Crow Lake Wind Emissions Reduction Project

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Project Title	Crow Lake Wind Emissions Reduction Project
Version	*1*
Date of Issue	*January 3, 2012*
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1 PROJECT DETAILS

1.1 Summary Description of the Project

The Crow Lake Wind project site is located east of Chamberlain, South Dakota. The site contains 100 GE 1.5-megawatt turbines owned by Prairiewinds SD 1, Inc. (PWSD1) - a wholly-owned subsidiary of Basin Electric Power Cooperative (BEPC) - 7 turbines owned by South Dakota Wind Partners (SDWP), a South Dakota limited liability company, and one turbine owned by Mitchell Technical Institute (MTI). The output of all of the turbines at the Crow Lake Project site is ultimately purchased by BEPC pursuant to Purchase Power Agreements (PPAs) by and between each of the turbine owners listed above. The 108 turbines described above have an aggregate generating capacity of 162 megawatts (MW). The commercial operation date of this project is February 1, 2011.

In addition to purchasing the output of the turbines located on the Crow Lake project site, BEPC operates and controls the turbines pursuant to an Operation and Management Agreement with PWSD1. The wind turbines at the Crow Lake project site are interconnected to the Western Area Power Administration (WAPA) – Upper Great Plains East (UGPE) bulk transmission system ("Integrated System" or "IS"), which is located within the Midwest Reliability Organization (MRO) region. The turbines on the Crow Lake project site generate emissions reductions by delivering onto the bulk transmission system electricity generated by use of a renewable fuel source (wind).

This project was developed on a voluntary basis, and it was not required to meet any state renewable portfolio requirements. In addition, the monetization of the green attributes from this project was part of the justification of the economics of the project to BEPC as they have more cost effective alternatives to obtain energy from grid connected resources, absent the value of the green attributes.

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Project Overview	
Nameplate Capacity	162 MWs
Location	Aurora, Jerauld and Brule Counties, East of Chamberlain, South Dakota
Commercial Operation Date	February 1, 2011
Capacity Factor/MWh per year	36% (YTD in 2011), ~513,000 MWh
Wind Study	Yes
Project Area under Lease	36,000 acres
Project Interconnection	WAPA Integrated System's 230 kV line at the Wessington Springs substation
Turbine Technology	GE 1.5-77 Class IEC TC IIA turbines
Turbine Warranty	[redacted]

1.2 Sectoral Scope and Project Type

As a grid-connected renewable energy project, the project activity may be principally categorized under Sectoral Scope Number 1: Energy industries (renewable/non-renewable sources).

Crow Lake Wind is a stand-alone project, and it is not a grouped project.

1.3 Project Proponent

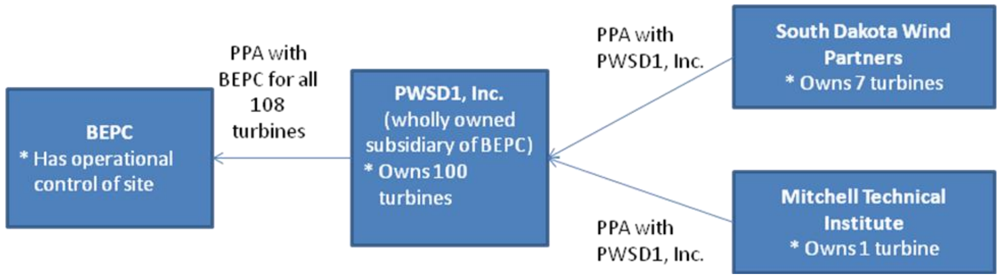
The project co-proponents are BEPC, SDWP, and MTI. BEPC's wholly owned subsidiary PWSD1 owns 100 turbines (150 MW) of the Crow Lake site; SDWP owns 7 turbines (10.5 MWs); and MTI owns 1 turbine (1.5 MW).

BEPC is a not-for-profit, wholesale electric generation and transmission cooperative based in North Dakota that provides electricity to 2.8 million customers across 135 rural distribution companies in 9 states (MT, MN, IA, SD, ND, CO, NM, NB, WY). Basin's charter is to provide low cost, reliable electric power to its members. BEPC incorporated its wholly owned subsidiary PrairieWinds SD1 (PWSD1) to develop the Crow Lake Wind project. Although PWSD1 is the owner of more than 92% of the wind project, it has delegated operating control to its parent, BEPC, pursuant to an Operation & Management Agreement; hence, BEPC has operational control over the site. BEPC is purchasing all of the power generated at the site from its subsidiary PWSD1 via an arms-length power purchase agreement (PPA). PWSD1 in turn is purchasing power from the turbines owned by the SDWP and MTI turbines via two separate PPAs.

SDWP is a limited liability company formed to provide an opportunity for investment by South Dakota residents in the growing wind industry. Four South Dakota organizations helped develop SDWP to provide the opportunity for their members to be a part of wind in South Dakota: East River Electric Coop, SD Corn Utilization Council, SD Farmers Union and SD Farm Bureau. SDWP has contracted with PWSD1 (which in turn has contracted with BEPC) to operate its turbines at the Crow Lake Wind project site.

MTI opened in 1968 in a system of post-high school vocational technical education in South Dakota that included four area institutes and the South Dakota Office of Adult, Vocational and Technical Education. Nearly 14,000 individuals have graduated from MTI since it opened. The central mission of the Institute is to provide job preparatory programs on a full- or part-time basis to all who can benefit. MTI's turbine is used as a teaching tool for students in its wind turbine technician program. As with South Dakota Wind Partners, MTI's turbine is operated by PWSD1 (which in turn has contracted with BEPC).

The graph below depicts the contractual relationships that are part of this project. Please note that BEPC (and not its wholly owned subsidiary PWSD1) is being listed as one of the three project co-proponents because BEPC has operational control over the projects pursuant to an operations and management agreement, and it owns the rights to all of the emissions reductions for the duration of the crediting period.



Contact information for BEPC is:

David Raatz Manager of Marketing and Power Supply Basin Electric Power Cooperative 1717 East Interstate Ave. Bismarck, ND 58503-0564 USA draatz@bepc.com Phone: 701-223-0441 Fax: 701-557-5329	Jason Doerr Sr. Marketing Engineer, Marketing & Power Supply Planning Division 1717 East Interstate Avenue Bismarck, North Dakota 58503-0564 jdoerr@bepc.com 701-557-5388

Contact information for SDWP is:

Nick Sershen, Project Coordinator South Dakota Wind Partners Val-Add Service Corporation nick@val-addservice.com 605-271-0578

Contact information for MTI is:

Greg Von Wald, President Mitchell Technical Institute Greg.vonwald@mitchelltech.edu 605-995-3022

1.4 Other Entities Involved in the Project

Element Markets, LLC is a renewable energy development and environmental credit marketing company based in Houston, Texas. Element Markets is the consultant and authorized representative for BEPC and is undertaking the verification and validation of the VCS project on behalf of BEPC.

Contact information for Element Markets:

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1.5 Project Start Date

The commercial operation date of the project is February 1, 2011. Please see Attachment #17 for documentation to this effect.

1.6 Project Crediting Period

The project crediting period for the projects will commence February 1, 2011, and conclude January 31, 2021, for a total of 10 years.

1.7 Project Scale and Estimated GHG Emission Reductions or Removals

Project	X
Mega-project	

Years	*Estimated GHG emission reductions* or removals (tCO2e)
2011 (Feb 1, – Dec. 31)	396,118
2012	432,128
2013	432,128
2014	432,128
2015	432,128
2016	432,128
2017	432,128
2018	432,128
2019	432,128
2020	432,128
2021 (Jan. 1 – Jan. 31)	36,011
Total number of crediting years	10

Total Estimated ERs	4,321,282
Average Annual ERs	432,128

Please see Attachment #24 for supporting information.

1.8 Description of the Project Activity

The Crow Lake Wind project activity is a zero emissions, grid-connected, electricity generation source. The electricity it generates will displace electricity generated from grid-connected resources in MRO. The project activity is expected to last 25 years.

1.9 Project Location

The Crow Lake Wind project is located across the span of Aurora, Jerauld and Brule counties, east of Chamberlain, South Dakota on a 36,000-acre plot of land at grid coordinates: Latitude: 43.8°N Longitude: -98.8°.

1.10 Conditions Prior to Project Initiation

Prior to project initiation, BEPC obtained power from other resources in its portfolio, which consisted predominantly of fossil fuel and other renewable generation resources. The Crow Lake Wind project turbines comprise a zero emissions, grid-connected electricity generation resource, so no GHG emissions are being generated for the purpose of their subsequent reduction.

1.11 Compliance with Laws, Statutes and Other Regulatory Frameworks

This project was constructed in accordance with all applicable Federal, State and local laws. BEPC/ PWSD1 were required to complete an extensive environmental impact assessment for the turbines included in this project as it was seeking a loan guarantee from the Rural Utility Service (RUS) for its turbines and was seeking interconnection to the IS through WAPA for all of the turbines to be located at the Crow Lake project site. Since both RUS and WAPA are federal agencies a review of the project was required by the National Environmental Protection Act (NEPA), which resulted in the development of an Environmental Impact Statement (EIS). The EIS compared construction of a wind project at the (eventually chosen) Crow Lake site, an alternative site (Winner), and no construction scenario. The evaluation involved extensive public workshops and assessment of numerous impacts, including:

- Air Emissions Impacts - none were found.
- Avian impacts – a potential impact to the whooping crane was found. BEPC voluntarily arranged for offsets to address these issues at significant expense ($[redacted]) after lengthy discussions with the Fish and Wildlife Service.

- Wetland / Grassland impacts – Basin included voluntary conservation measures to offset indirect impacts in its EIS, and this impact was resolved to the satisfaction of RUS and WAPA.

- Archaeology – no significant impacts were found. Any identified potential cultural resources were avoided.

Both RUS and WAPA concluded that impacts were minimized at the Crow Lake Wind site and allowed the project to proceed. Attachment #1 includes the Final Environmental Impact Statement, the WAPA and RUS decisions in the Federal Register approving the projects, and the letter detailing BEPC's offsets. In sum, BEPC/PWSD1 complied with all necessary processes in developing Crow Lake Wind.

1.12 Ownership and Other Programs

1.12.1 Proof of Title

BEPC's wholly owned subsidiary PWSD1 owns 150 MWs (100 turbines) of the wind project. SDWP owns 10.5 MWs (7 turbines), and MTI owns 1.5 MWs (1 turbine). SDWP and MTI sell the power from their turbines to PWSD1 under two PPAs, and PWSD1 sells that power, plus its own generation, to BEPC under a third PPA. [redacted] the PPA between PWSD1 and BEPC and [redacted] the PPA between SDWP and PWSD1 convey all environmental attributes from the projects back to BEPC (See Attachment #2). The sections state:

[redacted]

Credits are further defined [redacted] the PWSD1 PPA and [redacted] the SDWP PPA as:

[redacted]

Similarly, the definition of renewable attributes is on [redacted] the MTI PPA, and all rights are given to BEPC under the purchase agreement.

Hence, BEPC owns rights to all environmental credits attributable to the output of all of the 108 turbines located at the Crow Lake Wind project site.

1.12.2 Emissions Trading Programs and Other Binding Limits

The Crow Lake Wind project is not subject to any other emissions trading programs or binding limits.

1.12.3 Participation under Other GHG Programs

No entity has applied for, nor been denied acceptance under, any other GHG program with respect to any of the turbines at the Crow Lake project site. Attachment #28 provides BEPC's attestation to this fact.

