2005 Project Abstract
For the Period Ending June 30, 2010
PROJECT TITLE: **Community Wind Energy Rebate and Financial Assistance Program**
Project Manager: Stacy Miller
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FAX Number: 651-297-7891
Web Page address: www.energy.mn.gov
Funding Source: Environment and Natural Resources Trust Fund
Legal Citation: ML 2005, First Special Session, Chapter 1, Article 2, Section, 11, Subd. 10 (a), as amended by ML 2006, Chapter 243, Section 15, subdivision 10 (a) and as amended by ML 2009, Ch. 143, Subd. 16, paragraph (2).
Appropriation amount: $200,000

Overall Project Outcome and Results

The **Community Wind Energy Rebate and Financial Assistance Program** was designed to competitively select proposed community-owned wind energy projects to receive financial assistance and rebates of $200,000 for the successful completion of megawatt-scale, grid-connected wind turbines. The goal behind the program was to demonstrate how a local government could use local resources to utilize renewable energy development as a means to direct funding to the public and to help contribute to local renewable energy goals. Two local government projects were competitively selected to participate in this program including Winona County Economic Development Authority (EDA) and a collaborative effort by the Rural Minnesota Energy Board (RMEB) and the Metropolitan Energy Policy Coalition (MEPC), formerly known as the Metro County Energy Task Force (MCETF). Both entities found that publicly owned megawatt-scale wind projects are difficult to develop without private partnerships that allow for federal financial support.

In the case of Winona County EDA, there were a number of hurdles and barriers encountered. During the 2007 legislative session, the county first had to pursue legislation (*Minn Laws 2007 Ch. 57, art. 2, § 39)* to allow the county to sell power. Following that a number of financing options were considered before one was settled upon. Based on the selected option, Winona County EDA submitted their proposal for approval to receive the rebate in January 2010. However, at this time Winona County EDA's effort was determined to be ineligible for a rebate due to the project ownership structure necessary to allow eligibility for federal grants. Under the proposal, the Winona County EDA would have entered into a partnership with private investors to create a limited liability corporation. Winona County EDA proposed receiving the Environment and Natural Resources Trust Fund dollars and in turn, lending the funds to the project partners. However, this structure was deemed not to fit the requirements of the grant that the project be owned by a public entity. In a letter dated April 28, 2010, the Department of Commerce officially requested that the $200,000 in funds reserved for Winona County EDA be returned to the Trust Fund.

While this program did not contribute financial assistance to a local government to support the development of a megawatt-scale local wind project, the grant opportunity was helpful in obtaining the legal authorization to own interest in a wind generation project and to do so on a timeline that will allow for the contribution of federal funds. The lessons learned through this exercise are included in the final report and may be valuable to other public entities seeking to participate in public-private partnerships.

RMEB is a Joint Powers of sixteen counties in southern Minnesota formed to provide policy guidance on issues surrounding energy development in rural Minnesota. MEPC is a member group of seven metro area counties and the Metropolitan Council with "longterm interest in the use of secure, safe, reliable, sustainable, economical and environmentally responsible energy for constituents." The RMEB-MEPC County Wind Initiative (CWI) was the result of discussions among RMEB and MEPC members with mutual interest to assist in developing local wind projects, especially in rural southwest counties, with the potential to provide rural and metro counties with clean renewable electricity and the opportunity to stabilize energy costs.

These initial discussions explored the technical and governmental framework necessary for constructing 5-20 MW of community-owned wind generation capacity. Due to the complexity of the development process, CWI requested that LCCMR allow funds to be directed to assist with the planning process rather than as a $200,000 rebate. The request was approved with the objective of developing a procurement approach by which other public institutions in similar situations could develop and benefit from community-owned wind energy projects. The lessons learned through this exercise may be valuable to other public entities seeking to develop large-scale renewable energy projects by utilizing public-private partnerships and other governance structures.

