Wind Resource Assessment Report: Mille Lacs Indian Reservation, Minnesota

Antonio C. Jimenez

Produced under direction of the U.S. Environmental Protection Agency (EPA) by the National Renewable Energy Laboratory (NREL) under Interagency Agreement IAG-08-1719 and Task No. WFD3.1000.

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Technical Report
NREL/TP-5000-60429
December 2013

Contract No. DE-AC36-08GO28308

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List of Acronyms

AGL	above ground level
ASOS	automated surface observing station
BLCC	Building Life Cycle Cost software
C-BED	Community-Based Energy Development
COE	cost of energy
DOE	U.S. Department of Energy
EPA	U.S. Environmental Protection Agency
FAA	Federal Aviation Administration
FERC	Federal Energy Regulatory Commission
IEC	International Electrotechnical Commission
IRR	internal rate of return
ITC	investment tax credit
LCOE	levelized cost of energy
LLS	linear least squares
MACRS	Modified Accelerated Cost Recovery Scheme
MERRA	Modern Era Retrospective-Analysis for Research and Applications
MCP	measure-correlate-predict
NASA	National Aeronautics and Space Administration
NPV	net present value
NREL	National Renewable Energy Laboratory
NWS	National Weather Service
O&M	operations and maintenance
PPA	power purchase agreement
PTC	production tax credit
RE	renewable energy
REC	renewable energy certificate
RFP	request for proposals
ROI	return on investment
SAM	System Advisor Model
TI	turbulence intensity

Executive Summary

An Interagency Agreement (IAG-08-1719) between the U.S. Environmental Protection Agency (EPA) and the U.S. Department of Energy (DOE) was put into place to assist EPA in evaluating the potential to use wind energy at selected brownfield locations. DOE assigned the National Renewable Energy Laboratory (NREL) to facilitate this process by arranging the installation of a 60-m MET tower on the site of a brownfield located on the Mille Lacs reservation in Minnesota.

This report describes the wind resource measured at this location and examines the economic feasibility of a wind energy project. The dataset analyzed in this report includes a general validation and summarization of the 10-minute data taken from May 11, 2011, through November 20, 2012. For many of the analytic techniques applied to the data, a 1-year dataset from June 1, 2011, through May 31, 2012, was used.

The mean annual wind speeds from the data collected at the Mille Lacs MET tower were analyzed and then adjusted to reflect long-term data trends from the Modern Era Retrospective-Analysis for Research and Applications (MERRA) dataset M0202. Overall, the MERRA dataset indicated that the average wind speed during the monitoring period was slightly greater than the long-term average from the past 15 years, so the data collected at Mille Lacs should be adjusted downward accordingly. A correlation of the Mille Lacs data to the MERRA dataset was performed and then adjusted for the vertical wind shear patterns measured at Mille Lacs. This analysis resulted in the adjustment downward of -0.74% for the anemometer at 60 m. Vertical wind shear factors from Mille Lacs were applied to project the estimated wind speeds at multiple levels above the met tower as can be seen in Table ES-1.

Table ES-1. Mean Annual Wind Speed Before and After Long-Term Correlation

Source	Height	Short-term Mille Lacs Mean Wind Speed	Long-term Mille Lacs MCP Synthetic Mean Wind Speed	Adjustment to Long-term Mean Wind
	(m)	(m/s)	(m/s)	%
Measured	50	5.09	5.04	-0.98
Measured	60	5.38	5.34	-0.74
Extrapolated	80	5.84	5.80	-0.68
Extrapolated	100	6.20	6.15	-0.81

The expected long-term mean wind speed was used to model the energy performance of a representative low wind speed turbine—in this case the GE 1.6-100. The results can be seen in Table ES-2.

Table ES-2. Characteristics of the Representative Low Wind Speed Turbines

Turbine Model	Rated Power	Hub Height	Rotor Diameter	Mean Hub Height Wind Speed	Mean Net Energy Output	Net Capacity Factor
Turbine	(kW)	(m)	(m)	(m/s)	(kWh/yr)	(%)
Acciona AW 82/1500	1,500	80	82	5.8	2,626,420	20.0
Gamesa G97-2.0 MW	2,000	80	97	5.8	3,631,685	20.7
GE 1.6-100	1,500	80	100	5.8	3,512,175	25.1
Nordex N117/2400	2,400	80	117	5.8	5,291,483	25.2
Vestas V100 - 1.8 MW	1,800	80	100	5.8	3,761,152	23.7

Three business structures were examined using the System Advisor Model (SAM). The first case assumes the project is owned directly by the Mille Lacs reservation Tribe. In this case the project is not subject to federal or state taxes but is also not eligible for federal incentives such as the production tax credit (PTC), investment tax credit (ITC), or depreciation.

The second case assumes a for-profit venture with an equity partner that makes use of the PTC. This analysis assumes that the PTC can be fully monetized. One disadvantage of this is that maintaining a Tribal equity stake in a project while fully monetizing the tax credits requires a more complicated business structure that will probably involve an outside partner. An example of this is the "Minnesota Flip" model.

The third case also assumed a for-profit venture but used the ITC rather than the PTC. The ITC is especially attractive for a project located in lower resource areas because the value of the incentive does not depend on the energy production of the project.

Table ES-3 summarizes the key analysis assumptions. For each case, the analysis determined the minimum initial power purchase agreement (PPA) price required for the project to be economically viable.

Table ES-3. Economic Analysis Assumptions

	Tax Exempt	PTC	ITC
Turbine Model	GE 1.6-100	GE 1.6-100	GE 1.6-100
Rated Capacity (kW)	1,600	1,600	1,600
Tower Height (m)	80	60	60
Losses (%)	15.0%	15.0%	15.0%
Annual Energy Production (kWh/yr)	3,512,000	3,512,000	3,512,000
Net Capacity Factor (%)	25.1%	25.1%	25.1%
Installed Capital Cost ($/kW)	$2,600	$2,600	$2,600
Installed Capital Cost ($)	$4,160,000	$4,160,000	$4,160,000
Operations & Maintenance (O&M) ($/kW/yr)	$42	$42	$42
O&M ($/yr)	$67,200	$67,200	$67,200
O&M Escalation Rate (%/year)	1.0%	1.0%	1.0%
Net Salvage Value ($)	$0	$0	$0
Project Lifetime (years)	20	20	20
Inflation Rate (General) (%)	1.0%	1.0%	1.0%
Discount Rate (Real) (%)	6.0%	6.0%	6.0%
Discount Rate (Nominal) (%)	7.1%	7.1%	7.1%
Debt Percentage	70%	50%	50%
Debt Rate	7.0%	7.0%	7.0%
PPA Escalation Rate (%)	1.0%	1.0%	1.0%
Initial PTC Value ($/kWh)		$0.023	
PTC Escalation Rate (%)		1.00%	

Table ES-4 summarizes the analysis results.

Table ES-4. Analysis Results

Metric	Tax Exempt	PTC	ITC
Annual Energy Production (kWh/year)	3,512,000	3,512,000	3,512,000
Required Initial PPA Price ($/kWh)	$ 0.132	$ 0.101	$ 0.078
LCOE Nominal ($/kWh)	$ 0.142	$ 0.109	$ 0.084
LCOE Real ($/kWh)	$ 0.131	$ 0.100	$ 0.077
Internal Rate of Return (%)	10.0%	10.0%	10.0%
Minimum DSCR	1.44	1.47	1.05
Net Present Value ($)	$ 330,199	$ 219,269	$ 57,364
PPA Escalation Rate (%)	1.0%	1.0%	1.0%
Debt Fraction (%)	70%	50%	50%
Windfarm Capacity (MW)	1.6	1.6	1.6
Capacity Factor	25.1%	25.1%	25.1%

A sensitivity analysis reveals that the inputs that most affect the Required Initial PPA price, aka "PPA Price" or "Initial PPA Price," are the turbine installed cost and the annual energy output. A 20% change in the value of these variables resulted in a 15%–30% change in the initial PPA price ($0.01–$0.03/kWh).

The economic analysis indicates that the minimum PPA price for a project at this location ranges from $0.078–$0.132/kWh, with the ITC case giving the lowest initial PPA price. This is much higher than both the regional 2012 average PPA price of $0.031/kWh and the national 2012 average price of $0.038/kWh. The analysis used two somewhat optimistic assumptions. The first of these assumptions is that the site is suitable for a low wind speed turbine, such as the GE 1.6-100. The high turbulence at this site may preclude the use of these types of turbines. One thing to note is that turbulence generally decreases with increasing height, so the turbulence at 80 m (or 100 m) is more likely to be sufficiently low to allow for the use of a low wind speed turbine. The other optimistic assumption is that the equity investor will accept a 10% internal rate of return (IRR). As noted earlier, this is at the low end of the range of minimum rates of return required by wind energy project investors. Fortunately, the initial PPA price is not particularly sensitive to the minimum IRR. For the ITC case, increasing the IRR from 10% to 12% increased the PPA price by $0.003/kWh from $0.078/kWh to $0.081/kWh. The analysis further assumes an extension of the PTC and ITC.

Model results show that a turbine project at this location, selling into the wholesale market, is not economically competitive. Even significantly reduced cost and improved energy capture is not sufficient to provide economic viability. Taking the ITC case as an example, reducing the installed cost by 20% and increasing the energy production by 20% reduces the PPA price to $0.055/kWh. This is still significantly above the 2012 averages for the region and nation. To be economically viable, a project at this location will require some combination of a buyer willing to pay above-market rates for the energy, a large grant, or very low interest rate financing.

In principle, the Tribe could use the energy from the project to offset electricity use at Tribal facilities. However, this arrangement, sometimes called virtual net metering, is uncommon and would require the cooperation of the local electric utility.

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1 Wind Resource Assessment at Mille Lacs Indian Reservation

An Interagency Agreement (IAG-08-1719) between the U.S. Environmental Protection Agency (EPA) and the U.S. Department of Energy (DOE) was put into place to assist EPA in evaluating the potential to install wind turbines at brownfield locations. EPA's brownfield program assists local communities in reusing previously contaminated land parcels (brownfields). DOE tasked the National Renewable Energy Laboratory (NREL) with arranging for the installation of a 60-m MET tower at a brownfield site on the Mille Lacs reservation in Minnesota.

This report describes the wind resource measured at the monitoring location. The dataset analyzed in this report includes a general validation and summarization of the 10-minute data taken from May 5, 2011, through November 30, 2012. For many of the analytic techniques applied to the data, a 1-year dataset from June 1, 2011 through May 31, 2012, was used.

1.1 Station Location

The monitoring site is located within the Mille Lacs reservation on the "Ledin" parcel, located just west of Lake Mille Lacs. Grid coordinates are: N 46.17921°, W 93.80546°. The monitoring location is shown in Figure 1-1. The MET tower is located on a ridge top within an open field. The general terrain is hilly and wooded.

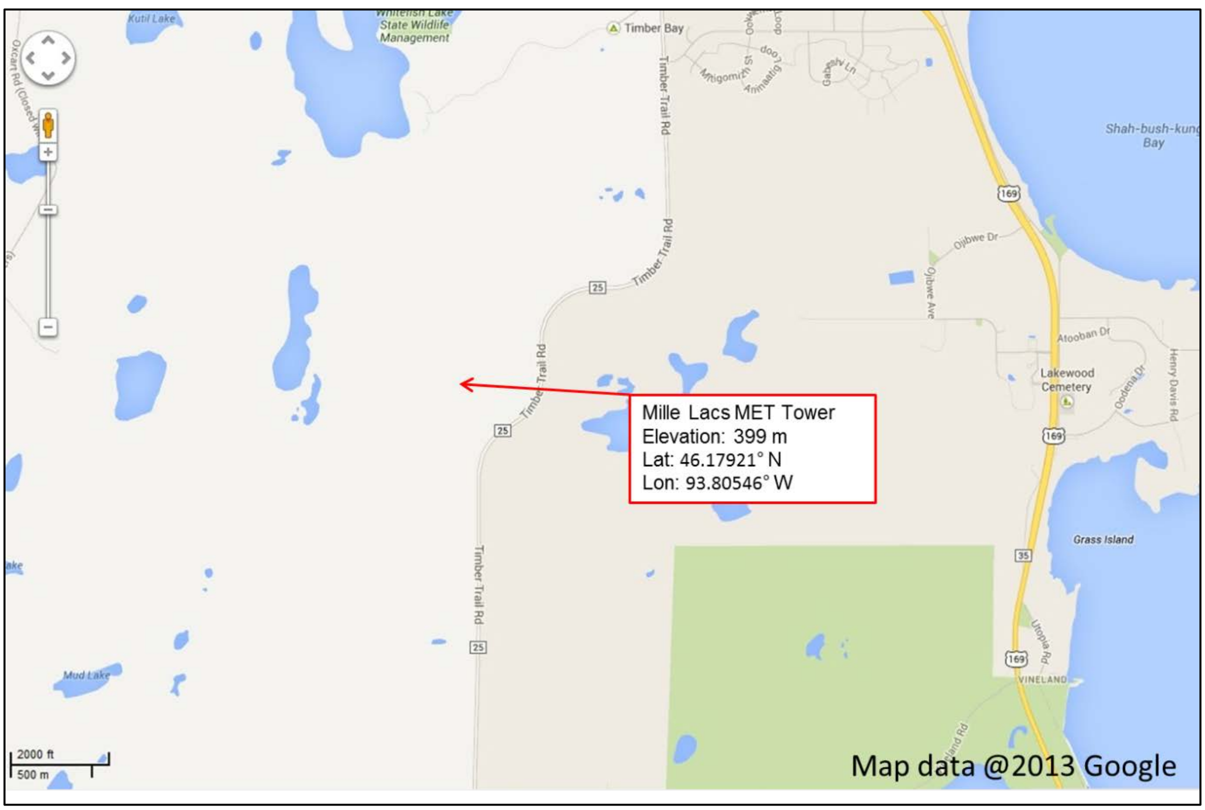

Figure 1-1. Mille Lacs MET tower location (map view)

Source: http://www.Googlemaps.com

Figure 1-2 shows the heavily forested terrain, broken up by occasional open fields, that surrounds the monitoring site.

Figure 1-2. Mille Lacs MET tower location (satellite view)

Source: *http://www.Googlemaps.com*

The complete dataset runs from May 5, 2011–November 30, 2012. To reduce errors caused by double counting the portions of the year where the data overlaps, a 1-year dataset running from June 1, 2011–May 31, 2012, is used for reporting and referencing to longer-term datasets. This portion of the dataset appeared to be the most complete and robust. Table 1-1 summarizes the details of the monitoring station over this 1-year period. The data was processed using Windographer[1] software (version 3).

[1] Mistaya Engineering, Incorporated. Accessed September 20, 2013: http://mistaya.net/index.htm.

Table 1-1. MET Tower Dataset Summary at Mille Lacs, Minnesota

Variable	Value
Latitude	N 46.17921
Longitude	W 93.80546
Elevation	399 m
Start date	6/1/2011
End date	5/31/2012
Duration	12 months
Length of time step	10 minutes
Calm threshold	1 m/s
Mean temperature	8.1 °C
Mean pressure	65.3 kPa
Mean air density	0.810 kg/m^3
Power density at 50m	81 W/m^2
Power law exponent	0.354
Surface roughness	2.86 m
Roughness class	4.79

1.2 Wind in Minnesota

There have been a significant number of wind farm installations in Minnesota during the past 20 years. With almost 3,000 MW installed (as of the end of 2012), Minnesota ranks seventh in the United States for total installed wind capacity. As can be seen in Figure 1-3, there is a wind resource throughout large regions of the state, particularly in the southwest part of the state.

Wind resources are very site specific. Different sites in close proximity to each other, but with varying vegetation (e.g., tall trees versus grassland or cropland), topographical features (e.g., ridges versus valleys or canyons versus mountains), and surface roughness (e.g., city skyscrapers versus flat or rolling farmland) may have entirely different wind regimes. One may prove to be economical and one may not. Wind maps are useful for determining, from a high-level view, the relative wind resource. Wind maps are not used to site large wind turbines/farms, as they do not have the degree of accuracy necessary. They are used to determine where it is merited to further investigate the wind with installation of an on-site wind monitoring station.

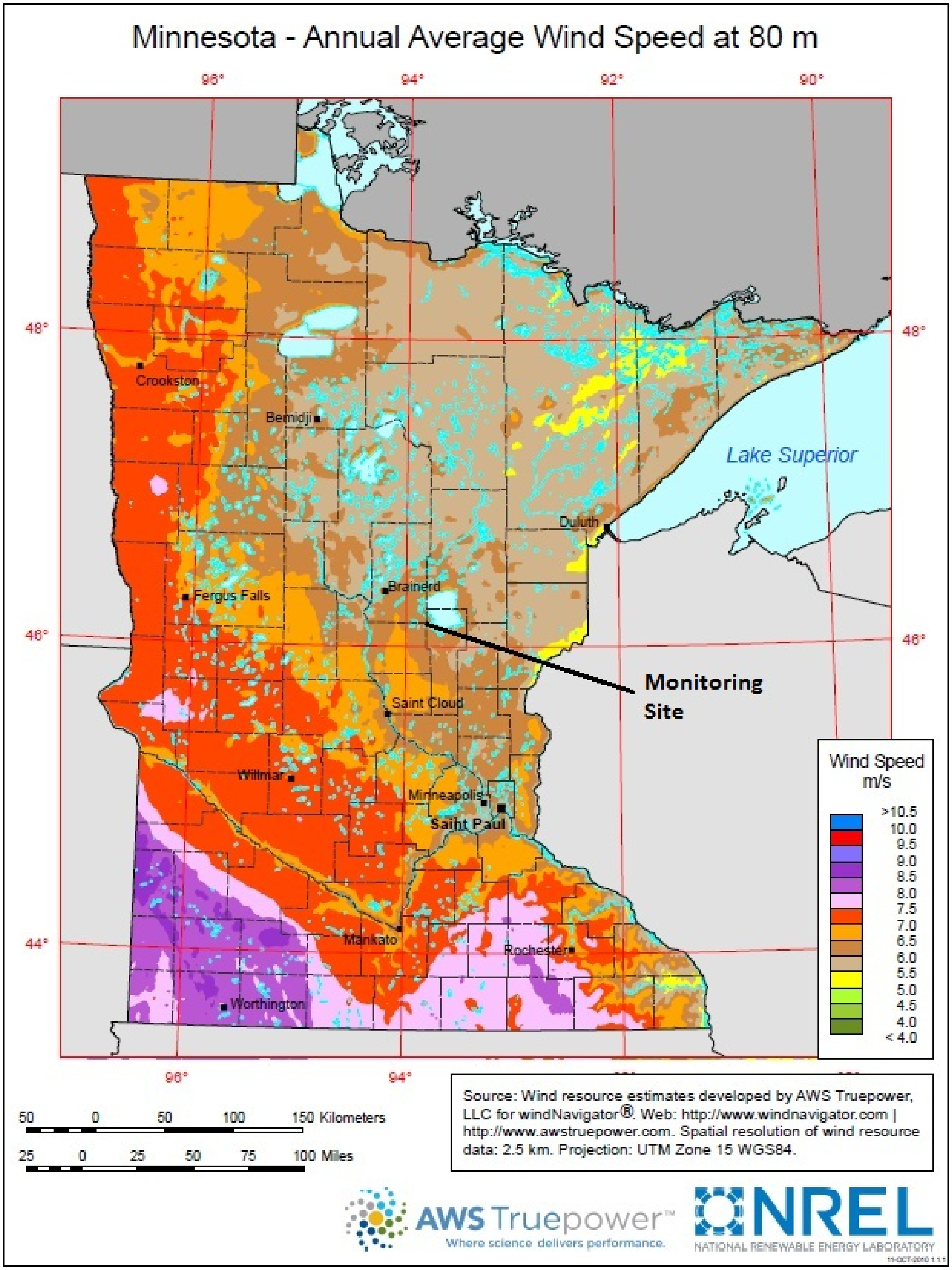

Figure 1-3. 80-m wind map of Minnesota

Source: *http://www.windpoweringamerica.gov/wind_resource_maps.asp?stateab=mn*

2 Instrumentation and Equipment

The project instrumentation consisted of an NRG 60-m XHD NRG Tall Tower, six anemometers, two wind vanes, temperature sensor, barometric pressure sensor, and a data logger. Details of the sensor configuration are summarized in Table 2-1. At each height (60 m, 50 m, and 40 m), two anemometers were installed: one at 315°, the other at 225°. The anemometers at 315° are labeled 60mA, 50mA, and 40mA, respectively. The anemometers at 225° are labeled 60mB, 50mB, and 40mB, respectively.

Table 2-1. Instrumentation Summary at Mille Lacs, Minnesota

Channel	Label	Sensor Type	Measurement	Slope	Offset	Height [m]	Boom Orientation [degrees]	Deadband Orientation [degrees]
1	60mA	NRG #40 Calibrated Anemomter	Wind Speed (m/s)	0.761	0.36	60	315	
2	60mB	NRG #40 Calibrated Anemomter	Wind Speed (m/s)	0.760	0.38	60	225	
3	50mA	NRG #40 Calibrated Anemomter	Wind Speed (m/s)	0.757	0.45	50	315	
13	50mB	NRG #40 Calibrated Anemomter	Wind Speed (m/s)	0.761	0.38	50	225	
14	40mA	NRG #40 Calibrated Anemomter	Wind Speed (m/s)	0.762	0.37	40	315	
15	40mB	NRG #40 Calibrated Anemomter	Wind Speed (m/s)	0.760	0.39	40	225	
7		NRG #200 Wind Direction Vane	Wind Dirctn (deg)	0.351	0	58	0	0
8		NRG #200 Wind Direction Vane	Wind Dirctn (deg)	0.351	0	38	0	0
9		NRG #110S Temperature Sensor	Temp (deg C)	0.136	-86.381	2	N/A	
10		NRG BP-20 Barometric Pressure Sensor	Pressure (mbar)	0.4255	652.86	2	270	

3 Data Recovery and Validation

The data logger sampled the sensors every 2 seconds and recorded the 10-minute average value for each sensor. Andy Boyd with the Mille Lacs Department of Natural Resources visited the MET tower periodically to collect the wind data and inspect the tower. He downloaded the data and emailed it to NREL for analysis. Flagging rules were applied to the data to detect and flag suspected anemometer and direction vane icing. The flagging rules are summarized in Table 3-1. The flagged data was excluded from the analysis.

Table 3-1. Mille Lacs Data Flagging Rules

Sensor	Rules
Speed	Period longer than 2 hours where • Speed is less than 0.6 m/s (minimum speed sensor reading) AND • Standard deviation of the speed is equal to zero AND • Temperature is less than 5°C
Direction	Period longer than 2 hours where • Standard deviation of the direction is equal to zero AND • Temperature is less than 5°C

Table 3-2 shows the recovery rates for the entire dataset, May 5, 2011–November 30, 2012. Valid records consist of unflagged, collected data. Flagged data points are any points with which there is a problem or suspected problem, such as speed sensor freezing. The recovery rate for the 60mB speed sensor is low because that sensor stopped working on June 19, 2012. The remaining channels all have high recovery rates of more than 99%, except for the speed sensors, which have recovery rates of more than 98%. The recovery rate is the proportion of total data for a given sensor that is unflagged (i.e., “good”).