1.12.4 Other Forms of Environmental Credit

The Crow Lake project site is currently listed in M-RETs (the Midwest Renewable Energy Tracking System), a third-party registry created to record the generation of renewable energy MWh and renewable energy credits (RECs). Please see Attachment #17 for the project's M-RETS registration information. A third party (WAPA) reports the number of MWh generated each month to M-RETs, which assigns unique serial numbers for each MWh. For the creation of VCUs, the MWh for which VCUs are being claimed will be retired in M-RETS and the reason for doing this (VCU creation) will be documented in M-RETS. A screenshot of the retirement will be provided during the verification process. The retirement of these credits and subsequent identification of the reason will ensure that those RECs will not be double sold, and that VCUs can be created with confidence. A sample screenshot is provided below:

1.12.5 Projects Rejected by Other GHG Programs

No entity has applied for, or been denied acceptance under, any other GHG program with respect to the turbines located at the Crow Lakes project site.

1.13 Additional Information Relevant to the Project

Eligibility Criteria

Per ACM0002, the following conditions are met; therefore, the project is eligible.

- The project activity is an installation of wind, an eligible resource under the methodology.

Leakage Management

Per the methodology, no leakage is applicable under this methodology.

Commercially Sensitive Information

Commercially sensitive information includes:

- PPA price and terms and conditions;
- Certain avoided cost data;
- Load Forecasts and BEPC future Renewable Energy Requirements;
- All financial data;
- Certain aspects of BEPC's 2007 Power Supply Analysis; and
- Certain aspects of the Environmental Assessment and BEPC's interactions with the U.S. Fish and Wildlife Commission.

Further Information

None.

2 APPLICATION OF METHODOLOGY

2.1 Title and Reference of Methodology

Title: ACM0002 - Consolidated baseline methodology for grid-connected electricity generation from renewable sources

Reference:
http://cdm.unfccc.int/filestorage/V/A/1/VA17EM2PNDJWBTFY34KGRLZO68S9UQ/Consolidated%20baseline%20methodology%20for%20grid-connected%20electricity%20generation%20from%20renewable%20sources.pdf?t=NXV8bHVwdzh6fDAPldA2Htix3vUsiCteQTKR

Version: Version 12.1.0

2.2 Applicability of Methodology

ACM0002 Version 12.1, Sectoral Scope 01 has been chosen as the most suitable for this project activity.

Applicability Guideline in Methodology	Project Characteristic
The project activity is the installation, capacity addition, retrofit or replacement of a power plant/unit of one of the following types: hydro power plant/unit (either with a run-of-river reservoir or an accumulation reservoir), wind power plant/unit, geothermal power plant/unit, solar power plant/unit, wave power plant/unit or tidal power plant/unit;	Crow Lake Wind is the installation of a new wind project.

2.3 Project Boundary

ACM0002 requires the project boundary to include:

- The Project Electricity System: Crow Lake Wind Facility (Project facility)
- The Connected Electricity System: All power plants connected physically to the electricity system, which in this case is the Midwest Reliability Organization (MRO) to which the wind project is connected (the electricity system)

	Source	Gas	Included?	Justification/Explanation
Baseline Emissions	CO2 emissions from electricity generation in fossil fuel fired power plants that are displaced due to the project activity	CO_2	Yes	This represents the main emissions source for the project. In the absence of the projects, grid connected resources would provide power to BEPC (this will be shown to be the appropriate baseline in the subsequent section), and hence lead to GHG emissions.
		CH_4	No	Minor emissions source
		N_2O	No	Minor emissions source
		Other	N/A	N/A
Project Activity	For geothermal plants, fugitive emissions from CH4, CO2 from non-condensable gases contained in geothermal steam	CO_2	No	No, this is not applicable as this is not a geothermal facility.
		CH_4	No	Minor emissions source
		N_2O	No	Minor emissions source
		Other	N/A	N/A
	CO2 emissions from the combustion of fossil fuels for electricity generation in solar thermal power plants and geothermal plants	CO_2	No	No, this is not applicable as this is not a geothermal or solar thermal facility.
		CH_4	No	Minor emissions source
		N_2O	No	Minor emissions source
		Other	N/A	N/A
	For hydro power plants, emissions of CH4 from reservoir	CO_2	No	No, this is not applicable as this is not a hydro power plant.
		CH_4	No	Minor emissions source
		N_2O	No	Minor emissions source
		Other	N/A	N/A

2.4 Baseline Scenario

Since this project activity is the installation of a new grid-connected renewable power plant / unit, the baseline scenario is the following:

> Electricity delivered to the grid by the project activity would have otherwise been generated by the operation of grid-connected power plants and by the addition of new generation sources, as reflected in the combined margin (CM) calculations described in the Tool to calculate the emission factor for an electricity system.

The additionality discussion below provides a justification of this as an appropriate baseline scenario for BEPC in absence of this project.

2.5 Additionality

We use version 5.2.1 of the Large Scale CDM additionality tool to carry out the analysis below.

Step 1: Identification of alternatives to the project activity consistent with current laws and regulations.

Step 1a: Define alternatives to the project activity

First, note that we examine additionality for this project predominantly through the lens of BEPC for several reasons:

1) BEPC formed PWSD1, as a wholly-owned subsidiary, to develop and own 100 turbines located at the Crow Lake wind project site. PWSD1, pursuant to certain contractual arrangements with SDWP and MTI, also developed, constructed, operates and purchases the electrical output of 7 wind turbines owned by SDWP and one turbine owned by MTI.

2) BEPC ultimately operates the turbines located at the Crow Lake project site, pursuant to various Operation, and Maintenance Agreements by and between BEPC, PWSD1, SDWP and MTI.

3) BEPC's involvement through its subsidiary PWSD1 was crucial for project to be built, especially for the portion of the project (11 MWs) owned by SDWP and MTI:

    a. BEPC / PWSD1 brought the development expertise necessary for the development of SDWP's and MTI's turbines
    b. The 151 MWs owned by PWSD1 created sufficient economies of scale for SDWP and MTI to own their eight turbines
    c. PWSD1 pays SDWP and MTI a higher PPA price (described in more detail below) for the 11 MWs owned by those entities than they receive from BEPC. This higher PPA price was offered to these entities in part to ensure the community owners were able to earn a rate of return.

4) BEPC owns the rights to all the environmental attributes and power generated at Crow Lake Wind through various PPAs.

Taking into account the aforementioned factors, it is clear that BEPC ultimately bears significant financial costs and risks associated with the turbines. Hence, we carry out the additionality analysis from the perspective of BEPC for the while project, and not SDWP or MTI for their respective turbines.

Given this perspective, BEPC must balance a range of interests as it determines which assets to add to its generation portfolio. This is in stark contrast to a merchant generator that is solely concerned with building generation to provide energy and managing the project economics. As a generation and transmission cooperative, BEPC has a dual mission to provide both reliable and cost effective electric service to its member cooperatives. In addition, BEPC's membership of 135 cooperatives across nine states has a range of motivations to support the addition of cleaner resources to BEPC's generation, including diversifying the generation mix to address potential future environmental legislation and responding to constituents' desire for environmental stewardship.

In 2007, BEPC recognized that its membership had experienced significant load growth from [redacted] – [redacted] and determined that the loads of its member systems would continue to grow at least until [redacted] (See Attachment #6), In particular, BEPC calculated that system peak demand increased on average by [redacted] MW annually from [redacted] – [redacted]. Basin noted:

> "The average increase in system peak demand required an [redacted]% capacity factor generation facility to meet load levels. This indicates that Basin Electric has been adding load at a capacity factor that is best served by base-load generation resources".

Similarly, from [redacted] – [redacted], BEPC forecasted that its peak system demand is expected to rise by [redacted] MW per year. Basin noted:

> "The average expected increase in energy sales compared to the average expected increase in peak demand requires a [redacted]% capacity factor generating facility".

This analysis implies that base-load facilities capable of achieving an [redacted]% capacity factor (which traditionally have been coal generation units in BEPC's portfolio) would be the optimal generation resource for BEPC to manage increasing load growth, not intermittent or non-dispatchable generation. In fact, BEPC was currently developing both coal and natural gas plants to meet these load growth requirements.

In this case, BEPC chose to develop non-base-load, non-dispatchable generation resources that displace generation from fossil fuel emitting resources connected to the grid. Hence, the appropriate alternative to the development of the wind project includes the following:

- The project activity undertaken without being registered as a VCS activity.
    - It will be shown (per Step 3) that this is not a feasible alternative.
- Electricity delivered to the grid would have otherwise been generated by the operation of grid-connected power plants and by the addition of new generation resources, as reflected in the combined margin calculations described in the "Tool to calculate the emission factor for an electricity system".
    - It will be shown (per Step 3) that this is the baseline in the absence of this project activity.
- Other plausible and credible alternatives
    - Solar generation
        - Solar, while uncorrelated with wind generation, is prohibitively costly and brings a much lower capacity factor, and is a relatively more limited resource in BEPC's service territory. With capacity factors between 20-35%, solar provides a lesser level of service per MW compared to wind. (Please see Attachment #19, pages 76-77, for corroboration that solar is intermittent, which much lower capacity factors.) In BEPC's 2007 Resource Alternative Assessment, BEPC notes that wind is "a better alternative than solar when

factoring the wind potential within the Dakotas and the limited availability of solar power within Basin's eastern system". Hence, solar is not a credible alternative given its limitations.

- Biogas
  - Biogas projects are in very limited supply – for example, to date, BEPC has contracted for ~ 1 MW of biogas, as shown on this website. Hence, biogas does not provide a comparable level of service to the wind project, so this alternative is not considered. The much smaller size of biogas projects, in addition to their limited availability, provides additional evidence that this is not a comparable alternative to the Crow Lake Wind project.
- Waste Heat
  - The potential for waste heat is very limited within BEPC's service territory. BEPC, in conjunction with Ormat Technologies, has developed approximately 44 MWs of waste heat to electricity projects along the Northern Border Pipeline. These eight projects represent 5.5 MW capacity on average. They also represent the majority of the waste heat projects done in the United States (eight sites out of a total of 13 sites as of 2009). All feasible waste heat projects available to BEPC have already been developed. In addition, the waste heat projects have PPA costs higher than the wind PPAs (higher prices are required to sustain this technology). Finally, BEPC seeks to diversify its renewable resource mix with non-dispatchable assets that are uncorrelated in their production profiles. Waste heat projects operate when the pipeline compressor stations operate, uncorrelated to wind patterns in North Dakota. Given all these factors, waste heat is not a viable alternative to Crow Lake Wind.
- Hydroelectricity
  - BEPC evaluated whether hydropower was a viable renewable resource in its 2007 Power Supply Assessment (See Attachment #19). The assessment noted that one project BEPC evaluated had a very high capital cost, realistic capacity factor of 20-30%, and would take more than 10 years to permit, construct, and get ready for commercial operation. Given these considerations and the highly variable nature of rain fall and several years of drought in 2007, BEPC determined this resource was limited at the time, and therefore not a viable option to pursue further.

Therefore, the alternatives considered (and to which subsequent steps are applied) are:

- The project activity undertaken without being registered as a VCS activity; and
- Electricity delivered to the grid would have otherwise been generated by the operation of grid-connected power plants and by the addition of new generation resources, as reflected in the combined margin calculations described in the "Tool to calculate the emission factor for an electricity system".

Step 2: List alternatives identified in Step 1 in compliance with local regulations

All identified alternatives are in compliance with local regulations, hence neither alternative is eliminated. In addition, this wind project is not specifically required under any laws or regulations in any of the nine states within which BEPC or its member cooperatives are active, nor is Crow Lake Wind the only way for BEPC and its members to meet their renewable goals. BEPC provides power to member cooperatives (who ultimately serve retail load) in nine states. Renewable legislation in those states varies widely in terms of the requirement it imposes on BEPC members (and BEPC).

