectric dams, and hydro RECs are usually traded at a discount to wind or solar. So \$5.00 per REC is probably on the low end of the spectrum. On the higher end of the spectrum, the JV5 Wind Project in Bowling Green, Ohio, which is also an AMP project, charges member communities \$30 per REC for its power.<sup>10</sup> For the purposes of this model, we take the average of those two prices and assume a value of \$17.50 per REC (\$0.0175/kWh.) This yields a PPA price of \$0.0905/kWh.
- B) **Duration.** The length of the PPA contract for a wind project should generally match the expected useful life of the turbines. Most commercial wind turbines, including the GE 1.5XLE model recommended here, have a 20-year design life. A 20-year PPA gives the host customer long-term price stability, and gives the developer sufficient time to

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<sup>10</sup> Source: OMLPS staff interview

recoup the initial investment. A shorter time period might not allow the developer to recoup the initial investment unless the price is raised.

- C) **Escalation.** One of the benefits of a long-term PPA is the ability of the host customer to lock in an escalation rate for the entire term. Electricity prices are highly variable, and difficult to predict. See *Appendix B* for a discussion of Oberlin's historical and predicted wholesale power rates. From this information, it would be possible to draw a 7-year trend from 2003 to 2010 showing a 7.32 percent annual increase in prices, or a 5.90 percent annual increase if the trend is followed out to OMLPS predictions on 2015 rates. (A full assessment of future electricity prices is outside of the scope of this report, and there is no shortage of qualified forecasters predicting lower rates of increase, or higher rates of increase and the end of cheap energy.) We assume that the PPA would have a 3 percent annual rate of increase for its entire term. This number provides significant potential long-term cost savings to the host customer, and allows the developer to keep up with operations and maintenance costs, which we also assume to rise at 3 percent annually.
- D) **Maintenance/Operations.** This model assumes that all maintenance and operations costs are borne by the developer<sup>11</sup> (see *Factor 7* below). Wind assets are exempt from Ohio personal property taxes but the owner/generator must make a Payment In Lieu of Taxes (PILOT) to the state instead of paying real estate taxes directly, as discussed in *State Support* section above.<sup>12</sup> The PILOT is variable from \$6,000-\$8,000 per MW of installed nameplate capacity per year, depending on the percentage of local workers employed on the project. The County is also able to levy an additional payment up to a maximum of \$9,000 per MW per year. For the purposes of this model we assume \$9,000 per MW.
- E) **Assets at end of term.** This model assumes that at the end of the PPA term, the developer will, at its cost, disassemble and remove the project from the host's land, and restore the host's site to its prior condition. (Other arrangements are sometimes used such as a purchase option by the host at fair market value, or an extension of the PPA on negotiated terms.) There is also often a residual value to the assets at the end of their service life. This model assumes these two values are equal, and the asset/liability at the end of the PPA term nets to zero.

#### Project Factor 5: Renewable Energy Credits:

As discussed in assumption 4A above, for environmental reasons, Oberlin College may want to control the RECs associated with the green energy, and rather than selling the RECs, the College would keep them off the market, thereby reducing the overall global energy footprint. This would be a negotiated point with a developer who may require the RECs to help financing the project. For the purposes of this model, we assume no open-market REC sales, and that the value of the

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<sup>11</sup> Operating costs in this assumption include insurance. This is a negotiated item in a PPA and should not necessarily be assumed for purposes outside of this model.

<sup>12</sup> Database of State Incentives for Renewable Energy (DSIRE). Qualified Energy Property Tax Exemption for Projects over 250 kW (Payment in Lieu). [http://www.dsireusa.org/incentives/incentive.cfm?Incentive\\_Code=OH60F&re=1&ee=1](http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=OH60F&re=1&ee=1) March 1, 2011

RECs is captured by Oberlin College.

#### Project Factor 6: Project Installation Costs

By far the most expensive factor in the pricing of a complete installation is the equipment itself, typically accounting for 80-85 percent of hard costs. Grid interconnection costs, foundations, electrical installation, and road construction make up the balance of the hard costs, generally in that order. These other factors can intervene to drive up project costs if there are special circumstances such as unsuitable or poorly compacting soils that increase foundation costs, etc.

The variety of minor factors that can influence the total installation costs of a project is endless, but several factors can be considered here: Turbine location proximity to roads/overall access of large trucks to the site, and site factors (wetlands, unsuitable soils, special considerations). The balance of these minor factors leads to the assumption that the cost for the described project will be roughly average, with no strong factors skewing costs either higher or lower.

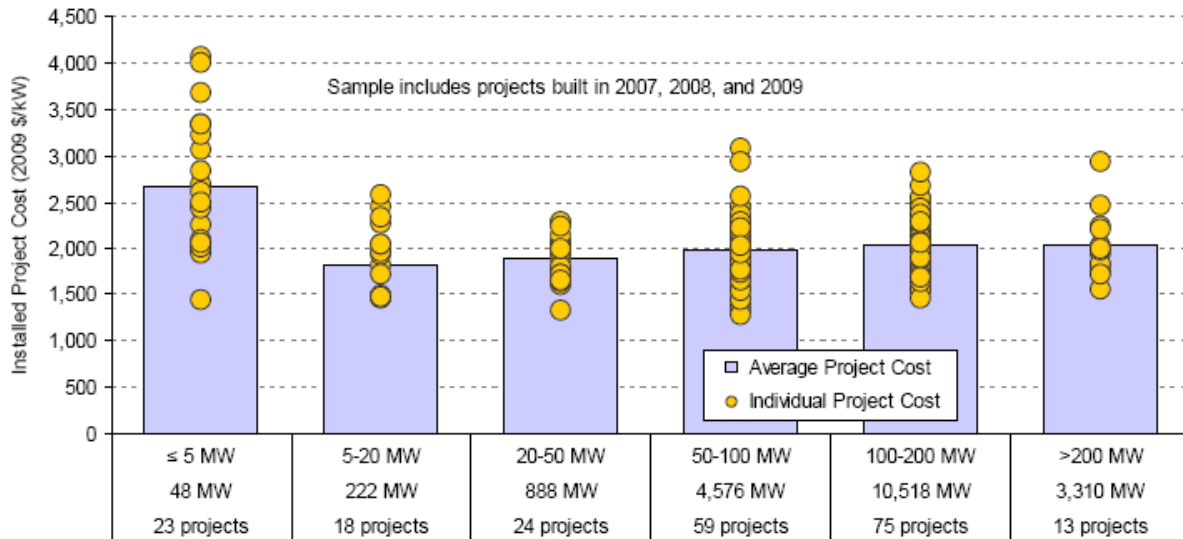
There is considerable uncertainty regarding near- and medium-term prices for turbines. Factors such as high and fluctuating metals and commodity prices and the relatively weak dollar have driven prices up during the recent recession. But prices have been dropping in 2011 as the market appears to be oversupplied. The possibility of placing a small order with a major manufacturer is much better for an Oberlin project today than it has been in recent years, but prices would likely not be as low as the \$1,400-\$1,500/kW headline prices being reported.<sup>13</sup>

Data for small orders of utility-scale turbines is less frequently reported, so 2011 pricing is uncertain. Historically, pricing for an order under 5MW has been 30-50 percent higher than for larger orders. See chart below from Berkeley Labs 2009 Wind Technologies Market Report.

Note that if a PPA structure is employed for a given project, then installation costs are borne by the developer, and would not impact the host.

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<sup>13</sup> Alex Morales, Wind Turbine Prices Below 1 Million Euros a Megawatt, Bloomberg News. February 7, 2011 <http://www.bloomberg.com/news/2011-02-07/wind-turbine-prices-fall-below-1-million-euros-per-megawatt-bnef-says.html>] March 1, 2011



Source: Berkeley Lab

Pricing for the turbines, if they were purchased today, is assumed to be at \$2,100/kW (a 40 percent premium to current average turbine prices, assumed to be \$1,500/kW.) Total system pricing is assumed to be \$2,500/kW, with the balance of \$400/kW made up by other hard costs.