Table 3-2. Mille Lacs Data Column Summary May 5, 2011–November 30, 2012 (Entire Dataset)

Label	Units	Height	Possible Records	Valid Records	Recovery Rate (%)	Mean	Min	Max	Std. Dev
Speed 60 m A	m/s	60 m	82,762	82,247	99.38	4.905	0.4	17.4	2.187
Speed 60 m A SD	m/s	60 m	82,762	82,247	99.38	0.927	0	6.9	0.498
Speed 60 m A Max	m/s	60 m	82,762	82,247	99.38	7.257	0.4	26.6	3.099
Speed 60 m A Min	m/s	60 m	82,762	82,247	99.38	2.543	0.4	11.4	1.684
Speed 60 m B	m/s	60 m	82,762	58,800	71.05	5.386	0.5	17.1	2.23
Speed 60 m B SD	m/s	60 m	82,762	58,800	71.05	0.889	0	5.1	0.493
Speed 60 m B Max	m/s	60 m	82,762	58,800	71.05	7.614	0.5	26.2	3.264
Speed 60 m B Min	m/s	60 m	82,762	58,800	71.05	3.196	0.5	11.1	1.541
Speed 50 m A	m/s	50 m	82,762	82,372	99.53	4.459	0.4	16.5	2.126
Speed 50 m A SD	m/s	50 m	82,762	82,372	99.53	0.942	0	6.3	0.489
Speed 50 m A Max	m/s	50 m	82,762	82,372	99.53	6.938	0.4	26.6	3.038
Speed 50 m A Min	m/s	50 m	82,762	82,372	99.53	2.218	0.4	10.3	1.58
Direction 58 m	°	58 m	82,762	81,886	98.94	233	0	359	99.4
Direction 58 m SD	°	58 m	82,762	81,886	98.94	10.3	0	127	7.2
Direction 58 m Max	°	58 m	82,762	81,886	98.94	0	0	0	0
Direction 58 m Min	°	58 m	82,762	81,886	98.94	0	0	0	0
Direction 38 m	°	38 m	82,762	81,818	98.86	226.3	0	359	97.5
Direction 38 m SD	°	38 m	82,762	81,818	98.86	10.9	0	122	7.4
Direction 38 m Max	°	38 m	82,762	81,818	98.86	0	0	0	0
Direction 38 m Min	°	38 m	82,762	81,818	98.86	0	0	0	0
Temperature	°C	2 m	82,762	82,756	99.99	10.1	-28.9	35.8	10.9
Temperature SD	°C	2 m	82,762	82,756	99.99	0.1	0	1.6	0.1
Temperature Max	°C	2 m	82,762	82,756	99.99	10.4	-28.9	35.9	11
Temperature Min	°C	2 m	82,762	82,756	99.99	10	-28.9	35.9	10.9
Pressure	mbar	2 m	82,762	82,756	99.99	652.9	652.9	653.2	0
Pressure SD	mbar	2 m	82,762	82,756	99.99	0	0	2.7	0
Pressure Max	mbar	2 m	82,762	82,756	99.99	652.9	652.9	673.7	0.1
Pressure Min	mbar	2 m	82,762	82,756	99.99	652.9	652.9	652.9	0
Speed 50 m B	m/s	50 m	82,762	82,483	99.66	4.474	0.4	16	2.113
Speed 50 m B SD	m/s	50 m	82,762	82,483	99.66	0.935	0	6.4	0.492
Speed 50 m B Max	m/s	50 m	82,762	82,483	99.66	6.932	0.4	26.3	3.04
Speed 50 m B Min	m/s	50 m	82,762	82,483	99.66	2.248	0.4	9.9	1.564
Speed 40 m A	m/s	40.5 m	82,762	82,419	99.59	4.004	0.4	15.3	2.035
Speed 40 m A SD	m/s	40.5 m	82,762	82,419	99.59	0.923	0	5.8	0.482
Speed 40 m A Max	m/s	40.5 m	82,762	82,419	99.59	6.539	0.4	27	3.003
Speed 40 m A Min	m/s	40.5 m	82,762	82,419	99.59	1.899	0.4	10	1.363
Speed 40 m B	m/s	40.5 m	82,762	82,555	99.75	4.079	0.4	15	2.013
Speed 40 m B SD	m/s	40.5 m	82,762	82,555	99.75	0.919	0	6	0.478
Speed 40 m B Max	m/s	40.5 m	82,762	82,555	99.75	6.59	0.4	26.6	2.974
Speed 40 m B Min	m/s	40.5 m	82,762	82,555	99.75	1.975	0.4	9.5	1.382
Air Density	kg/m³		82,762	82,762	100	0.804	0.736	1.179	0.032
Speed 60 m A TI			82,762	82,247	99.38	0.22	0	1.85	0.15
Speed 60 m B TI			82,762	58,800	71.05	0.18	0	1.25	0.1
Speed 50 m A TI			82,762	82,372	99.53	0.24	0	1.75	0.16
Speed 50 m B TI			82,762	82,483	99.66	0.24	0	1.82	0.16
Speed 40 m A TI			82,762	82,419	99.59	0.27	0	1.79	0.17
Speed 40 m B TI			82,762	82,555	99.75	0.26	0	1.7	0.16
Speed 60 m A WPD	W/m²		82,762	82,247	99.38	77	0	2091	102
Speed 60 m B WPD	W/m²		82,762	58,800	71.05	96	0	1984	116
Speed 50 m A WPD	W/m²		82,762	82,372	99.53	62	0	1783	89
Speed 50 m B WPD	W/m²		82,762	82,483	99.66	62	0	1626	89
Speed 40 m A WPD	W/m²		82,762	82,419	99.59	48	0	1413	75
Speed 40 m B WPD	W/m²		82,762	82,555	99.75	49	0	1413	75

At each height, the readings from both anemometers were merged to create a consolidated 1-year dataset for use in the analysis. The consolidated dataset includes data for the period June 1, 2011–May 31, 2012. Generally, the readings from the "A" anemometers are used in the consolidated dataset. To minimize tower shadow effects, readings from the "B" anemometers were used when the wind direction (as measured by the closet wind vane) was in the range of 105°–165°.

The tower can influence the wind speed that is measured by the anemometers. This effect is known as tower shading. The effect can most easily be seen mathematically or graphically by comparing the wind speed ratios of the redundant anemometers.

The wind speeds for two anemometers at the same height are expected to be the same or very close to the same. The ratio of the wind speeds of these two anemometers should typically be 1 or very close to 1. Predictable impacts of the tower can be seen when the wind must go around the tower (i.e., "in the tower shadow") to reach one of the anemometers. The sensor in the shadow of the tower sees turbulent wind often at reduced wind speeds compared to the other anemometer at the same height. Though the absolute difference in wind speeds may be small, the ratio can be an identifiable marker for the impact of the tower. It can be seen graphically in Figure 3-1. The wind speed data from the anemometer not in the tower shadow is used when the wind is coming from directions that will cause tower shading. In this case, data from anemometer B was used when the wind direction was from 105°–165°.

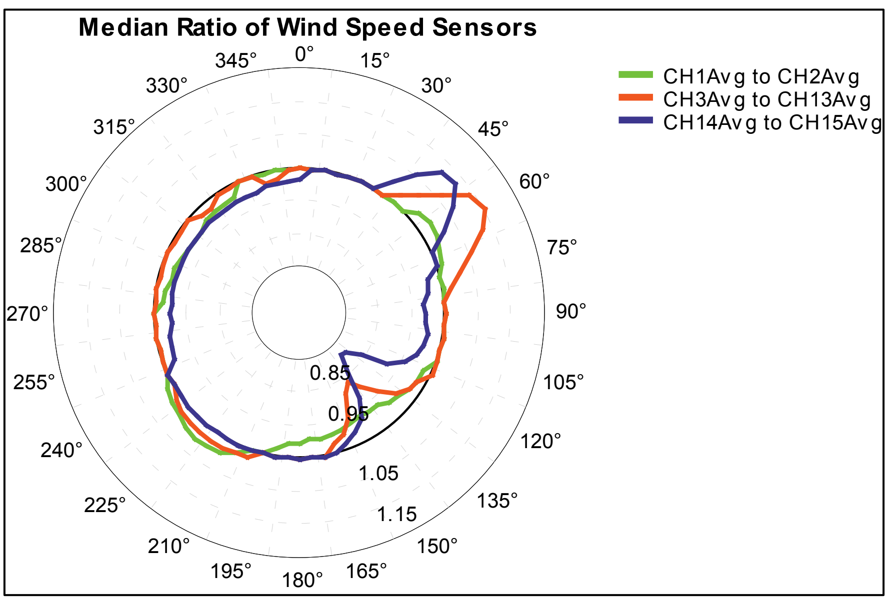

Figure 3-1. Tower shadow impact on wind speed ratios

Table 3-3 shows the recovery rates for the consolidated dataset used in the analysis, June 1, 2011–May 31, 2012.

Table 3-3. Mille Lacs Data Column Summary June 1, 2011–May 31, 2012 (Consolidated Dataset)

Label	Units	Height	Possible Records	Valid Records	Recovery Rate (%)	Mean	Min	Max	Std. Dev
Speed 60 m	m/s	60 m	52,704	52,191	99.03	5.381	0.4	17.4	2.22
Speed 60 m SD	m/s	60 m	52,704	52,191	99.03	0.887	0	5.1	0.496
Speed 60 m Max	m/s	60 m	52,704	52,191	99.03	7.609	0.4	22.8	3.264
Speed 60 m Min	m/s	60 m	52,704	52,191	99.03	3.185	0.4	11.4	1.532
Speed 50 m	m/s	50 m	52,704	52,369	99.36	5.086	0.4	16.5	2.094
Speed 50 m SD	m/s	50 m	52,704	52,369	99.36	0.886	0	4.9	0.49
Speed 50 m Max	m/s	50 m	52,704	52,369	99.36	7.334	0.4	23.2	3.188
Speed 50 m Min	m/s	50 m	52,704	52,369	99.36	2.907	0.4	10.3	1.379
Direction 58 m	°	58 m	52,704	51,861	98.4	236.6	0	359	98.5
Direction 58 m SD	°	58 m	52,704	51,861	98.4	10.2	0	112	6.8
Direction 58 m Max	°	58 m	52,704	51,861	98.4	0	0	0	0
Direction 58 m Min	°	58 m	52,704	51,861	98.4	0	0	0	0
Direction 38 m	°	38 m	52,704	51,804	98.29	228.3	0	359	96.2
Direction 38 m SD	°	38 m	52,704	51,804	98.29	10.8	0	122	6.9
Direction 38 m Max	°	38 m	52,704	51,804	98.29	0	0	0	0
Direction 38 m Min	°	38 m	52,704	51,804	98.29	0	0	0	0
Temperature	°C	2 m	52,704	52,698	99.99	8.1	-28.9	35.8	11.3
Temperature SD	°C	2 m	52,704	52,698	99.99	0.1	0	1.4	0.1
Temperature Max	°C	2 m	52,704	52,698	99.99	8.3	-28.9	35.9	11.3
Temperature Min	°C	2 m	52,704	52,698	99.99	7.9	-28.9	35.9	11.3
Pressure	mbar	2 m	52,704	52,698	99.99	652.9	652.9	653.2	0
Pressure SD	mbar	2 m	52,704	52,698	99.99	0	0	2.7	0
Pressure Max	mbar	2 m	52,704	52,698	99.99	652.9	652.9	673.7	0.1
Pressure Min	mbar	2 m	52,704	52,698	99.99	652.9	652.9	652.9	0
Speed 40 m	m/s	40 m	52,704	52,411	99.44	4.651	0.4	15.1	1.989
Speed 40 m SD	m/s	40 m	52,704	52,411	99.44	0.892	0	4.5	0.491
Speed 40 m Max	m/s	40 m	52,704	52,411	99.44	6.954	0.4	23.6	3.136
Speed 40 m Min	m/s	40 m	52,704	52,411	99.44	2.502	0.4	9.5	1.219
Air Density	kg/m^3		52,704	52,704	100	0.81	0.736	1.179	0.033
Speed 60 m TI			52,704	52,191	99.03	0.18	0	1.25	0.1
Speed 50 m TI			52,704	52,369	99.36	0.18	0	1.25	0.09
Speed 40 m TI			52,704	52,411	99.44	0.2	0	1.14	0.1
Speed 60 m WPD	W/m^2		52,704	52,191	99.03	96	0	2091	114
Speed 50 m WPD	W/m^2		52,704	52,369	99.36	82	0	1783	99
Speed 40 m WPD	W/m^2		52,704	52,411	99.44	64	0	1,366	83

4 Wind Resource Summary

This section examines in detail the characteristics of the wind resource based on the on-site data collected.

4.1 Measuring Power in the Wind

Wind speeds vary by season, time of day, and according to weather events. Uneven heating of the earth's surface creates wind energy. Variation in heating and factors, such as surface orientation or slope (azimuth), absorptivity (albedo), and atmospheric transmissivity, also affect the wind resource. In addition, the wind resource can be accelerated, decelerated, or made turbulent by factors such as terrain, bodies of water, buildings, and vegetative cover.

The wind speed and air density determine the amount of power the wind contains. The power available is given by:

Equation 4-1. Power in the Wind

$$P = \frac{1}{2} * A * \rho * V^3$$

where

P = power of the wind [W]

A = windswept area of the rotor (blades) [m^2] = $\pi D^2/4 = \pi r^2$

ρ = density of the air [kg/m^3] (at sea level at 15°C)

V = velocity of the wind [m/s]

As shown, wind power is proportional to velocity cubed (V^3). This is important to understand because if wind velocity is doubled, the available power is increased by a factor of eight ($2^3 = 8$). Consequently, what may appear to be a small increase in average speed yields a significant increase in available energy. Typically, wind developers looking to capture energy from higher velocity winds select taller wind turbine towers. Accordingly, the wind industry has been steadily moving toward taller towers, with the industry norm increasing from 30 m to 80+ m over the last 15–20 years for utility-scale turbines.

4.2 Wind Speed Data

Wind speed data was collected at 60 m, 50 m, and 40 m with a redundant wind speed sensor at each level. The wind speed data from the "A" anemometers was used, except when the winds came from the direction sector 105°–165°, in which case the "B" anemometers were used. These consolidated wind speeds are used in data displays and calculations through the rest of this report, unless otherwise noted.

The wind varies widely throughout the day and night and by season as illustrated by the 3 months of collected data at 60 m in Figure 4-1. As shown, there are 10-minute periods that have wind speeds less than 3 m/s. Likewise, there are periods that have wind speeds in excess of 10 m/s. This sort of variability is typical, but further statistical analysis will illuminate important trends and patterns.

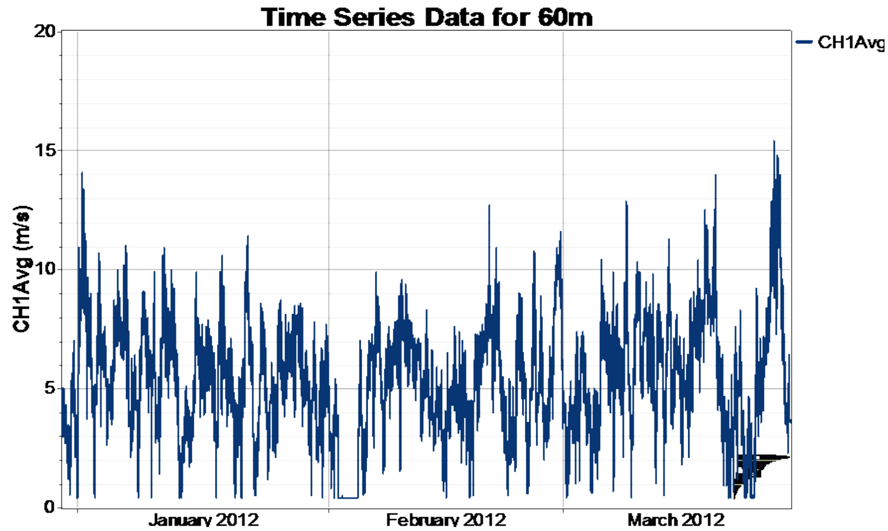

Figure 4-1. Wind data at 60 m at Mille Lacs for January 2012–March 2012

A box plot indicating the monthly maximum wind speed, the average daily high, the monthly mean, the average daily low, and monthly minimum wind speed of the collected 60-m data is shown in Figure 4-2.

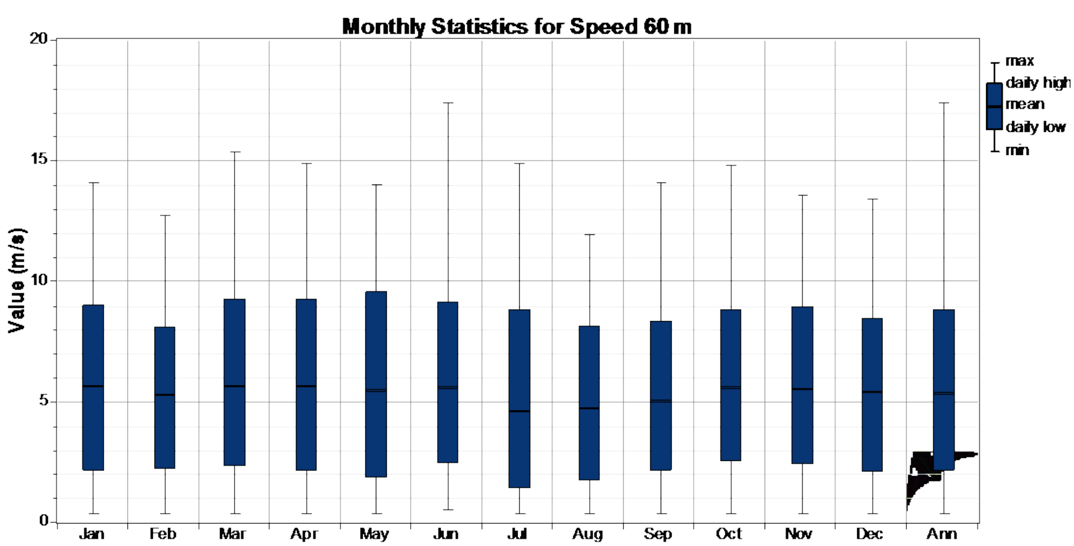

Figure 4-2. Boxplot of the wind speed data at 60 m at Mille Lacs June 1, 2011–May 31, 2012

Figure 4-3 shows the wind speeds at each anemometer height as they are plotted against time to depict the seasonal trends. Wind speeds typically increase with increased height above the ground. The collected data follows that pattern. The fall through spring months (October–June) are the windiest, and summer months (July–September) are the least windy.

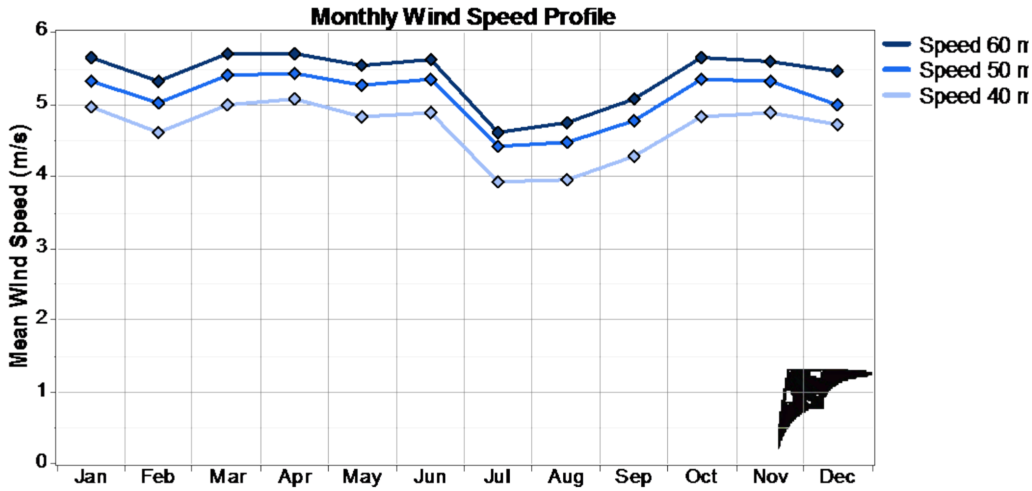

Figure 4-3. Seasonal wind speed profile at Mille Lacs June 1, 2011–May 31, 2012

Figure 4-4 shows the annual average diurnal (daily) profile for the site. The diurnal profile for this site is fairly flat for winds 40–60 m above ground level (AGL), with the wind speeds typically highest at night and in the afternoon. The wind speeds dip in the late morning and early evening. At low heights, the wind speeds typically peak just after mid-day, while higher up, the wind speeds peak at night. The figure captures this transition, with the 40-m winds peaking in the afternoon, while the 60-m winds peak at night.

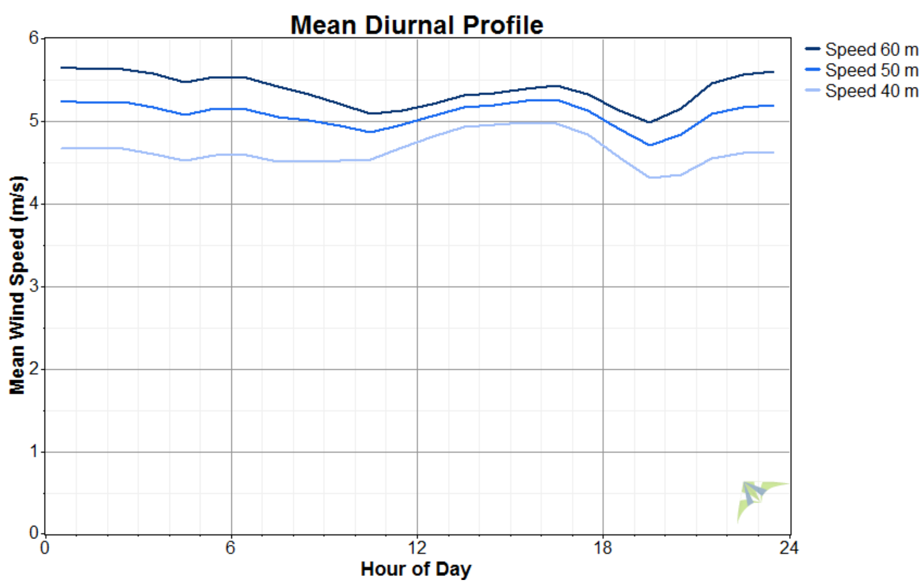

Figure 4-4. Diurnal wind speed profile at Mille Lacs June 1, 2011–May 31, 2012

Figure 4-5 depicts the diurnal (daily) wind pattern by month, revealing a great deal of month-to-month variation. The profile tends to be a bit flatter in the winter months. March shows high wind speeds at night and low wind speeds during the day. The late summer and early fall months (August–October) have a "double dip" profile with the winds dipping in the morning and evening.

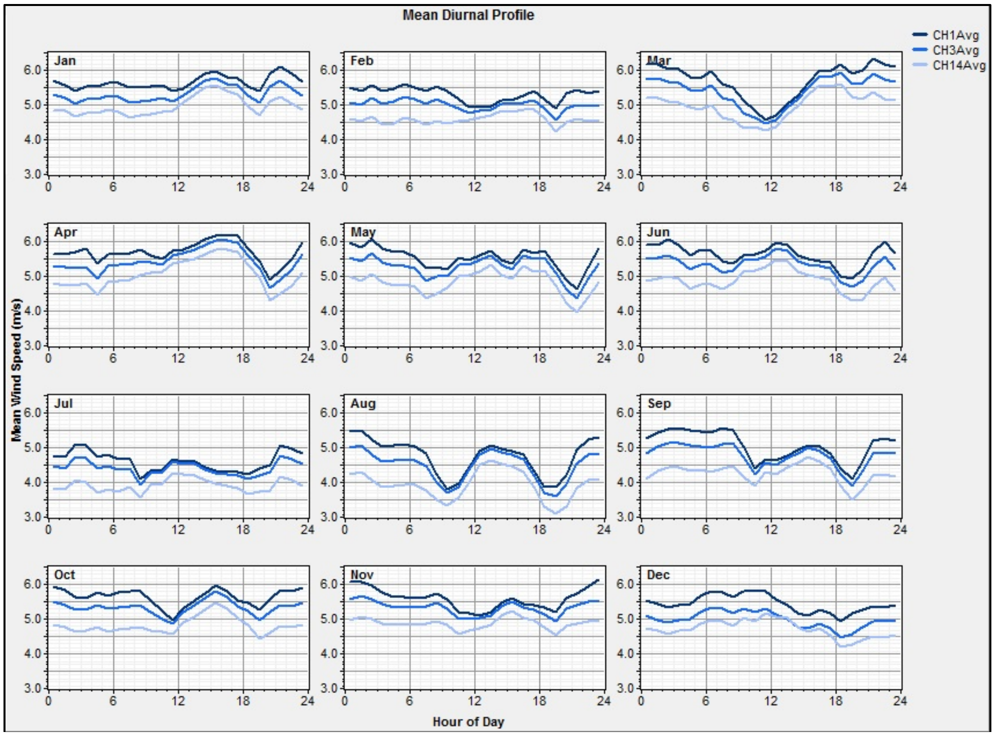

Figure 4-5. Diurnal wind speed profile by month at Mille Lacs June 1, 2011–May 31, 2012

4.3 Wind Direction Data

The wind frequency rose on the left in Figure 4-6 shows the frequency at which the wind comes from each direction for the 58-m direction vane. As can be seen, the winds most frequently come from the south with a secondary peak from the northwest.