- Colorado, Minnesota and New Mexico have enacted Renewable Portfolio Standards (RPS) that apply to electric cooperatives requiring them to procure a certain percentage of their generation from renewable resources

- North and South Dakota have enacted "Renewable Energy Objectives" creating voluntary goals for electric cooperatives to procure 10% of their generation from either renewable or recycled energy (or in the case of South Dakota, energy efficiency) by 2015. These objectives are voluntary in nature, with no penalty assessed for a failure to meet them.
- Iowa and Montana have enacted Renewable Portfolio Standards that do not apply to electric cooperatives.
- Nebraska and Wyoming have no Renewable Portfolio Standard.

BEPC has only one member (Tri-State Generation and Transmission Association, or "Tri-State") in Colorado and New Mexico that is responsible for its own compliance for the state RPS'. BEPC has a contractual relationship with Tri-State to sell them a fixed amount of power to meet a portion of Tri-State's Wyoming and Colorado load requirements. BEPC does not supply any power for Tri-State's New Mexico system and thus has no RPS requirement in that state. Tri-State has independently procured renewable resources for their New Mexico obligation. BEPC's policy regarding power sales to Tri-State provides for BEPC to offer Renewable Energy Credits in the same percentage as the Colorado RPS such that the total annual power delivery would be compliant. For point of reference, that percentage is 1% for 2010, 3% for 2011 thru 2014, 6% for 2015 thru 2019, and 10% for 2020 and beyond.

In Minnesota, BEPC has an obligation to provide RECs to meet specific percentages of the company's and their members' loads. The Minnesota RPS was originally a non-mandated, "good faith" renewable energy objective that had a target of 7% of all retail sales by 2010 being served by eligible generation resources. In 2007 this was changed to a mandate through the passage of S.F. 4. For point of reference, that percentage is 7% thru 2011, 12% for 2012 thru 2015, 6% for 2016 thru 2019, and 20% for 2020 and beyond.

Based on the load forecast for Tri-State and for the Minnesota members (see Attachment # 3 – Renewable Requirements by State), the total number of RECs Basin needed is listed below:

[redacted]

Well before the Crow Lake project wind turbines were constructed (indeed, by the end of 2007), BEPC had acquired a portfolio of nearly 168 MW's of eligible capacity, which was capable of generating over [redacted] RECs per year, through PPAs signed with merchant generators as well as their own development efforts (See Attachments # 3 and #4). The number of available RECs in 2007 far exceeded the mandatory requirements of BEPC's members through 2022. The renewable generation from the Crow Lake Wind project, therefore, was not necessary for meeting these mandates, and the development of the project was not required to meet these state programs. In addition, BEPC's supply of RECs far exceeds its voluntary needs through 2014, and these RECs are not required, nor will they be retired, to meet these goals either.

North and South Dakota have both enacted Renewable Energy Objectives (REO) that apply to all retail providers of electricity in those states. However, as a voluntary objective (as opposed to a mandatory standard), there are no penalties or sanctions for failing to meet these goals. While each retail provider is required to file an annual report to the states' public service commissions detailing the amount of renewable energy they generated for that year and their planned renewable capacity additions going forward, there is no "ramp-up" to the 15% target. Consequently, there is no need to retire or even procure any credits prior to 2015.

Finally, in 2010 the North Dakota Public Utilities Division recommended in PU-10-19 (see Attachment #5, Page 5):

- Electric utilities with RECs allocated to ND should be encouraged not to retire RECs in the years leading up to 2015.
- Electric utilities with RECs allocated to ND should be encouraged to sell all these RECs in the years leading up to 2015. It is understood that the mechanism to credit ND ratepayers will differ between investor-owned utilities vs. generation & transmission cooperatives and municipal joint action agencies.
- By the year 2015 and after, if the electric utility has shown compliance with the REO, the PUD recommends that the Commission consider allowing electric utilities to continue to sell all of their RECs attributable to ND rather than retiring them to show compliance, given that the objective is voluntary.

While not deciding on the last point of continuing to sell RECs in 2015 and thereafter, the North Dakota Public Service Commission did rule (see Attachment #7, Page 2):

> "All allocated RECs must be considered excess and no RECs may be considered needed for compliance until 2015."

Thus BEPC is under no obligation in either of these states to procure renewable generation. If it does procure renewable generation, it is under no obligation to retire its credits toward those objectives.

With respect to federal mandates, there was much discussion regarding a potential federal Renewable or Clean Energy Standard or a Greenhouse Gas Cap and Trade program from 2007 - 2009. However, under the proposed 4,000,000 MWh annual threshold for inclusion detailed in the most recent proposed federal legislation, namely Bingaman's Renewable Portfolio Standard and Waxman and Markey's American Clean Energy and Security Act, not a single one of BEPC's members would have been subject to an obligation given their system loads. Indeed, BEPC's move to add renewable generation took place long before the proposed legislation merited.

In 2005, BEPC's membership authorized a *voluntary* resolution (Resolution D-5: Renewable Energy Goal – see Attachment # 8) that directed the company to:

> "... seek to obtain renewable or environmentally benign resources equal to 10 percent of the MW capacity needed to meet its member demand by 2010."

BEPC's internal target was developed to show support to renewable resources and respond to member and community interest in renewable generation. BEPC had no obligation to meet the target nor was there any internal requirement to do so. Indeed, the resolution was voluntary in nature in the first place (and was not treated internally as a "binding requirement"). Second, the resolution noted that BEPC should sell the green tags from its projects to mitigate the economics of relatively higher priced green resources and for the benefit of their members. The same resolution also directed BEPC to:

- "... actively market "green credits" for the benefit of cooperative members."

Green Tag revenue was contemplated and a key consideration in reaching the target in the first place. Finally, at the time that the Crow Lake Wind project was completed, Basin had exceeded its target (to obtain renewable resources equal to 10% of the MW capacity needed to meet member demand); thus, this resource was not necessary to meet the internal resolution.

BEPC's 2007 Power Supply Analysis noted about BEPC's voluntary resolution that:

> "a fundamental component underlying this policy is the marketing of the Green Tags (aka renewable energy credits) resulting from these resources. The revenue from the marketing of the credits is integral to achieving the economics of the goal." (Attachment #9)

In summary:

- BEPC's mandated obligation through 2020 of up to [redacted] RECs was met in 2006, well before the Crow Lake Wind project was constructed. In addition, their obligation for 2020 and beyond can actively be met with other resources in BEPC's portfolio.
- BEPC did establish a renewable capacity goal and was proactively monitoring any potential renewable obligation, no matter how remote, far in advance of any mandate.
- BEPC's Board (as well as the Public Service Commission of the State of North Dakota) has encouraged the company to monetize the Renewable Energy Credits generated by their renewable project portfolio, in part to recover the costs associated with adding more expensive, greener generation, so as to compensate their electric customers.

Step 2: Investment Analysis:

Step 2a: Determine appropriate analysis method

Since the project activity derives benefit from energy and VCUs, it is appropriate to apply Option III, using Benchmark Analysis.

Again, we look at the investment analysis through the perspective of BEPC only - the role of BEPC's wholly owned subsidiary PWSD1 was crucial to moving this project forward, especially for the turbines owned by SDWP and MTI. PWSD1's ownership of the majority of this project (151 MWs) ensured the economies of scale for costs to be such that SDWP and MTI could participate in this project. As described above, PWSD1 also brought the development expertise needed for the project to move forward. PWSD1 also pays SDWP and MTI a higher PPA price (described in more detail below) for the 11 MWs owned by those entities than they receive from BEPC. This higher PPA price was offered to these entities in part to ensure the community owners were able to earn a rate of return. Taking into consideration these factors coupled with the fact that BEPC owns all the power and environmental attributes generated by Crow Lake Wind, it is clear that BEPC is bearing significant costs and risks associated with this project. In evaluating the benefits provided by the wind project versus its relative costs, therefore, we only consider BEPC's point of view.

As a generation and transmission cooperative, BEPC's mission is to provide reliable, low cost power to its member cooperatives, which in turn provide it on a retail basis to residential, commercial, and industrial customers.

BEPC's generation resources provide two separate sets of services to electrical consumers.

- Energy – which reflects the amount of electricity supplied throughout the year during each interval (measured in MWhs); and
- Capacity – which reflects the potential ability of generating resources to be available to meet peak demand. Capacity demand is determined by calculating the system requirements to meet the peak demand period, and units must be available during that period. Hence, capacity value is generally attributed to resources which can be dispatched with an adequate degree of reliability.

If BEPC's members experience load growth, BEPC must acquire sufficient electric capacity and energy to meet its member's needs. The primary determinants with respect to BEPC's decision to acquire that additional capacity and energy by construction of new generation resources is the cost of the resources and the end result – delivered cost of generated electricity. BEPC seeks the most cost effective resources to serve member load.

Sub-step 2b: Apply Benchmark Analysis (Option III)

The rate which captures the fuel displacement value of the energy from the Crow Lake Wind project is the annual avoided cost which is published by BEPC. The avoided cost rate is defined under Public Utilities Regulatory Policy Act (PURPA) as "the incremental costs of electric energy, capacity, or both, which, but for the purchase from the qualified facility, such utility would generate itself or purchase from another source." BEPC's interpretation of this definition is to identify the cost of marginal generation which would provide power on their system in the absence of the project activity. This method conforms to the "Component/Peaker Method" as identified by the Edison Electric Institute (EEI) (Attachment #21), which assumes that the facility "displaces the marginal, or most expensive, generation source in the utility's system at any given time." BEPC utilizes this method to calculate its system-wide avoided costs, and, in keeping with the "standard offer" approach outlined in the EEI publication, submits it for approval to the Federal Rural Utilities Service (RUS) and publishes it for the benefit of its members. While this method can be used to estimate both the avoided costs associated with capacity and with energy, since the Crow Lake Wind project provides no capacity benefit, only the avoided costs associated with energy are considered here.

The avoided cost rate calculated by BEPC is equal to BEPC's reduced power production costs and reduced transmission and distribution line losses associated with delivering the generation to load. It reflects the cost of energy that BEPC is able to avoid by purchasing power from the PURPA resource. On BEPC's eastern system, where the Crow Lake Wind project is located, this marginal unit is currently identified to be [redacted], a coal unit.

The avoided cost metric fits option "e" (any other indicators) among the allowable indicators, since the other allowable indicators are not pertinent for BEPC.