#### Project Factor 7: Project Operations Costs

Project operational costs are shown, for modeling purposes, as levelized costs with an annual inflation factor of 3 percent applied. Actual costs, if the project were built and placed in service, would be highly variable from year to year, and would have a steeper rate of increase. Operational costs for repairs and major component rebuild/replacement will be zero while the turbines are under warranty (typically two to five years) and higher in later years of operation than in earlier years. Other costs such as scheduled maintenance will remain relatively stable over the project lifetime. Therefore the actual costs will be lower than shown in this model in early years, and higher in later years. Particularly in a project with such a small number of turbines, the annual costs will be highly variable. Any funds budgeted for operations but not spent would be placed in a reserve account for later unscheduled repairs. Operations costs are generally projected based on kWh output, much as the cost of operating an automobile is projected on a per-mile basis. Typical costs range from \$0.010 to \$0.015 per kWh; \$0.014 is assumed here, reflecting a high-quality equipment supplier that should result in lower costs (all other things equal) but also a smaller project with less bargaining power with service providers and fewer turbines over which to spread fixed costs.

Note that if a PPA structure is employed for a given project, then operations costs are borne by the developer, and would not impact the host.

#### Project Factor 8: Predevelopment Costs and Soft Costs

Most of the factors that could help lower predevelopment costs are not in place here. As discussed in the *Policy Recommendations* section below, there is no existing zoning classification designed to permit wind development, and no guidance in any existing zoning classifications that could help eliminate uncertainty. Environmental reviews will be needed to assess the impact on migratory birds, etc. The lack of the virtual net metering legislation needed pursuant to *Factor 3B* above

increases uncertainty, increases legal/consulting costs, and likely adds time to the predevelopment timeline. This, in combination with the amount of legal and accounting work to be overseen, leads to a higher developer fee.

Grid interconnection and the associated costs are assumed to be part of the EPC contractor's scope. If a PPA structure is employed for a given project, then predevelopment costs are not borne by the host site, and would not be relevant to its analysis of the project. If however, an accommodating environment (zoning, net metering, etc.) is not in place, then the likelihood of attracting PPA providers is decreased.

#### Other Case-Study Model Assumptions:

- Each turbine is assumed to be operational 97 percent of the time. Of course, in earlier years the uptime will likely be higher (or guaranteed by the manufacturer) and in later years it may be lower.
- Electricity lost due to parasitic factors (friction, transmission, transformers): 5 percent

### **Project Financing: Role of Banks and Private Equity**

#### ITC, PTC, and the 1603 Grant Program

Renewable energy facilities face considerable uncertainty regarding the future of existing tax credits. Predictions regarding subsidies that will be available or extended in the future are problematic, and financial assumptions should be attentive to the changing landscape. For the purposes of this report, the project is assumed to be placed in service under the current subsidy regime. (In practice that would necessitate an accelerated predevelopment and development process.)

The stimulus package of 2009 (ARRA) contained a provision for energy tax credits to be exchanged for a direct cash grant from the U.S. Treasury (Section 1603). This was done to alleviate a temporary lack of tax credit buyers. The program proved popular with the renewable energy industry because the cash benefits, unlike tax credits, were claimed up front instead of being spread over five years and cash was preferable to a credit against taxes

Section 707 of the Tax Relief, Unemployment Insurance Reauthorization and Job Creation Act of 2010 (that is, the Obama/House Republican tax cut package that passed in the lame duck session of late 2010) extends 1603 eligibility to projects that begin construction in 2011. It does not, however, extend the relevant deadline for when a project must be placed in service in order to qualify. Large wind projects (that is, projects over 100kW) have until January 1, 2013 to be placed in service. It is possible that an Oberlin wind project could meet this deadline, although it would certainly be aggressive. It is also possible that the deadline could be extended or the program re-authorized. For the purposes of this report, the project is assumed to be placed in service under the current subsidy scenario, and elects to take the 1603 grant as opposed to the ITC or PTC.<sup>14</sup>

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<sup>14</sup> In this case, the most advantageous way to bring in the 1603 grant would be to have a bank lend the expected grant amount to the project and then repay the bank when the Treasury department funds the grant. This way, the grant can be used as part of the leverage loan (i.e., the grant can be counted as part of the basis on which the New Markets Tax Credit is allocated, see below.)



## New Markets Tax Credit

The New Markets Tax Credit (NMTC) is a U.S. Treasury program designed to encourage job creation and investment in low-income areas. In recent years, developers have begun employing the NMTC as part of renewable energy projects.<sup>15</sup>

It is assumed that this project will utilize NMTC equity. This would be a complex, multi-stage process, but would yield significant economic benefit for the project. The process would involve finding an approved CDE (Community Development Entity) with an existing NTMC allocation, or applying directly to the CDFI Fund for an allocation. This latter route is not recommended because the project would need to invest significant time and money up-front to develop its own CDE and make its application. Competition for allocations is high, with only approximately 10-20 percent of allocation requests being granted each year. (A new CDE with a relatively narrow mission and little experience in placing allocations would probably have a low chance of receiving an allocation, making the time and money invested in the process a poor allotment of resources.) Many existing CDEs serve Ohio, and would likely find a wind project in Oberlin to be a compelling story if the development team and the balance of the financing were already in place. The 2009 NMTC award round gave allocations to fourteen CDEs working in Ohio, with \$840 million of total allocation. The awardees include:

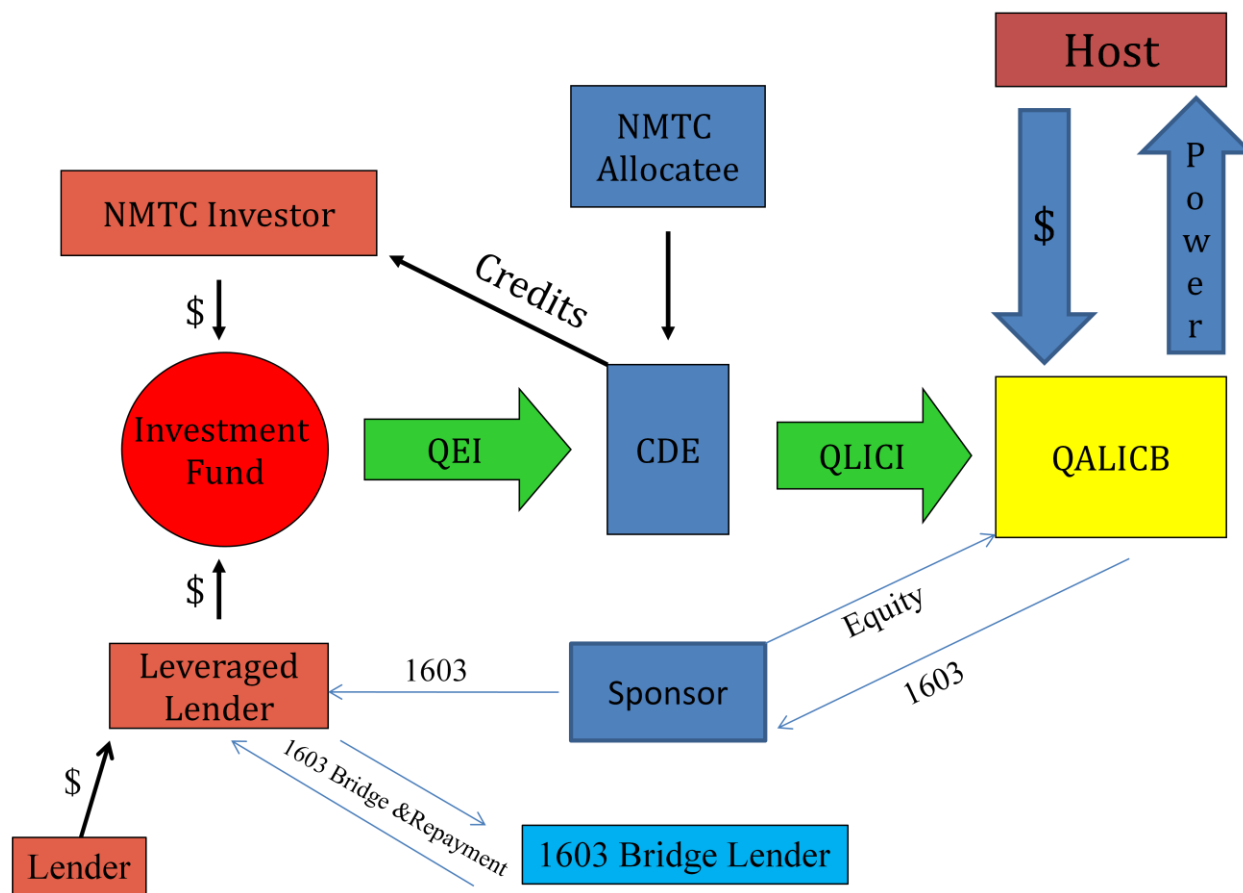
- Chase New Markets Corporation (\$40 million)
- Cincinnati Development Fund (\$30 million)
- Consortium America, LLC (\$80 million)
- HEDC New Markets, Inc. (\$110 million)
- Key Community Development New Markets LLC (\$50 million)
- MBS Urban Initiatives CDE, LLC (\$40 million)
- National New Markets Tax Credit Fund, Inc. (\$75 million)
- National Trust Community Investment Corporation (\$35 million)
- NCB Capital Impact (\$90 million)
- Ohio Community Development Finance Fund (\$50 million)
- Stonehenge Community Development, LLC (\$80 million)
- University Circle New Markets, Inc. (\$20 million)
- Uptown Consortium, Inc. (\$45 million)