The total wind energy rose on the right in Figure 4-6 indicates that most of the wind energy during the course of the year comes from the south, with a secondary peak from the northwest. In siting a wind turbine at this location, attention should be paid to ensuring a clear fetch to the south and northwest of the wind turbine to the greatest degree possible as these winds will produce the bulk of the turbine annual energy production. Surface obstructions (trees or buildings) to the south or northwest should be avoided as they will increase the turbulence intensity (TI) the wind turbine will experience.

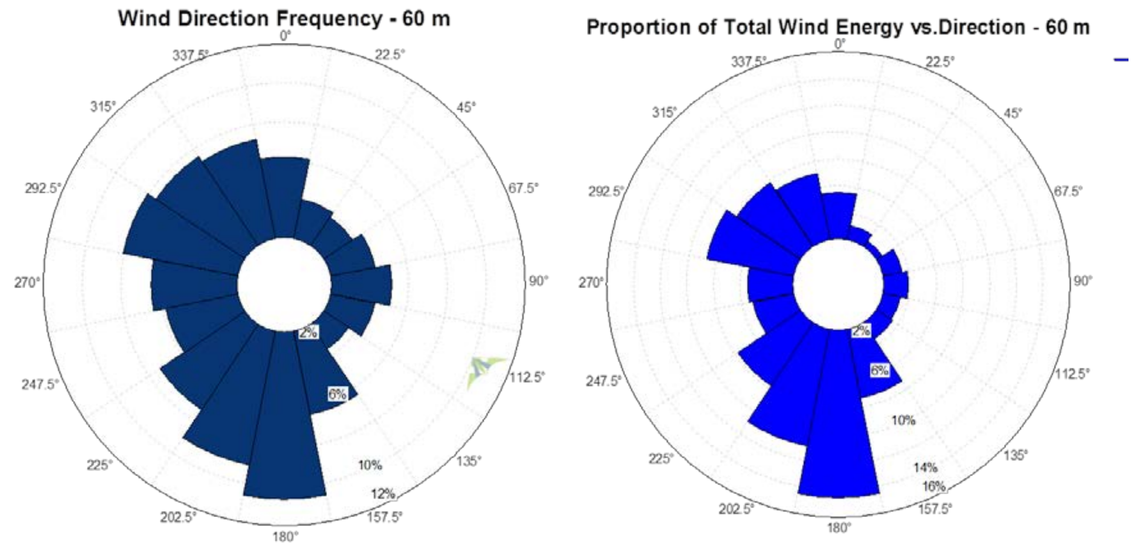

Figure 4-6. Wind frequency and wind speed rose at Mille Lacs June 1, 2011–May 31, 2012

Figure 4-7 shows how the total wind energy rose varies by month. In general the south winds are the most energetic, but there is a great deal of month-to-month variation.

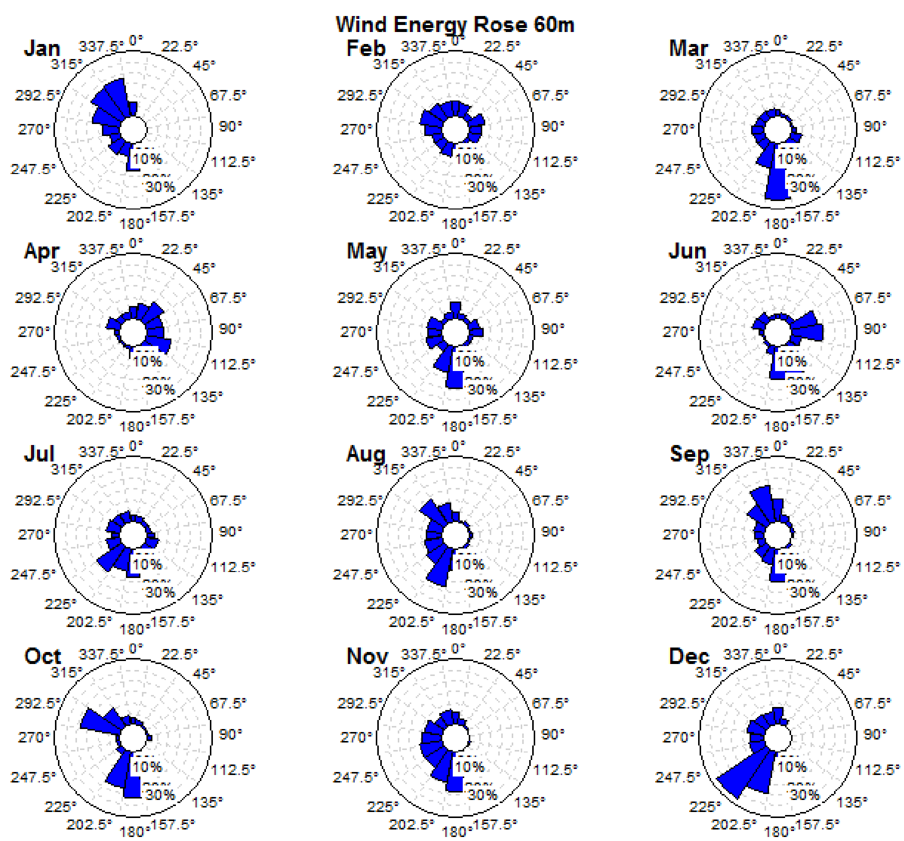

Figure 4-7. Wind energy rose at 60-m by month at Mille Lacs June 1, 2011–May 31, 2012

4.4 Wind Frequency (Probability) Distribution

Figure 4-8 illustrates the frequency (%) of time that the wind (at 60 m) is at a given wind speed. This probability distribution is typically described using a Weibull distribution. There are two commonly used factors to describe the characteristics of this distribution function, the Weibull k and Weibull c factors. The Weibull k value is a unit-less measure indicating how narrowly/widely the wind speeds are distributed about the mean with values ranging from 1.0–3.5. The Weibull c is the scale factor for the distribution related to the annual mean wind speed.

The best fit Weibull distribution parameters for the measured data at 60 m are k = 2.57 and c = 6.04. The distribution in Figure 4-8 shows that the most frequent winds are between 4 m/s and 7 m/s, as measured by the speed sensor at 60 m.

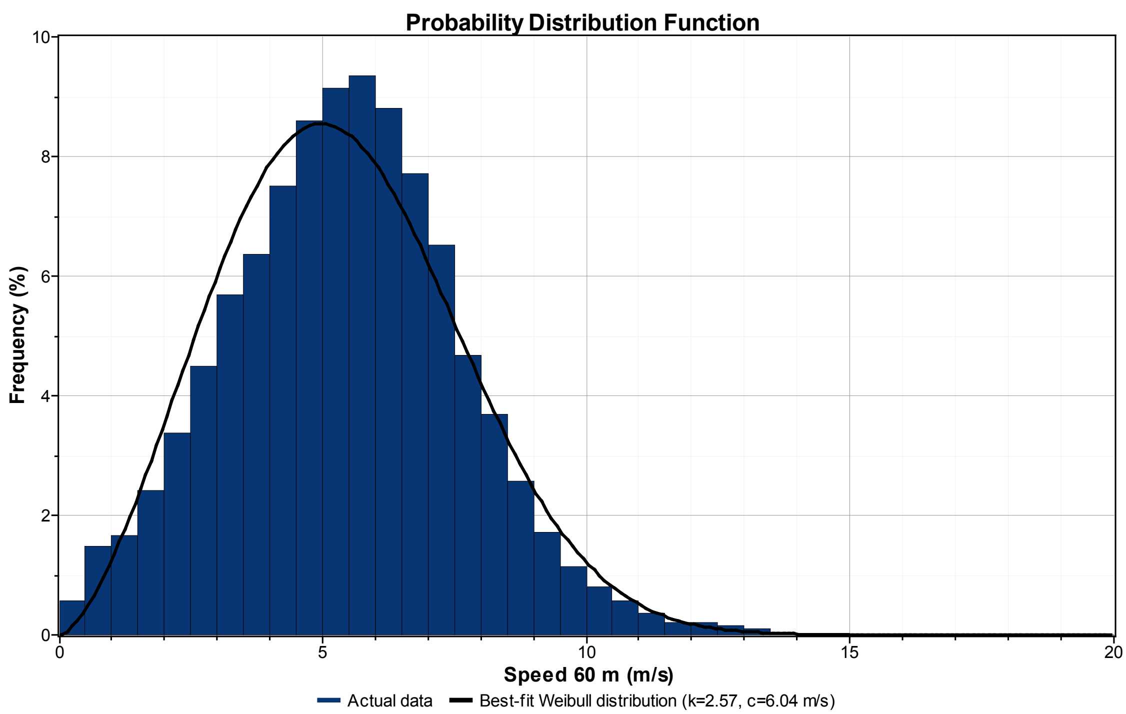

Figure 4-8. Wind speed distribution at 60 m at Mille Lacs June 1, 2011–May 31, 2012

Figure 4-9 illustrates how the wind speed distribution varies throughout the year. To make the graph easier to read, representative distributions are shown only for selected months. As can be seen, the profiles for July, August, and September are shifted to the left indicating lower average wind speeds in those months. Likewise, the windier winter through spring months show a similar shift to the right.

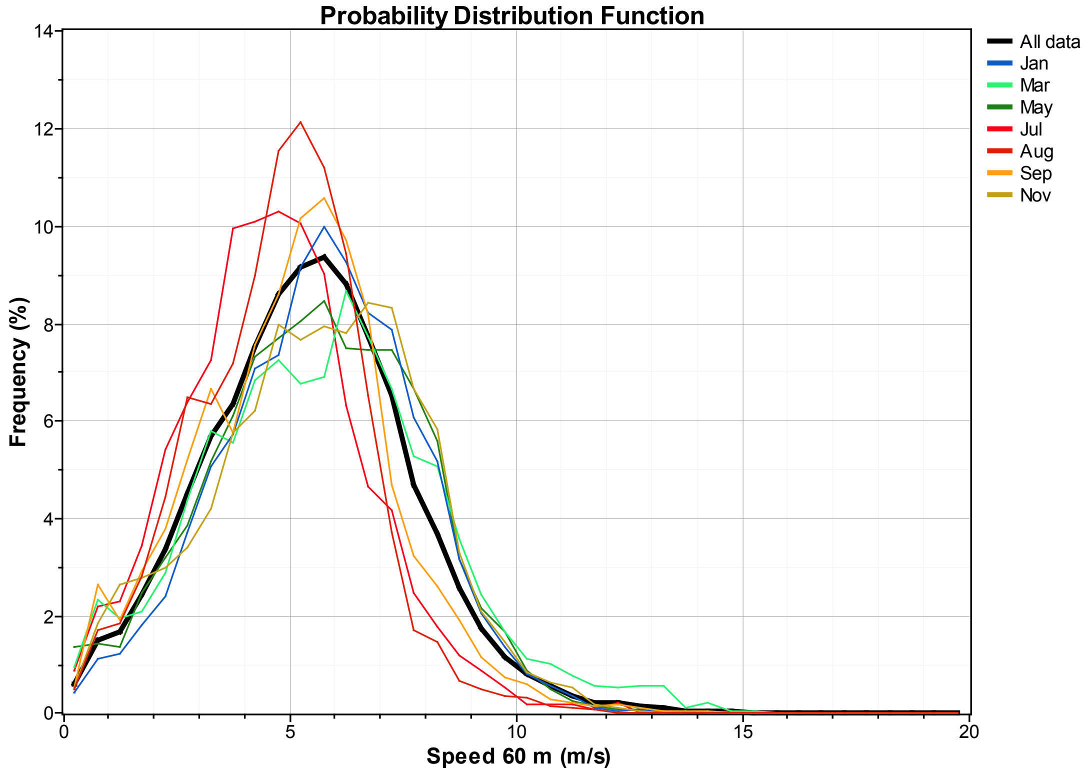

Figure 4-9. Monthly wind speed distributions at 50 m at Mille Lacs June 1, 2011–May 31, 2012

4.5 Vertical Wind Shear

Vertical wind shear is defined as the change in wind speed with the change in height. Typically, wind speed increases as the height above the ground increases. This variation of wind speed with elevation is called the vertical profile of the wind speed or vertical wind shear. In wind turbine engineering, the determination of vertical wind shear is an important design parameter because: (1) it directly determines the productivity of a wind turbine on a tower of certain height, and (2) it can strongly influence the lifetime of major components, such as the blades and gearbox.

One of two mathematical relations is typically used to characterize the measured wind shear:

- Power law profile, aka power law
- Logarithmic profile, aka log law.

The power law equation is shown in Equation 4-2. Depending on what data is known and what is sought, the equation can be manipulated to solve for any of the variables.

Equation 4-2. Power Law Equation

$$V = V_{ref}\left[\frac{Z}{Z_{ref}}\right]^{\alpha}$$

where

V = wind speed at height of interest (e.g., hub height)
V_{ref} = wind speed measured at height Z_{ref}
Z = height of interest (e.g., hub height)
Z_{ref} = height of measured data
α = wind shear exponent

The wind shear exponent, α, is often referred to as the vertical wind shear factor. It defines how the wind speed changes with height. When the actual wind shear value is not known, a typical value used to estimate the wind shear exponent is 0.14 (i.e., $1/7^{th}$ power law). When wind speed readings are available at multiple heights, the wind shear factor can be calculated using the power law equation. This was done with the collected data at Mille Lacs. Table 4-1 and Table 4-2 list the calculated wind shear values between the various anemometer heights.

The vertical wind shear factors from several heights with known wind speeds are used to estimate both the vertical wind shear factor and wind speed at other heights of interest above the measured data (e.g., turbine hub height). Depending on the type of terrain and surface roughness features, the wind shear factor typically varies from 0 to 0.4.

The log law uses a parameter known as the surface roughness length (measured in meters) in predicting the wind shear profile. Smooth surfaces, such as calm, open sea, have very low wind shear values (e.g., 0.0002 m), while crops are a little higher at 0.05 m of surface roughness length. Areas with few trees have surface roughness of about 0.1 m, while cities with tall buildings would be about 3.0 m.

The surface roughness parameter is "solved for" from the existing wind speed data at various heights. The resultant surface roughness characterization may not always match the actual surface conditions, but it serves as a descriptor of the vertical wind shear profile. The resultant surface roughness lengths have been calculated for Mille Lacs and are shown in Table 4-1, Figure 4-9, and Table 4-2. The surface roughness and shear factor were calculated using the 40–50-m and 50–60-m data.

Table 4-1. Power Law Exponent and Surface Roughness Length at Mille Lacs June 1, 2011–May 31, 2012

Wind Speed Sensor	Height	Time Steps	Mean Wind Speed	Power Law Exponent	Surface Roughness
	[m]	[#]	[m/s]	[-]	[m]
Speed 60 m	60	52,180	5.38	0.296	1.870
Speed 50 m	50	52,180	5.10	0.398	3.62
Speed 40 m	40	52,180	4.67		

In Figure 4-10, the wind speeds from each pair of anemometers at 40 m, 50 m, and 60 m have been consolidated for both the power law and log law calculations. As shown, both the power law and log law approach yield comparable results at the heights of measured data. However, for extrapolating upwards to 80 m or 100 m, the log law yields slightly more conservative values than the power law for the increased wind speed at higher elevations. Because the data shows the shear declining going from 40-m to 60-m AGL, the more conservative log law is more appropriate for extrapolating upwards from 60-m AGL.

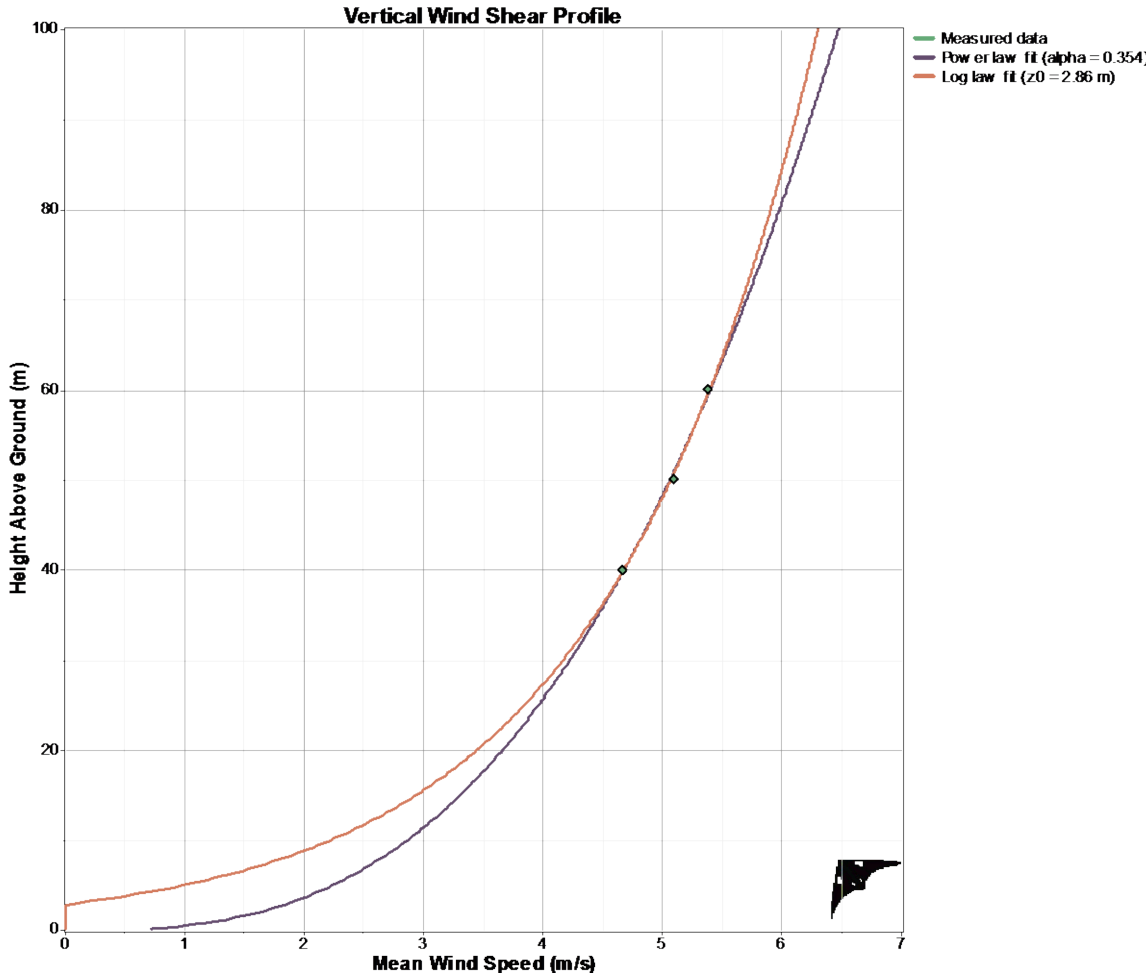

Figure 4-10. Power law and logarithmic law at Mille Lacs, June 1, 2011–May 31, 2012

Table 4-2 shows the mean wind speeds at each height, power law exponent, and surface roughness calculation for each direction sector taken from the wind vane at 58 m. These surface roughness factors, in combination with subsequent factors, will be used later in the report to calculate the adjustment to the 40- and 50-m wind speeds to normalize the Mille Lacs data to the long-term data from the Modern Era Retrospective-Analysis for Research and Applications (MERRA) dataset.

Table 4-2. Power Law Exponent and Surface Roughness Length by Direction at Mille Lacs, June 1, 2011–May 31, 2012

Direction Sector	Time Steps	Mean Wind Speed (m/s)			Best-Fit	
		@ 60 m	@ 50 m	@ 40 m	Power Law Exp	Surface Roughness
[deg]	[#]	[m/s]	[m/s]	[m/s]		[m]
348.75° - 11.25°	3,193	5.23	5.00	4.60	0.321	2.141
11.25° - 33.75°	2,120	4.80	4.64	4.28	0.288	1.478
33.75° - 56.25°	1,976	4.27	4.14	3.84	0.262	1.048
56.25° - 78.75°	2,246	4.62	4.46	4.07	0.317	2.037
78.75° - 101.25°	2,653	4.74	4.59	4.17	0.323	2.148
101.25° - 123.75°	2,260	4.79	4.59	4.16	0.352	2.784
123.75° - 146.25°	1,857	5.11	4.84	4.46	0.338	2.503
146.25° - 168.75°	3,306	5.71	5.35	4.96	0.347	2.737
168.75° - 191.25°	5,511	6.20	5.87	5.38	0.355	2.877
191.25° - 213.75°	4,700	5.90	5.56	5.04	0.391	3.736
213.75° - 236.25°	3,787	5.63	5.26	4.78	0.402	4.034
236.25° - 258.75°	3,021	5.24	4.88	4.46	0.395	3.863
258.75° - 281.25°	3,347	5.13	4.82	4.44	0.354	2.878
281.25° - 303.75°	4,158	5.61	5.29	4.84	0.365	3.124
303.75° - 326.25°	3,900	5.51	5.20	4.74	0.370	3.243
326.25° - 348.75°	3,748	5.47	5.18	4.72	0.367	3.163

The average daily wind shear profile for each month of the year can be seen in Figure 4-11. This is a reasonably typical set of diurnal shear profiles. The shear is higher at night because in the absence of the sun's heat, the air at different heights becomes more stratified. The air at a given height is less affected by the air at different heights. During the day the air closest to the ground tends to be heated the most and thus rises leading to air mixing and lower shear. Note that the summer months (July–September) tend to have higher shear, especially at night. The shear is lower during the winter months.

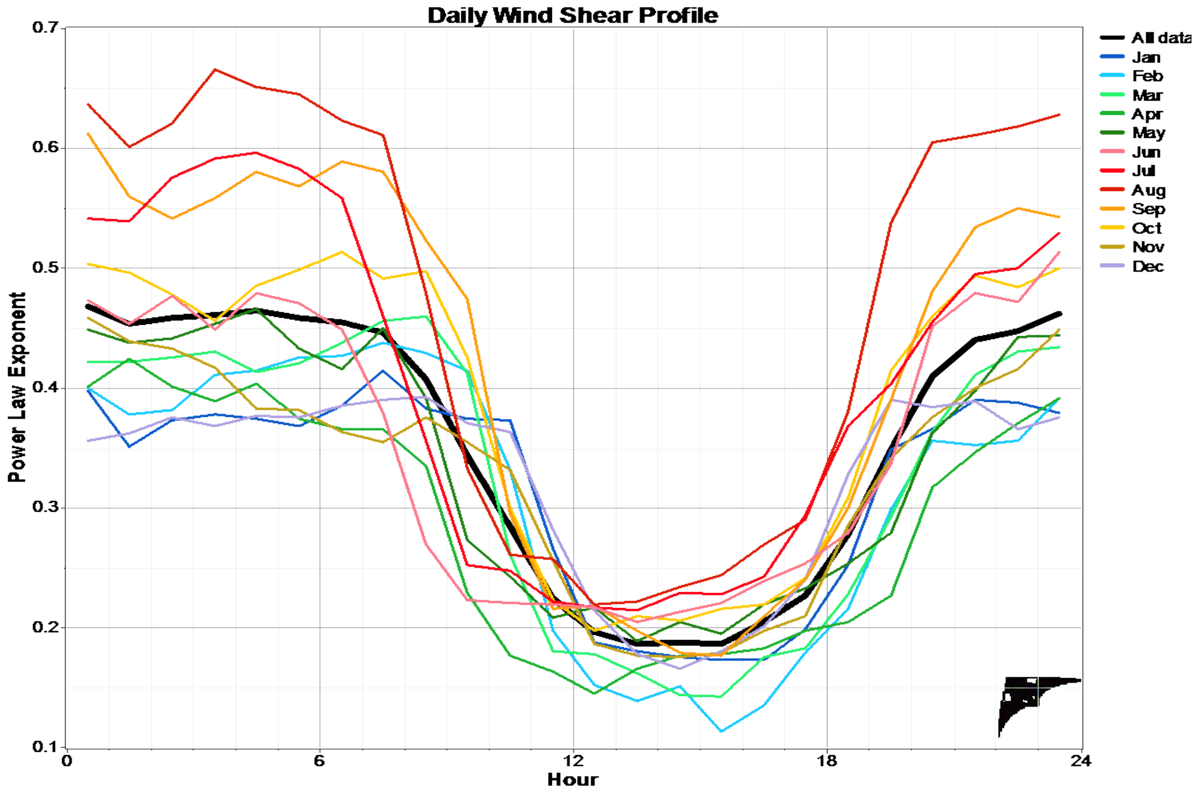

Figure 4-11. Daily wind shear profile by month at Mille Lacs, June 1, 2011–May 31, 2012

Table 4-3 shows the mean wind speeds at each height. Power law exponent and surface roughness calculation are shown for each month with the 58-m wind vane as the reference.