Potential Benchmark	Reason benchmark is not appropriate
a) Government bond rates, increased by a suitable risk premium	As a not-for-profit rural electric cooperative, BEPC does not build projects based on rates of return in the same way a private developer would seek to do. As a generation and transmission cooperative, BEPC's mission is to serve reliable, low cost power to its member cooperatives, which in turn provide it on a retail basis to residential, commercial, and industrial customers. If BEPC's members have load or experience load growth, BEPC is required to build or procure energy. The primary measure for the

	cooperative on whether to build is the cost of the project and the end result – delivered cost of generated electricity. BEPC seeks the most cost effective resources which can be used to serve member load. BEPC does not seek to build projects on the basis of an internal rate of return (IRR). Therefore, this is not a pertinent benchmark.
b) Estimates of cost of financing and required return on capital	BEPC does not build projects based on IRRs. As a generation and transmission cooperative, BEPC's mission is to serve reliable, low cost power to its member cooperatives, which in turn provide it on a retail basis to residential, commercial, and industrial customers. If BEPC's members have load or experience load growth, BEPC is required to build or procure energy. The primary measure for the cooperative on whether to build is the cost of the project and the end result – delivered cost of generated electricity. BEPC seeks the most cost effective resources which can be used to serve member load. BEPC does not seek to build projects on the basis of an IRR. Therefore, this is not a pertinent benchmark.
c) A company internal benchmark that has been used to assess similar activities in the past	The avoided cost figure is not an internal benchmark that is used to make specific investment decisions. The avoided cost rate is used under the PURPA regulation such that entities seeking to provide power to BEPC on an unsolicited basis are entitled to be paid BEPC's avoided cost. However, since investment decisions are not made based on avoided cost, this benchmark is not applicable.
d) Government / official approved benchmark that is used for investment decisions	While the avoided cost benchmark is published by BEPC and submitted to the RUS under PURPA, BEPC does not make specific investment decisions based on avoided cost. The avoided cost rate is used under the PURPA regulation such that entities seeking to provide power to BEPC on an unsolicited basis are entitled to be paid BEPC's avoided cost. However, since investment decisions are not made based on avoided cost, this benchmark is not applicable.
e) Any other indicator, if the project participant can demonstrate that the above options are not applicable and their indicator is appropriately justified	As stated above, the avoided cost metric does not fit into the other four options of allowable benchmarks, but is eminently suitable for the analysis of this project as being additional to BEPC. The avoided cost metric is suitable because: 1) The wind project cannot be dispatched, and therefore cannot provide true capacity value to BEPC. The benefit to the system is to displace the variable costs of other facilities which are not run due to the operation of this site. In other words, the wind project has "fuel displacement value". 2) For this same reason, a traditional levelized cost measure (that includes all-in fixed and variable

	costs for various technology types) is not appropriate to use here. A coal unit or a natural gas unit which has capacity value to BEPC cannot be compared on a strict cost basis to a wind unit which does not. 3) The avoided cost metric published by BEPC for PURPA is specifically designed to capture the fuel displacement value of the marginal unit which is no longer run, or run at lower levels, because these facilities are operating. 4) While no investment decision is made on an avoided cost basis, it does capture the value to the system that is provided by a non-dispatchable resource.

Substep 2c: Calculation and Comparison of Financial Indicators

Avoided costs from [redacted] are comprised of [redacted], and the [redacted] tax. These rates represent the avoided costs of the wholesale power supply component of the cooperative system and are computed at BEPC's point of delivery to its members. The avoided costs for BEPC have historically ranged from $10 / MWh - $20 / MWh. For example, the average avoided cost to Basin for the period 2005 – 2011 is $14.57 / MWh. Hence, the system value Basin derives per MWh of wind power it receives is captured by this metric. The historical avoided cost values from 2005 – 2011 are provided below in units of $ / MWh (Attachment #10).

	Avoided Cost (System Value to Basin)
2005	$ 10.00
2006	$ 12.70
2007	$ 14.20
2008	$ 15.90
2009	$ 15.10
2010	$ 16.80
2011	$ 17.30

The cost of the Crow Lake Wind project is reflected in the "contract price" BEPC pays to PWSD1, SDWP, and MTI in their PPAs. For PWSD1, the PPA price is based on the "true cost" to BEPC of owning this wind farm [redacted]. In the event that [redacted], the true cost to BEPC is HIGHER than is reflected in the PPA price. This is reflected [redacted] of the PPA between BEPC and the PWSD1 subsidiary (Attachment #2), which notes that [redacted]. As a result, the use of the "after tax" PPA price to reflect the cost of wind to BEPC is a *conservative* measure. The PPA price for the PWSD1 subsidiary starts at $[redacted] / MWh in [redacted] and escalates to $[redacted] in [redacted]. Again, this is a lower price paid to PWSD1 [redacted]; i.e. this is a more conservative benchmark perspective for the purposes of this additionality analysis.

For SDWP and MTI, BEPC pays a higher PPA price than is paid to PWSD1. The PPA price for SDWP and MTI starts at $[redacted] / MWh and is over $[redacted] by the end of the PPA term. The average cost of the PPA to BEPC for the contracted output from the Crow Lake Wind project on a weighted average basis over the life of the PPAs is $[redacted] / MWh (Attachment #12).

In addition, the intermittent / non-dispatchable nature of the wind project also imposes real costs to BEPC from a load shaping perspective. A number of utilities attempting to integrate wind have attempted to quantify the burden these intermittent resources put on system operators who must integrate renewable onto the grid. Most recently, Southern California Edison proposed a $15 / MWh integration cost for wind to be integrated into its grid (see Attachment #11). Although MRO has not determined what these costs would be for the region, it does illustrate the substantial costs of integrating such resources.

To adequately compare the system value to BEPC (as determined by the avoided cost) to the cost (as determined by the PPA), we forecast the potential avoided cost value for BEPC until [redacted]. The primary and most volatile determinant of the avoided cost calculation is based on the cost of combusting coal at Leland Olds. Using BEPC's proprietary long-term coal price forecast, the coal price is expected to increase by an average of [redacted]% per year for the next 10 years (Attachment #13). Similarly, the long-term coal price is expected to increase by an average of [redacted]% at BEPC's other coal unit on the eastern system, Antelope Valley. To be conservative, we apply the average of these 2 values ([redacted]%) to the 2011 published avoided cost rate (to date the highest value) and forecast BEPC's avoided cost rate to [redacted]. Note that this is conservative since other components of the avoided cost are not expected to increase as much as the coal cost.

We are also conservative in that for the purposes of comparing the system benefit to BEPC versus the costs incurred, we exclude the substantial integration costs for intermittent resources.

[redacted]

Comparing the PPA price to the forecasted avoided cost rate, it becomes apparent that the wind project's cost far exceeds its value, unless the GHG or renewable value is taken into account. Indeed, the average avoided cost benefit to BEPC on a per MWh basis from [redacted] - [redacted] is $[redacted] while the weighted average PPA cost is $[redacted] (please see Attachment #12).

The "green value" of BEPC's renewable generation was a key consideration for them in moving forward with these relatively more uneconomic projects. In their 2007 Power Supply Analysis (Attachment #6), BEPC modelled a number of potential carbon costs in considering which resources to add to their generation portfolio. The graph below illustrates their three cost curves for GHG allowances which BEPC considered viable ($[redacted] / ton in 2012 with a [redacted]% escalator; $[redacted]/ ton in 2012 with a [redacted]% escalator; $[redacted] / ton in 2012 with a [redacted]% escalator).

[redacted]

The expected revenue / benefit of the environmental attributes have been recognized by the board as a mitigating factor to help address the difference between the project's value to the system and the project's cost. The importance of green tag revenue to BEPC is underscored on its website, which notes that

> "We are selling the green tags from our green and renewable resources to benefit the economics of those resources."

In summary, as a generation and transmission cooperative, BEPC signed PPAs at a higher cost than a feasible alternative to take into account the potential GHG and renewable benefits from the generation when there were no existing state or federal laws compelling them to do so at that time. The potential VCU revenue compensates them for taking such a risk ahead of time and helps mitigate the difference between the cost BEPC is bearing for these resources and its true system benefit as a fuel displacer.

Substep 2d: Sensitivity Analysis

In the base case, the escalator used for the avoided cost is [redacted]%. For sensitivity analysis purposes, we increased the base case escalator by 10%, thus using a [redacted]% escalator to project forward the avoided cost. Similarly, we decreased the base case escalator by 10%, thus using a [redacted]% escalator to project the long term avoided cost escalator.

The results of this analysis are presented below. Again, taking into account the sensitivities, the average cost of the Crow Lake Wind PPAs is higher than their relative benefit to the system. The revenue from the green tags is critical to closing the gap.

[redacted]

Hence, the alternative of "undertaking this project without VCU revenues" is not feasible, and the appropriate alternative is for BEPC to obtain power from grid connected resources.

Step 4: Common Practice Analysis

Crow Lake Wind is the largest facility owned by a subsidiary of and operated by an electric cooperative in the United States. It is also the only facility in the United States where a portion of the project is jointly owned by a consortium of 600 farmers and ranchers (SDWP) and an educational institute (in other words, the project has a community wind component.) The analysis below outlines a number of the aspects which makes this project unique.

First, we note that wind penetration in MRO is still low relative to its potential. Next we discuss that cooperative ownership is even more rare, the majority of wind being owned by independent power producers (IPPs) or investor owned utilities (IOUs). We point out that IOU/IPP projects are able to avoid certain risks or costs which this project, because of its majority cooperative ownership, was not able to avoid. We then discuss the unique community wind aspects of this project, which (as discussed above) highlight the characteristics which set this project apart from other wind projects in MRO. Critically, while other cooperative owned projects, and other community wind projects exist, there is no other project in the country which has critical elements of both.

Step 4a: Analyze other activities similar to the project activity

Wind projects were still a relatively small portion of the total generation in MRO at the time this project was being contemplated. Based on EIA 923 2009 data, the last complete database available, wind contributed 8.15% of the total generation in MWh in MRO (See Attachment #13, tab "Wind Penetration (TotalGen)"). In comparison, coal and nuclear generation provide over 80% of the power in MRO in terms of MWh. Hence, BEPC's project is relatively unusual in the region.

This "penetration" is even lower when the installed wind capacity in 2009 is compared to the wind *potential* in the region. According to NREL's state level wind resource assessment, the eight U.S. states which are part of MRO could feasibly host over 4232 GWs of wind resources with capacity factors over 35% (please note this resource assessment is based on what is technically feasible, not necessarily what is economically feasible). In comparison, in 2009, MRO hosted approximately ~7.269 GWs of installed capacity of wind, representing less than 0.172% of the potential. (See Attachments #13, tab “Wind Penetration (Potential)” and 21, the NREL state level wind resource assessment).

Based on the 2009 EIA 860 database, there were 198 wind projects representing 7.269 GWs of installed capacity in MRO (AllWindProjectsinMRO tab, Attachment #13). Note that the EIA database actually listed 199 projects, but one wind project, the Smoky Hills Wind project, with a name plate capacity150 MW is located in Kansas, which is not part of MRO. We believe this classification to be an error, hence we remove this project from the total list of projects.

Of the 198 projects, 97 projects representing 7.229 GWs in total are larger than 5 MWs, the threshold we use to identify “utility scale” projects. We choose the 5 MW threshold because BEPC offers a number of rates to purchase energy from: small projects – a small renewable rate for projects under 150 kW; a “large” wind rate for projects between 150 kW – 2 MW; and a distributed generation rate for projects between 2 MW – 5 MW. Projects over 5 MW would have to negotiate a PPA with BEPC. (Please see Attachment #29, page 22 – 38 for additional information).

We then break down the installed wind projects by owner name and owner category (Attachment #13, tab “UtilScaleWindProjectsinMRO”). The owner categories include: 1) projects owned by a public power entity / electric cooperative; 2) projects owned by an independent power producer (IPP); and 3) projects owned by investor owned utilities (IOUs).

Looking at the total pool of projects over 5 MWs, cooperative /public power owned projects are extremely rare within MRO, representing just 2.85% of installed wind capacity (5 projects out of 97 projects, including BEPC’s PWND1 project).

Owner Type	Nameplate Capacity (MW)	Number of Projects
IPP	5,133.4	68
IOU	1,863.6	22
Public Power / Electric Cooperative	206.4	5
Community Wind	26.2	2
Total	**7,229.6**	**97**

Within the IPP/IOU category, large developers dominate the wind market – over 73% of the installed capacity in MRO is owned by five companies.