Trust Fund 2005 Work Program Final Report
Date of Report: August 24, 2010
Final Report
Project Completion Dates:
Project A Clean Energy Resource Teams: June 30, 2007
Project B Community Wind Energy Rebate: June 30, 2010
Project C Community Wind Financial Assistance Programs: June 30, 2010

I. PROJECT TITLE: Community Wind Energy Financial Assistance

Project Manager: Stacy Miller
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Total LCMR Project Budget C (Community Wind Financial Assistance)	**LCMR Appropriation:**	**$200,000.00**
	Minus Amount Spent:	**$178,171.12**
	Equal Balance:	**$21,828.88**

Legal Citation: ML 2005, First Special Session, Chapter 1, Article 2, Section, 11, Subd. 10 (a), as amended by ML 2006, Chapter 243, Section 15, subdivision 10 (a) and as amended by ML 2009, Ch. 143, Subd. 16, paragraph (2).

Appropriation Language:
Clean Energy Resource Teams and **Community Wind Energy Rebate and Financial Assistance Programs**
10 (a) $350,000 the first year and $350,000 the second year are from the trust fund to the commissioner of commerce. $300,000 of this appropriation is to provide technical assistance to implement cost-effective conservation, energy efficiency, and renewable energy projects. $400,000 of this appropriation is to assist Minnesota communities in developing locally owned wind energy projects by offering financial assistance and rebates. This appropriation is available until June 30, 2010, at which time the project must be completed and final products delivered, unless an earlier date is specified in the work program.

This appropriation has been divided into three separate work programs, Work Program A for Clean Energy Resource Teams (CERTs), Work Program B for Community Wind Energy Rebates, and Work Program C for the Community Wind Financial Assistance Program. This document, **Work Program C**, addresses **Community Wind Financial Assistance**.

The following attachments are included:

Attachment A Final Budget
Attachment B Wind Resource
Attachment C Web Notice to Minnesota Energy Developers
Attachment D Proposed Project Timeline
Attachment E Community Wind Work Plan
Attachment F Project Planning Minutes June 11, 2008
Attachment G Project Planning Minutes June 16, 2008
Attachment H Final Project Summary
Attachment I Project Financials

II. and III. FINAL PROJECT SUMMARY

Overall Project Outcome and Results

The **Community Wind Energy Financial Assistance Program** originated in response to a request for proposals (RFP) to competitively select proposed wind energy projects to receive rebates of $200,000 for the successful completion of community-owned megawatt-scale, grid-connected wind turbines that would be constructed more than 35 miles from similar, existing structures. The goal behind the grant opportunity was to demonstrate how a local government could use local resources to utilize renewable energy development as a means to direct funding to the public sector and to help contribute to local renewable energy goals. Two projects were competitively selected to receive a rebate through this program, including Winona County and a collaborative effort by the Rural Minnesota Energy Board (RMEB) and the Metropolitan Energy Policy Coalition (MEPC), formerly known as the Metropolitan Counties Energy Task Force.

RMEB is a Joint Powers of sixteen counties in southern Minnesota formed to provide policy guidance on issues surrounding energy development in rural Minnesota. MEPC is a member group of seven metro area counties and the Metropolitan Council with "long-term interest in the use of secure, safe, reliable, sustainable, economical and environmentally responsible energy for constituents."

The RMEB-MEPC County Wind Initiative (CWI) was the result of discussions among RMEB and MEPC members with mutual interest to assist in developing local wind projects, especially in rural southwest counties, with the potential to provide rural and metro counties with clean renewable electricity and the opportunity to stabilize energy costs.

These initial discussions explored the technical and governmental framework necessary for constructing 5-20 MW of community-owned wind generation capacity. Due to the complexity of the development process, CWI requested that LCCMR funds be directed to assist with the planning process rather than as a $200,000 rebate. The request was approved with the objective of developing a procurement approach by which other public institutions in similar situations could develop and benefit from community-owned wind energy projects. The lessons learned through this exercise may be valuable to other public entities seeking to develop large-scale renewable energy projects by utilizing public-private partnerships and other governance structures.