Table 4-3. Power Law Exponent and Surface Roughness Length by Month at Mille Lacs, June 1, 2011–May 31, 2012

Month	Time Steps	Mean Wind Speed			Best-Fit	
		@ 60 m	@ 50 m	@ 40 m	Power Law Exp	Surface Roughness
	[#]	[m/s]	[m/s]	[m/s]		[m]
Jan	4,464	5.65	5.32	4.97	0.317	2.076
Feb	3,809	5.31	5.06	4.68	0.312	1.963
Mar	4,464	5.70	5.41	4.99	0.331	2.357
Apr	4,306	5.70	5.45	5.08	0.285	1.441
May	4,464	5.52	5.25	4.82	0.336	2.454
Jun	4,320	5.62	5.34	4.88	0.351	2.782
Jul	4,464	4.61	4.41	3.92	0.406	4.047
Aug	4,458	4.75	4.48	3.93	0.470	5.694
Sep	4,320	5.06	4.78	4.26	0.425	4.564
Oct	4,464	5.63	5.33	4.82	0.388	3.643
Nov	4,307	5.59	5.34	4.89	0.332	2.371
Dec	4,340	5.44	5.05	4.77	0.326	2.309

4.6 Turbulence Intensity

Turbulence intensity, (TI) is defined as the standard deviation of the wind speed within a time step divided by the mean wind speed over that time step. It is a measure of the gustiness of the wind. High turbulence can lead to increased turbine wear and potentially increased operations and maintenance (O&M) costs. At lower wind speeds, the calculated TI is often higher as can be seen in Figure 4-12. At low wind speeds, the turbulence is of little consequence to the wind turbine itself. Turbulence at higher winds speeds is of greater interest and concern to wind turbine manufacturers.

Turbulence analysis determines the suitable types of turbine designs for a given wind energy project. Because wind turbines must withstand a variety of wind conditions, design standards have been developed by the International Electrotechnical Commission (IEC). The IEC 61400-1:2005 has two components—one for wind speed and one for turbulence—and can be seen in Table 4-4.[2] The standard designates four different classes of wind turbines—I through IV—which are designed for varying degrees of wind resource, with Class I turbines designed for a very high mean wind speed and Class IV designed for a relatively low mean wind speed. Also shown are corresponding classifications for extreme wind events (i.e., 50-year gust), which is of particular importance due to the periodic occurrence of high wind speeds events.

The standard also designates a wind turbulence classification—A through C—that describes the amount of turbulence a turbine must be designed to withstand, with A being the highest turbulence and C being the lowest. In recent years, wind turbine manufacturers have introduced turbine designs for sites with lower wind speeds and low turbulence known as *low wind speed turbines*. These turbines have larger rotors, for a given generator size, and are thus capable of producing significantly more annual energy at a low wind speed site than the Class I or II or Class A or B turbines of similar generator size.

Several different metrics are used to characterize TI. The representative TI, for a set of 10-minute time steps, is equal to the 90th percentile of the TI values. Assuming a normal distribution of these values, it represents the mean value plus 1.28 standard deviations. The mean TI is the mean value of all of the TI data at a particular wind speed.

[2] International Electrotechnical Commission (IEC). "International Standard IEC 61400-1 Third Edition." Geneva, Switzerland: IEC, 2005.

Table 4-4. IEC Wind Turbine Classes, Ratings, and Characteristics of Turbulence Intensity[3]

Wind Turbine Generator Class	IEC I High Wind	IEC II Medium Wind	IEC III Low Wind	IEC IV Low Wind
V_{ave} - average wind speed at hub-height (m/s)	10	8.5	7.5	6
V_{50} - extreme 50-year gust (m/s)	70	59.5	52.5	42
Mean turbulence intensity at 15 m/s - turbulence Class A	14%–16%			
Mean turbulence intensity at 15 m/s - turbulence Class B	12%–14%			
Mean turbulence intensity at 15 m/s - turbulence Class C	0%–12%			

Figure 4-12 shows the representative and mean TI as a function of wind speed at 60 m at Mille Lacs.

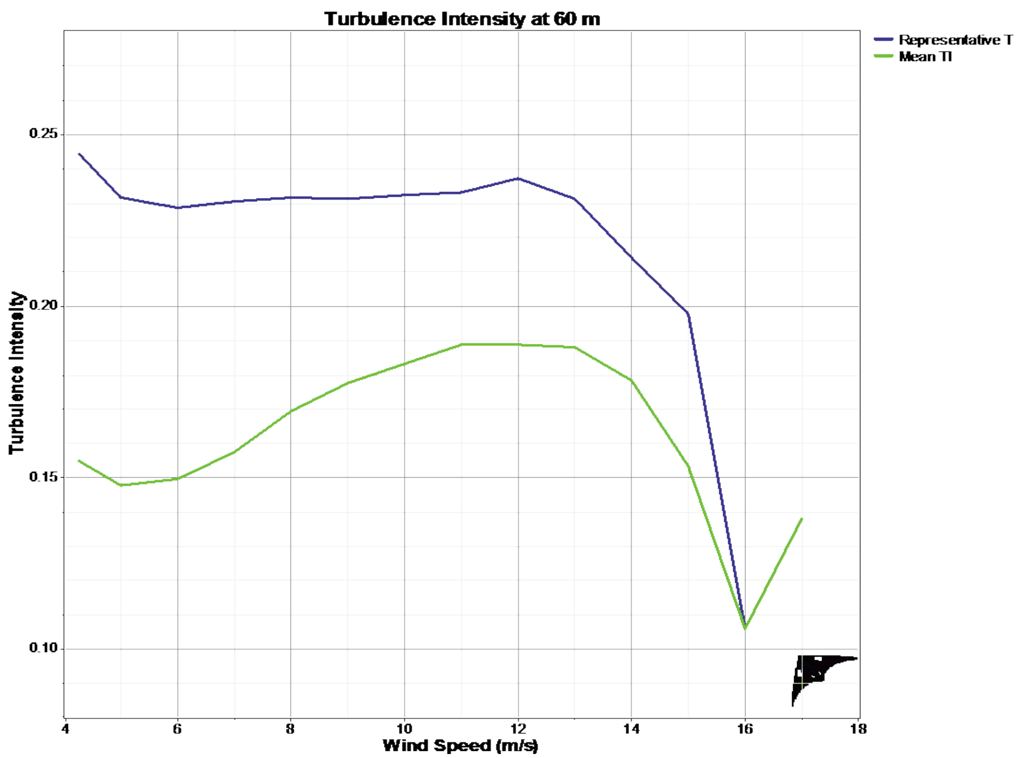

Figure 4-12. Turbulence intensity at 60 m at Mille Lacs, June 1, 2011–May 31, 2012

Figure 4-13 shows the IEC turbulence ratings relative to the representative TI. A point of primary interest is the mean TI at 15 m/s, which is 0.15 (15.0%). This indicates relatively high turbulence that may preclude the use of low wind speed turbines that would maximize energy production at this site. The potential wind loading due to extreme winds must be addressed during the turbine selection process.

[3] IEC/TC88, 61400-1 ed. 3, Wind turbines - Part 1: Design Requirements, International Electrotechnical Commission (IEC), 2005.

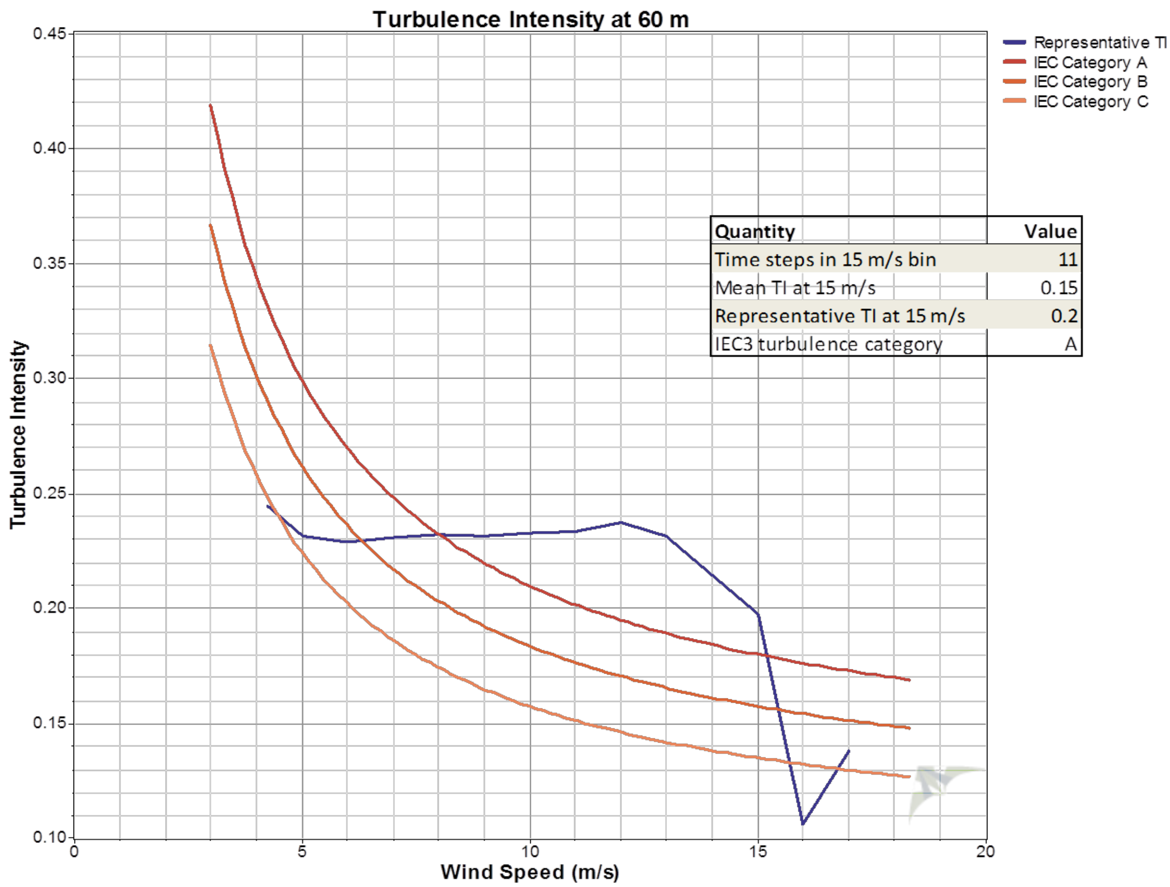

Figure 4-13. Turbulence intensity at 50 m at Mille Lacs, June 1, 2011–May 31, 2012

The different TI values, broken down by wind speed bin, can be seen in Table 4-5.

Table 4-5. Turbulence Analysis at 60 m at Mille Lacs, June 1, 2011–May 31, 2012

Bin	Bin Midpoint	Bin Endpoints		Records in Bin	Bin Freq.	Mean TI	Std Dev of TI	Represent. TI	Peak TI
		Lower	Upper						
	[m/s]	[m/s]	[m/s]	[#]					
1	4.3	4	4.5	3,922	10.161	0.15	0.07	0.24	0.8
2	5	4.5	5.5	9,250	23.966	0.15	0.07	0.23	0.77
3	6	5.5	6.5	9,487	24.58	0.15	0.06	0.23	0.49
4	7	6.5	7.5	7,435	19.263	0.16	0.06	0.23	0.63
5	8	7.5	8.5	4,360	11.296	0.17	0.05	0.23	0.61
6	9	8.5	9.5	2,238	5.798	0.18	0.04	0.23	0.4
7	10	9.5	10.5	1,017	2.635	0.18	0.04	0.23	0.34
8	11	10.5	11.5	483	1.251	0.19	0.03	0.23	0.32
9	12	11.5	12.5	217	0.562	0.19	0.04	0.24	0.3
10	13	12.5	13.5	137	0.355	0.19	0.03	0.23	0.3
11	14	13.5	14.5	38	0.098	0.18	0.03	0.21	0.23
12	15	14.5	15.5	11	0.028	0.15	0.03	0.2	0.24
13	16	15.5	16.5	1	0.003	0.11	0	0.11	0.11
14	17	16.5	17.5	1	0.003	0.14	0	0.14	0.14
15	18	17.5	18.5	0	0				

The scatterplot in Figure 4-14 provides a visual display of the array of data that are averaged to produce the discrete curves in Figure 4-12 and Figure 4-13.

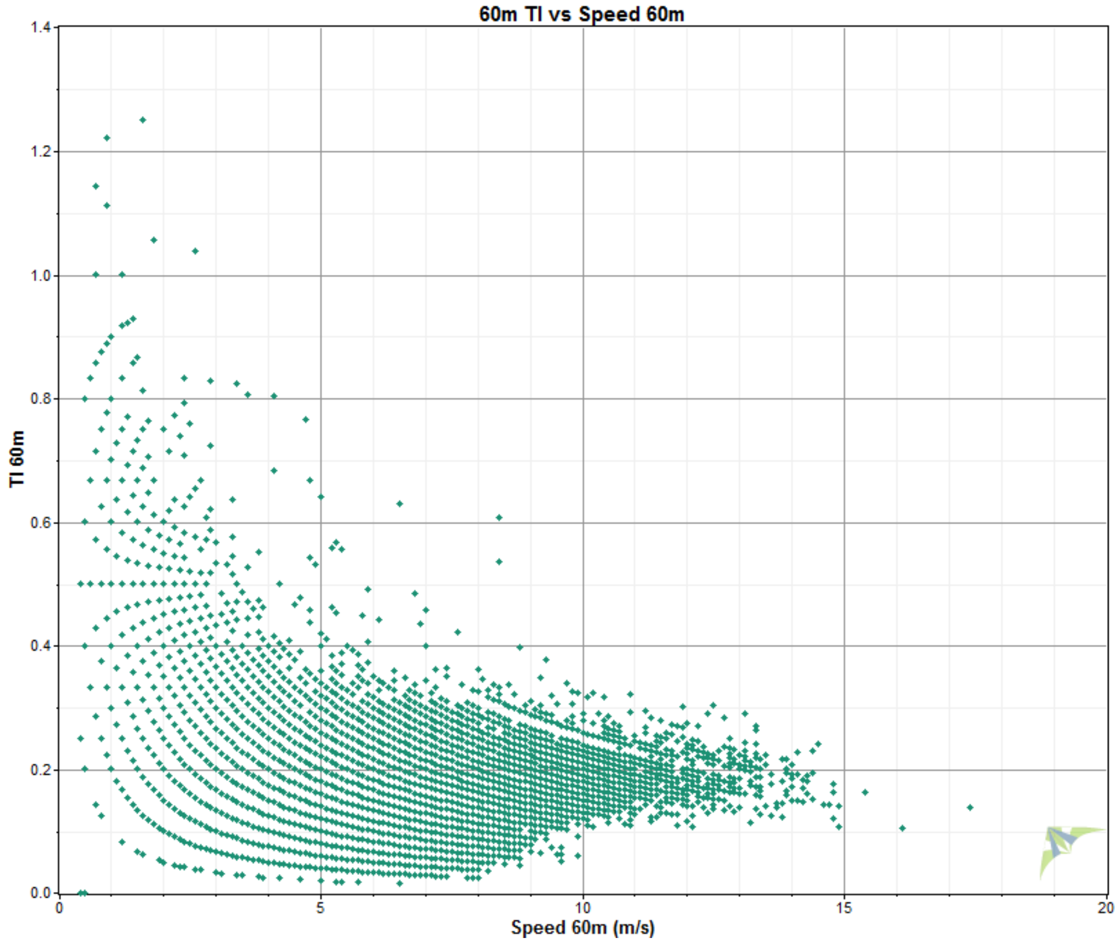

Figure 4-14. Turbulence intensity versus wind speed at 60 m at Mille Lacs, June 1, 2011–May 31, 2012

The monthly TI factors are displayed in Figure 4-15. The mean TI remains fairly constant throughout the year. The representative TI is somewhat higher in the summer compared to the rest of the year.

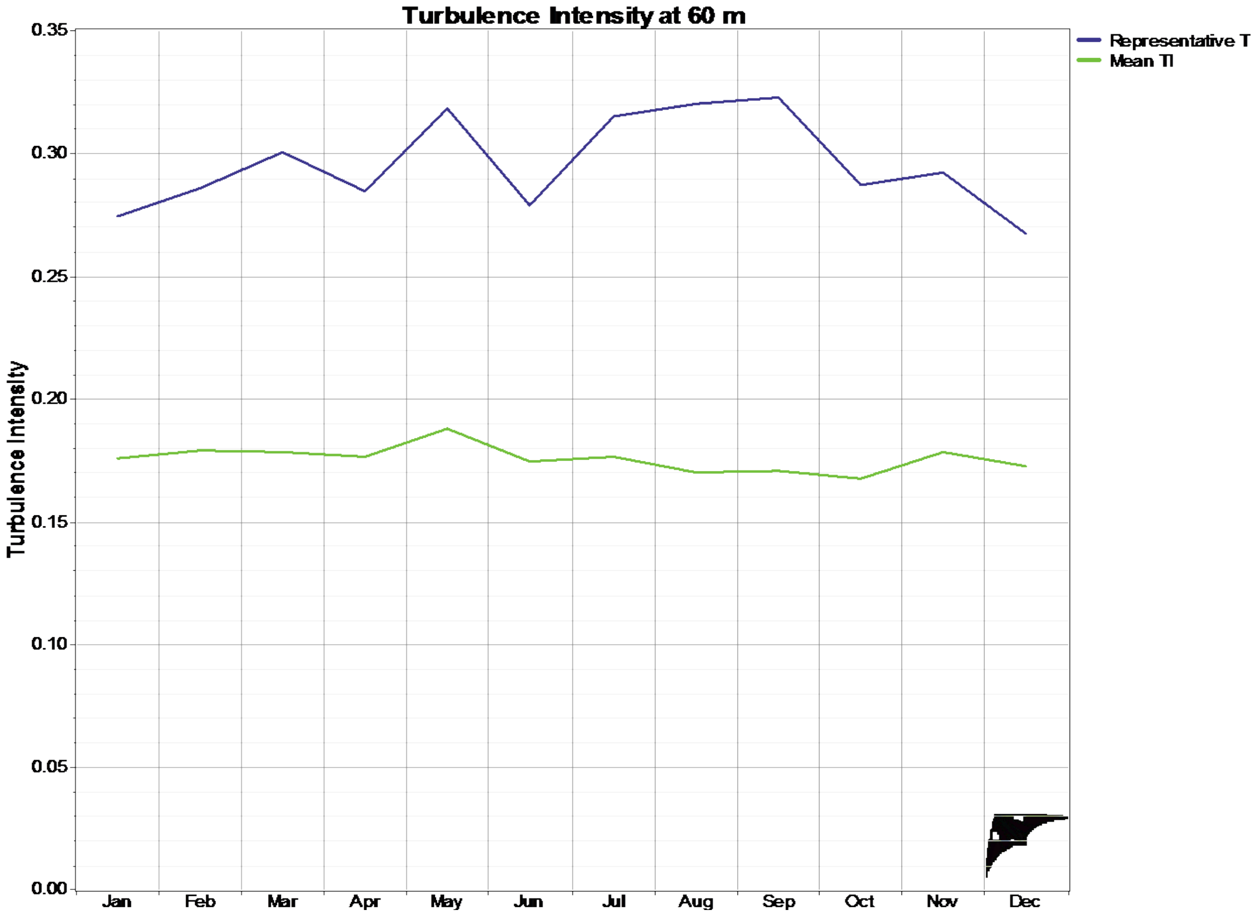

Figure 4-15. Turbulence intensity by month at 60 m at Mille Lacs, June 1, 2011–May 31, 2012

The TI rose in Figure 4-16 illustrates TI as a function of direction. The turbulence direction does not vary much with direction. The TI is somewhat higher from the northeast, east, and southeast compared to other directions.

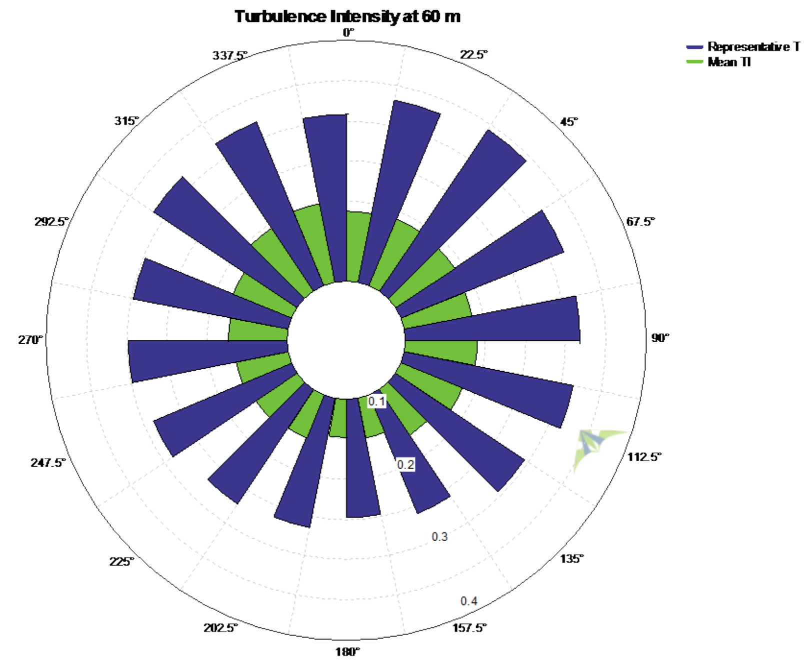

Figure 4-16. Turbulence intensity rose at 60 m at Mille Lacs, June 1, 2011–May 31, 2012

5 Long-Term Correlation

It is important to consider whether the monitoring period data reflects a high, low, or average year in terms of the wind resource. One goal of the wind resource assessment campaign is to determine whether the data monitoring period is representative of the long-term wind resource at the site and, if not, to adjust it to reflect the long-term resource. Different methodologies are used to estimate the long-term wind resource at the site where a short-term MET tower study was conducted. The purpose of this estimate is to provide a normalized, realistic estimate of the long-term wind resource and the resulting wind turbine energy production. Though wind turbine production at any site will vary year-to-year, the goal is to have the long-term energy production estimate minimize the uncertainty associated with the relatively short period of collected data.

5.1 Measure – Correlate – Predict

A standard industry approach with a number of variations is measure-correlate-predict (MCP), where a short-term dataset is correlated to a long-term wind dataset from a nearby monitoring station (reference site). Using the linear regression approach as an example, the correlation relationship (i.e., an equation with y-intercept and a scaling factor) is then applied to the measured data at the site of interest to project the expected long-term wind resource. An R^2 correlation factor of 80% (0.80) or greater is usually considered sufficient, but what is acceptable varies considerably depending upon terrain factors and availability of other sources of wind data, for example. Individual companies doing this analysis may have internal standards dictating at least 85% or even 90% correlation factor or in an unusual circumstance may accept a correlation factor of 70% or 75%.

There are a number of MCP methods available for determining the correlation relationship between the reference site and the site of interest. The essential steps of MCP are:

1. Establish a correlation between the site of interest wind data and the reference site wind data for a concurrent period of time, preferably at least 1 year.
2. Use the correlation relationship to create a "synthetic" dataset for the site of interest for the time period covered by the reference dataset. If there is reasonable correlation (i.e., 0.85 or greater) between the site of interest and the reference site, the synthesized dataset will reasonably reflect the historical long-term average resource at the site of interest.

The Windographer software offers and compares seven different MCP techniques. The MCP method selected for this analysis utilized linear regression as it appeared to give the best overall results. The R^2 value is a measure of "goodness of fit" of the linear regression equation relative to the scatterplot of the data it is calculated from.

The time step for correlation analysis tends to have a noticeable impact on the R^2 value. Ideally, the time step for comparison of the site of interest to the reference site would be 10-minute intervals. Often, the reference site may only have hourly data as in the case of an automated surface observing station (ASOS), for instance. In these cases, the hourly data file of each site would be compared, which typically improves the correlation factor. Generally, increasing the time step to 3, 12, or 24 hours will improve the correlation factor. On an annual basis, the overlapping time steps decrease from 52,260 concurrent time steps for 10-minute data, to 8,760 for hourly data, to 365 for daily data. As the number of overlapping time steps are reduced, the uncertainty in the resultant correlation relationship increases as the resultant synthetic dataset will have fewer data points. Typically, increasing the time-step interval results in fewer overlapping time steps but higher correlation factors.