Prior year allocations were similar, and multiple CDEs with Ohio in their service areas received awards. A significant portion of prior-year allocations have not been placed with projects lately, due to both normal project delays and also increased project uncertainty and cancellations due to the recession. This serves to increase the pool of available allocations and CDEs that would be interested in discussing an investment in a project involving a stable institution like Oberlin College. CDEs charge fees to the projects they invest in to support the CDEs operations and the costs associated with NMTC compliance. CDE fees of six percent of the allocation amount are assumed for this model.

Given all of these considerations, the NMTC investment is assumed to be structured as per the flow chart below.

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<sup>15</sup> (See the *Federal Support* section for more background, and the program website at [www.cdfifund.gov/what\\_we\\_do/programs\\_id.asp?programid=5](http://www.cdfifund.gov/what_we_do/programs_id.asp?programid=5))



In this flowchart, the funds are first collected in the Investment Fund (the Investor for NMTC purposes.) Three sets of funds are collected in the Fund.

1. NMTC equity investor (the entity ultimately receiving the NMTC benefit) invests based on the value of future tax credits that it will receive. Tax credit pricing is assumed to be 71 cents on the dollar, representing both the discount rate and project/compliance risk.
2. The 1603 Bridge Lender lends in anticipation of the 1603 grant, plus fees.
3. The Lender will be repaid with interest and fees over the duration of the project, with returns subject to project performance<sup>16</sup>.

<sup>16</sup> Leverage Loan Terms: In addition to the NMTC equity and 1603 funds, additional funds will be needed. In this scenario, we assume a 20-year loan with 20-year amortization. The actual structuring would be more complex than this, due to the unwind of the NMTC structure in year seven. Most likely the initial loan would be structured as a 7-year term and a 20-year amortization, with a balloon payment at the end of the NMTC compliance period. The loan would be repaid with PPA revenue. A new loan for the balance of the service life of the project could then be made directly to the project. There is some difficulty in principal repayment during the NMTC compliance period, but given that only approximately 27 percent of the principal would be in question, recapture risk can be avoided by using the combination of escrowed funds at the QALICB level (up to 5 percent of total assets), the return of moderate amounts of principal to the CDE, up to the “substantially all” threshold, and escrowing funds with third party guarantors if necessary.

The Investment Fund then makes the Qualifying Equity Investment (QEI) into the Community Development Entity (CDE.) The amount of tax credits received is based on this QEI.

The CDE then makes its Qualified Low Income Community Investment (QLICI) into the Qualifying Active Low Income Community Business (QALICB.) The QALICB would be the entity that actually owns and operates the project, and enters into the PPA with the host.

While the NMTC structure is complicated, it brings in important subsidy that would be hard to replace. The financial model shows \$4.4 million of NMTC equity introduced through the structure. One tradeoff that should be noted is that a leveraged NMTC structure as shown here would not be compatible with several (otherwise promising) funding mechanisms listed above in the *Federal Support* and *State Support* sections. Loan guarantees through USDA, or low-interest loans through a Port Authority or OAQDA, would not be compatible because the loans would have to be made directly to the project instead of through the leveraged structure.

#### Private Equity

Even using all of the available subsidies and a creative financing structure, this wind project would likely not be able to be financed on commercial terms. A private equity investor could be brought in to fill the gap between project sources and project costs. The returns on this equity position would not be market-rate returns, but a philanthropically- or environmentally-motivated investor would be able to make an investment that likely yields substantial tax benefits, a modest rate of return, and a large community impact. An investment of approximately \$2.5M would leverage approximately \$16 million in renewable energy, and still produce a return in the 5-6 percent range annually over 20 years.

## **OTHER AMP COMMUNITIES**

### **Wind Power Feasibility**

Several AMP cities in the 9th District have a wind profile that is similar to Oberlin and would likely require a similar type of structured finance as the one illustrated in the above model. For example, in Amherst, Ohio, the Cleveland Clinic owns a great deal of land on its campus and could be a beneficial partner on a wind project. The Clinic has already entered into a Solar PPA on its Cleveland Campus and might want to engage in such a project in an effort to increase its renewable energy profile. In order to facilitate such a project, the City of Amherst could also adopt a “remote” net metering policy which would open up land possibilities to the Clinic throughout Amherst and beyond the property on their current campus. In such a project, the New Market Tax Credit would not be applicable because the Clinic is not located in a Qualified Census Tract. The REAP and B&I programs also would not be applicable because Amherst does not qualify as a rural district. However, a Port Authority (such as Lorain or Toledo) could help fill a funding gap through low-cost loans. Alternatively, the clinic could seek Qualified Energy Conservation Bonds through the state or local government.

In some of the smaller townships in Lucas County such as Oregon or Jerusalem Township where zoning for wind already exists, a similar funding structure could be utilized with the incorporation of the USDA REAP or B&I Programs in lieu of the New Markets Tax Credit. Local institutions such as the University of Toledo or Toledo Electrical Joint Apprenticeship and Training

Committee facility could be used as sites for both energy savings and to train workers on turbine installation.

Given the amount of subsidy and the extent of the public, private, and philanthropic partnership that would be required to finance a medium sized wind project, AMP communities in the 9th Congressional District with stronger wind profiles than Oberlin will likely be more appealing to a wind developer. Areas in the western part of the 9<sup>th</sup> District, like Huron County and the city of Bowling Green near western Lake Erie and Bowling Green University, have better wind profiles than the eastern part of the district. AMP built the first commercial wind farm in Ohio in Bowling Green, which began operations in late 2003. Two 400-foot tall turbines were added a year after the first two turbines were installed. The total output of the project is 7.2 MW. Because AMP Ohio helped finance the project through loans to the developers, nine other AMP communities (including Oberlin) tapped into the energy produced while Bowling Green retains half of the produced energy. In this scenario, Bowling Green agreed to pay half the debt and half of the ongoing operational and maintenance costs. Once the debt is retired, Bowling Green will be paying between 2.5 cents and 3.5 cents per kilowatt-hour of wind energy. The city now is paying about 10 cents per kilowatt-hour, a reasonable cost given the greenness and location of the energy.<sup>17</sup>

## **POLICY RECOMMENDATIONS**

### **Local and County Government**

**Regional Planning:** Lorain County should form a regional authority to assist townships and cities on wind related issues. Currently the Toledo-Lucas County Planning Commission serves as a recommending body for Lucas County and has offered guidance in drafting wind legislation and ensuring code uniformity among townships. Lorain County could effectively utilize the same sort of regional approach

**Flat Fees:** Communities can expedite consideration of renewable energy projects by developing a streamlined process and flat permit fees for developers.