Owner	Nameplate Capacity	Number of Projects	Installed MW as % of Utility Scale Wind in MRO	Owner Type
FPL/NextEra	1886.9	24	26.10%	IPP
MidAmerican	1283.8	11	17.76%	IOU
Iberdrola	952.9	12	13.18%	IPP
enXco (EDF Company)	603	6	8.34%	IPP
Horizon	601.1	4	8.31%	IPP
Edison Mission Group	373.7	11	5.17%	IPP
Alliant (IP&L and Wisconsin Power and Light)	267.4	2	3.70%	IOU
Acciona	191.9	2	2.65%	IPP
AES	187.4	2	2.59%	IPP
Enel	148.5	1	2.05%	IPP
Otter Tail Power	138	3	1.91%	IOU
Basin Electric Power Cooperative	115.5	1	1.60%	Public Power /Electric Cooperative
Invenergy	99	1	1.37%	IPP
Entergy	80	1	1.11%	IOU
Garwin McNeilus	64	4	0.89%	IPP
Nebraska Public Power District /Consortium of Public Utilities	59.4	1	0.82%	Public Power /Electric Cooperative
Madison Gas and Electric	40.7	2	0.56%	IOU
Community Wind	26.2	2	0.36%	Community Wind
BP Alternative Energy	25	1	0.35%	IPP
Minnesota Power	25	1	0.35%	IOU
Iowa Lakes Electric Cooperative	21	2	0.29%	Public Power /Electric Cooperative
Montana Dakota Utilities	19.5	1	0.27%	IOU
MEAN	10.5	1	0.15%	Public Power /Electric Cooperative
Wisconsin Public Service Corp	9.2	1	0.13%	IOU
Total	**7229.6**	**97**		

This IPP/IOU/cooperative ownership distinction is critical for several reasons. IOUs and IPPs (most of whom are also publicly traded) can leverage a number of advantages associated with developing renewable projects that are not available to cooperative owned projects. These advantages include: 1) Less permitting risk due to their ability to avoid the National Environmental Protection Act (NEPA) process; 2) Ability to leverage economies of scale across large project portfolios to reduce development, operating and maintenance costs; and 3) relatively more favorable treatment from tax equity investors, who tend to prefer entities with large portfolios of renewable projects and a long track record for renewable development at the time this project was being developed.

Each of these benefits is discussed in turn below to show that the appropriate peer group against which to evaluate the Crow Lake Wind project is other public power or electric cooperative owned and developed projects.

First, private developers and IOUs are able to avoid an automatic trigger of the National Environmental Policy Act (NEPA) provision, unlike a rural electric cooperative like BEPC, which could not avoid this trigger because it relied on Rural Utility Service (RUS) loan guarantees for its projects. A private developer will only trigger NEPA if they incur a Federal “nexus”, such as developing a project on land managed by the Bureau of Land Management (BLM), which most developers will try to avoid in order to limit permitting risk. BEPC, on the other hand, did not have this option. The impact of this step in the permitting process is significant in terms of timing and cost, as NEPA requires the preparation of a very extensive Environmental Assessment or Environmental Impact Statement.

For the Crow Lake Wind project, this lengthy permitting process took ~3 years and cost BEPC in excess of $[redacted] in preparation costs (in addition to the cost of the conservation offsets of ~$[redacted]). The NEPA process for Crow Lake Wind entailed the following:

- Public Participation (Scoping Meetings)
  - Notice of Intent published in Federal Register
  - Scoping meetings in Winner, SD and Plankinton, SD
- Multiple interagency meetings to encourage federal, state and local agencies to participate in Scoping discussions
- Open House and Public Hearings in February 2010 with wind resource maps, EIS process, timeline, turbine and transmission siting parameters, etc
  - A court reporter was made available to record public feedback
- Publishing of a draft Environmental Impact Statement (EIS) and a public comment period, with BEPC agreeing to undertake various mitigation measures
- Assessment of multiple alternatives (Crow Lake site and Winner Site) to satisfy NEPA process – this step adds considerable cost because all studies must be repeated for both locations to ensure that the site with the least impact is chosen.
- Impact Assessments
  - Geology and Soils
  - Water Resources
  - Climate Change and Air Quality
  - Biological resources
    - Avian studies (bats, whooping cranes, other birds)
    - This assessment resulted in BEPC purchasing conservation offsets to preserve habitat for the whooping crane, at a cost of $[redacted].
  - Cultural Resources – BEPC had to do considerable assessment with a number of tribal lands in the region, again adding to the time and expense of completing the project.
  - Land Use
  - Transportation
  - Visual Resources
  - Noise
  - Socioeconomics
  - Environmental Justice
  - Health and Safety

Therefore, the permitting process that BEPC underwent is significantly more costly and fraught with risk than one which most private developers must undergo.

Moreover, large private owner/developers with sizeable global wind portfolios are able to leverage economies of scale and achieve lower development and operating costs that are not available to BEPC. In MRO, over 70% of installed wind capacity is owned by 5 large developers who own or operate sizeable global wind portfolios. These entities have global wind portfolios which are even larger:

Private Owner/ Developer	Size of Global Wind Portfolio (MW)
FPL/NextEra	8077
MidAmerican	2316
Iberdrola	4301
Horizon	3141
enXco (EDF Energy)	3486

Source: FPL, MidAmerican, Iberdrola and Horizon: http://www.awea.org/learnabout/publications/factsheets/upload/2010-Annual-Market-Report-Rankings-Fact-Sheet-May-2011.pdf; For enXco (EDF), http://www.edf-energies-nouvelles.com/en/group/key-figures (accurate as of Dec. 2nd, 2011)

This size and expertise enables these entities to leverage economies of scale to procure turbines and to exploit their existing knowledge base to develop and operate projects more efficiently and in a more cost effective manner than an entity which is developing its first or second project (like BEPC). FPL/Nextera acknowledges the scale advantages they enjoy in a June 2009 presentation, where they note that their large size allows for a fleet approach for operations, and their "one power generation division (PDG) environment gives NextEra Energy Resources wind operations a tremendous competitive advantage" (Attachment #14).

BEPC, on the other hand, has had to cultivate both development and operations expertise in-house, a more complex and risky endeavor for an entity developing its first large wind site versus one developing its 20th. Indeed, BEPC's peer cooperatives in MRO have either avoided renewable generation or signed PPAs with independent developers to avoid taking on the development and project operations risk. Minnkota Power Cooperative in North Dakota, Wolverine Power Cooperative in Michigan, Sunflower Electric in Kansas, Prairie Power in Illinois, and Corn Belt Power signed PPAs from regional wind farms, but have not taken on development or operations risk.

BEPC itself has signed a number of PPAs with other wind farms in MRO (Attachment #4 provides detailed information about BEPC's PPAs). PPAs provide energy to the cooperative while eliminating the risk associated with building, operating and maintaining a project. For example, siting, permitting, transmission studies, construction risk, and operations and maintenance were not undertaken by BEPC in connection with their PPAs with other wind farms. If the capacity factor one year is lower than anticipated, BEPC simply does not buy that power. Because of this ownership difference, we do not consider BEPC's other wind projects in this common practice analysis (the equity risk resides elsewhere, not within BEPC's portfolio). Note that BEPC has two projects it developed and owns. PrairieWinds ND1 (PWND1) is seeking VCS validation, hence we do not consider that project here. BEPC also has a small project it developed adjacent to PWND1, called Minot Wind. This project was developed in 2 stages – the first stage was completed in 2002 for 2.6 MW and the second stage was completed in 2009 for 4.5 MW. A separately permitted and constructed project, each separate phase of this site fall under 5 MW, and hence the project is excluded from consideration as a "utility scale" project.

Finally, at the time this project was being developed, IOUs and IPPs with a *portfolio* of wind projects and a long track record of renewable development were more favorably viewed by potential tax equity investors than entities with one or two projects and a lesser renewable energy development history. Chardbourne and Park (C&P), a well known renewable finance law firm, estimates that in early 2009, given the severe retrenchment in the tax equity markets, the most common type of tax financing deal was for entities with a portfolio of wind farms. In addition, C&P noted that the yields required by the remaining financial institutions were quite high, and their preference was to work with developers with whom they had existing relationships (i.e. large established developers with a history of projects) (see Attachment #30, pages 28-32 for additional information). BEPC, on the other hand, was developing its second project and did not have as significant a track record for large scale renewable development at the time Crow Lake Wind was being contemplated. They were able to overcome the financing challenges of this period in part due to the Section 1603 cash grant passed under the American Resources and Recovery Act of 2009.

IOUs have yet another benefit in that their public utility commissions will give them a guaranteed rate of return on any project they undertake, significantly eliminating risks associated with new projects. (Attachment #31 provides an example of a MidAmerican filing requesting a rate of return for an Iowa wind project. Attachment #32 has additional information on traditional rate of return regulation.) Therefore, it is clear that the risks faced by a cooperative are significantly different than those faced by an IOU/IPP, and that IOU/IPP projects should not be considered similar to cooperative owned projects. Note that Element Markets' own experience as a wind developer (prior to the sale of our wind assets to International Power / GDF Suez) has helped inform this analysis.

Given these distinctions between privately owned and operated wind farms and those which are publicly owned and operated, the peer group of projects similar to Crow Lake Wind includes other utility scale, cooperative owned and operated wind farms, of which there are only four. There are two small community wind projects in MRO (Hardin Hilltop and MinWind Energy), which are owned by a number of local landowners. We do not consider those projects to be similar to Crow Lake Wind because there is no element of cooperative or cooperative subsidiary ownership.

Project	Owner	Nameplate Capacity	State
Ainsworth Wind	Nebraska Public Power District + Public Power Utilities	59	NE
Superior Wind	Iowa Lakes Electric Cooperative	10.5	IA
Lakota Wind	Iowa Lakes Electric Cooperative	10.5	IA
Kimball Wind	Municipal Energy Agency of Nebraska (MEAN)	10.5	NE

Step 4b: Discuss similar options that are occurring (including essential differences between the other project activities and the project)

Project	Essential Distinctions	Source
Ainsworth Wind	To our knowledge, Ainsworth Wind did not go through a NEPA process (we were not able to locate their NEPA filing or the federal register notice about the project). Hence, Ainsworth did not face the significant cost and permitting risk that Crow Lake Wind faced, which included 36 months for preparation of the appropriate filings, a public approval process and a $[redacted] cost for mitigation of potential environmental effects (and $[redacted] in preparation costs). In addition, this project is selling voluntary carbon offsets through Terrapass, a carbon offset retailer. Based on the additionality tool guidance, a project which is selling carbon credits does not have to be considered as a "similar project activity" because it displays a need for carbon credits. Our consideration of Ainsworth, therefore, is a conservative approach to Common Practice.	http://www.terrapass.com/projects/details/ainsworth-wind-energy-facility.html
Superior Wind	To our knowledge, Superior and Lakota Wind did not go through a NEPA process (we were not able to locate their NEPA filing or the federal register notice about the project). Hence, they did not face the significant cost and permitting risk that Crow Lake Wind faced, which included 36 months for preparation of the appropriate filings, a public approval process, and a $[redacted] cost for mitigation of potential environmental effects (and $[redacted] in preparation costs). These projects needed special financing to be able to build – they were initially not feasible due to lack of incentives. Once	http://www.esthervilledailynews.com/page/content.detail/id/504231/Iowa-Lakes-Electric-Cooperative-dedicates-wind-energy-project.html
Lakota Wind		http://www.ktiv.com/Global/story.asp?S=10966401

	Congress passed the Clean Renewable Energy Bond (CREB) program in 2005, these projects received $43 million in financing, which was critical for them to be built. In addition, these projects signed agreements to provide power to a nearby ethanol plant, receiving additional economic support.	
Kimball Wind	To our knowledge, Kimball Wind did not go through a NEPA process (we were not able to locate their NEPA filing or the federal register notice about the project). Hence, it did not face the significant cost and permitting risk that Crow Lake Wind faced, which included 36 months for preparation of the appropriate filings, a public approval process, and a $[redacted]cost for mitigation of potential environmental effects (and $[redacted] in preparation costs).	http://www.nmppenergy.org/KimballWindProject/facts#Costs

The Crow Lake Wind ownership structure is entirely unique in the world of cooperative wind development. Seven of the turbines located at the Crow Lakes project site are owned indirectly by 600 landowners (through South Dakota Wind Partners). One turbine is owned by the Mitchell Technical Institute. No other project in the country has utilized this unique structure, which has yielded many benefits to the community, such as local economic development through the distribution of economic rents across multiple landowners in BEPC's service territory, and the training of wind technicians at MTI.