5.2 Long-Term Data Sites

Locating high-quality, nearby wind datasets of sufficient length, useful heights, and reasonable accuracy and resolution is often a challenging endeavor. The Federal Aviation Administration (FAA) and National Weather Service (NWS) own and operate automated surface observing systems, ASOS for the purposes of aviation and weather observation. These datasets generally represent the most consistent weather observation data as the FAA and NWS are tasked with building an historical long-term surface weather observation record. Other long-term weather observation datasets include military airfield observations, ocean buoy observations, and other forms of surface observations. Nearby airport data has most often been used when long-term datasets at heights comparable to the met tower of interest have not been available. Historically, local airports had met towers with a single anemometer located at the pilot height above ground of a typical airplane using that airport, usually between 6 m and 10 m AGL.

There is a relatively new climate data capability available from the National Aeronautics and Space Administration (NASA) called the Modern Era Retrospective-Analysis for Research and Applications MERRA dataset. MERRA is a climate analysis dataset generated by NASA's Global Modeling and Assimilation Office using the Goddard Earth Observing System atmospheric model and data assimilation system. The dataset covers the modern satellite era from 1979 to the present, and there are 26 different data products to select from.

The aspect of this dataset that makes it particularly useful in its intended application with the Kingman data and separates it significantly from typical "modeled" wind data is that the modeled MERRA dataset is adjusted "after the fact" to reflect the actual atmospheric conditions, not merely the predicted ones. This post-weather adjustment makes the MERRA dataset particularly robust and suitable for use as a reference dataset. The locations for the MERRA datasets are separated north-south by 0.5°, which equates to roughly 55.6 km (34.5 mi). The datasets are separated east-west by 0.67°, which equates to roughly 52.5 km (32.6 mi).

For this effort, three ASOS sites and one MERRA site were examined to determine their respective suitability as a reference site. The three ASOS sites are Brainerd, Aitkin, and Isedor-Iverson. The examined MERRA point is labeled M0202. The locations of the potential reference sites, as well as the actual monitoring site, are shown in Figure 5-1. Table 5-1 provides a summary of each location. Ultimately the MERRA dataset was determined to provide the best correlation with the monitoring site data and was used to generate the long-term synthetic dataset.

As shown in Table 5-1, for three of the four reference sites the average wind speed during the monitoring period is slightly higher than the long-term average wind speed for the site. Only at Aitkin is the wind speed during the monitoring period lower than the long-term average wind speed. It must be noted that the data for Isedor should be used with some care because the long-term dataset only extends from 2005–2012, while for the other three sites the long-term dataset runs from 1998–2012. However, the preponderance of data indicates that the wind speeds during the monitoring period are slightly higher than normal.

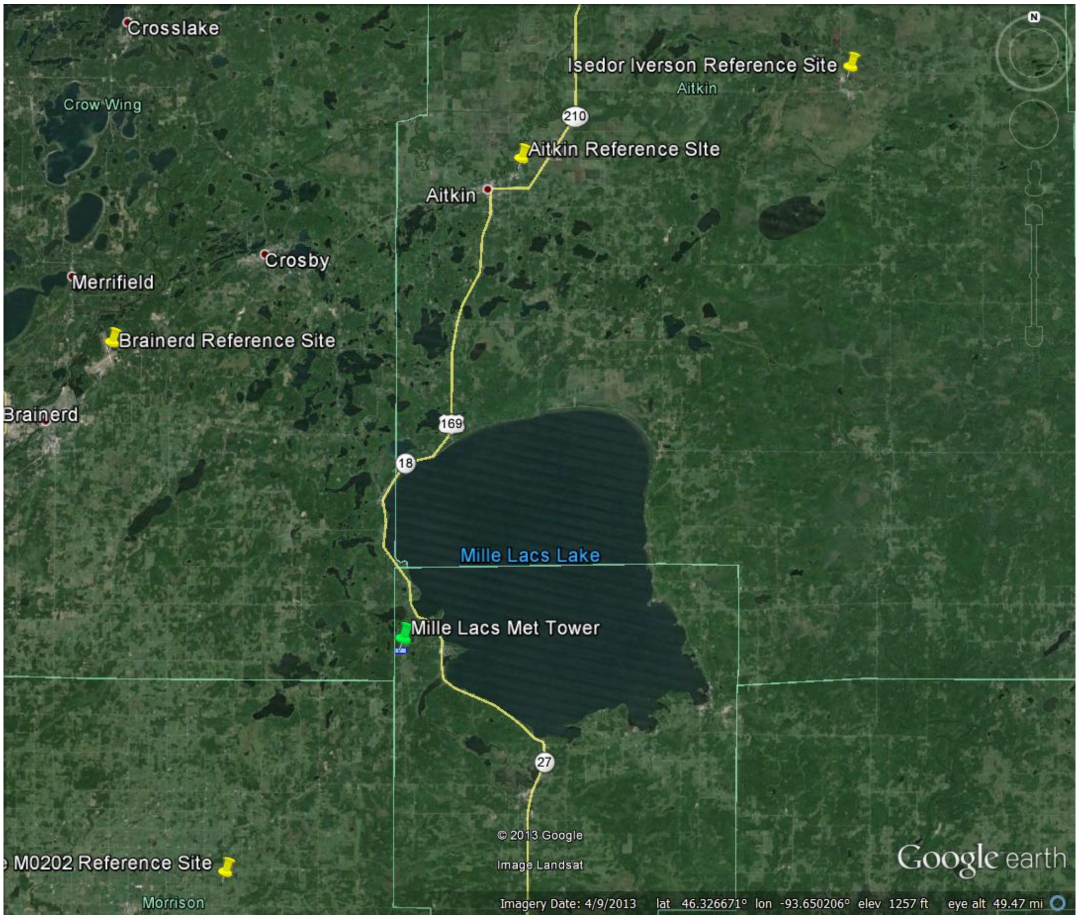

Figure 5-1. Mille Lacs MET tower site and reference sites

Table 5-1. Mille Lacs Monitoring and Reference Site Summary

	Mille Lacs	MERRA M0202	Brainerd	Aitkin	Isedor
Latitude	N 46.179	N 46.000	N 46.405	N 46.548	N 46.619
Longitude	W 93.805	W 94.000	W 94.131	W 93.677	W 93.310
Elevation (m)	395	395	373	366	374
Time Step	10 min	60 min	60 min	60 min	60 min
Begin Data	6/1/2011	1/1/1998	1/1/1998	1/4/1998	1/1/2005
End Data	5/31/2012	12/31/2012	12/31/2012	12/31/2012	12/31/2012
Height (m)	50	50	10	10	10
Avg Wind Speed (All) (m/s)	N/A	6.85	3.52	2.77	3.27
Avg Wind Speed (Monitor. Period) (m/s)	5.09	6.93	3.64	2.67	3.34
Ratio (All/Monitor Period)	N/A	0.99	0.97	1.04	0.98

5.3 MERRA Long-Term Data

Table 5-2 summarizes the wind dataset for this site for the period January 1, 1998–December 31, 2012. As shown, the mean of the MERRA dataset over the 15-year reference period is 6.85 m/s. The mean of the MERRA data at 50 m is 6.93 m/s for the period of interest, June 1, 2011–May 31, 2012, concurrent with the data collected at Mille Lacs. The period of interest mean wind speed for the MERRA dataset is 1.2% higher than the 15-year mean wind speed. The mean of the data collected is higher than the long-term mean wind speed, indicating it was a (slightly) windier-than-average year. Consequently, the Mille Lacs data should be correspondingly adjusted downward to reflect the expected annual wind speeds on a long-term basis. The adjustment will be made using an MCP method, as explained later in this chapter.

Table 5-2. MERRA M0202 Long-Term Wind Data at 50 m (January 1, 1998–December 31, 2011)

Year	Possible Records	Valid Records	Recovery Rate	Mean	Median	Min	Max	Std. Dev.	Weibull k	Weibull c
	[#]	[#]	[%]	[m/s]	[m/s]	[m/s]	[m/s]	[m/s]		[m/s]
1998	8,760	8,760	100	6.56	6.36	0.14	19.09	2.91	2.384	7.4
1999	8,760	8,760	100	7.15	6.99	0.01	20.95	3.11	2.444	8.05
2000	8,784	8,784	100	6.82	6.65	0.16	17.84	2.97	2.437	7.68
2001	8,760	8,760	100	6.89	6.73	0.05	17.78	2.95	2.484	7.76
2002	8,760	8,760	100	6.9	6.74	0.03	19.77	3.05	2.398	7.77
2003	8,760	8,760	100	7.03	6.88	0.1	17.08	3.03	2.477	7.92
2004	8,784	8,784	100	6.91	6.8	0.12	18.48	3.09	2.365	7.78
2005	8,760	8,760	100	6.73	6.5	0.18	17.53	3.01	2.368	7.59
2006	8,760	8,760	100	6.86	6.8	0.12	18.58	2.91	2.508	7.72
2007	8,760	8,760	100	7.26	7.21	0.09	17.05	3.09	2.52	8.17
2008	8,784	8,784	100	7.01	6.73	0.07	18.37	3.05	2.437	7.89
2009	8,760	8,760	100	6.64	6.41	0.08	18.11	3.01	2.336	7.49
2010	8,760	8,760	100	6.55	6.44	0.07	19.15	2.99	2.317	7.38
2011	8,760	8,760	100	6.78	6.57	0.1	17.64	3.08	2.327	7.65
2012	8,784	8,784	100	6.73	6.54	0.13	17.81	3.03	2.355	7.59
All Data	131,496	131,496	100	6.85	6.69	0.01	20.95	3.03	2.403	7.72
Mean of monthly means				**6.85**						

The long-term wind speed data of 6.85 m/s for the MERRA dataset can be seen graphically in Figure 5-2 by the horizontal red line. The annual mean wind speeds at MERRA dataset can be seen graphically in the blue curved line. The mean wind speed of 6.93 m/s for the period of interest, June 1, 2011–May 31, 2012, is the green line. Overall, the period June 1, 2011–May 31, 2012, represents a wind year slightly above (1.2%) the average wind year.

Interestingly, the average wind speed for the monitoring period is significantly above the annual average wind speeds for both 2011 and 2012. Further investigation showed that the portions of 2011 and 2012 that comprise the monitoring period were windier than usual. The portions of the 2011 and 2012 not in the dataset were less windy than usual. Thus, the average wind speed during the monitoring period is higher than the annual average wind speed of the years over which the dataset extends.

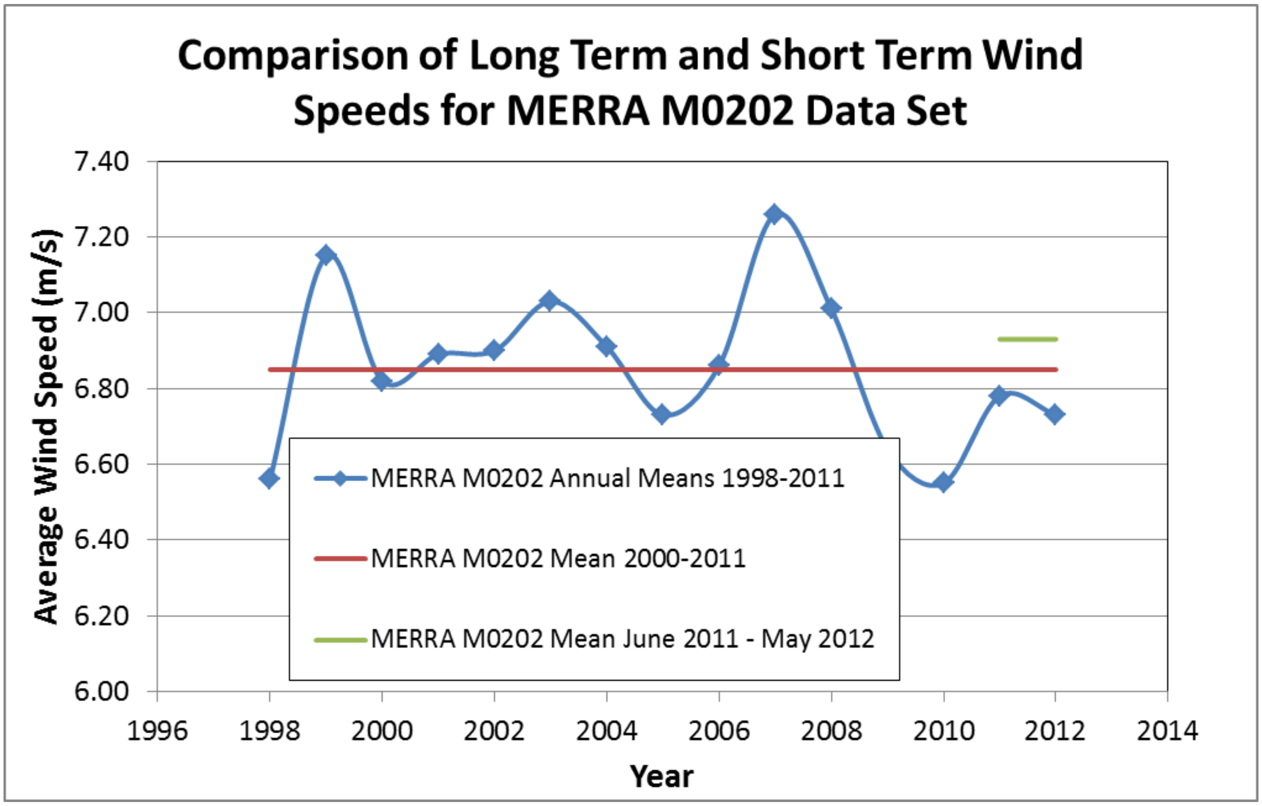

Figure 5-2. Long- and short-term mean wind speeds for the MERRA M0202 dataset

5.4 Correlation of Mille Lacs to MERRA M0202

The wind speed data collected at Mille Lacs from June 1, 2011–May 31, 2012, was compared to the reference site wind speed data during the same period to determine the degree of correlation between the monitoring site and each of the reference sites. To minimize uncertainties due to shear, the MERRA data was correlated to the 50-m wind speed data at Mille Lacs. The data from the ASOS sites, taken at 10 m, was correlated to the 30-m wind data at Mille Lacs. Using a time step of 4 hours, the R^2 coefficient of determination (i.e., correlation factor) was calculated between the Mille Lacs site and each of the four reference sites. Table 5-3 shows the results.

Table 5-3. Correlations Between Mille Lacs and Reference Sites

Pair	R^2
Mille Lac (30 m) to Brainerd (10 m)	0.70
Mille Lac (30 m) to Aitkin (10 m)	0.66
Mille Lac (30 m) to Isedor (10 m)	0.63
Mille Lac (50 m) to MERRA M0202 (50 m)	0.77

As can be seen, the correlation is highest with the MERRA dataset with an R^2 of 0.77. This is adequate. Thus, the MERRA dataset was used to create the synthetic long-term data file.

There exist several methods for conducting an MCP analysis, of which the Windographer module has seven. Unfortunately there is no single approach that is the best in all circumstances. The module includes a feature that compares the different methods using four different metrics to help users select the best method for their situation. After some iterating it was apparent that using a linear least squares (LLS) approach gives the best overall results in this case. To minimize uncertainties due to shear, the MERRA data was correlated to the 50-m monitoring site data.

LLS works by correlating the monitoring site data to the reference site data using a best fit straight line. To increase the correlation, the wind speed data was broken into 16 sectors by direction, and a separate correlation equation was created for each sector. While a 4-hour average was used to evaluate the reference sites for correlation, a 1-hour average was used to create the synthetic data file.

The comparison is shown graphically in Figure 5-3 for the sector 146.25°–168.75°. The linear correlation equation, shown by the trend line, for long-term to short-term data for the year of collected data at Mille Lacs for the direction sector 146.25°-168.75° is:

Equation 5-1.

$$\mathbf{y = mx + b}$$

$$y = 0.517x + 1.944$$

y = expected wind speed at 50-m
m = 0.517 = slope of correlation trend line
x = wind speed at 50-m reference site
b = 1.944 = y intercept of correlation trend line

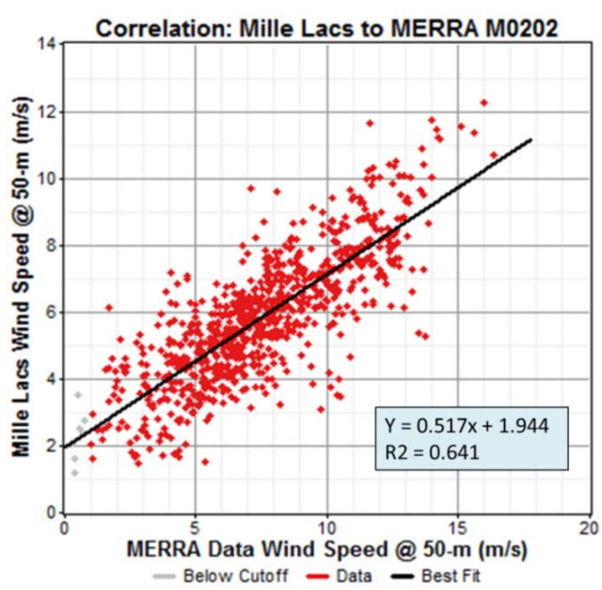

Figure 5-3. Linear least squares correlation for Mille Lacs and MERRA M0202 for the direction sector 146.25°–168.75°

The best fit intercepts and slopes for each sector are listed in Table 5-4. As can be seen from the table, the overall R^2 is 0.692.

Table 5-4. Correlations Between Mille Lacs and MERRA M0202

Sector	Time Steps	Best-fit Intercept	Slope	R2
348.75° - 11.25°	532	1.136	0.515	0.634
11.25° - 33.75°	341	0.590	0.678	0.776
33.75° - 56.25°	235	0.479	0.682	0.773
56.25° - 78.75°	328	0.937	0.630	0.711
78.75° - 101.25°	325	1.191	0.564	0.700
101.25° - 123.75°	331	1.159	0.589	0.748
123.75° - 146.25°	456	1.307	0.557	0.706
146.25° - 168.75°	745	1.415	0.565	0.666
168.75° - 191.25°	836	1.944	0.517	0.641
191.25° - 213.75°	590	1.309	0.620	0.714
213.75° - 236.25°	488	1.706	0.555	0.661
236.25° - 258.75°	399	1.818	0.532	0.726
258.75° - 281.25°	459	1.745	0.490	0.663
281.25° - 303.75°	746	1.469	0.505	0.703
303.75° - 326.25°	847	1.477	0.458	0.688
326.25° - 348.75°	809	1.280	0.479	0.698
All	**8,467**			**0.692**

The set of correlation equations relate wind speeds of the MERRA dataset at 50 m to the Mille Lacs site at 50 m during the same period. Equations for each directional sector were used to modify the long-term wind speed data of the MERRA dataset to represent the expected long-term wind speeds at Mille Lacs.

Increasing the time interval for the correlation increases the correlation factor but reduces the number of overlapping time steps. For improved granularity of the resultant annual energy production of a wind turbine, whose output varies considerably with real-time wind variation, the hourly correlation was chosen for improved overall accuracy.

Table 5-5, Figure 5-4, Figure 5-5, Figure 5-6, and Figure 5-7 show how the monitoring period data compares to the synthesized data. Table 5-5 gives overall statistics for the "raw" 10-minute monitoring site data, the "processed" 1-hour monitoring site data, and the 1-hour synthesized data spanning 15 years. As can be seen, averaging the 10-minute data into 1-hour data did not change the mean wind speed, which stayed at 5.086 m/s. The Weibull k increased from 2.573 to 2.700. The mean wind speed for the synthesized data is 5.044 m/s. This drop is expected because it was shown earlier that the monitoring period wind speeds appear to be slightly higher than the long-term wind speeds. The Weibull k of the synthesized dataset is 3.249.

Table 5-5. Mille Lacs Measured and Synthesized Data Statistics

Property	Measured Data (10 min)	Measured Data (Hourly)	Synthesized Data
Start time	6/1/2011 0:00	6/1/2011 0:00	1/1/1998 0:00
End time	6/1/2012 0:00	6/1/2012 0:00	12/31/2012 0:00
Duration	12 months	12 months	15 years
Time step	10 minutes	60 minutes	60 minutes
Time steps - speed	52,369	8,730	131,472
Time steps - direction	51,861	8,634	131,472
Mean speed @ 50 m	5.086 m/s	5.086 m/s	5.044 m/s
MoMM spd. @ 50 m	5.086 m/s	5.086 m/s	5.044 m/s
Min. speed @ 50 m	0.400 m/s	0.400 m/s	0.400 m/s
Max. speed @ 50 m	16.500 m/s	13.083 m/s	13.083 m/s
Weibull k @ 50 m	2.573	2.7	3.249
Weibull c @ 50 m	5.712 m/s	5.712 m/s	5.625 m/s
Mean WPD @ 50 m	82 W/m2	116 W/m2	102 W/m2
Mean dir. @ 58 m	236.6°	236.7°	266.2°

Figure 5-4 shows the annual wind speed profiles of the monitoring period data and the long-term synthesized dataset.

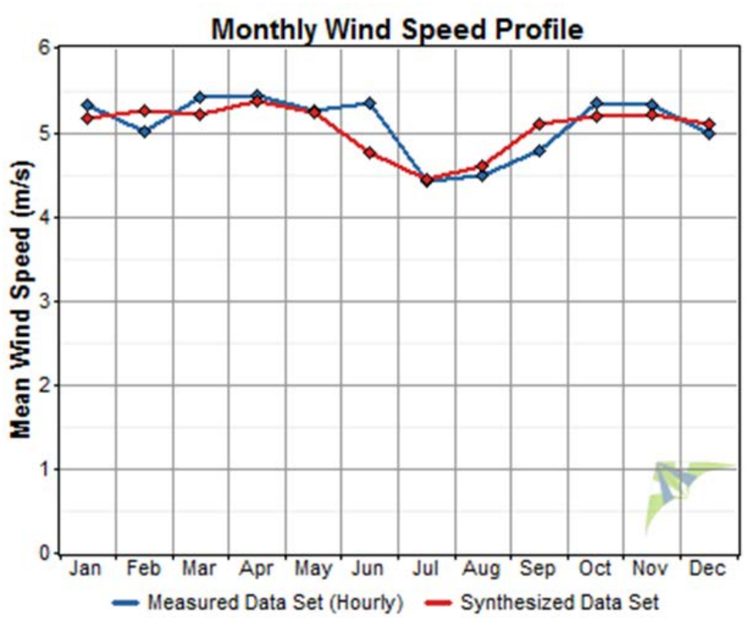

Figure 5-4. Mille Lacs measured and synthesized annual wind speed profiles

Figure 5-5 shows the diurnal profile of the measured data and the synthesized data.

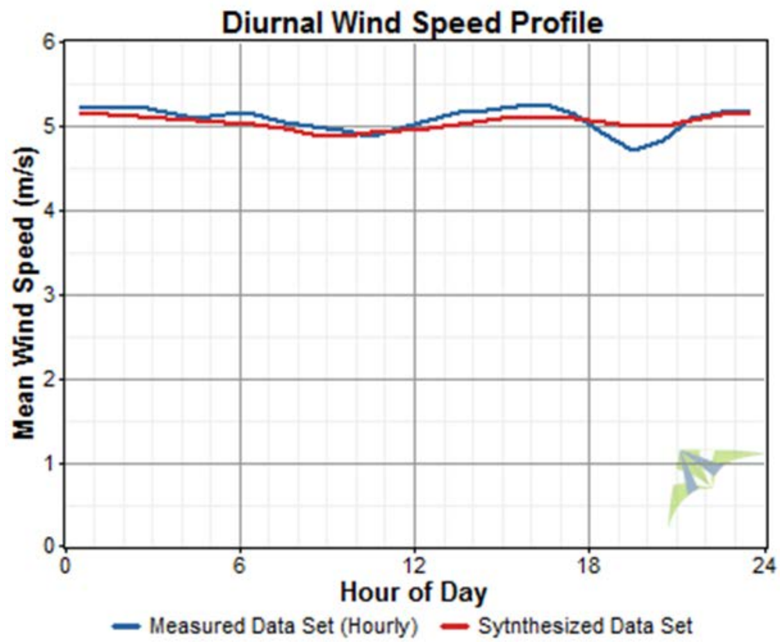

Figure 5-5. Mille Lacs measured and synthesized diurnal wind speed profiles

Figure 5-6 shows the frequency distributions for both the monitoring period "processed" (1-hour) data and the synthesized data.