**Zoning:** In much the same way cities create zoning for recreation facilities, shopping malls and parks, local governments can use wind opportunities to create a renewable energy zoning classifications that can help provide guidance to wind projects. While some discretion should lie with the local areas planning and design commission, the more regulations that can be spelled out for developers the more attractive the community will be for a potential wind project. Richfield Township, Waterville Township, and Jerusalem Township in the 9<sup>th</sup> district have all developed zoning guidelines for wind projects that other communities can emulate (see exhibit). New zoning codes should address the following potential impacts of wind development:

- Turbine size relative to available land.
- Turbine height relative to neighboring properties.
- Turbine distance and fall zone criteria.

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<sup>17</sup> Kevin Maynard, Large Wind Case Study. 2005 Michigan Wind Energy Conference. <http://www.grea.org/education/UTP/KevinMaynard.pdf> March 1, 2011

- Appropriate lighting, environmental and noise regulations - Zoning codes have often times referred to a maximum decibel level that can emanate from a given wind site. Governing bodies typically require documentation that the noise level will not exceed a certain decibel level. Environmental restrictions can be written to ensure that the developer work closely with the Ohio Department of Natural Resources to ensure that turbines are placed in such a way that minimized the harm done to wildlife and complies with the Endangered Species and Migratory Bird Protections acts.
- Fencing/Security – A recommended security/safety fence that prohibits people from entering the area.
- Architectural expressions – Municipalities should reserve the right to approve the aesthetics of the turbine project.
- Protecting residential landowners -- depending on the make-up of the township or community, the zoning code could address how close a turbine can be to a residence or populated area.

Communities should also consider identifying areas that could be of high value to wind developers and memorializing this in the land use plan of the community.

Port Authority: To date the Toledo Port Authority has been very active in alternative energy development. Among other accomplishments the Toledo Port Authority has leveraged \$15 million of DOE grant money for energy efficiency and renewable energy projects, has lent \$75 million over the last 3 years and is assisting the City of Toledo with finding solar and wind projects. The Lorain County Port Authority should be more involved in trying to encourage wind development. The Port Authority's ability to lend money on below market rate returns is a resource that can be used by potential developers, especially as advanced energy programs are being under-funded due to economic distress.

Pre-Development: One of the largest obstacles to wind development is the cost-intensive nature of the studies a developer must do in order to determine the viability of a site or geographic area. Local governments could decrease the pre-development costs, time and risks that developers face by conducting some of the wind capacity testing that is typically necessary. This data could be utilized as an effective recruiting tool for developers.

#### Education and Community Readiness

Local government has a role to play in ensuring that residents are informed and ready to capitalize on the wind opportunities. A prepared citizenry can lead to more renewable energy development and greater and more diverse utilization of farmland. Having landowners understanding the basic framework for leasing land to a developer and typical profit structure will make more likely that residents are comfortable leasing their land for wind turbines. If the City or Regional authority were to help landowners collect wind data prior to developers approaching, the landowners could have increased leverage to negotiate better deals for their land.

#### **State Policy**

The passage of House Bill 562 directed the Ohio Power Siting Board (OPSB) to prescribe reasonable regulations concerning the siting and construction of wind energy generating facilities with an aggregate capacity of 5MW or greater. Because of the extensive length of the approval

process, the uncertain permit fees, and the costs of pre-development studies, it is unlikely that local developers generate wind projects in the 9<sup>th</sup> District over 5MW. Raising the size that requires OPSB approval to 10MW may allow for more mid-size wind projects to move forward by working directly with local communities and bypassing a cumbersome process.

*Ohio should extend its net metering legislation to include Virtual Net Metering.* This would allow for energy credits to be applied against all meters located on a customer's property or within a certain distance of the generation facility. Currently Pennsylvania's net metering laws allow meter aggregation for all related meters within two miles of the generation facility (see Pennsylvania Code Sections 75.11-14, [www.pacode.com/secure/data/052/chapter75/subchapBtoc.html](http://www.pacode.com/secure/data/052/chapter75/subchapBtoc.html)). Similar legislation exists in Oregon, Washington and Rhode Island. In another example of virtual net metering under the 'Neighborhood Net Metering' measures in its 2008 Green Communities Act, Massachusetts placed into law a rule that allows ten or more individuals to invest in a single renewable energy facility and receive net metering credits as if it had a single owner. Similar programs exist run in Vermont and Maine. In California, a Virtual Net Metering clause exists, and can be used for multifamily affordable solar housing. The benefits of solar power generation, in terms of utility bill offsets, can be distributed to units as a percentage of the total credit. If Ohio were to adopt a hybrid of what these states have done it would open the door to more renewable energy projects by expanding the interest level in energy generation from strictly developers to different entities such as universities and non-profits. It would also expand the number of geographical areas where renewable energy projects would be considered viable.

Extend and Protect the Advanced Renewable Portfolio Standards – Ohio political leadership must vigorously defend the integrity of the renewable portfolio standards legislation. The law mandates that by 2025, at least 25 percent of all electricity sold in the state come from alternative energy resources. At least half of the standard, or 12.5 percent of electricity sold, must be generated by renewable sources such as wind, solar (which must account for at least 0.5 percent of electricity use by 2025), hydropower, geothermal, or biomass. At least half of this renewable energy must be generated in state. The bill also creates a renewable energy credit (REC) tracking system, which allows utilities to buy, sell, and trade credits to comply with the renewable energy and solar energy requirements. Additionally, electric utilities will be required to achieve energy savings of 22.5 percent by the end of 2025 through energy efficiency programs. Any changes to this legislation, either in the percentages of required renewable or the requirement that this energy be generated in Ohio will erode the growing alternative energy market and create a regulatory uncertainty. Any uncertainty will lead to a decline in REC pricing and a backing off of alternative energy investment by the private sector.

### **Federal Policy**

Continue and increase the New Markets Tax Credit. The New Markets Tax Credit is an important tool for developers when building a financial model that support wind development. Without an extension of this program it is likely wind projects will have a difficult time supporting the debt and equity requirements that such a project necessitates.

## **APPENDICES**

- Appendix A: Case Study Financial Model
- Appendix B: OMLPS Background
- Appendix C: OMLPS/OC Net Metering Contract for AJLC
- Appendix D: OMLPS Net Metering Regulation
- Appendix E: Ohio Net Metering Regulation
- Appendix F: Sample Remote Net Metering Legislation (Pennsylvania)

**Appendix A**

**Case Study Financial Model**



## Sources & Uses of Funds

System Size (Watts) 4,500,000

### Uses of Funds

<u>Hard Costs</u>		<u>Total</u>	<u>Cost/W</u>
Equipment and Installation (EPC Contract)		11,250,000	2.50
Hard Costs Contingency	5.00%	562,500	0.13
<b>SUBTOTAL: HARD COSTS</b>		<b>11,812,500</b>	<b>2.63</b>
 <b><u>SOFT COSTS</u></b>			
Planning & Feasibility Study		75,000	0.02
Legal & Accounting		450,000	0.10
Soft Costs Contingency	3.8%	150,000	0.03
Property Taxes (Construction Period)		40,500	0.01
Interest Costs (Construction Period)	6.00%	282,000	0.06
Loan Fees	1.50%	70,500	0.02
Developer Fee	15.00%	1,856,700	0.41
NMTC Fee	6.00%	947,400	0.21
Reserves		100,000	0.02
<b>SUBTOTAL: SOFT COSTS</b>		<b>3,972,100</b>	<b>0.88</b>
 <b>TOTAL PROJECT COSTS</b>		 <b>15,784,600</b>	 <b>3.51</b>

### Sources of Funds

Leverage Loan	4,700,000	30%
1603 Cash Grant	4,175,760	26%
NMTC Equity	4,372,251	28%
Private Equity	2,536,589	16%
<b>Total Sources</b>	<b>15,784,600</b>	<b>100%</b>