Developing the structure alone entailed significant time and expense. More importantly, the power price paid to these entities on a per MWh basis is [redacted]% higher than the price earned by BEPC's PWSD1 subsidiary. This added cost is borne by BEPC in part so that the cooperative supports economic development in the community. The higher expense of this power from the community owned portion of Crow Lake Wind and the additional risk of developing this structure will be partially mitigated with the revenue from the VCUs. Indeed, none of the projects described above includes this unique ownership structure.

Given the additional financial assistance, size, and lack of permitting risk faced by the other projects, it is clear that PWSD1 has essential distinctions from these other cooperative owned projects. As the largest project of this size undertaken single-handedly by a cooperative in the U.S. at the time of its online date, this project does not represent common practice, and hence is additional.

2.6 Methodology Deviations

None

3 QUANTIFICATION OF GHG EMISSION REDUCTIONS AND REMOVALS

3.1 Baseline Emissions

Baseline emissions include only CO2 emissions from electricity generation in fossil fuel fired plants that are displaced due to the project activity. The methodology assumes that all project electricity generation above baseline levels would have been generated by existing grid connected power plants and the addition of new grid connected power plants.

The baseline emissions are $BE_y = EG_{PJ,y} * EF_{grid,CM,y}$ where

BE_y = Baseline emissions in year y (tCOE2 / yr)

$EG_{PJ,y}$ = Quantity of net electricity generation that is produced and fed into the grid as a result of the implementation of the CDM project activity in year y (MWh/yr)

$EF_{grid,CM,y}$ = Combined margin CO2 emission factor for grid connected power generation in year y calculated using the latest version of the "Tool to calculate the emission factor for an electricity system" (tCO2 / MWh)

Calculation of $EG_{PJ,y}$ for Greenfield plants:

If the project activity is the installation of a new grid-connected renewable power plant/unit at a site where no renewable power plant was operated prior to the implementation of the project activity, then:

$EG_{PJ,y} = EG_{facility,y}$

Where:

$EG_{PJ,y}$ = Quantity of net electricity generation that is produced and fed into the grid as a result of the implementation of the CDM project activity in year y (MWh/yr)

$EG_{facility,y}$ = Quantity of net electricity generation supplied by the project plant/unit to the grid in year y (MWh/yr)

We next calculate $EF_{grid,CM,y}$ based on the "Tool to calculate the emission factor for an electricity system".

Step 1: Identify the relevant electricity systems.

For the purpose of determining the electricity emission factors, a project electricity system is defined by the spatial extent of the power plants that are physically connected through transmission and distribution lines to the project activity (e.g. the renewable power plant location or the consumers where electricity is being saved) and that can be dispatched without significant transmission constraints. The protocol requires that if electricity systems are well defined in the country in question, that those official designations be used.

The United States has a well defined electricity system, with eight regional electric systems defined by the North American Electric Reliability Council (NERC). The BEPC facility is interconnected to the WAPA Integrated System for the Upper Great Plains region, which is part of the MRO NERC region. Since this presents a clear grid boundary for the projects, MRO is defined as the appropriate electricity system in which all the calculations are done.

Step 2: Choose whether to include off grid power plants

We choose not to include off grid power plants, as this is optional in the methodology, and we do not have access to that data. Hence, we follow Option 1, only grid connected power plants are included in the calculation.

Step 3: Select a method to determine the operating margin (OM).

The calculation of the operating margin emission factor ($EF_{grid,OM,y}$) is based on the Simple Operating Margin (Simple OM, Step 3, option a). In addition, the ex-ante option is chosen for the Simple OM. The Simple OM is allowed to be used if low cost must-run resources (LCMR) constitute less than 50% of the total grid generation based on the 5 most recent years of historical data.

We define low cost must-run resources as nuclear, hydro, wind, solar and *any other unit with a capacity factor over 80%.* This follows the precedent that EPA used in developing their eGRID database, where baseload units were defined as those with a capacity factor over 80% (EPA eGRID Technical Support Document, Attachment #15). Where coal units meet or exceed this capacity factor, they are considered baseload.

Indeed, it is important to note that coal is not always the most frequently run unit in MRO. On a weighted average basis, coal units in MRO have capacity factors ranging from 63 – 70%. This calculation is based on EIA 860 data for units that use bituminous, sub-bituminous, or lignite coal as a primary fuel. (The Operating Margin calculation for each individual year has a tab called Coal Units Run Time, which calculates the weighted average coal unit capacity factor in MRO based on MWh from Coal Units and Name Plate Capacity.)

	Coal Unit Weighted Capacity Factor
2005	69.7%
2006	67.8%
2007	64.02%
2008	66.9%
2009	63.3%

These capacity factors suggest that coal units, on average, are often *intermediate units which are displaced* as opposed to *baseload, low cost must-run* units in MRO. In other words, if other, cheaper generation is available, the coal units are backed down to accommodate those resources. For example, the summer of 2011 has seen significant availability of hydro resources in the Western Area Power Administration's (WAPA) Upper Great Plains region (which comprises a significant portion of MRO). These hydro resources are comprised of large dams built on the Missouri River by the federal government and managed by WAPA, a federal agency. This year's hydro availability has been so significant that certain coal units have been shut off or backed down to accommodate this power. For example, in late August, BEPC's Antelope Valley Station and Leland Olds Station (AVS and LOS, both coal) had capacity factors between [redacted]-[redacted]% (see charts below) because they were backed down to accommodate hydro. Laramie River Station (LRS, a coal unit) is running over 90%, as is the Duane Arnold nuclear unit – these are clearly low cost must-run / baseload units. Therefore, it is not automatic that every coal unit, regardless of its run time, should be considered baseload (i.e. low cost, must-run (LCMR)). Hence, we use the EPA's eGRID precedent and identify any unit with a capacity factor greater than or equal to 80% as a LCMR unit.

[redacted]

The EIA 923/906 and 860 databases sets are used to calculate the Simple OM (all calculations are given in Attachment #16). The EIA database is widely recognized in the United States as a high quality survey of all power plants and generators. The EIA 923 database is an annual survey that provides information on the amount and type of fuel used (in MMBtus) at each plant and the total MWh generated at each plant by fuel type. The EIA 860 database provides information on units available at each plant, the fuel types used, the online date of each unit, and the unit's nameplate capacities. Unit level generation and fuel usage is not available in EIA 860, and therefore the combination of the 2 databases is necessary to get unit level information, as called for in the protocol. At the time this analysis was conducted, EIA data was complete through calendar year 2009 (2010 data was partially available, but not yet complete). Hence 2009 is regarded as the most recent year of completely available data where EIA data is used, and all calculations are done at a unit level. The LCMR assessment is based on a five year historical average, hence the calculation is done from 2005-2009.

We calculate the proportion of total generation from LCMR resources using the following process:

1) The EIA 860 Data for each year surveys units by fuel types used and operating status. We focus our analysis only on operating units at the plant (retired, stand-by and out-of-service units are not included unless the unit is expected to return to service). We then calculate the plant's total nameplate capacity. Next, we calculate each unit's proportion of the plant's total nameplate capacity. This is the Unit Scaling factor (See sample below)

PLNTCODE	NAMEPLATE	Total Plant Size	Unit Scaling Factor	Fuel 1	Fuel 2
55135	186.6	373.2	50.0%	NG	DFO
55135	186.6	373.2	50.0%	NG	DFO
55038	1.2	3.6	33.3%	NG	DFO
55038	1.2	3.6	33.3%	NG	DFO
55038	1.2	3.6	33.3%	NG	DFO
55035	0.8	1.6	50.0%	OBG	NG
55035	0.8	1.6	50.0%	OBG	NG
55033	1	3	33.3%	OBG	NG
55033	1	3	33.3%	OBG	NG
55033	1	3	33.3%	OBG	NG
55027	0.5	1	50.0%	OBG	NG
55027	0.5	1	50.0%	OBG	NG
55010	177.3	283.5	62.5%	NG	DFO

2) We use this factor to get the unit's MWh generated and the emissions since the EIA 923 database only provides data at a total plant level for each individual fuel type used at the plant. Specifically, the EIA 923 database for the MRO region is then used to build a separate table: total MWh produced at the plant arranged by fuel type.

Example – EIA 923 Data

Plant ID	Plant Name	Operator Name	Reported	ELEC FUEL CONSUMPTION MMBTUS	NET GENERATION (megawatthours)
30	Madelia	City of Madelia	DFO	99	-207
30	Madelia	City of Madelia	NG	0	0
59	Platte	Grand Island City of	SUB	6,772,698	609,970
60	Whelan Energy Center	Hastings City of	DFO	8,102	485
60	Whelan Energy Center	Hastings City of	SUB	5,667,098	496,857
785	Kingsley	Central Nebraska Pub P&I Dist	WAT	142,852	14,453
1046	Dubuque	Interstate Power and Light Co	DFO	556	-76
1046	Dubuque	Interstate Power and Light Co	BIT	1,225,032	93,056
1046	Dubuque	Interstate Power and Light Co	NG	59,811	4,423
1046	Dubuque	Interstate Power and Light Co	SUB	2,868,237	215,206
1047	Lansing	Interstate Power and Light Co	DFO	220	19
1047	Lansing	Interstate Power and Light Co	BIT	2,320,931	210,640
1047	Lansing	Interstate Power and Light Co	DFO	37,175	3,132

Example – Total MWh by Fuel Type

Sum of NET GENERATION (megawatthours)	Fuel Type								
Plant ID	AB	BIT	BLQ	DFO	KER	LFG	LIG	MSW	NG
30				118.998					492
59									
60				141.999					
378									
785									
1046		155411		-32					
1047		0		2602					
1048									3908
1052				6.001					
1058		0		0					34084
1060									
1067									
1068				46947					
1073		0		105		13679			4002
1077		113149							4660.999

3) The EIA 860 database also identifies all the fuel types used at each unit. The first fuel type is generally the primary fuel; the other fuel types are often starter fuels and therefore used in significantly smaller quantities. For each fuel type (of which there are up to 6), the MWh and electric MMBtus for that plant and for that fuel type are queried using the MWh by Plant and Fuel Type table. The unit level MWh and electric MMBtus produced at that unit for the particular fuel type is determined by multiplying the plant level number by the unit scaling factor. The unit's capacity factor is then calculated using the unit's nameplate capacity and the TOTAL MWh produced at the unit for all fuel types. Note that unit level scaling provides the most objective measure available to conduct these calculations at a unit level as required in the protocol. The unit level scaling measure assumes that each unit's contribution to the total MWh generated is based on its nameplate capacity.

4) LCMR units are identified using the following process:

   a. All nuclear, hydro and wind units are considered LCMR units

   b. All units with capacity factors >= 80% are considered LCMR

5) Total LCMR unit MWh are then calculated as a percentage of the total MWh generated by all units in MRO.

6) For the simple OM, the percentage of LCMR hours needs to be less than 50% over 5 years. Each year's LCMR unit hours and total MWh generated and the percentage is calculated in the Summary – Unit Level OM Calculation spreadsheet.