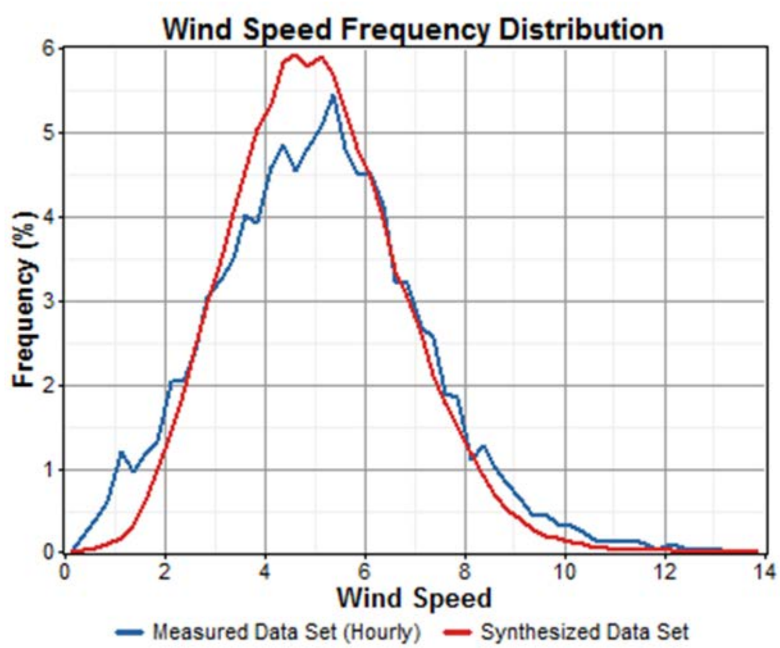

Figure 5-6. Mille Lacs measured and synthesized wind speed frequency distributions

Figure 5-7 shows the wind rose for the measured data and the synthesized data. Compared to the measured data, the synthesized data shows more of the winds coming from the northwest and a smaller proportion of the winds coming from the south.

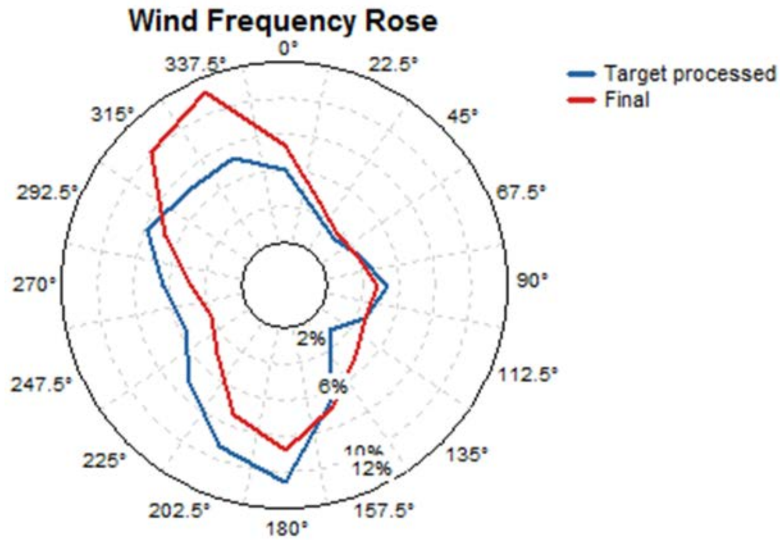

Figure 5-7. Mille Lacs measured and synthesized wind frequency roses

5.5 Adjustment to the Mille Lacs Wind Speed Data

Based on the analysis described above, the MCP process utilizing the linear regression technique resulted in a new long-term dataset representing the expected wind speeds during a15-year period, 1998–2012, at the Mille Lacs site. The resultant dataset has wind speed data and direction data at 50 m for the Mille Lacs site.

The next step is to estimate the wind resource at typical wind turbine hub heights of 80 m to 100 m. This extrapolation can be done either using the log law or the power law. In this case the log law was used because it results in a slightly more conservative wind speed estimate when extrapolating up. Recall that from Section 4.5 the wind shear appears to be decreasing with height. Extrapolating up using the shear or surface roughness values calculated using the 50-m and 60-m data is likely to result in overestimating the wind resource. Using the slightly more conservative log law somewhat compensates for this.

The surface roughness values by direction and time of day from the period of interest at Mille Lacs were applied to the 50-m synthetic dataset with the end result being a 15-year dataset at multiple heights between 50 m and 100 m that can be used for energy production estimates for a variety of wind turbines and hub heights. A comparison of the measured short-term data at Mille Lacs and the projected long-term data can be seen in Table 5-6 along with the variance that the long-term data represents.

Table 5-6. Comparison of Short-Term to Long-Term Synthetic Wind Speed Data at Mille Lacs

Source	Height	Short-term Mille Lacs Mean Wind Speed	Long-term Mille Lacs MCP Synthetic Mean Wind Speed	Adjustment to Long-term Mean Wind
	(m)	(m/s)	(m/s)	%
Measured	50	5.09	5.04	-0.98
Measured	60	5.38	5.34	-0.74
Extrapolated	80	5.84	5.80	-0.68
Extrapolated	100	6.20	6.15	-0.81

5.6 Comments on the Wind Resource at the Monitoring Site

The adjusted mean wind of 5.04 m/s speed at 50 m indicates that this site has a modest wind resource. This is not too surprising as the 80-m wind map (Figure 1-3) indicates that this site has a modest wind resource at best. The resource at 80 m and 100 m appears to be somewhat better. However, the estimated wind resource at these heights assumes that the relatively high shear value backed out from the 50-m and 60-m measured data applies to heights above 60 m. What the low wind resource means is that most likely it will be difficult for a turbine project to be economically viable absent some sort of grant or subsidy.

6 Energy Production Estimates at Mille Lacs

The Ledin site can accommodate approximately one to three utility-scale turbines to produce electricity for the wholesale market. For economic modeling purposes, a single GE 1.6-100 on an 80-m tower was selected. A multiple turbine project may have slightly better economics. This is one of a class of low wind speed turbines (with extra-large rotors) that will extract the most energy from the site's modest wind resource. Note that it is possible, due to the site's high turbulence, that low wind speed turbines may not be suitable for this site. Thus, the use of a low wind speed turbine for the economic modeling represents something of a best-case scenario.

An estimate of the annual energy production of a single utility-scale wind turbine (a GE 1.6-100) was made using the long-term dataset created for the site. A conservative energy production loss factor of 15% was assumed in the calculation. The details of the loss factor can be found in Appendix C. A sampling of the output of individual wind turbines, including the GE 100-1.6, can be seen in Table 6-1.

Table 6-1. Energy Performance of Low Wind Speed Turbines at Mille Lacs

Turbine Model	Rated Power	Hub Height	Rotor Diameter	Mean Hub Height Wind Speed	Mean Net Energy Output	Net Capacity Factor
Turbine	(kW)	(m)	(m)	(m/s)	(kWh/yr)	(%)
Acciona AW 82/1500	1,500	80	82	5.8	2,626,420	20.0
Gamesa G97-2.0 MW	2,000	80	97	5.8	3,631,685	20.7
GE 1.6-100	1,600	80	100	5.8	3,512,175	25.1
Nordex N117/2400	2,400	80	117	5.8	5,291,483	25.2
Vestas V100 - 1.8 MW	1,800	80	100	5.8	3,761,152	23.7

7 Economic Analysis

Figure 7-1 illustrates the relationship between the mean annual wind speed and the cost of wind energy. This is not an exact curve, rather it is meant to illustrate the relationship between critical factors. The greater the wind speed, the lower the cost of wind energy. The higher the cost of competing electricity (e.g., northeast United States), the lower the mean wind speed can be while still having an economically viable project. In contrast, areas with very low cost of electricity (e.g., Pacific Northwest) require a higher mean wind speed to have an economically viable project. Generally speaking, sites with low wind speeds and low competing cost of electricity (the region below the viability curve) will not be economic, while sites with higher wind speeds and higher electricity costs (above the cost curve) will be economically viable. At $0.13/kWh, the cost of wind energy at Mille Lacs is significantly higher than the U.S. average.

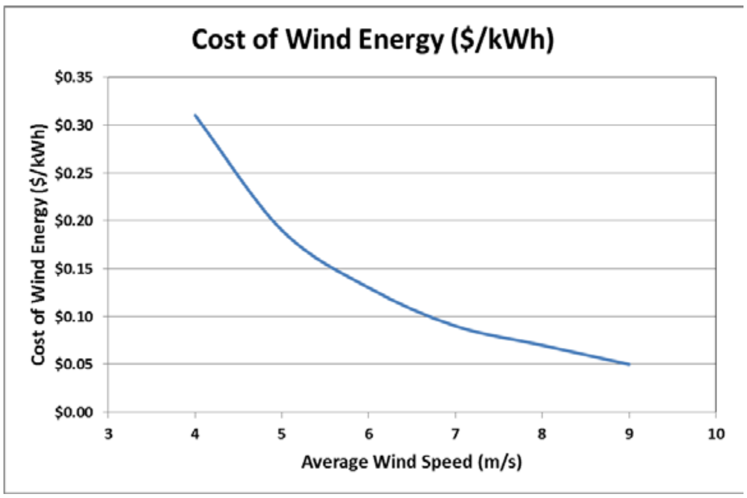

Figure 7-1. Illustration of the relationship of cost of electricity and wind speed

7.1 Wind Turbine Economics with Incentives

Wind turbine project costs are dynamic. The wind industry has experienced fluctuations both up and down over the past 5 years due to both policy changes and market forces. It is expected that some of this volatility will continue during the next 1–2 years as the economic recovery is still uncertain, the future status of the extended/revised production tax credit (PTC) is not predictable, and future changes to state-mandated renewable portfolio standards are unknown.

7.2 Wind Turbines—Size and Economic Impacts

Wind turbine project construction costs are closely held corporate information and thus difficult to obtain. Additionally, there are so many site-specific factors that individual project costs at one location may not apply at another. Data from public sources has inconsistent cost breakdowns, making comparison difficult.

The turbine costs used for this analysis and report were obtained from installed cost data in the *2012 Wind Technologies Market Report*.[4] Cost breakdowns for components and principal activities were derived from percentage allocations detailed in the *2011 Cost of Wind Energy Review*.[5] The selected turbine models are representative of suitable turbines for this site based on the wind data and their expected energy performance. There is no endorsement of a particular turbine intended in this analysis. It is assumed that an analysis of actual wind turbine prices contained in responses to requests for proposals (RFP) is a more worthwhile approach to determining specific wind turbine costs than trying to predict future bids based on available turbine price data. The data and tables are industry-focused, which means the figures cited represent aggregate costs that are broken down into meaningful groupings wherever possible.

7.3 Wind Turbine Size Impacts

The data in Figure 7-2 show the percentage of land-based installed turbines in the United States that were between 0.1 MW and 3.0 MW during the past 13 years. As shown, the relative proportion of turbine sizes has changed dramatically over these years. While turbines between 0.51 MW and 1.0 MW dominated the market in 1998–1999, the proportion of turbines in this size range had shrunken to 10% in 2008 and to nearly zero in 2011.

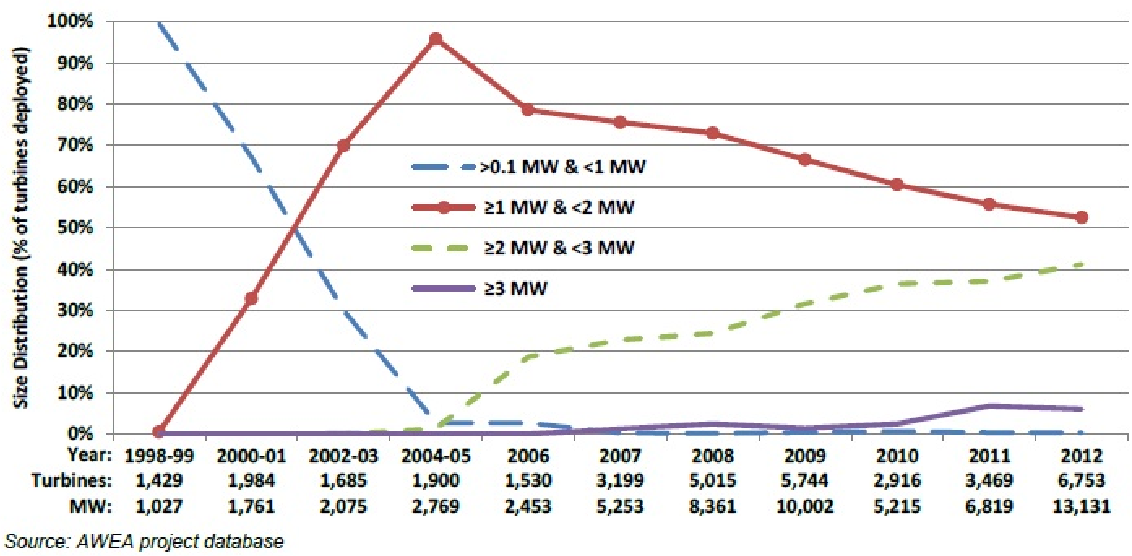

Figure 7-2. Size distribution of number of turbines over time[6]

Other important wind turbine trends can be seen in Figure 7-3. As shown, average wind turbine nameplate capacity has been steadily climbing over the past 3 years. This coincides with increasing rotor diameters as wind developers and manufacturers have begun to accept that most of the best wind sites in the country without development restrictions have already been

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[4] Wiser, R.; Bollinger, M. *2012 Wind Technologies Market Report*. Washington, DC: U.S. Department of Energy. Accessed August 2013: http://www.windpoweringamerica.gov/pdfs/2012_annual_wind_market_report.pdf .

[5] Tegen, S.; Lantz, E.; Hand, M.; Maples, B.; Smith, A.; Schwabe, P. *2011 Cost of Wind Energy Review*, National Renewable Energy Laboratory, Technical Report NREL/TP-5000-56266, March 2013. Accessed March 2013: http://www.nrel.gov/publications/recent_publications.html.

[6] Wiser, R.; Bollinger, M. *2012 Wind Technologies Market Report*. Washington, DC: U.S. Department of Energy. Accessed August 2013: http://www.windpoweringamerica.gov/pdfs/2012_annual_wind_market_report.pdf .

developed. Consequently, manufacturers have been producing more low wind speed turbines, which are wind turbines with enlarged rotors (other components such as generators and gearboxes typically stay the same) that can capture more wind energy at a given wind speed. This capability affords greater annual energy (kWh/yr) produced at a given site than would have been possible with typical turbines just 5 years ago. The wind developers have been embracing these turbines as they enable economic wind development in areas that were not economic a few years ago. Roughly speaking, the economics that existed 5 years ago for a Class 4 wind site are now essentially available for a Class 3 wind site and so on.

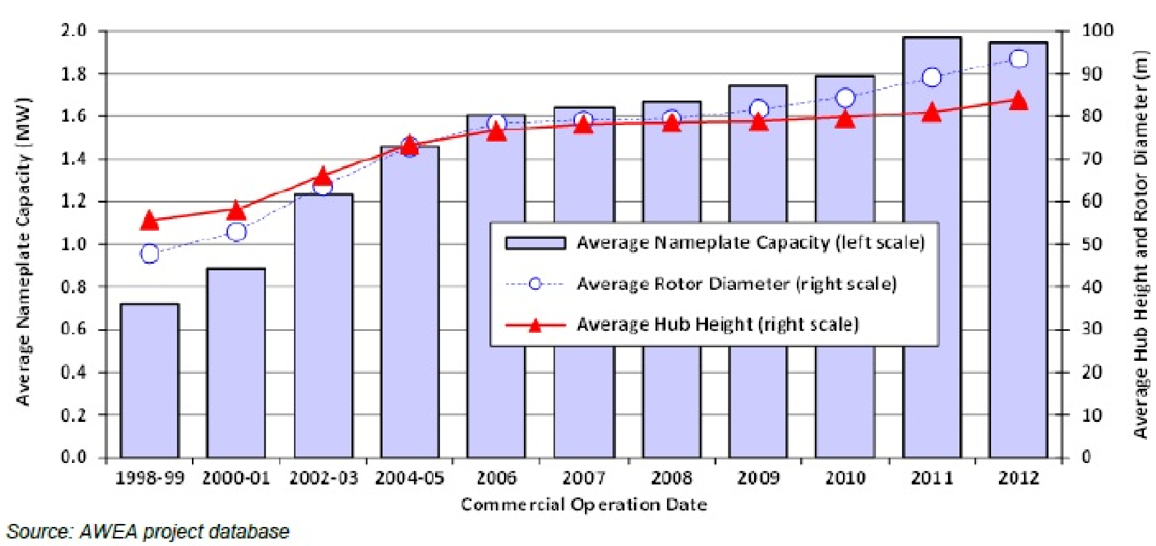


Figure 7-3. Average turbine capacity, hub height, and rotor diameter[7]

7.4 Wind Turbines—Costs

Wind turbine price trends can be seen in Figure 7-4. After two decades of steadily declining turbine prices through 2002, the next 7 years saw steadily increasing turbine prices as worldwide demand for wind turbines soared at the same time as commodity prices for steel, copper, and concrete generally rose. The recession, which began in 2008, has impacted the wind turbine market, but due to the long-term nature of wind turbine procurement contracts (approximately 12–24 months prior to installation), there was a time lag of about 18–24 months before the recession effects began to impact the market in earnest. Installed project costs in 2012 are noticeably below their 2009–2010 peak.

[7] Wiser, R.; Bollinger, M. *2012 Wind Technologies Market Report*. Washington, DC: U.S. Department of Energy. Accessed August 2013: http://www.windpoweringamerica.gov/pdfs/2012_annual_wind_market_report.pdf .

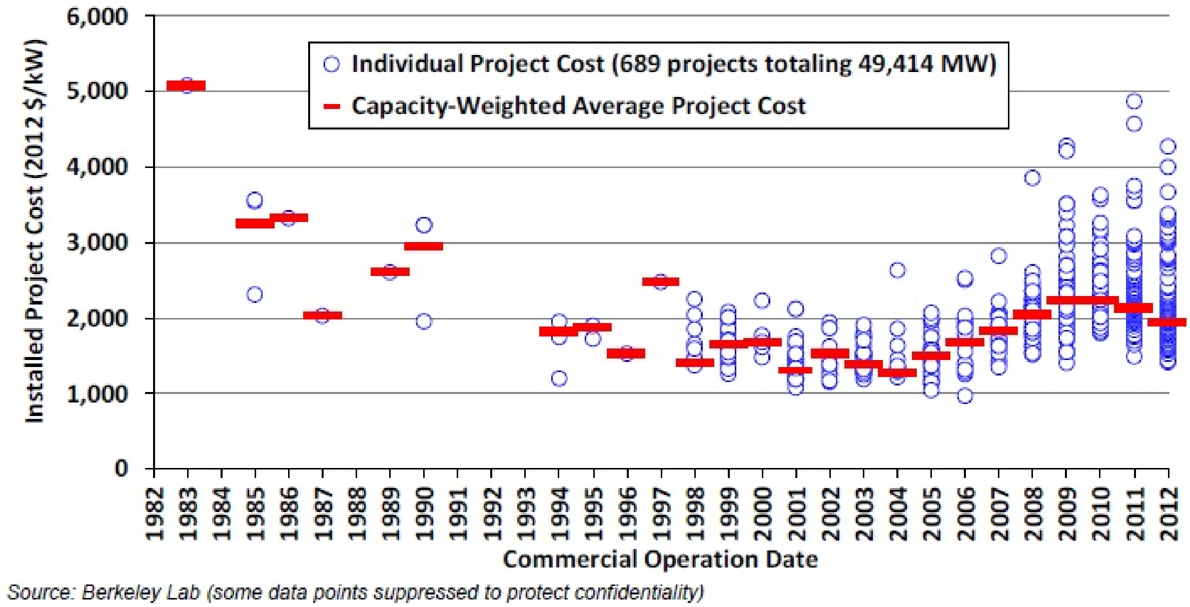


Figure 7-4. Installed wind power project costs over time[8]

Table 7-1 gives a generic cost breakdown for an installed 1.5-MW turbine on a large wind farm. Costs are given in terms of both dollars per kilowatt and dollars per megawatt-hour. The breakdown is based on 2011 data, so the overall cost is a bit higher than current costs for large wind farms. The average installed cost per 1.5-MW turbine was $2,098/MW in 2011. As a reference, it is worth noting from this table, that the expected cost of electricity per kilowatt-hour, with no incentives, is $0.072/kWh, assuming a 37% capacity factor. The annual O&M costs are in the $0.01/kWh range. These are averages of all turbines at all sites in the dataset. Costs will be higher for smaller projects using only a single turbine or a few turbines.

[8] Wiser, R.; Bollinger, M. *2012 Wind Technologies Market Report*. Washington, DC: U.S. Department of Energy. Accessed August 2013: http://www.windpoweringamerica.gov/pdfs/2012_annual_wind_market_report.pdf .

Table 7-1. Summary of Inputs and Results for 1.5-MW Land-Based Wind Reference Turbine[9]

Data Source		1.5-MW $/kW	1.5-MW $/MWh
Model	Turbine capital cost	1,286	37
Model	Balance of station	446	13
Model	Soft costs[6]	172	5
Market	Market price adjustment[7]	195	6
Market	**INSTALLED CAPITAL COST**	**2,098**	**61**
Market	Annual operating expenses ($/kW/yr)	35	11
Market	Fixed charge rate (%)	9.5	
Model	Net annual energy production (MWh/MW/yr)	3,263	
Model	Capacity factor (%)	37	
	TOTAL LCOE ($/MWh)	**72**	

[7] The market price adjustment is the difference between the modeled cost and the market price for a typical wind turbine in 2010.

As seen in Figure 7-5, there is a significant cost premium (approximately 15%–20%) for wind turbine projects less than 5 MW in size. It should be noted that the overall price spread between projects in this size range is a little greater than for the other size ranges.

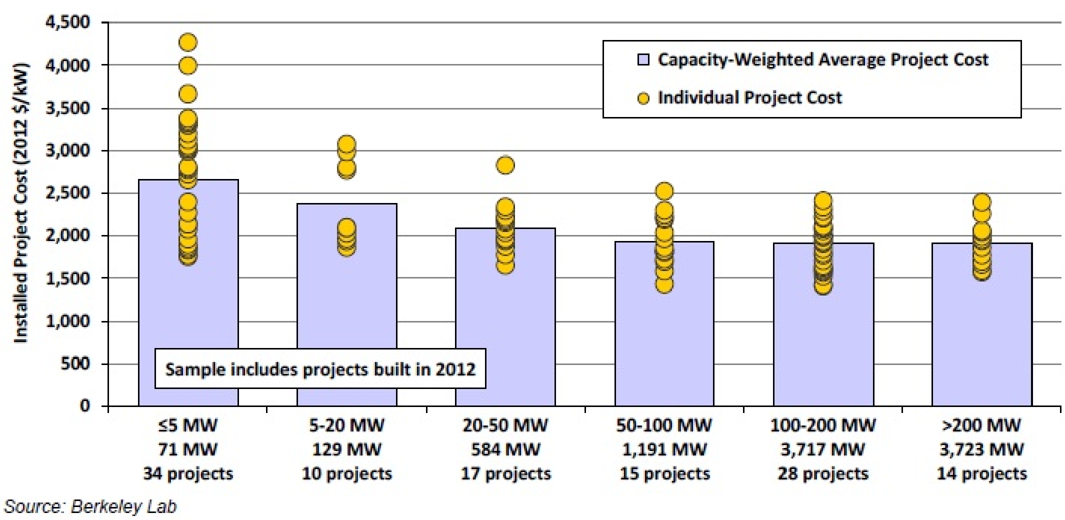
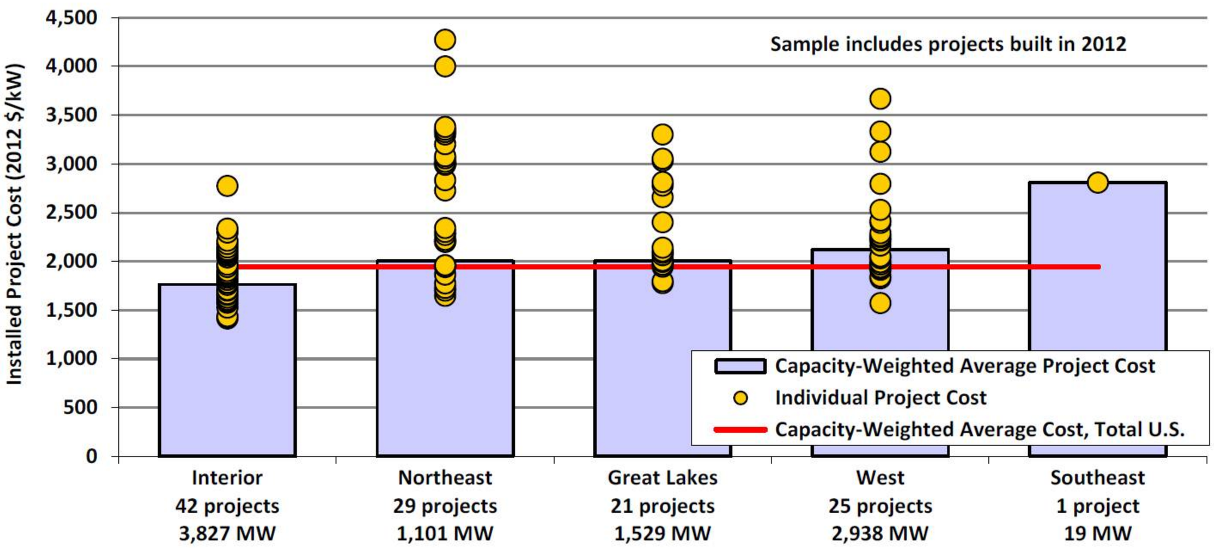


Figure 7-5. Installed wind power project costs by project size: 2012 projects[10]

[9] Tegen, S.; Lantz, E.; Hand, M.; Maples, B.; Smith, A.; Schwabe, P. *2011 Cost of Wind Energy Review*, National Renewable Energy Laboratory, Technical Report NREL/TP-5000-56266, March 2013. Accessed March 2013: http://www.nrel.gov/publications/recent_publications.html.
[10] Wiser, R.; Bollinger, M. *2012 Wind Technologies Market Report*. Washington, DC: U.S. Department of Energy. Accessed August 2013: http://www.windpoweringamerica.gov/pdfs/2012_annual_wind_market_report.pdf .