## Tax Credit and Debt Assumptions: Oberlin Wind Project

<b>Debt Assumptions</b>	
Size	4,700,000
Term (years)	20
Amortization (years)	20
Interest Rate	6.0%
Constant	8.7%
Minimum DCR	120%
Fees	1.50%
Annual PMT	409,767

<b>1603 Assumptions</b>	
Total Project Costs	15,784,600
Less Ineligible Costs	(1,865,400)
Eligible Basis	13,919,200
ITC Credit	30%
<b>1603 Grant</b>	<b>4,175,760</b>

<b>NMTC Assumptions</b>	
Total Project Costs	15,790,000
Less Ineligible Costs	0
Eligible Basis	15,790,000
NMTC Credit	39%
Credit Pricing	0.71
<b>NMTC Equity</b>	<b>4,372,251</b>
CDE Fees	6%
Fee Amount	947,400



## Appendix B

### **OMLPS Background**

Oberlin Municipal Light and Power Systems (OMLPS) is a municipally-owned utility that operates on a not-for-profit basis. That is, it sets its rates to cover its costs and provide the lowest possible prices to its customers, as opposed to trying to provide a maximum rate of return to investors. OMLPS costs can be thought of in two general categories: generation/transmission, and operations/maintenance. Generation and transmission costs are directly variable based on the amount of power purchased. Operations and maintenance costs are less variable based on the amount of power purchased. These costs include staff devoted to maintenance and repair, staff devoted to billing and recordkeeping, equipment maintenance, etc. OMLPS is essentially a retailer of electricity. It buys the product wholesale (the generation/transmission costs), and then marks it up from wholesale to retail prices to cover its retail operations (the operations/maintenance costs.) OMLPS also owns and operates a 20-megawatt natural gas and diesel-fired power plant, but that is not directly related to the discussion here.

#### OMLPS Pricing Structure

OMLPS has two price structures for its customers. The first is residential, which is also used for small commercial. In this pricing structure, the customer pays a minimum charge of \$2.50 per month, and then a flat charge of \$0.109 per kWh thereafter (2011 rates). The second pricing structure is commercial, in which the customer pays a flat “Generation Charge” of \$0.073 per kWh, and then a “Demand Charge” which is equal to \$8.69 multiplied by the customer’s peak kilowatt consumption for a 15-minute period during the month. This commercial structure helps to incentivize “smoother” consumption by customers.

The residential rate of \$0.109/kWh is made up of the Generation Charge of \$0.073, a Distribution Charge of \$0.032 cents, and a \$0.004 tax. The Generation Charge is essentially the wholesale purchase of power, and the Distribution Charge is essentially the markup OMLPS places on the power to fund their operations and maintenance.

In the existing commercial net metering contract (such as with Oberlin College,) OMLPS gives its customer a credit on its monthly bill for each kWh of power produced by the customer’s generating equipment. The credit is equal to the Generation Charge. In this way, OMLPS (approximately) recovers its operations costs, even if the customer produces as much electricity as it consumes.

## OMLPS Power Sources

OMLPS Wholesale Power Costs 2003-2015 (Predicted; per OMLPS Director Steve Dupee in a public presentation to City Council 2010).

Year	Avg. Wholesale Cost	% Change	Implied Trend
2003	43.41		
2004	46.46	7.03%	7.03%
2005	59.06	27.12%	17.07%
2006	52.89	-10.45%	7.90%
2007	52.64	-0.47%	5.81%
2008	56.35	7.05%	6.05%
2009	68.69	21.90%	8.70%
2010	68.07	-0.90%	7.32%
2011	66.70	-2.01%	6.16%
2012	64.97	-2.59%	5.18%
2013	74.05	13.98%	6.06%
2014	77.48	4.63%	5.93%
2015	81.79	5.56%	5.90%

**Appendix C**

**OMLPS/OC Net Metering Contract for AJLC**

## NET METERING AGREEMENT

This Net Metering Agreement (the "Agreement"), is made as of SEPT. 18, 2001, by and between Oberlin College, an Ohio not-for-profit corporation, whose address is 70 N. Professor St. (the "College") and the City of Oberlin, an Ohio municipal corporation whose address is 85 S. Main, Oberlin, OH (the "City").

WHEREAS, Oberlin Municipal Light & Power System ("OMLPS"), a department of the City, operates a municipal electric power system for the generation, purchase, transmission, distribution and sale of electric power and energy, and

WHEREAS, the College intends to install and operate photovoltaic generating equipment to generate electric power to supply certain College buildings, which shall be connected to the load side of the OMLPS billing meter; and

WHEREAS, the College desires to return any excess generation capability to OMLPS to reduce the College's energy costs.

NOW, THEREFORE, in consideration of the mutual promises contained herein, the College and the City agree as follows:

### 1. DEFINITIONS

"Net Metering" means an arrangement by which the College's PV Equipment is connected to the load site of the OMLPS billing meter. The resultant electric power generated by the PV Equipment is permitted to run in synchronism with the OMLPS 60 cycle, alternating current electric power and carry all or part of the load of the building in which it is installed. Generated energy which is in excess of that required by the building load is permitted to flow in a reverse direction through the billing meter. Such electric power (measured in kilowatt-hours) is either subtracted from the meter's kilowatt-hour register or accounted for in a separate "Kilowatt-hours Received" register and used to set-off "Kilowatt-hours Delivered" for billing purposes.

"Photovoltaic Generating Equipment" or "PV Equipment" means the College's equipment used for generating electricity directly from the sun's rays and converting such energy to 60 cycle, alternating current including solar panels, DC to AC inverter, safety and disconnect devices and excluding energy storage devices.

### 2. PV EQUIPMENT INSTALLATION

The City authorizes the College to connect and operate Photovoltaic Generating Equipment subject to the terms and conditions of this Agreement. The College's installation shall comply with IEEE Standard 929-2000 for "Recommended Practice for Utility Interface of Photovoltaic (PV) Systems" (the "IEEE Standard") as the same may be amended or

supplemented from time to time. The College agrees to use good industry practice and shall not operate the PV Equipment in a manner that jeopardizes the health and safety of City or OMLPS employees. The College also agrees to repair or replace damaged City Equipment (defined below) which is directly caused by the negligent installation or operation of the Photovoltaic Generating Equipment; provided however, the College shall assume no responsibility, financial or otherwise for losses to City Equipment caused by Force Majeure (defined below) or other failures which are beyond the College's control. The College agrees to provide a standard dial-up phone line at its expense at each meter location where PV Equipment is installed. The College agrees to notify and submit plans to OMLPS before installing and operating PV Equipment. OMLPS will review and approve plans with regard to compliance with this Agreement and good industry practice, including but not limited to the IEEE Standard and will conduct an inspection of the installation of the PV Equipment before the College places the PV Equipment into operation.

3. **INDEMNIFICATION**

Each party hereto shall defend, hold harmless and indemnify the other party from and against any and all claims, liabilities, costs and expenses, including without limitation attorney's fees, due to proprietary right infringement, personal injury or death of any person(s) or damage to property to the extent said personal injury, death or property damage is caused by the negligent acts or omissions of such party, its officers, agents, employees, contractors or subcontractors.

4. **PROPRIETARY RIGHTS**

All materials of the College used in generating electricity with the PV Equipment, including but not limited to solar panels, hardware, software, written materials, art work, labels, marks, calculations, and methods of calculations and any upgrades thereto ("Proprietary Material") shall remain the property of the College. The City Equipment shall remain the property of the City.

5. **METER INSTALLATION/MODIFICATION**

The City agrees to use Net Metering on those College facilities with PV Equipment. The College agrees to purchase power and energy from the City at the rates established by Oberlin City Council. The City shall maintain its equipment installed at the College, including, but not limited to, metering equipment, test devices, cabling, switches, fuse boxes, circuit breakers and the like (the "City Equipment") in good operating condition and in accordance with all applicable safety procedures and good industry practice. The City shall promptly repair any defects or malfunctions in the City Equipment in accordance with standard industry practice and insure the uninterrupted supply of electric power to the buildings serviced. In addition to the billing meter(s), the College agrees to allow the City, at its option, to install metering equipment to measure the power output of the PV equipment for engineering and survey purposes. The City agrees to make all measured load data available to the College at a reasonable cost.