PLNTCODE	NAMEPLATE	Total Plant Size	Unit Scaling Factor	Fuel 1	Fuel 2	MWH from Fuel 1 at Unit	MWH from Fuel 2 at Unit	Total MWhrs at Unit	Unit Capacity Factor	LCMR Unit?
10223	8.5	8.5	100%	SUB		45605.52	#N/A	45,606	61.25%	0
1956	2	2	100%	DFO		34	#N/A	34	0.19%	0
1958	1.2	9.2	13%	DFO		7.557521739	#N/A	8	0.07%	0
1958	4	9.2	43%	DFO	NG	25.19173913	29.15652174	54	0.16%	0
1958	4	9.2	43%	DFO	NG	25.19173913	29.15652174	54	0.16%	0
7966	2.3	2.3	100%	WND		5038.999	#N/A	5,039	25.01%	LCMR Unit
54710	1.5	1.5	100%	DFO		19.001	#N/A	19	0.14%	0
54210	13.3	13.3	100%	SUB		81375.22	#N/A	81,375	69.85%	0
54211	3	5	60%	SUB		22518.744	#N/A	22,519	85.69%	LCMR Unit
54211	2	5	40%	SUB		15012.496	#N/A	15,012	85.69%	LCMR Unit
54212	3.5	6.5	54%	SUB		20609.73869	#N/A	20,610	67.22%	0

Over a 5 year basis, this results in LCMR resources being 41.99% of total generation on a weighted average basis.

	2005	2006	2007	2008	2009
MWhrs from LCMR Units	78,893,736	88,880,056	94,297,504	89,121,139	83,617,242
Total MWhrs in MRO	183,871,190	217,902,933	209,332,455	212,248,071	212,131,844
LCMR Units as % of Total MWhrs	42.91%	40.79%	45.05%	41.99%	39.42%
5 Year Wtd Average	41.99%				

Hence, we can use the Simple OM.

Step 4: Calculate the operating margin emissions factor according to the selected method

The Simple OM is calculated using Option A1, based on the net electricity generation and the CO2 emission factor of each power unit.

$$EF_{grid,OMsimple,y} = \frac{\sum_{m} EG_{m,y} \times EF_{EL,m,y}}{\sum_{m} EG_{m,y}}$$

where

$EF_{grid,\ OM\ simple\ y}$ - Simple operating margin CO2 emissions factor in year y

$EG_{m,y}$ - Net quantity of electricity generated by power unit m in year y

$EF_{EL,\ m,y}$ - CO2 emission factor of power unit m in year y (tCO2 / MWh)

M - All power units serving the grid except low cost must run units

Y - Relevant year

$EF_{EL,\ m,y}$ is further determined by:

$$EF_{EL,m,y} = \frac{\sum_{i} FC_{i,m,y} \times NCV_{i,y} \times EF_{CO2,i,y}}{EG_{m,y}}$$

Where

$FC_{i,m,y}$ - Amount of fossil fuel type i consumed by power unit m in year y (Mass or Unit Volume)

$NCV_{i,y}$ - Net Calorific value (energy content) of fossil fuel type i in year y (GJ/mass or unit volume)

$EF_{CO2,i,y}$ - CO2 Emissions Factor of Fossil Fuel type i in year y (tCOe2/GJ)

$EG_{m,y}$ - Net quantity of electricity generated by power unit m in year y (MWh)

M - All power units serving the grid except low cost must run units

Y - Relevant year

I - Fossil fuel types combusted in power unit m in year y.

The emissions for each unit are then calculated using the following process:

1. For each fuel type used at the unit, we look up the EIA's GHG combustion factor by fuel type. This combustion factor is provided by EIA for each fuel type and is used for the preparation of GHG inventories. A sample is provided below.

Code	***Meaning***	***Emissions Factors (kg / MMBtu)***
AB	Agricultural Crop Byproduct	0
BIT	Anthracite Coal and Bituminous Coal	93.46
BLQ	Black Liquor	0
DFO	Distillate Fuel Oil (Diesel, No. 1, No. 2,	73.15
JF	Jet Fuel	70.88
KER	Kerosene	72.31
LFG	Landfill Gas	0
LIG	Lignite	96.43
MSB	Municipal Solid Waste – Biogenic com	0
MSN	Municipal Solid Waste – Non-biogenic	41.14
NG	Natural Gas	53.06
NUC	Nuclear	0
OBG	Other Biomass Gas (includes digester g	0
OBL	Other Biomass Liquids (specify in Com	0
OBS	Other Biomass Solids	0

2. The product of NCV $_{i,y}$ and FC $_{i,m,y}$ is given by the Elec Fuel Consumption factor (in MMBtus) in the EIA 923 database. A separate table is built arranging the MMBtus from each fuel type by plant, which is then scaled to a unit level using the unit scaling factor calculated earlier.

Example – Elec Fuel Consumption in MMBtus by Fuel Type

Sum of ELEC FUEL CONSUMPTION MMBTUS	Fuel Type										
Plant ID	AB	BIT	BLQ	DFO	JF	KER	LFG	LIG	MSB	MSN	NG
30				99							0
59											
60				8102							
785											
1046		1225032		556							59811
1047		2320931		37395							
1048											12540
1058		0		0							664121
1060											
1067											
1068				749797							
1073		1404530		1880			143352				120829
1077		0		0							179082
1079											15131

3. Then the electricity MMBtus for that fuel type at that unit are multiplied by the EIA's GHG combustion factor (this factor is in kg CO2 / MMBtu) for that fuel type. The total emissions for that unit are the SUM of emissions from each fuel type divided by 1,000 to convert it into Metric Tons. The total MWh generated by the unit was then calculated (and is explained above under the LCMR analysis section).

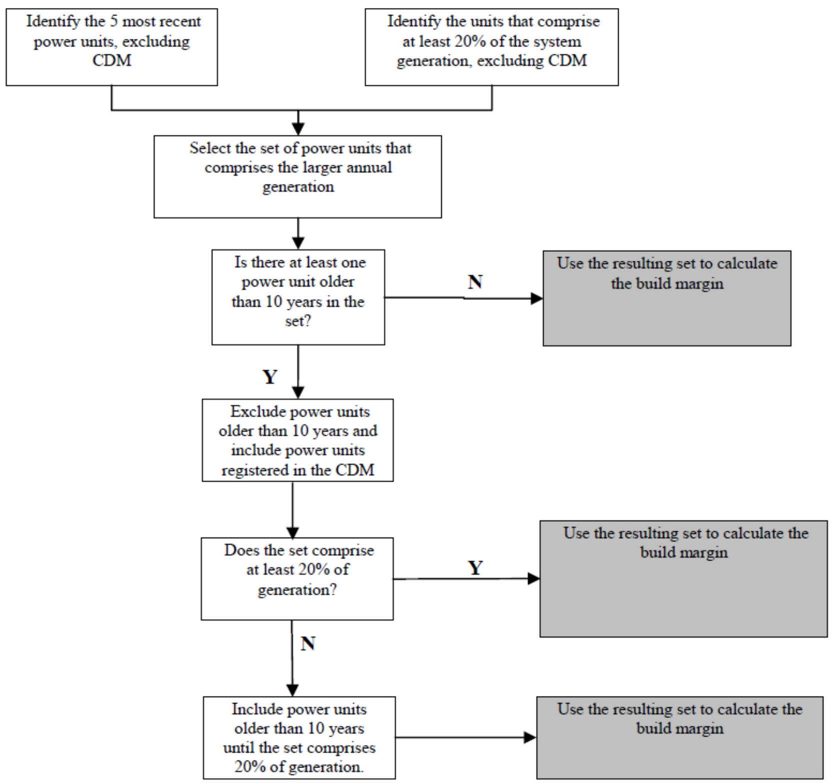
   Metric Tons and MWh are calculated only for non-LCMR units, per the protocol, for the 3 most recent years for which data is available. Hence, the Simple OM is 0.98542.

	2007	2008	2009
Non-LCMR Unit Emissions (Metric Tons)	112,612,426	121,874,545	126,842,217
Non-LCMR Unit MWhrs	115,034,951	123,126,932	128,514,602
Intensity Factor (Metric Tons / MWh)	0.979	0.990	0.987
3 Yr Historcal Wtd Average	0.98542		

All calculations are provided in Attachment #16.

Step 5: Calculate the Build Margin Emission Factor (BM)

The build margin is calculated using both EIA using Option 1 (See attachment #16) using EIA 860 and 923 data from 2009. The build margin uses the following procedure:



Hence, using this Unit Generation in MWhs factor, the above procedure is implemented to identify the set of plants for the Build Margin. Ultimately, the set of power plants used is power units older than 10 years that comprise 20% of the generation. The outcome for each of the substeps for Step 5 is given below:

Step 5a: Identify the set of five power units, excluding power units registered as CDM (VCS) project activities that started to supply electricity to the grid most recently and determine their annual electricity generation (AEG).

$AEG_{Set5Units}$ = 45,533 MWh

Step 5b: Determine the annual electricity generation of the project electricity system and identify the set of power units that started to supply electricity to the grid and comprise 20% of the total.

AEG $_{Set>20\%}$ = 43,971,662 MWh

Step 5c: Since the number in step 5b is larger, the Set_{sample} is the set which comprises 20% of the total generation.

Step 5d: The set of plants that comprises 20% of the generation includes units over 10 years old, so we include projects seeking VCS registration and exclude units that came online over 10 years ago. The generation in MWh from this new set is:

AEG $_{SetSampleVCS}$ = 35,383,819 MWh

20% of the total AEG (AEG_{total}) is 42,424,699 MWh

Since AEG $_{SetSampleVCS}$ < $AEG_{total,}$ we go to Step 5e

Step 5e: Include units seeking VCS registration and units over 10 years old until 20% of total generation is reached. This is called $Set_{SampleVCS>10yrs}$ and is the sample group of units used for the Build Margin.

The build margin is calculated using the following:

$$EF_{grid,BM,y} = \frac{\sum_m EG_{m,y} \times EF_{EL,m,y}}{\sum_m EG_{m,y}}$$

Since the group of units for calculating the Build Margin includes units over 10 years old, Option A2 from the Simple Operating Margin calculation is used to calculate the Build Margin.

$$EF_{EL,m,y} = \frac{EF_{CO2,m,i,y} \times 3.6}{\eta_{m,y}}$$

As before, a combination of the EIA 860 and 923 data is used for this calculation. Only Operating Units are considered and are sorted based on the online date of the unit. Total MWh at each unit are calculated using the Simple OM above using the unit scaling factor and the EIA 923 database.

Here, $n_{m,y}$ is the conversion efficiency of the power unit in year y, and the conversion efficiency is found in the default factors provided in Annex A of the methodology. The prime mover column and other and the corresponding EIA fuel combustion factor is used for this calculation. A sample spreadsheet is given below.

PLANT_CODE	OPERATING_YEAR	Fuel 1	Total MWhrs at Unit ($Eg_{m,y}$)	$EF_{CO2,m,I,y}$ (FUEL 1 ONLY) kg CO2 / MMBtu	$n_{m,y}$ (DEFAULT TABLE VALUES)	$EF_{EL,m,y}$ (Tons CO2 / MWh)	$EG_{m,y}$ * $EF_{EL,m,y}$ (METRIC TONS)
1172	**2009**	WND	-	-	1	-	-
55995	**2009**	WND	3,444	-	1	-	-
56607	**2009**	WND	711	-	1	-	-
56831	**2009**	WND	17,845	-	1	-	-
56880	**2009**	WH	7,691	-	1	-	-
57097	**2009**	WND	-	-	1	-	-
57111	**2009**	WND	24,244	-	1	-	-
57045	**2009**	WND	7,354	-	1	-	-
57120	**2009**	WND	36,900	-	1	-	-
50413	**2009**	DFO	-	73.15	40.0%	0.624	-
56355	**2009**	WND	40,919	-	1	-	-

Step 5f: Calculate the build margin emission factor.