As seen in Figure 7-6 the “interior” region, which includes Minnesota, has the lowest installed project costs in the nation, though these figures apply more to large wind farm projects rather than the single turbine type of project anticipated for Mille Lacs.



Source: Berkeley Lab

Figure 7-6. Installed wind power project costs by region: 2012 projects[11]

7.5 Wind Turbines—Power Purchase Agreement Prices

Most utility-scale wind turbine projects sell the generated electricity at a guaranteed price under a long-term power purchase agreement (PPA). The purchase price may be the same over the life of the contract or may escalate slightly over time, typically 0.5%–2%, to ensure adequate cash flow to cover O&M costs that typically increase over time. For the given project to actually be built, the anticipated revenue needs to be sufficient to pay O&M expenses, pay back any debt used to the finance the project, and provide a reasonable rate of return for the equity investment. Current PPA prices provide the most reasonable estimate for what a wind project could earn from the generated electricity. Figure 7-7 shows PPA prices over time broken down by region. As can be seen, PPA prices have declined dramatically in recent years and are now quite low. PPA prices in the “interior” region, which includes Minnesota, averaged $31/MWh ($0.031/kWh). Nationally, PPA prices in 2012 averaged $38/MWh. To be competitive, a proposed project at Mille Lacs should be economically viable at or near this price.

[11] Wiser, R.; Bollinger, M. *2012 Wind Technologies Market Report*. Washington, DC: U.S. Department of Energy. Accessed August 2013: http://www.windpoweringamerica.gov/pdfs/2012_annual_wind_market_report.pdf .

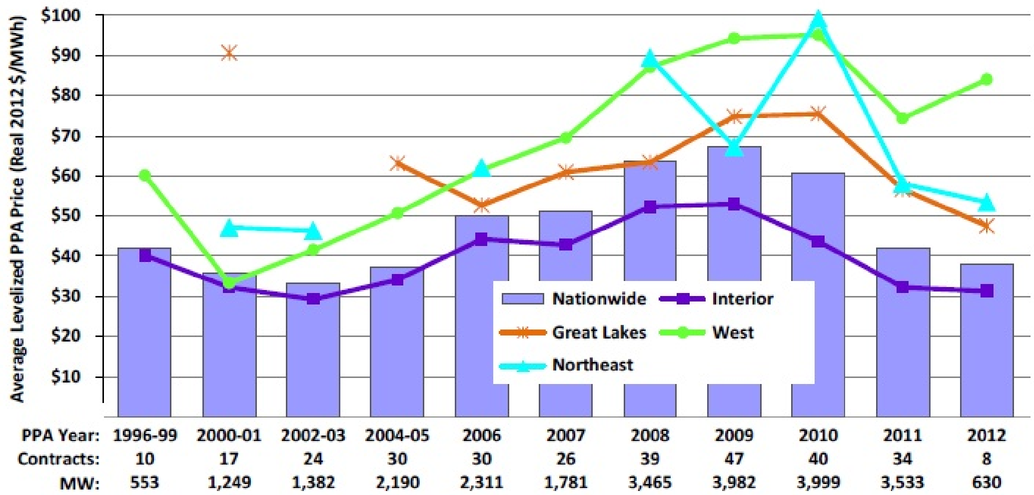


Figure 7-7. Power purchase agreement prices by region: 2012 projects[12]

7.6 Analysis Inputs and Assumptions

Numerous inputs are required to assess potential wind turbine economic performance. These factors have been grouped into the following categories: wind turbine performance, wind turbine costs, regulatory and market factors, and business/financial structure.

7.6.1 Wind Turbine Performance Factors

As shown previously in Table 6-1, the energy performance of several turbine models was analyzed with the Windographer software package using the long-term-corrected wind speed data. For purposes of economic modeling, the GE 1.6-100 was selected as a representative low wind speed turbine.

7.6.2 Wind Turbine Cost Factors

The data sources cited above are representative of past cost trends in the wind industry at various turbine and project sizes and locations. They should be considered qualified, representative estimates. It is assumed that an analysis of actual wind turbine prices contained in responses to an RFP is a more worthwhile approach to determining specific wind turbine costs than trying to predict future bids based on available turbine and project price data. The data and tables are industry-focused, which means figures cited represent aggregate costs, and they were broken down into meaningful groupings wherever possible.

7.6.2.1 Installed Cost

For economic modeling purposes, an installed cost of $2,600/kW was used. This figure includes the turbine, foundation, installation, and interconnection. This matches the average installed costs of projects of less than 5 MW given in Figure 7-5.

[12] Wiser, R.; Bollinger, M. *2012 Wind Technologies Market Report*. Washington, DC: U.S. Department of Energy. Accessed August 2013: http://www.windpoweringamerica.gov/pdfs/2012_annual_wind_market_report.pdf .

7.6.2.2 Operations and Maintenance

O&M costs, as shown in Table 7-1, are cited at $35/kW/yr in the *2011 Cost of Wind Energy Review*.[13] This represents a $7/kW/yr decline from the 2010 O&M average. There are substantial research and development investments currently being made by both the private and public sector aimed at reducing O&M costs. The trend shown is indicative of the success of these efforts.

Because the O&M figures cited are aggregated from wind farm-sized projects, it is assumed these costs will be higher for single turbine projects. These costs are site specific and are negotiable with the O&M providers. A cost 20% higher than the wind farm rate, at $42/kW/yr or $67,200/yr, was assumed over the life of the project. It increases at the rate of inflation.

7.6.2.3 Project Life

The project life is assumed to be 20 years. Wind turbine design life is typically at least 20 years. There have been extensive research and development efforts in the past 15–20 years focused on improving component design throughout the entire wind system and reducing O&M costs. The wind turbine useful life is estimated to be 20–30 years, depending on actual O&M practices and environmental conditions.

7.6.2.4 Salvage Value

The actual value of wind turbines at the end of their useful life is a figure commonly estimated at 5%–10% of turbine purchase cost, though actual salvage value data is difficult to find. This analysis assumes that the salvage value of the turbine is equal to the decommissioning costs.

7.6.3 Regulatory and Market Factors

There are a number of market and regulatory factors that impact the overall economic analysis. These are described below.

7.6.3.1 Production Tax Credit and Investment Tax Credit

The federal renewable electricity PTC is a per-kilowatt-hour tax credit for electricity generated by qualified energy resources and sold by the taxpayer to an unrelated person during the taxable year.[14] The current value of the PTC is $0.023/kWh for electricity produced during the first 10 years of operation from a wind turbine.

In lieu of the PTC, turbine project owners can take an investment tax credit (ITC)[15] equal to 30% of the project cost. In this case, where the site has a modest wind resource, the ITC may be more valuable.

[13] Tegen, S.; Lantz, E.; Hand, M.; Maples, B.; Smith, A.; Schwabe, P. *2011 Cost of Wind Energy Review*, National Renewable Energy Laboratory, Technical Report NREL/TP-5000-56266, March 2013. Accessed March 2013: http://www.nrel.gov/publications/recent_publications.html.

[14] Database of State Incentives for Renewables & Efficiency. "Renewable Electricity Production Tax Credit." Accessed August 30, 2013: http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=US13F&re=1&ee=1.

[15] Database of State Incentives for Renewables & Efficiency. "Renewable Electricity Investment Tax Credit." Accessed August 30, 2013: http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=US02F&re=0&ee=0.

The PTC and ITC have received a 1-year extension that will apply to wind turbines that are in the process of being installed by the end of 2013, but there is some uncertainty about exactly how the determination of "in process" will ultimately be defined. As it currently stands, it appears unlikely that there is enough time for a wind developer to engage in suitable project cost activities by the end of the 2013 calendar year to be able to take advantage of these incentives. Given its volatile history, it would not be unreasonable to anticipate the possibility of the PTC (and possibly the ITC) being reinstated at some point in the next few years, but the political uncertainty is not a quantity that can be readily modeled for economic projections.

Economic modeling examined the following three cases to illustrate the impact of incentives on project financial viability:

- No incentives in effect
- PTC
- ITC.

7.6.3.2 Accelerated Depreciation

To further incentivize wind energy development, federal tax rules allow for the rapid depreciation of wind turbine equipment. In contrast to comparable non-renewable capital equipment, which typically is depreciated over a period of 15–20 years, wind turbines are eligible for a 5-year Modified Accelerated Cost Recovery Scheme (MACRS) depreciation. Depreciation is only applicable to for-profit entities.

7.6.3.3 Other Incentives

Several locally available incentives could benefit a wind project on the Mille Lacs reservation. Because these incentives are not large, they are not explicitly modeled in the analysis. They are worth investigating if it is decided to move forward with an actual project.

Minnesota provides a state sales tax exemption[16] for renewable energy equipment, including wind energy equipment.

Under Minnesota Law utilities are required to provide so called Community-Based Energy Development (C-BED) Tariffs[17] for community-owned renewable energy projects. Under the law, utilities are not required to pay more for the energy from these types of projects. Rather, the utilities are required to structure the PPA so that the payments are higher during the first 10 years and lower the second 10 years. This makes it easier for these types of projects to repay any debt financing. This law also reduces the costs of obtaining a PPA because the price and terms are standardized for a given utility. Utilities are not absolutely required to purchase power from a given project but rather must negotiate "in good faith."

[16] Database of State Incentives for Renewables & Efficiency. "Minnesota Sale Tax Exemption."Accessed August 30, 2013: http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=MN10F&re=0&ee=0.
[17] Database of State Incentives for Renewables & Efficiency. "Community Based Energy Development Tariff." Accessed August 30, 2013: http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=MN15R&re=0&ee=0.

7.6.3.4 Renewable Energy Certificates

In some renewable energy projects, the generation and sale of renewable energy certificates (RECs) can be a significant source of project revenue. Given the current low price of RECs in Minnesota, approximately $1–$2/MWh or $0.001–$0.002/kWh,[18] the sale of RECs is not considered to be a significant revenue source for a wind project and was consequently left out of the economic analysis.

7.6.4 Economic and Finance Factors

The economic and financial factors described below comprise the final class of factors impacting project financial viability.

7.6.4.1 Inflation and Discount Rates

There are prescribed economic analysis processes for federal energy projects as described in the Building Life Cycle Cost (BLCC) Program[19] through its Life Cycle Costing Manual. This process and manual prescribe the energy escalation rate to use in analyzing a variety of types of federal projects. While a Tribal project would not necessarily be bound by these processes, the values for the discount rate and inflation are listed here as a starting point. The DOE discount and inflation rates for 2012 are given in Table 7-2, along with the values used in the analysis.[20]

Table 7-2. Inflation and Energy Escalation Rates

Item	DOE Rate	Rate Used in Analysis
Real rate (excluding general price inflation)	3.00%	6.00%
Nominal rate (including general price inflation)	3.50%	7.06%
Implied long-term average rate of inflation	0.50%	1.00%

The BLCC listed inflation rate has been low in recent years, less than 1%, due to the recession. A rate of 1% was used for the analysis as a more likely value for future years. This rate was applied to annual O&M costs and the PTC value.

Due to current low borrowing costs, the federal government has a very low (real) discount rate of 3.00%. A rate of 6.0% was used for this analysis as more suitable for a Tribal government. As it turns out, the discount rate does not affect the minimum PPA price needed to achieve a given rate of return. Rather, the discount rate affects the net present value (NPV) of the project. A higher discount rate reduces the project NPV.

7.6.4.2 Rate of Return

The analysis assumes a minimum IRR on equity of 10%. This is at the low end of the range of minimum IRRs required by wind energy project investors.

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[18] "Renewable Energy Certificates." The Green Power Network, Energy Efficiency & Renewable Energy, U.S. Department of Energy. Accessed August 2013: http://apps3.eere.energy.gov/greenpower/markets/certificates.shtml?page=5.

[19] "Building Life-Cycle Cost, Federal Energy Management Program," U.S. Department of Energy. Accessed October 7, 2013: http://www1.eere.energy.gov/femp/pdfs/ashb12.pdf.

[20] *Energy Price Indices and Discount Factors for Life-Cycle Cost Analysis – 2012.* Building Life-Cycle Cost, Federal Energy Management Program, U.S. Department of Energy. Accessed October 7, 2013: http://www1.eere.energy.gov/femp/pdfs/ashb12.pdf.

7.6.4.3 Debt Ratio

The debt fraction variance impacts the return on investment (ROI) an equity investor may earn for supplying project capital in lieu of bank financing. The higher the debt fraction, the higher the percent of the project financed by bank financing and the lower the percentage of equity financing supplied by the equity investor. Given constant project revenue based on fixed PPA price for kilowatt-hours produced, the lower the dollar amount of equity investment, the higher the ROI rate. Likewise, the higher the dollar amount of equity investment, the lower the ROI rate even though the total dollars of ROI may be higher.

Interest rates are currently low, even for wind projects. Generally speaking, wind farm projects are viewed as having some degree of performance risk and wind developers often resort to equity financing for at least a portion of the project when a bank loan is not feasible for the entire project capital cost. Equity investors expect a significantly higher ROI than a bank interest rate. The higher the portion of equity financing, the higher the PPA price will be.

For economic modeling purposes, a debt-equity ratio of 70/30 was assumed as the base case for the non-taxable case, and ratios of 50/50 were used for the taxable cases. Sensitivity studies were conducted with other debt fractions (DF) to show the effect of different DFs on the project bottom line. The analysis assumed a 20-year loan with a 7% interest rate.

At this point in time, there are a number of project variables that are undefined or undetermined. These project variables will have a large impact on the willingness of investors to provide equity financing for this project. It is premature to prescribe what the ideal DF should/could be at this point in project development. It is anticipated that once all project variables have been resolved and costs assigned, a better defined project risk profile can be developed and the level of interest by equity investors will be solidified.

7.7 Analysis Overview

This analysis examines three cases. The first case assumes the project is owned directly by the Mille Lacs Band (the Tribe). In this case the project is not subject to federal or state taxes but is also not eligible for federal incentives such as the PTC, ITC, or depreciation. In the case of wind projects the federal incentives are more lucrative than a tax exemption. The incentives pretty much eliminate the tax liability of the project with excess tax credits left over that can be applied elsewhere. Thus, the entities that can best use or “monetize” the federal incentives are those that have a tax liability from some other line of business in addition to owning wind farms. A further downside is that the Tribe will have to provide any equity required for the project.

The second case assumes some sort of for-profit entity that makes use of the PTC. This analysis assumes that the PTC can be fully monetized. One disadvantage of this is that maintaining a Tribal equity stake in the project while fully monetizing the tax credits requires a complicated business structure, such as the “Minnesota flip,” that will probably involve an outside partner. This partner may demand a higher rate of return that would increase the PPA price and/or reduce the value of the project for the Tribe.

The third case also assumes a for-profit entity, but uses the ITC rather than the PTC. The ITC is especially attractive for projects located in lower resource areas because the value of the incentive does not depend on the energy production of the project.

All three cases assume the electricity from the project is sold into the wholesale market. If this proves infeasible, it may be possible to use electricity from the project to offset the Tribe's consumption. The project costs would be the same. The economics would depend on the retail electricity rate(s) paid by the Tribe. Given that the location does not appear to be near any major Tribal load, this approach would require the cooperation of the utility.

Table 7-3 summarizes the respective base cases. The analysis assumptions previously discussed are summarized in Table 7-4. The remaining analysis assumption is that the PPA rate escalates at 1% annually.

Table 7-3. Base Cases

Method Name	Key Terms and Features	Comments
Tax Exempt	Simple business structure Tax exempt	Not eligible for federal incentives. The Tribe has to provide the equity.
Production Tax Credit	Uses PTC	Maintaining Tribal equity stake will require a more complicated business structure.
Investment Tax Credit	Uses ITC	Maintaining Tribal equity stake will require a move complicated business structure.

Table 7-4. Analysis Assumptions

	Tax Exempt	PTC	ITC
Turbine Model	GE 1.6-100	GE 1.6-100	GE 1.6-100
Rated Capacity (kW)	1,600	1,600	1,600
Tower Height (m)	80	60	60
Losses (%)	15.0%	15.0%	15.0%
Annual Energy Production (kWh/yr)	3,512,000	3,512,000	3,512,000
Net Capacity Factor (%)	25.1%	25.1%	25.1%
Installed Capital Cost ($/kW)	$2,600	$2,600	$2,600
Installed Capital Cost ($)	$4,160,000	$4,160,000	$4,160,000
Operations & Maintenance (O&M) ($/kW/yr)	$42	$42	$42
O&M ($/yr)	$67,200	$67,200	$67,200
O&M Escalation Rate (%/year)	1.0%	1.0%	1.0%
Net Salvage Value ($)	$0	$0	$0
Project Lifetime (years)	20	20	20
Inflation Rate (General) (%)	1.0%	1.0%	1.0%
Discount Rate (Real) (%)	6.0%	6.0%	6.0%
Discount Rate (Nominal) (%)	7.1%	7.1%	7.1%
Debt Percentage	70%	50%	50%
Debt Rate	7.0%	7.0%	7.0%
PPA Escalation Rate (%)	1.0%	1.0%	1.0%
Initial PTC Value ($/kWh)		$0.023	
PTC Escalation Rate (%)		1.00%	

7.8 Economic Analysis

The SAM software[21] (beta version 2013.7.12) was selected for cost and economic modeling for this wind project using the GE 1.6-100 turbine and the performance and cost data outlined earlier.

For each case SAM was used to determine the minimum initial PPA price that would pay the O&M expenses, repay the debt, and provide the minimum 10% IRR. Sensitivity studies ±20% were conducted on the variables listed in Table 7-5.

[21] "System Advisor Model," National Renewable Energy Laboratory, Department of Energy. Accessed September 20, 2013: https://sam.nrel.gov/.

Table 7-5. Sensitivity Variables

Variable	High	Base	Low
Turbine Capital Cost ($/kW)	$2,080	$2,600	$3,120
Turbine Energy Production (kWh/yr)	4,214,000	3,512,000	2,810,000
Loan Rate (%)	8.4%	7.0%	5.6%
Minimum IRR (%)	12%	10%	8%
First-Year O&M Cost ($/yr)	$49	$42	$35
Debt Fraction (tax exempt) (%)	60%	50%	40%
Debt Fraction (taxable) (%)	84%	70%	56%

7.9 Analysis Results

Table 7-6 shows the value of the federal incentives. The for-profit case using the ITC results in the lowest initial PPA price—$0.078/kWh. The tax exempt case results in a PPA price of $0.132/kW. Unfortunately, even the ITC PPA price is much higher than the average regional 2012 PPA price of $0.031/kWh or even the national average 2012 PPA price of $0.038/kWh.

Table 7-6. Economic Analysis Results

Metric	Tax Exempt	PTC	ITC
Annual Energy Production (kWh/year)	3,512,000	3,512,000	3,512,000
Required Initial PPA Price ($/kWh)	$ 0.132	$ 0.101	$ 0.078
LCOE Nominal ($/kWh)	$ 0.142	$ 0.109	$ 0.084
LCOE Real ($/kWh)	$ 0.131	$ 0.100	$ 0.077
Internal Rate of Return (%)	10.0%	10.0%	10.0%
Minimum DSCR	1.44	1.47	1.05
Net Present Value ($)	$ 330,199	$ 219,269	$ 57,364
PPA Escalation Rate (%)	1.0%	1.0%	1.0%
Debt Fraction (%)	70%	50%	50%
Windfarm Capacity (MW)	1.6	1.6	1.6
Capacity Factor	25.1%	25.1%	25.1%

Figure 7-8, Figure 7-9, and Figure 7-10 show “tornado diagrams” with the results of a sensitivity analysis for each case.