6. **ADMINISTRATION OF AGREEMENT**

Each party hereby designates the employee identified below as its administrator for this Agreement. The administrator shall be responsible for representing their respective employers in contractual and commercial matters relative to the administration of this Agreement. Each party may change its administrator by giving not less than ten (10) days prior written notice of its new administrator to the other party.

College Name: *Andrew Brown*  
Title: *VICE PRESIDENT FOR FINANCE*  
Address: *OBERLIN COLLEGE*  
*OBERLIN OH 44074*  
Telephone: *440-775-8460*  
Fax: *440-775-8462*

City Name: *Vic Oeftering*  
Title: *Tech Service Supt*  
Address: *289 S. Professor, Oberlin, OH*  
Telephone: *(440) 775-7265*  
Fax: *(440) 775-1546*

7. **TERMINATION**

Either party shall have the right to terminate this Agreement with or without cause and for any reason whatsoever upon thirty (30) days written notice to the other party. The College shall reimburse the City for the electric power and other services provided by the City to the date of such termination. Either party may terminate this Agreement immediately upon notice if the other party is adjudicated bankrupt or makes a general assignment for the benefit of creditors or otherwise, or takes the benefit of any insolvency, reorganization or other relief act, or if a receiver or trustee is appointed for its property.

8. **ORDERLY TERMINATION**

Except as provided otherwise in this Agreement, upon the termination or expiration of this Agreement, each party shall return to the other all papers, materials and property of the other held by such party in connection with the performance of this Agreement. In addition, each party shall assist the other in the orderly termination of this Agreement and the transfer of all aspects hereof, both tangible and intangible, as may be necessary for the orderly continuation of the business of each party.

9. **OTHER CHARGES, TAXES AND FEES**

Any taxes, fees, assessments or other charges at the federal, state, municipal, or local level resulting from the purchase of electric power by the College shall be the sole responsibility of College. However, no taxes shall be charged if the College provides evidence of exemption from such taxes, fees, assessments or other charges.

10. **PAYMENT TERMS**

Invoices will be submitted monthly by the City and shall be due and payable thirty (30) calendar days after the invoice date.

11. **APPLICABLE LAW**

This Agreement shall be construed solely in accordance with the laws of the State of Ohio.

12. **FORCE MAJEURE**

Neither party shall be deemed to be in default of any provision of this Agreement, or for failures in performance, resulting from acts or events beyond the reasonable control of such party. Such acts shall include but not be limited to acts of God including weather, civil or military authority, civil disturbance, war, strikes, fires, other catastrophes, or other events beyond the parties' reasonable control (collectively, "Force Majeure").

13. **MISCELLANEOUS**

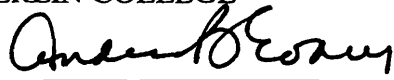
If any term, provision or restriction of this Agreement is determined to be invalid, void or unenforceable in any way in any jurisdiction, all remaining provisions shall continue to be valid and enforceable. It is hereby stipulated and declared to be the intention of the parties that they would have executed the Agreement if it contained the remaining terms, provision, covenants and restrictions without including any of such which might be hereafter declared invalid, void or unenforceable.

This Agreement shall supersede and replace any previous agreements, both oral and written, between the College and the City and represents the entire Agreement. Any changes to this Agreement shall be made in writing by the parties and evidenced by their respective approvals in writing.

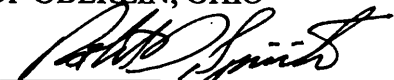
This Agreement may be executed in two or more counterparts and when so executed shall have the same force and effect as though all signatures appeared on one document.

IN WITNESS WHEREOF, each of the parties have caused this Agreement to be executed by a duly authorized representative on the respective dates entered above.

OBERLIN COLLEGE

By:   
Name: ANDREW O. EVANS  
Title: VICE PRES. FOR FINANCE

CITY OF OBERLIN, OHIO

By:   
Name: Robert DiSpirito  
Title: CITY MANAGER

**Appendix D**

**OMLPS Net Metering Regulation**

#### **913.04 SERVICE RULES AND REGULATIONS.**

The following electric service standard rules and regulations shall apply to all sections of this chapter.

(a) Applications and Contracts.

(1) Service application.

An application accepted by the City or other form of contract between the City and the consumer will be required from a consumer for each class of service requested before the service is supplied. This requirement shall apply to new installations, or where service is to be re-established, or a change in the class of service or a change of consumer. This shall not be construed as releasing the property owner from liability for payment.

(2) Service contract. The service contract shall constitute the entire agreement between the consumer and the City and no promise, agreement or representation of any agent, representative or employee of the City shall be binding upon it unless the same shall be incorporated in the service contract.

(3) Large capacity agreements. Consumers now served who seek to increase their present capacity requirements to more than 500 KVA and new consumers who seek to purchase capacities of more than 500 KVA shall negotiate agreements with the City looking towards an equitable arrangement both as to the term of contract and other conditions requiring special consideration as such capacities may require changes in area facilities or rearrangement of facilities owned by the City and/or the consumer. (Ord. 1106AC CMS. Passed 4-21-75.)

(b) Character of Service.

(1) Type. Electric service supplied by the City will be 60 hertz alternating current delivered at the standard voltages available adjacent to the premises where the consumer is located.

(2) Continuity. The City will endeavor, but does not guarantee, to furnish a continuous supply of electric energy and to maintain voltage and frequency.

(3) Net Metering. **Net metering** (an interactive interconnection between the City's utility system and the consumer's electric service panel using a standard kilowatt hour **meter** capable of registering the flow of electricity in both directions) is allowed when on-site generating capacity does not exceed 10 KW (kilowatts) and is derived from solar power. In cases where capacity exceeds 10 KW, both the customer and utility must sign a **net metering** agreement before connecting to the utility.

(c) Billing.

(1) Bills for electric service will be rendered monthly.

(2) The electricity used by the same person, firm or corporation, but delivered and **metered** separately or at different locations, will not be combined for billing purposes.

(3) The City will make available upon the request of a residential customer a plan for uniform monthly payments for electric service over specified periods.

(4) For **net metering** purposes, if the current **meter** reading is less than or equal

to the highest previous **meter** reading, there are no billable kilowatt-hours for the current month. However, the appropriate customer charge will still apply and continue to be billed monthly. Otherwise, the difference between the current **meter** reading and the highest previous **meter** reading is the billable kilowatt-hours. (Ord. 03-70AC. Passed 10-6-03.)

(d) Connection and **Meter** Requirements.

(1) The City will furnish one **meter** or one unified set of **meters** for each service contract. The consumer shall bring his/her service wires from his/her building in such a manner as to be readily accessible from the City's lines.

(2) All equipment furnished by the City shall remain its exclusive property and the City shall have the right to remove the same after termination of service for any reason whatsoever.

(3) The consumer shall permit only authorized agents of the City, or persons otherwise lawfully authorized, to inspect, test or remove City equipment located on the consumer's premises. If this equipment is damaged or destroyed due to the negligence of the consumer, the cost of repairs or replacement shall be paid by the consumer.

(4) The **meter** or **meters** shall be located to the approval of the Director of the Municipal Light and Power Department.

(e) Consumer's Wiring and Equipment; Installation. The consumer shall supply all wiring on the consumer's side from the point of attachment as designated by the City. All consumer's wiring and electrical equipment shall be installed and maintained by the consumer to meet the provisions of the City Electrical Code.

(Ord. 1106 AC CMS. Passed 4-21-75.)

(f) Discontinuance and Reconnection of Service.

(1) A consumer may order service discontinued at any time unless there is a provision to the contrary in the service contract or applicable rate schedule, but the consumer is responsible for any use of the electric service until the City has had a reasonable time to secure a final reading or to remove the **meter**. Service will be disconnected in accordance with Chapter [919](#).

(2) Service may be discontinued by the City in case the consumer is in arrears in the payment of bills or fails to comply with the terms of the service contract. Service will be disconnected in accordance with Chapter [919](#).