IV. OUTLINE OF PROJECT RESULTS*:*

Result 4: Community Wind Energy Financial Assistance Program Description:
2/20/2006: Department of Commerce requested the following as a change in priorities for the $400,000 wind portion in Result 4 and was approved by LCMR 2/20/2006.

1. $200,000 for a wind turbine rebate was committed to the competitively selected Winona project. Since the project was not completed, the money returns to the LCCMR Trust Fund.
2. Continued Commerce Department assistance to the Rural Minnesota Energy Board (RMEB) to study the feasibility of a coordinated effort to produce over 75 turbines versus the one or two that would have resulted from individual turbine projects. The RMEB project appeared feasible after a preliminary evaluation and Commerce returned to LCCMR with a budget and scope of work to receive $200,000 for financial assistance to RMEB. Because the RMEB proposal was original and unique, this was not done on a competitive basis.

Early details on the project development and rationale are provided below:
The Community Wind Energy Rebate and Financial Assistance program solicited community-oriented wind energy projects to install grid-connected wind turbines, at least one of which will be competitively solicited, and issue two $200,000 awards for completed projects. Community-oriented projects were defined as owned by non-taxable entities, including but not limited to counties or municipalities, educational institutions, or non-profit community or nature centers, and involving multi-stakeholder coalitions in the non-technical/non-construction portions of planning, construction, operation, and ongoing management and utilization of the wind project.

The Department of Commerce coordinated the projects by:

- Issuing a request for proposals for community projects to apply for a $200,000 rebate on September 30, 2005;
- Selecting two projects with the promise of maximizing non-LCCMR funds, promoting local community involvement, providing geographic diversity across Minnesota, providing ongoing educational opportunities and curriculum, and showing technical expertise and capabilities to complete the project by June 30, 2007, extended to June 30, 2010; and
- Working with the selected communities to develop project parameters and provide technical assistance in project development where applicable.

The RMEB developed a business plan and public report, in consultation with the Department of Commerce and other designated stakeholders, about the project's process, repeatability, lessons learned, feasibility, and other pertinent issues for future community wind projects.

Summary Budget Information for Result 4:	LCCMR Budget	$200,000.00
	- Spent	$178,171.12
	Balance	$21,828.88

Completion Date: June 30, 2010

Program Description

A request for proposals was issued on August 1, 2005 for a community wind project, and the Department of Commerce (Department) received one proposal by the October 6, 2005 deadline. Winona County's application was accepted and the award reservation was announced on November 1, 2005. Several parties had indicated a strong interest in the rebate and were informally surveyed to determine how to potentially restructure the rebate for a second issuance. These parties expressed two common concerns: ownership structure and the deadline.

Interested parties indicated that the project completion deadline of June 30, 2007 was an impediment to an application because of a wind turbine supply shortage affecting the industry, and applicants were hesitant to commit to such a short construction schedule. The Department requested a no-cost two-year work program extension to June 30, 2009 to allow additional time for rebate recipients to complete projects, and the extension was approved.

Regarding ownership, the Department originally required 100% community (public) ownership. However, many financial incentives are only available to taxable entities. An alternative for the second Request for Proposals (and as an option for Winona County) was chosen that corresponds with new statutory language regarding community wind energy development.

Those considered qualifying applicants included local/regional governments, educational institutions, or tribal governments (216B.1612, Subd 2, part c, numbers 5 & 6) who maintain decision-making authority over the project's development. Qualifying owners could be Minnesota residents, limited liability corporations, non-profits, cooperatives, local/regional government, educational institutions, or tribal government (216B.1612, Subd 2, part c, numbers 1-6), but at least 51% of the financial benefits must accrue to the community applicant over the project's life (216B.1612, Subd 2, part f, numbers 2).