The Build Margin is calculated to be the following:

Numerator (Metric Tons CO2)	18,145,405
Demonimator (MWh)	43,980,064
Build Margin	0.4126

Step 6: Calculate the combined margin (CM) emissions factor.

The wind units are not dispatchable and are intermittent in nature. They also have no capacity value. Hence, a weight of 75% is used for the operating margin, and 25% is used for the Build Margin (this is Option A under Step 6, the Weighted Average CM).

The Combined Margin, given by $EF_{grid,CM,y,}$ is then calculated to be:

$EF_{grid,CM,y}$ = 75%*0.98542 + 25% *0.4126 = 0.8422 metric tons / MWhr.

Hence, the baseline emissions for this project are based on the MWhs generated by the wind unit and are 0.8422 metric tons / MWh combined margin.

The expected production at the wind project is expected to be 162 MWs * 8760 hours * 36.1558% capacity factor = 513,095 MWh per year. (Please see Attachment #24).

The baseline emissions, therefore, are 513,095 MWh * 0.8422 metric tons / MWhr = 432,128 metric tons per year.

Production Year	Term	MWh	Baseline Emissions
2011	Feb 1 -Dec 31	470,337	396,118
2012	Jan - Dec	513,095	432,128
2013	Jan - Dec	513,095	432,128
2014	Jan - Dec	513,095	432,128
2015	Jan - Dec	513,095	432,128
2016	Jan - Dec	513,095	432,128
2017	Jan - Dec	513,095	432,128
2018	Jan - Dec	513,095	432,128
2019	Jan - Dec	513,095	432,128
2020	Jan - Dec	513,095	432,128
2021	Jan 1 - Jan 31	42,758	36,011
	Total (Metric Tons)		4,321,282
	Average Annual Metric Tons		432,128

3.2 Project Emissions

Per the methodology ACM0002, project emissions from this project are zero. Per the methodology, we do not consider project emissions because this is not a geothermal, solar thermal, or hydro project.

3.3 Leakage

Per ACM0002, no leakage is considered.

3.4 Summary of GHG Emission Reductions and Removals

Therefore, the total emissions reductions from this project are expected to be:

$ER_y = BE_y - PE_y$

Here, PE_y is equal to zero.

Years	Estimated baseline emissions or removals (tCO2e)	Estimated project emissions or removals (tCO2e)	Estimated leakage emissions (tCO2e)	Estimated net GHG emission reductions or removals (tCO2e)
2011 (Feb. 1 – Dec. 31)	396,118	0	0	396,118
2012	432,128	0	0	432,128
2013	432,128	0	0	432,128
2014	432,128	0	0	432,128
2015	432,128	0	0	432,128
2016	432,128	0	0	432,128
2017	432,128	0	0	432,128
2018	432,128	0	0	432,128
2019	432,128	0	0	432,128
2020	432,128	0		432,128
2021	36,011	0	0	36,011
Total	4,321,282	0	0	4,321,282

4 MONITORING

4.1 Data and Parameters Available at Validation

Monitoring will consist of

- Metering the electrical energy produced – this is provided by a revenue grade meter.

Data Unit / Parameter:	$EF_{grid,CM,y}$
Data unit:	Metric tons / MWhr
Description:	The CO_2 emissions factor for the grid displaced due to the project activity, during the year y in metric tons CO_2/MWh, as calculated by the combined operating margin (CM), which is a weighted average of the Simple Operating Margin and Build Margin.
Source of data:	Calculated based on Tool for calculating emissions intensity of the grid; Sources include EIA 923/860 databases, EIA fuel emissions factors
Value applied:	0.8422

Justification of choice of data or description of measurement methods and procedures applied:	w1 * Simple OM + w2 * Build Margin, where w1 = 0.75, w2 = 0.25, Simple OM = 0.98542 and Build Margin = 0.4126.
Any comment:	The ex-ante option is chosen

Data Unit / Parameter:	$EF_{grid,OMsimple,y}$
Data unit:	Metric tons / MWh
Description:	Simple Operating Margin CO2 emissions factor in year y
Source of data:	Calculated based on Tool for calculating emissions intensity of the grid; Sources include EIA 923/860 databases, EIA fuel emissions factors
Value applied:	0.98542
Justification of choice of data or description of measurement methods and procedures applied:	Calculated based in Tool for calculating emissions intensity of the grid.
Any comment:	The ex-ante option is chosen

Data Unit / Parameter:	$EG_{m, y}$
Data unit:	MWh
Description:	Net quantity of electricity generated by power unit m in year y (m includes all power units except low cost must run power units)
Source of data:	EIA 923/860 databases
Value applied:	Varies by unit
Justification of choice of data or description of measurement methods and procedures applied:	N/A
Any comment:	N/A

Data Unit / Parameter:	For simple operating margin - $EF_{EL,m, y}$
Data unit:	Metric tons / MWh
Description:	CO2 emissions factor of power unit m in year y (tCO2 / MWh)
Source of data:	EIA 923/860 databases
Value applied:	Varies by unit
Justification of choice of data or description	Calculated using EIA 923 / EIA 860 databases

of measurement methods and procedures applied:	and EIA Fuel emissions factors
Any comment:	N/A

Data Unit / Parameter:	$FC_{i,m,y}$ and $NCV_{i,y}$
Data unit:	MMBtus
Description:	Amount of fossil fuel type i consumed by power unit m in year y (mass or unit volume) and the Net Calorific Value (energy content) of fossil fuel type i in year y
Source of data:	EIA 923/860 databases and EIA Fuel Emissions Factors
Value applied:	Varies by unit
Justification of choice of data or description of measurement methods and procedures applied:	The EIA 923 database provides the product of these two factors and provides the MMBtus consumed for electricity generation for each plant in the grid.
Any comment:	N/A

Data Unit / Parameter:	$EF_{CO2,i,y}$
Data unit:	Kg CO2e/MMBtu
Description:	CO2 emissions factor of fossil fuel type i in year y
Source of data:	EIA 923/860 databases and EIA Fuel Emissions Factors
Value applied:	Varies by fuel type
Justification of choice of data or description of measurement methods and procedures applied:	EIA fuel emissions factors are default values that have been used to prepare GHG inventories.
Any comment:	N/A

Data Unit / Parameter:	$EF_{grid,BM,y}$
Data unit:	Metric Tons / MWh
Description:	CO2 emissions factor of fossil fuel type i in year y
Source of data:	Calculated using Option A2 for simple OM, but including all units as defined in the methodology. EIA 923/860 databases and EIA Fuel Emissions Factors
Value applied:	0.4126

Justification of choice of data or description of measurement methods and procedures applied:	Calculation described in Section #3.
Any comment:	N/A

Data Unit / Parameter:	For Build Margin - $EF_{EL,m,y}$
Data unit:	Metric tons / MWh
Description:	CO2 emissions factor of power unit m in year y (tCO_2 / MWh)
Source of data:	EIA 923/860 databases
Value applied:	Varies by unit
Justification of choice of data or description of measurement methods and procedures applied:	Calculated using EIA 923 / EIA 860 databases and EIA Fuel emissions factors, based on Option A2 as described under the Simple OM.
Any comment:	This factor uses the power generation efficiency factor and the CO2 emissions factor of fossil fuel type I in year y.

Data Unit / Parameter:	For Build Margin - $n_{m,y}$
Data unit:	MMBtus / MWh
Description:	Average net energy conversion efficiency of power unit m in year y
Source of data:	Default table, Annex 1
Value applied:	Varies by unit
Justification of choice of data or description of measurement methods and procedures applied:	This is required by the Tool for the option chosen.
Any comment:	N/A

4.2 Data and Parameters Monitored

Data Unit / Parameter:	$EG_{facility,y}$
Data unit:	MWh/yr
Description:	Quantity of net electricity generation supplied by the project plant/unit to the grid in year y (MWh/yr)
Source of data:	Project activity revenue meter at the site (JemStar Meter)

Description of measurement methods and procedures to be applied:	Revenue grade meters record power generated on a continuous basis. Production is then aggregated at an hourly interval so that an 8,760 hourly production shape is available for each year. Data monitoring takes place on a monthly basis, when WAPA reads the meters and submits data to the Midwest Renewable Energy Tracking System (M-RETS). This monthly data from M-RETS is what will be used to calculate the emissions reductions.
Frequency of monitoring/recording:	Data Recording: Continuous Data Aggregation: Hourly Data Monitoring: Monthly
Value applied:	Varies based on meter output
Monitoring equipment:	The project operator will provide a revenue quality metering device which provides information for all test, measurement, and project operating equipment on or before the start of project operations. This information will be updated over the life of the project as devices are replaced. The device record will include a basic specification sheet for each metering device used to measure the wind energy output to the grid.
QA/QC procedures to be applied:	The project operator will perform metering device calibrations as required in the Interconnection Agreement. The project operator will provide an annual report detailing the calibration activities associated with the project activity.
Calculation method:	Meter readings
Any comment:	N/A

4.3 Description of the Monitoring Plan

BEPC is responsible for monitoring the electricity generation facility. The monitoring plan will include data monitoring, regular equipment maintenance and calibrations, and data management/archiving. Overall responsibility for the accurate measurement and archival of generation information is managed by BEPC and WAPA. The parameters laid out in section 4.2 above will be monitored and the associated data will be aggregated and reported according to the following procedures.

- Data Monitoring

- Revenue grade meters record power generated on a continuous basis.
- Production is then aggregated at an hourly interval so that an 8,760 hourly production shape is available for each year.
- Data monitoring takes place on a monthly basis when WAPA reads the meters and submits data to the Midwest Renewable Energy Tracking System (M-RETS).
- This monthly data from M-RETS is what will be used to calculate the emissions reductions.

- Metering Devices:
  - BEPC will provide a revenue quality metering device which provides information for all test, measurement, and project operating equipment on or before the start of project operations. This information will be updated over the life of the project as devices are replaced. The device record will include a basic specification sheet for each metering device used to measure the wind energy output to the grid.
  - Calibration Log: BEPC or one of its member cooperatives will perform metering device calibrations as required in the Interconnection Agreement. BEPC will provide an annual report detailing the calibration activities associated with the project activity. If no calibration activities are performed, BEPC will provide an attestation detailing this.
  - Extraordinary Events: BEPC will report any extraordinary and significant unscheduled maintenance or repair activities identified that cause system downtime and would therefore prevent the production of emission reductions from the power generation source.

All records will be retained for 12 years by BEPC, which is 2 years beyond the project crediting period of 10 years.

5 ENVIRONMENTAL IMPACT

This project is a zero emissions project. It has a positive environmental impact as it displaces electricity on the grid. A NEPA review was conducted for this site, resulting in an Environmental Impact Statement (EIS). The EIS is discussed in detail in the Common Practice Section under additionality above. Attachment #2 provides additional information.

6 STAKEHOLDER COMMENTS

There are currently a variety of public documents that report, publicize, and praise this novel project. Examples include:

1) A video from MTI about learning how to maintain turbines at Crow Lake Wind: http://www.youtube.com/watch?v=J2-jmKn86Ew
2) A general description of the project: http://www.mitchellrepublic.com/event/article/id/50773/

In addition, the EIS process resulted in multiple public workshops and a stakeholder review. Entities involved in the process were either supportive of the project or their concerns were adequately resolved per the NEPA process. The EIS process has already been discussed in the Common Practice and permitting sections. Additional information is provided in Attachment #2.