(3) Additionally, the City may discontinue service upon discovery that the consumer has made misrepresentation of a material fact to the City regarding the use of electric service, or has in any other manner fraudulently entered into the service contract. Upon discovery, the City shall post notice of disconnection seven days prior to the termination of service.

(4) The City may also discontinue service in case the **meter** or wiring on the consumer's premises is tampered with in any manner to permit the use of unmetered electric energy. In case of discontinuance of service for this reason, the City shall restore service only after the consumer has paid for the **metered** and estimated unmetered energy used and has made at his/her expense such changes in the wiring and service entrance as the City may specify. Prior to disconnection, the City shall post a notice of disconnection

seven days prior to the termination of service.  
(Ord. 95-70 AC. Passed 9-19-95.)

**Appendix E**

**Ohio Net Metering Statute**



# Ohio Revised Code

## 4901:1-10-28 Net metering.

(A) Standard net metering.

(A)(1) Each EDU electric utility shall develop a tariff for net metering. Such tariff shall be made available to qualifying customer generators upon request.

(a) A qualifying customer generator is one whose generating facilities are:

(i) Fueled by solar, wind, biomass, landfill gas, or hydropower, or use a microturbine or a fuel cell.

(ii) Located on a customer generator's premises.

(iii) Operated in parallel with the electric utility's transmission and distribution facilities.

(iv) Intended primarily to offset part or all of the customer generator's electricity requirements.

(b) Net-metering arrangements shall be made available regardless of the date the customer's generating facility was installed.

(2) The electric utility's tariff for net metering shall be identical in rate structure, all retail rate components, and any monthly charges, to the tariff to which the same customer would be assigned if that customer were not a customer generator. Such terms shall not change simply because a customer becomes a customer generator.

(3) No electric utility's tariff for net metering shall require customer generators to:

(a) Comply with any additional safety or performance standards beyond those established by rules in Chapter 4901:1-22 of the Administrative Code, and the "National Electrical Code," the "Institute of Electrical and Electronics Engineers," and "Underwriters Laboratories," in effect as set forth in rule [4901:1-22-03](#) of the Administrative Code.

(b) Perform or pay for additional tests beyond those required by paragraph (A)(3)(a) of this rule.

(c) Purchase additional liability insurance beyond that required by paragraph (A)(3)(a) of this rule.

(4) Net metering shall be accomplished using a single meter capable of registering the flow of electricity in each direction. A customer's existing single-register meter that is capable of registering the flow of electricity in both directions satisfies this requirement. If the customer's existing electrical meter is not capable of measuring the flow of electricity in two directions, the electric utility, upon written request from the customer, shall install at the customer's expense a meter that is capable of measuring electricity flow in two directions.

(5) The electric utility, at its own expense and with the written consent of the customer generator, may install one or more additional meters to monitor the flow of electricity in each direction. No electric utility shall impose, without commission approval, any additional interconnection requirement or additional charges on customer generators refusing to give such consent.

(6) The measurement of net electricity supplied or generated shall be calculated in the following manner:

(a) The electric utility shall measure the net electricity produced or consumed during the billing period, in accordance with normal metering practices.

(b) If the electric utility supplies more electricity than the customer generator feeds back to the system in a given billing period, the customer generator shall be billed for the net electricity that the electric utility supplied, as measured in accordance with normal metering practices.

(c) If the customer generator feeds more electricity back to the system than the electric utility supplies to the customer generator, only the excess generation component shall be allowed to accumulate as a credit until netted against the customer generator's bill, or until the customer generator requests in writing a refund that amounts to, but is no greater than, an annual true-up of accumulated credits over a twelve-month period.

(7) In no event shall the electric utility impose on the customer generator any charges that relate to the electricity the customer generator feeds back to the system.

(B) Hospital net metering.

(1) Each electric utility shall develop a separate tariff providing for net metering for hospitals. Such tariff shall be made available to qualifying hospital customers upon request.

(a) As defined in section 3701.01 of the Revised Code, "hospital" includes public health centers and general, mental, chronic disease, and other types of hospitals, and related facilities, such as laboratories, outpatient departments, nurses' home facilities, extended care facilities, self-care units, and central service facilities operated in connection with hospitals, and also includes education and training facilities for health professions personnel operated as an integral part of a hospital, but does not include any hospital furnishing primarily domiciliary care.

(b) A qualifying hospital customer generator is one whose generating facilities are:

(i) Located on a customer generator's premises.

(ii) Operated in parallel with the electric utility's transmission and distribution facilities.

(2) Net-metering arrangements shall be made available regardless of the date the hospital's generating facility was installed.

(3) The tariff shall be based both upon the rate structure, rate components, and any charges to which the hospital would otherwise be assigned if the hospital were not taking service under this rule and upon the market value of the customer-generated electricity at the time it is generated. For purposes of this rule, market value means the locational marginal price of energy determined by a regional transmission organization's operational market at the time the customer-generated electricity is generated.

(4) For hospital customer generators, net metering shall be accomplished using either two meters or a single meter with two registers that are capable of separately measuring the flow of electricity in both directions. One meter or register shall be capable of measuring the electricity generated by the hospital at the time it is generated. If the hospital's existing electrical meter is not capable of separately measuring electricity the hospital generates at the time it is generated, the electric utility, upon written request from the hospital, shall install at the hospital's expense a meter that is capable of such measurement.

(5) The tariff shall allow the hospital customer-generator to operate its electric generating facilities individually or collectively without any wattage limitation on size.

(6) The hospital customer generator's net metering service shall be calculated as follows:

(a) All electricity flowing from the electric utility to the hospital shall be charged as it would have been if the hospital were not taking service under this rule.

(b) All electricity generated by the hospital shall be credited at the market value as of the time the hospital generated the electricity.

(c) Each monthly bill shall reflect the net of paragraphs (B)(6)(a) and (B)(6)(b) of this rule. If the resulting bill indicates a net credit dollar amount, the credit shall be netted against the hospital customer generator's bill until the hospital requests in writing a refund that amounts to, but is no greater than, an annual true-up of accumulated credits over a twelve-month period.

(7) No electric utility's tariff for net metering shall require hospital customer generators to:

(a) Comply with any additional safety or performance standards beyond those established by rules in Chapter 4901:1-22 of the Administrative Code, and the National Electrical Code, the institute of electrical and electronics engineers, and underwriters laboratories, in effect as set forth in rule [4901:1-22-03](#) of the Administrative Code.

(b) Perform or pay for additional tests beyond those required by paragraph (B)(7)(a) of this rule.

(c) Purchase additional liability insurance beyond that required by paragraph (B)(7)(a) of this rule.

(8) In no event shall the electric utility impose on the hospital customer generator any charges that relate to the electricity the customer generator feeds back to the system.

Effective: 06/29/2009

R.C. [119.032](#) review dates: 11/26/2008 and 09/30/2012

Promulgated Under: [111.15](#)

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Prior Effective Dates: 9/18/00, 1/1/04, 10/22/07

## Appendix F

### Sample Remote Net Metering Legislation

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#### State of Pennsylvania Code Subchapter B

#### NET METERING

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Sec.

75.11. [Scope.](#)

75.12. [Definitions.](#)

75.13. [General provisions.](#)

75.14. [Meters and metering.](#)

75.15. [Treatment of stranded costs.](#)

#### **§ 75.11. Scope.**

This subchapter sets forth net metering requirements that apply to EGSs and EDCs which have customer-generators intending to pursue net metering opportunities in accordance with the act.