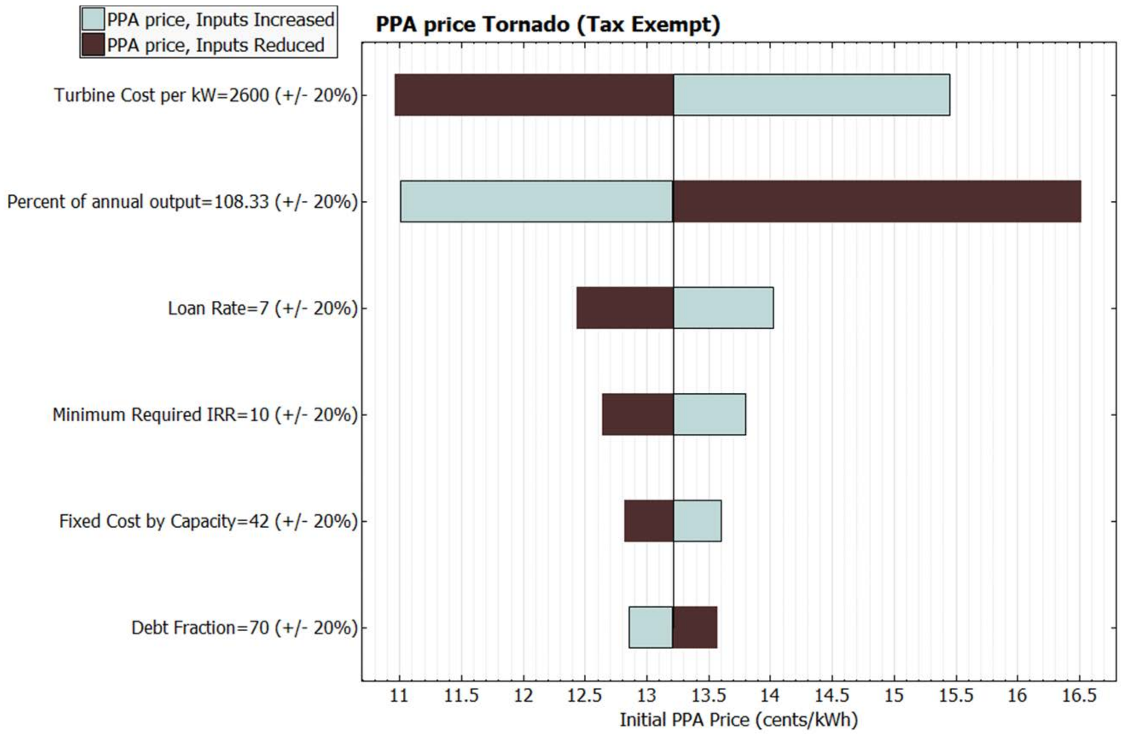


Figure 7-8. Sensitivity results for the tax-exempt case

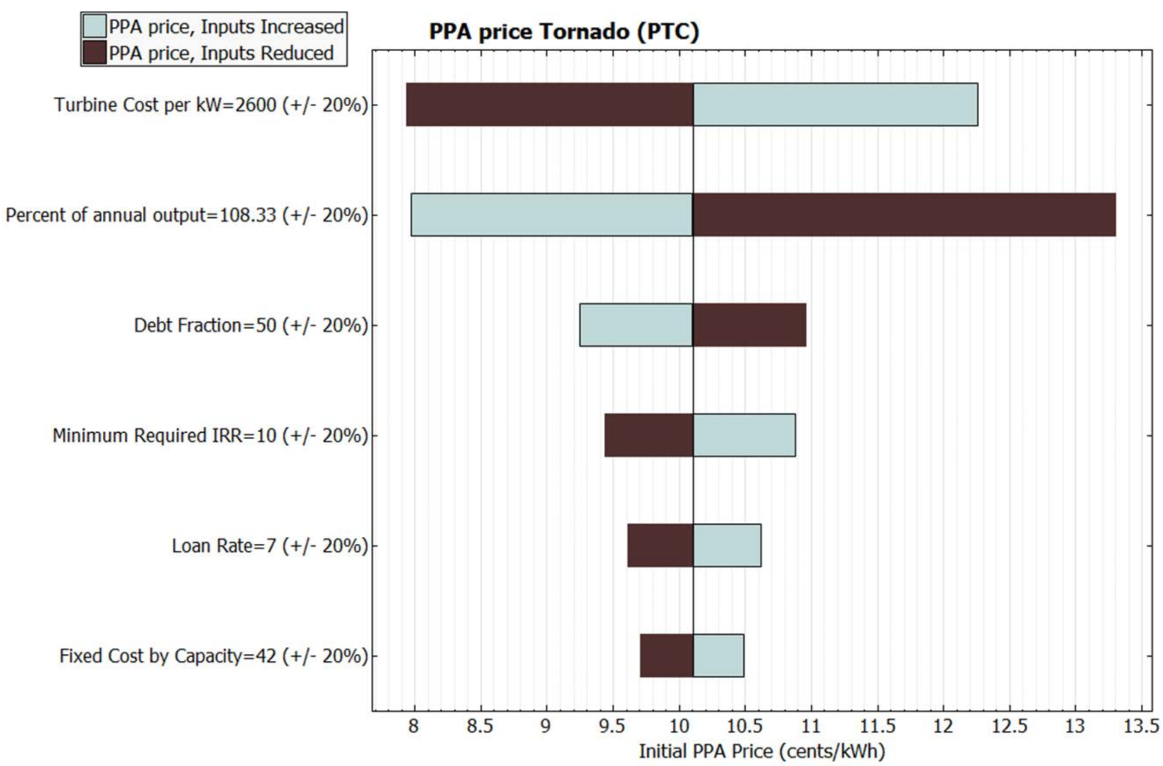


Figure 7-9. Sensitivity results for the PTC case

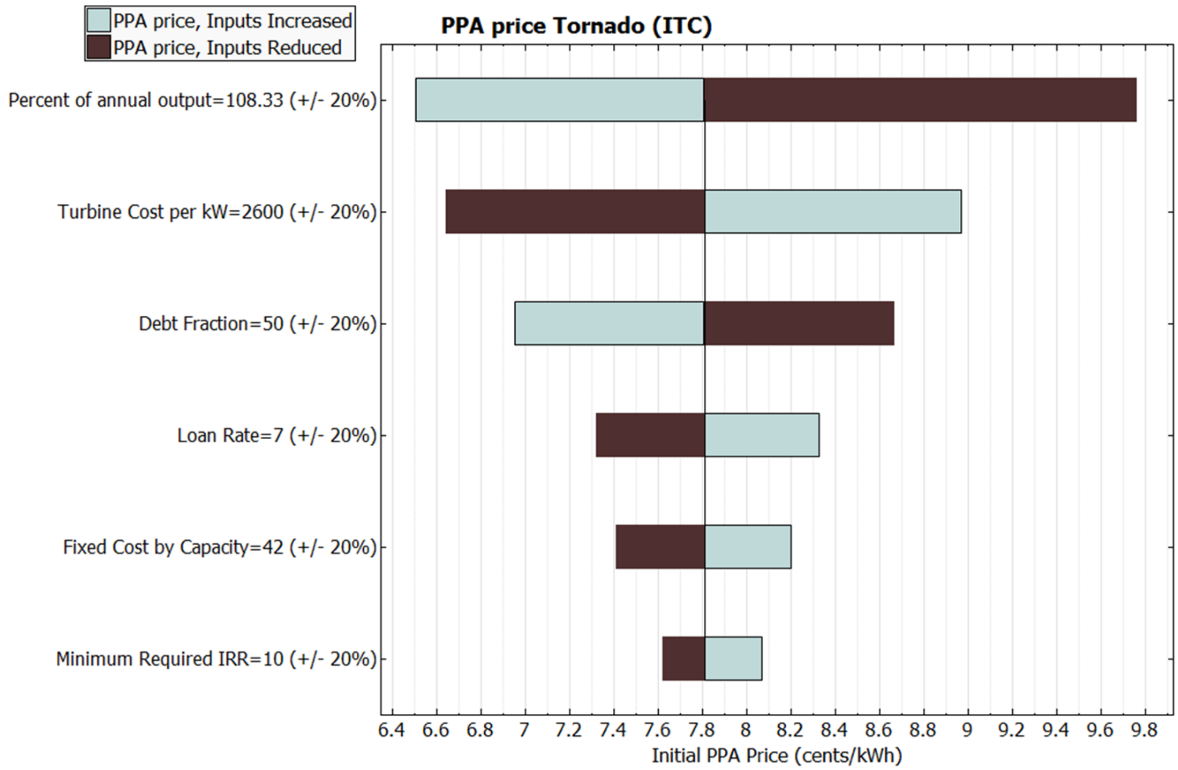


Figure 7-10. Sensitivity results for the ITC case

For all the cases, the inputs that most affect the PPA price are the turbine-installed cost and the annual energy output. A 20% change in the value of these variables resulted in a 15%–30% change in the initial PPA price ($0.01–$0.03/kWh). With one exception, changes in the other sensitivity variables have much less effect on the initial PPA price. The exception is for the ITC case where the PPA price proves to be almost as sensitive to the debt fraction as it is to the installed cost and the energy production.

7.10 Conclusions

The economic analysis indicates that the minimum PPA price for a project at this location ranges from $0.078–$0.132/kWh. This is much higher than both the regional 2012 average PPA price of $0.031/kWh and the national 2012 average price of $0.038/kWh. The analysis used two optimistic assumptions. The first of these assumptions is that site is suitable for a low wind speed turbine, such as the GE 1.6-100. The high turbulence at this site may preclude the use of these types of turbines. One hopeful note is that turbulence generally decreases with increasing height, so the turbulence at 80 m (or 100 m) is more likely to be sufficiently low to allow for the use of a low wind speed turbine. The other somewhat optimistic assumption is that the equity investor will accept a 10% IRR. As noted earlier, this is on the low end of the range of IRRs that a project investor is likely to demand. Fortunately, the initial PPA price is not particularly sensitive to the minimum IRR. For the ITC case, increasing the IRR from 10% to 12% increased the PPA price by $0.003/kWh from $0.078/kWh to $0.081/kWh. The analysis further assumes an extension of the PTC and the ITC.

The results of this analysis show that a turbine project at this location is not economically competitive for generating electricity for the wholesale market. Even significantly reduced cost and improved energy capture is not sufficient to provide economic viability. Taking the ITC case as an example, reducing the installed cost by 20% and increasing the energy production by 20% reduces the PPA price to $0.055/kWh. This is still significantly above the 2012 averages for the region and nation. To be economically viable, a project at this location will require some combination of a buyer willing to pay above-market rates for the energy, a large grant, or very low interest rate financing.

One possible alternative is using the electricity to meet Tribal loads. In this case the electricity from the turbine displaces higher-priced retail electricity. However, in most “behind-the-meter” projects like this the turbine is adjacent to the load it is serving. In this case the monitoring site is 3,430 m due west from any major Tribal loads. The nearest power transmission lines are 520 m east of this site. The electrical substation serving the major Tribal load is located 3,430 m to the northeast of the site, with the major Tribal load located another 1,330 m to the southeast of the electrical substation.[22] Therefore, the energy from the turbine would have to be “wheeled” to the load. This would require the cooperation of the utility. Because this arrangement may negatively impact the utility’s bottom line, such cooperation is unlikely, absent some sort of government mandate. There are other reasons to install a wind system, such as to meet environmental or energy goals. However, in most cases, the decision is based, at least in part, on electricity need and economics.

[22] Lippert, C.; Boyd, A., private communication; 15 October 2013

8 Wind Project Development Process

This report examines two critical pieces of the wind project development process—the wind resource and economic feasibility. Unfortunately, these do not look promising.

If it is decided that the challenges could be overcome, there are a number of other critical steps to developing a successful wind project:

- Decide on a business structure for the project
- Look for possible purchasers of the energy to see how much the Tribe might receive for the energy
- Look for possible sources of grant funding or low-interest loans
- Look into permitting, including environmental permitting, National Environmental Policy Act (NEPA) analysis, military operations, land use, FAA, Department of Defense, and radar
- Analyze constructability, including foundations, roads, transmission lines, cranes, and concrete batch plant
- Prepare an interconnection study and agreement, including an application the Federal Energy Regulatory Commission (FERC) (qualifying facility application) and the utility (interconnection requirements on Tribal side of the meter)
- Create a process for collecting information regarding key issues and identify potential bidders and contractors.

Should the Mille Lacs Tribe decide to move forward on this project, NREL would be pleased to provide assistance.

Appendix A. MET Tower Configuration and Components

60-m XHD TallTower

6- #40 anemometers (item 1899)

2- #200P wind vanes (item 1904)

1- #110S temperature sensor (item 1906)

1- #BP20 barometric sensor (item 2046)

2- 2C cables for 60-m level (item 2276)

2- 2C cables for 50-m level (item 1934)

1- 2C cable for 40-m level (item 1933)

1- 3C cable for 60-m level (item 2430)

1- 3C cable for 50-m level (item 1939)

NRG #40C Anemometer (item: 1900)

The NRG #40 maximum anemometer is the industry standard anemometer used worldwide. NRG #40 anemometers have recorded wind speeds of 96 m/s (214 mph). Their low moment of inertia and unique bearings permit very rapid response to gusts and lulls. Because of their output linearity, these sensors are ideal for use with various data retrieval systems.

A four-pole magnet induces a sine wave voltage into a coil producing an output signal with a frequency proportional to wind speed. The #40 is constructed of rugged Lexan cups molded in one piece for repeatable performance. A rubber terminal boot is included.

A calibration certificate verifying that the sensor is traceable to the National Institute of Standards and Technology (USA) is available through electronic download.

Figure A-1. #40C anemometer (item 1900)

NRG #200P Wind Direction Vane, 10K (item: 1904)

The NRG #200P wind direction vane is the industry standard wind direction vane used worldwide. The thermoplastic and stainless steel components resist corrosion and contribute to a high strength-to-weight ratio. The vane is directly connected to a precision conductive plastic potentiometer located in the main body. An analog voltage output directly proportional to the wind direction is produced when a constant DC excitation voltage is applied to the potentiometer. A rubber terminal boot is included.

Figure A-2. NRG #200P wind direction vane (item 1904)

Mounting Booms

NRG side mounting booms allow you to easily mount sensors to your tower or mast at any height. Mounting hardware is included. Heavy-duty mounting booms are designed specifically for icing environments and mounting NRG IceFree sensors.

Figure A-3. Boom, side, 2.4 m (95"), galvanized steel, with clamps (item: 4214)

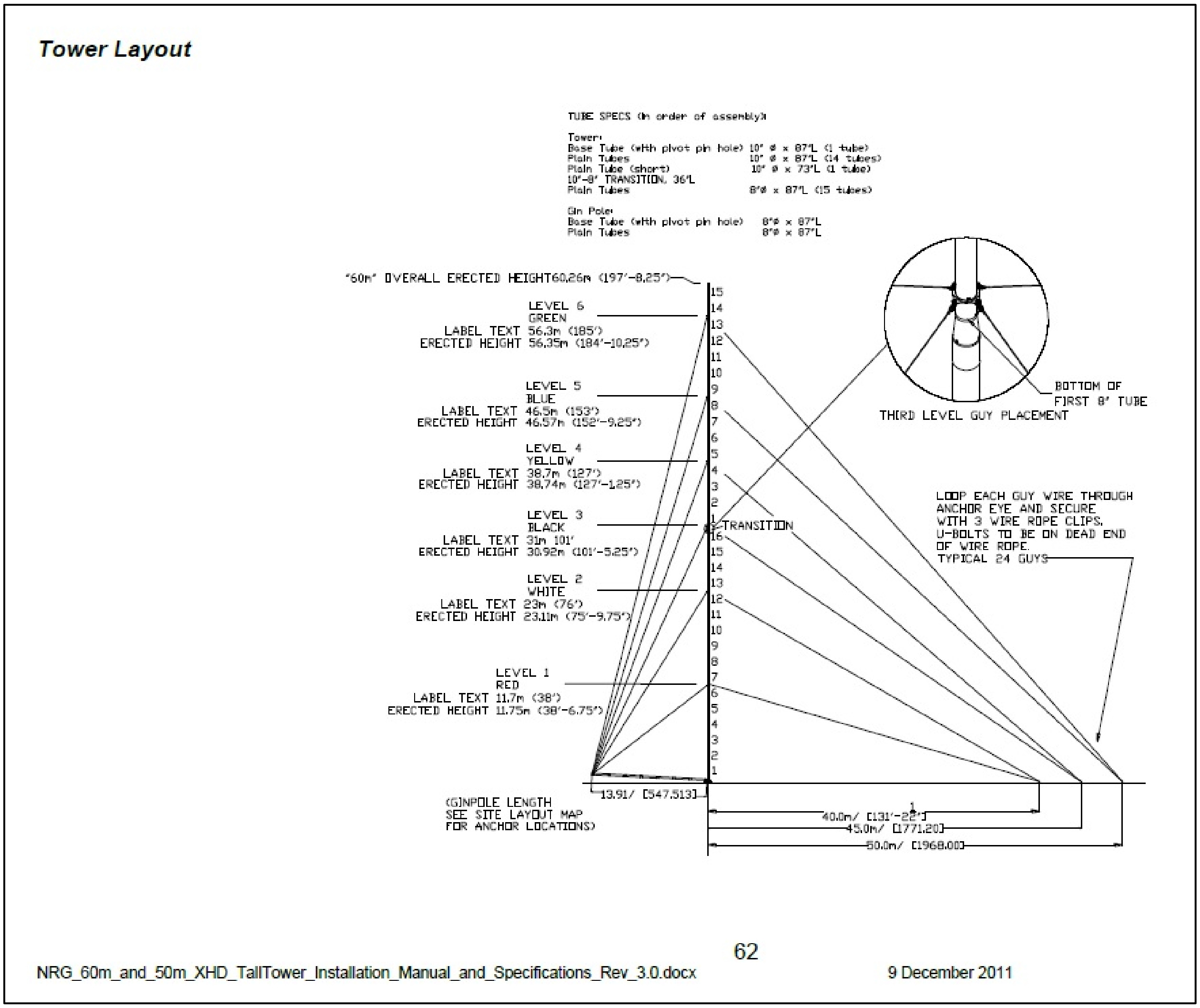
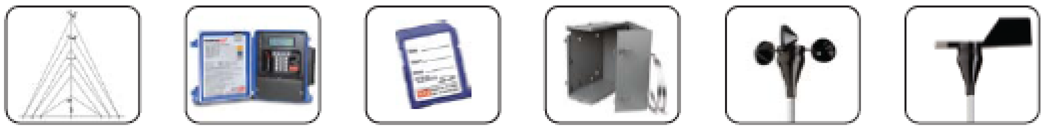


Figure A-4. 60-m XHD tower configuration[23]

[23] Renewable NRG Systems. "Installation Manual and Specifications," 2011. Accessed September 20, 2013: http://www.nrgsystems.com/FileLibrary/fdbaaba20b7f4542b8a9f95aea6aa617/NRG%2060m%20and%2050m%20XHD%20TallTower%20Installation%20Manual%20-%20Rev%203.0.pdf.

Complete 60m XHD Symphonie*PLUS*®3 System



60 meter (197'8") NRG XHD TallTower™ | NRG Symphonie*PLUS3* 15-channel data logger | 128 MB non-volatile SD flash-memory card | Steel shelter box enclosure with mounting hardware | NRG #40C calibrated anemometer with protective terminal boot | NRG #200P wind direction vane with protective terminal boot

NRG #110S temperature sensor with radiation shield | Sensor side-mount booms with clamps | 2C shielded sensor cables | 3C shielded sensor cables | Grounding kit | Symphonie® Data Retriever Software.

System Features

- Fully integrated components: tower, logger, sensors
- All calibrated NRG #40C anemometers
- Industry proven Symphonie*PLUS3* data logger
- NRG XHD ice-rated TallTower
- Strong steel tube construction
- Easy to assemble and transport
- Compact Envirocrate™ packaging
- Remote data transfer options

Optional Communication Modules

- Symphonie iPackGPS for GSM Worldwide cellular, with PV kit (Item #4722)
- Symphonie iPackGPS for CDMA cellular, with PV kit (Item #4724)
- Symphonie iPackGPS for Iridium satellite with PV kit & 400 bundled service minutes (Item #4721)

Accessories and Options

- Datakit4 for Symphonie*PLUS3* data loggers and iPacks (Item #3279) for data analysis.
- Installation kit for 50m and 60m XHD TallTowers (Item #3931): Ginpole, winch and toolkit.
- 2.4m (95") sensor side-mount boom – meets or exceeds IEC 61400-12-1 recommendation. 1.53m (60.5") booms are also available:
  - 60m – Substitute Item #4200 for #4068
  - 50m – Substitute Item #4199 for #4065

System Includes:

	QTY	
✓	1	60 meter (197'8") NRG XHD TallTower: 254mm – 203mm (10.0-8.0") diameter with galvanized steel baseplate, guywires, screw-in anchors, and all necessary hardware components for tower assembly.
✓	1	Symphonie*PLUS3* 15-channel data logger
✓	1	Non-volatile SD flash-memory card
✓	1	Steel shelter box enclosure with mounting hardware
✓	6	NRG #40C calibrated anemometer with protective terminal boot
✓	2	NRG #200P wind direction vane with protective terminal boot
✓	1	NRG #110S temperature sensor with radiation shield
✓	8	Sensor side-mount boom with clamps
✓	6	2C shielded sensor cable: two 60m, two 50m, two 40m
✓	2	3C shielded sensor cable: one 60m, one 50m
✓	1	Grounding kit: two 2.1m (7'2") ground rods and one 2.74m (9') lightning spike
✓	1	Symphonie Data Retriever Software (Free download)
✓	25	Yellow guy guards/markers, 2.44m (8')

No component substitutions

Ordering Information

- 60m XHD Symphonie*PLUS3* – Item No. 4066-5507-4200
- 50m XHD Symphonie*PLUS3* – Item No. 4063-5505-4199

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Figure A-5. SympnoniePLUS Description

Appendix B. Commissioning Report

Table B-1. Tower Commissioning Report

MET TOWER COMMISSIONING SHEET			***Site:***	***Mille Lacs***
State:	Minnasota	Tower Type: NRG 60m XHD	Date Installed:	5/5/2011
Township/County:	Mille Lacs	Comm info N/A	Installed By:	WINData Inc.
Project Name:	NREL-MilleLacs	Logger Cell #: N/A	Data Retrieval By:	Andy Boyd
Logger Type & S/N	NRG	Magnetic Decl. 4° E	Tel #:	(320) 532-7779
ESN:	N/A	Tower Lat/Long: 46°10'44.39"N, 93°48'20.39"W	Local Contact:	Andy Boyd
Landowner(s):	Mille Lacs	Map Datum: World Geodetic System of 1984 (WG	Tel #:	(320) 532-7779
Tel #:		Elevation: 399m	Lock Combination:	N/A

Instrument Type (ch# / sensor)	Instrument Height (nominal)	Instrument Orientation (deg from True N)	NOTES (Serial number, slope/offset, etc.)		AS-Built (height/orientation, etc.)	
Ch1 NRG#40C	60.0	315	95" Boom	Slope: 0.760, Offset: 0.40	60.2	315
Ch2 NRG #40C	60.0	135	95" Boom	Slope: 0.757, Offset: 0.46	60.2	225
Ch3 NRG #40C	50.0	315	95" Boom	Slope: 0.757, Offset: 0.45	50.2	315
Ch13 NRG #40C	50.0	135	95" Boom	Slope: 0.761, Offset: 0.38	50.2	225
Ch14 NRG #40C	40.0	315	95" Boom	Slope: 0.762, Offset: 0.37	40.5	315
Ch15 NRG #40C	40.0	135	95" Boom	Slope: 0.760, Offset: 0.39	40.5	225
Ch7 NRG #200P	58.0	0	95" Boom	Default	58.2	0
Ch8 NRG #200P	38.0	0	95" Boom	Default	37.8	0
Ch10 NRG #110S	2.0	0	On pole	Default	2	0
Ch9 NRG #BP20	2.0	0	On pole	Slope: 0.4255, Offset: 652.86	2	270
				Lat/Long As-Built	46°10'44.39"N, 93°48'20.39"W	

Lead Technician: Marty Wilde Date: 5/5/2011

Appendix C. Typical Energy Production Loss Factors

All energy projects will incur some type of energy loss due to real-world conditions differing from the idealized case. The resulting decrease in efficiency is often accounted for by a series of estimated and calculated loss factors. The loss factors for the Mille Lacs wind analysis include:

- **Turbine availability:** This term accounts for the expected downtime a wind turbine will experience during its annual operation. This includes routine maintenance, faults, and any component failures. Turbine availability or uptime is typically covered in the manufacturer's warranty terms with a value of 95% or greater. Five percent availability loss was assumed.
- **Array efficiency:** This loss parameter is associated with the wakes created by the turbines. This results in a decrease in wind speed and increase in turbulence as the wind moves through the wind farm array. This is a value estimated to be low in this area due to the relatively constant prevailing wind and the proposed turbine siting arrangement. With single turbine installations, there should be no wake impacts to turbines. Zero percent wake loss was assumed.
- **Topographic efficiency:** This parameter relates to the increase or decrease in wind resource across the project due to topographic influences. This can be a positive or negative value and is dependent on the location of the meteorological measurements along with the model used to predict flow across the site. Due to nearby buildings and vegetation, a 1% loss factor was assumed.
- **Electrical:** Electrical losses occur in the process of collecting and transmitting the project energy across the site. As the power moves through the transformers and collection system, a certain percentage will be lost as heat. This value was estimated at 3%.
- **Hysteresis:** This is the term for when a turbine shuts down to protect itself from ambient climate events that are outside of the design envelope. This typically involves a high wind event that forces the turbine to shut down for a predetermined amount of time. The Mille Lacs site did not show any evidence of regular high wind events during the period of collection and therefore is not expected to incur regular losses from hysteresis. Hysteresis was estimated at 1%.
- **Environmental:** Environmental losses occur because of ambient conditions that may affect blade aerodynamics or turbine operation. This includes icing, blade soiling, insect accumulation, and extreme cold or hot events. This is expected to happen at Mille Lacs on rare occasions and is anticipated to be on the order of 2%.
- **Operational:** All operational energy requirements, such as power for the control system, heating system, and other parasitic loads, were estimated at 2%.
- **Power curve variation:** The power curve may deviate from the manufacturer-stated designation due to yaw system misalignment, incorrect programming, or ambient weather events, such as high turbulence or variations in atmospheric stability. This was assumed to be 1%.
- **Sector management:** Sector management can be required if the wind rose has multiple directions that affect the turbine layout. This is not the case at Mille Lacs.

- **Substation downtime:** The collection substation on the Mille Lacs side of the utility interconnection will likely require some downtime for routine maintenance. This is estimated at 0.5% for Mille Lacs.
- **Utility downtime:** Utility transmission and distribution uptime or availability is generally very high. However, there are certain areas of the country or seasons of the year with more risk. The Mille Lacs site is assumed to experience energy loss of 0.5% due to the utility electrical system being unavailable for power transmission.

These loss factors are combined and used in turbine energy performance modeling. As the wind is not always blowing and the turbine is not always generating electricity, the performance-weighted value for these losses is 15.05%.