#### **§ 75.12. Definitions.**

The following words and terms, when used in this subchapter, have the following meanings unless the context clearly indicates otherwise: *Base year*—For customer-generators who initiated self generation on or after January 1, 1999, the base year will be the immediate prior calendar year; for all other customer generators, the base year will be 1996. *Billing month*—The term has the same meaning as set forth in § 56.2 (relating to definitions). *Customer-generator facility*—The equipment used by a customer-generator to generate, manage, monitor and deliver electricity to the EDC. *Electric distribution system*—That portion of an electric system which delivers electricity from transformation points on the transmission system to points of connection at a customer's premises. *Meter aggregation*—The combination of readings from and billing for all meters regardless of rate class on properties owned or leased and operated by a customer-

generator for properties located within the service territory of a single EDC. Meter aggregation may be completed through physical or virtual meter aggregation. *Net metering*—The means of measuring the difference between the electricity supplied by an electric utility or EGS and the electricity generated by a customer-generator when any portion of the electricity generated by the alternative energy generating system is used to offset part or all of the customer-generator’s requirements for electricity. *Physical meter aggregation*—The physical rewiring of all meters regardless of rate class on properties owned or leased and operated by a customer-generator to provide a single point of contact for a single meter to measure electric service for that customer-generator. *Virtual meter aggregation*—The combination of readings and billing for all meters regardless of rate class on properties owned or leased and operated by a customer-generator by means of the EDC’s billing process, rather than through physical rewiring of the customer-generator’s property for a physical, single point of contact. Virtual meter aggregation on properties owned or leased and operated by a customer-generator and located within 2 miles of the boundaries of the customer-generator’s property and within a single electric distribution company’s service territory shall be eligible for net metering. *Year and yearly*—Planning year as determined by the PJM Interconnection, LLC regional transmission organization.

#### **Authority**

The provisions of this § 75.12 amended under 66 Pa.C.S. § § 501 and 1501.

#### **Source**

The provisions of this § 75.12 amended November 28, 2008, effective November 29, 2008, 38 Pa.B. 6473. Immediately preceding text appears at serial pages (324588) to (324589).

#### **§ 75.13. General provisions.**

(a) EDCs shall offer net metering to customer-generators that generate electricity on the customer-generator’s side of the meter using Tier I or Tier II alternative energy sources, on a first come, first served basis. EGSs may offer net metering to customer-generators, on a first come, first served basis, under the terms and conditions as are set forth in agreements between EGSs and customer-generators taking service from EGSs.

(b) An EDC shall file a tariff with the Commission that provides for net metering consistent with this chapter. An EDC shall file a tariff providing net metering protocols that enable EGSs to offer net metering to customer-generators taking service from EGSs. To the extent that an EGS offers net metering service, the EGS shall prepare information about net metering consistent with this chapter and provide that information with the disclosure information required in § 54.5 (relating to disclosure statement for residential and small business customers).

(c) The EDC shall credit a customer-generator at the full retail rate, which shall include generation, transmission and distribution charges, for each kilowatt-hour produced by a Tier I or Tier II resource installed on the customer-generator’s side of the electric revenue meter, up to the total amount of electricity used by that customer during the billing period. If a customer generator supplies more electricity to the electric distribution system than the EDC delivers to the customer-

generator in a given billing period, the excess kilowatt hours shall be carried forward and credited against the customer-generator's usage in subsequent billing periods at the full retail rate. Any excess kilowatt hours shall continue to accumulate until the end of the year. For customer-generators involved in virtual meter aggregation programs, a credit shall be applied first to the meter through which the generating facility supplies electricity to the distribution system, then through the remaining meters for the customer-generator's account equally at each meter's designated rate.

(d) At the end of each year, the EDC shall compensate the customer-generator for any excess kilowatt-hours generated by the customer-generator over the amount of kilowatt hours delivered by the EDC during the same year at the EDC's price to compare.

(e) The credit or compensation terms for excess electricity produced by customer-generators who are customers of EGSs shall be stated in the service agreement between the customer-generator and the EGS.

(f) If a customer-generator switches electricity suppliers, the EDC shall treat the end of the service period as if it were the end of the year.

(g) An EDC and EGS which offer net metering shall submit an annual net metering report to the Commission. The report shall be submitted by July 30 of each year, and include the following information for the reporting period ending May 31 of that year:

(1) The total number of customer-generator facilities.

(2) The total estimated rated generating capacity of its net metering customer-generators.

(h) A customer-generator that is eligible for net metering owns the alternative energy credits of the electricity it generates, unless there is a contract with an express provision that assigns ownership of the alternative energy credits to another entity or the customer-generator expressly rejects any ownership interest in alternative energy credits under § 75.14(d) (relating to meters and metering).

(i) An EDC shall provide net metering at nondiscriminatory rates identical with respect to rate structure, retail rate components and any monthly charges to the rates charged to other customers that are not customer-generators. An EDC may use a special load profile for the customer-generator which incorporates the customer-generator's real time generation if the special load profile is approved by the Commission.

(j) An EDC may not charge a customer-generator a fee or other type of charge unless the fee or charge would apply to other customers that are not customer-generators. The EDC may not require additional equipment or insurance or impose any other requirement unless the additional equipment, insurance or other requirement is specifically authorized under this chapter or by order of the Commission.

(k) Nothing in this subchapter abrogates a person's obligation to comply with other applicable law.

#### **Authority**

The provisions of this § 75.13 amended 66 Pa.C.S. § § 501 and 1501.

#### **Source**

The provisions of this § 75.13 amended November 28, 2008, effective November 29, 2008, 38 Pa.B. 6437. Immediately preceding text appears at serial pages (324589) to (324590).

#### **§ 75.14. Meters and metering.**

(a) A customer-generator facility used for net metering must be equipped with a single bidirectional meter that can measure and record the flow of electricity in both directions at the same rate. If the customer-generator agrees, a dual meter arrangement may be substituted for a single bidirectional meter.

(b) If the customer-generator's existing electric metering equipment does not meet the requirements in subsection (a), the EDC shall install new metering equipment for the customer-generator at the EDC's expense. Any subsequent metering equipment change necessitated by the customer-generator shall be paid for by the customer-generator.

(c) When the customer-generator intends to take title or transfer title to any alternative energy credits which may be produced by the customer-generator's facility, the customer-generator shall bear the cost of additional net metering equipment required to qualify the alternative energy credits in accordance with the act.

(d) When the customer-generator expressly rejects ownership of alternative energy credits produced by the customer-generator's facility, the EDC may supply additional metering equipment required to qualify the alternative energy credit at the EDC's expense. In those circumstances, the EDC shall take title to any alternative energy credit produced. An EDC shall, prior to taking title to any alternative energy credits produced by a customer-generator, fully inform the customer-generator of the potential value of the alternative energy credits and other options available to the customer-generator for the disposition of those credits. A customer-generator is not prohibited from having a qualified meter service provider install metering equipment for the measurement of generation, or from selling alternative energy credits to a third party other than an EDC.

(e) Virtual meter aggregation on properties owned or leased and operated by a customer-generator shall be allowed for purposes of net metering. Virtual meter aggregation shall be limited to meters located on properties owned or leased and operated within 2 miles of the boundaries of the customer-generator's property and within a single EDC's service territory. Physical meter aggregation shall be at the customer-generator's expense. The EDC shall provide the necessary equipment to complete physical aggregation. If the customer-generator requests virtual meter aggregation, it shall be provided by the EDC at the customer-generator's expense. The customer-

generator shall be responsible only for any incremental expense entailed in processing his account on a virtual meter aggregation basis.

#### **Authority**

The provisions of this § 75.13 amended 66 Pa.C.S. § § 501 and 1501.

#### **Source**

The provisions of this § 75.14 amended November 28, 2008, effective November 29, 2008, 38 Pa.B. 6437. Immediately preceding text appears at serial pages (324590) to (324591).

#### **Cross References**

This section cited in 52 Pa. Code § 75.13 (relating to general provisions).

#### **§ 75.15. Treatment of stranded costs.**

If a net metering small commercial, commercial or industrial customer's self-generation results in a 10% or more reduction in the customer's purchase of electricity through the EDC's transmission and distribution network for an annualized period when compared to the prior annualized period, the net metering small commercial, commercial or industrial customer shall be responsible for its share of stranded costs to prevent interclass or intraclass cost shifting under 66 Pa.C.S. § 2808(a) (relating to competitive transition charge). The net metering small commercial, commercial or industrial customer's stranded cost obligation shall be calculated based upon the applicable "base year" as defined in this chapter.