Rural Minnesota Energy Board Community Wind Initiative Proposal

The RMEB and MEPC partnership was intended to develop renewable energy to meet the electrical needs of members and to help stabilize energy costs. The originally proposed scope of work was ambitious, seeking to establish two to five megawatt wind farms in each interested RMEB county. The Department provided $20,000 in seed funding to do an initial evaluation of project feasibility that was matched equally by the RMEB and MEPC for a total of $60,000. After this initial evaluation the decision was made to continue with project pre-development plans, but to scale the project for an initial phase of five to twenty megawatts total. The RMEB presented a complete proposal for a work program change during a 2006 LCMR commission meeting. The proposal was approved.

Along with the first request for a no-cost two-year extension, the Department requested an additional statutory change that would provide financial assistance for project planning for RMEB, rather than as a rebate for a completed project. This request was approved. (Minn Laws 2006, Chapter 243, Section 15, subdivision 10 (a).)

The RMEB was the fiscal agent and primary applicant from the onset of the grant request. Once a grant agreement was executed between the Department and RMEB, an executive team was established with three members each from the RMEB and MEPC to oversee key decisions. The business plan required not only financial and technical feasibility studies, but also regulatory assessments of the proposed project.

The RMEB launched its Community Wind Initiative (CWI) and issued a request for proposals to complete recommendations for a business structure for community wind projects with ownership interest by multiple local units of government in summer 2006. As a result, RMEB contracted with Avant Energy and Lindquist, and Vennum to develop and recommend a governance structure for RMEB and MEPC.

MEPC was (and remains) interested in developing renewable energy to meet the operational electrical needs of its members and to stabilize energy costs. The RMEB was (and remains) interested in developing the wind resource of its members in ways that maximize local economic development. Key to this is to keep the revenues from electricity generated from wind in the communities in which the electricity is generated. Subcommittees of both RMEB and MEPC met regularly with Avant Energy and Lindquist and Vennum to develop the framework for a successful business structure for multiple community-based wind projects. Such projects would be implemented within the 24 Minnesota counties served by the two groups.

On December 4, 2006 the consultants presented their final report on the proposed business plan and organizational structure in which they recommended the creation of an agency structure to a joint meeting of RMEB and MEPC. The subcommittees continued to meet since modifications to the strategies proposed were necessary. Avant recommended a governance board to ensure that objections of either the rural or metro members were met. There was much discussion by the two groups to identify a satisfactory governance structure as they developed a technical work plan.

Representatives from the RMEB and MEPC gathered on June 12, 2007 and July 19, 2007 to develop a technical work plan that would result in wind turbines operational within the RMEB region as early as 2011. A follow-up meeting on August 20 discussed governance structures and developed a technical work plan.

Project development and work plan

RMEB and MEPC met in October 2007 to produce a final work plan outlining how to proceed with project development. The resulting Community Wind Initiative work plan is included as Attachment E.

Given the technical expertise required in planning wind development, the group agreed that it was necessary to hire a consultant to manage the project and move forward with the technical feasibility studies. This was outlined as the first step in the work plan.

To facilitate expediency in decision making, the participants formed an Executive Committee to promote project progress. This group of designees will share responsibility for the completion of tasks outlined in the work plan while fairly representing the interests of both the RMEB and MEPC.

The grant agreement between the Department of Commerce and the Rural Minnesota Energy Board, the fiscal agent for this appropriation, took effect January 14, 2008. The agreement was drafted based on the duties outlined in *Attachment E, Work Plan for Legislative-Citizen*

Commission on Minnesota Resources (LCCMR) Grant to the Department of Commerce for a Wind Energy Project by the MEPC and RMEB.

An RFP for a project manager was completed by RMEB, approved by the MEPC, and issued in February to select a project manager to implement the duties outlined in Attachment E and meet the project deliverables as described in the LCCMR work program. Only one response was received, from Hammel, Green, and Abrahamson, Inc. (HGA). HGA is an architectural and engineering firm located in Minneapolis, Minnesota. On April 7, 2008 the Executive Committee interviewed HGA at the Association of Minnesota Counties office in Saint Paul. Members of the project team presented their perspective on the planned Community Wind Initiative project. The Executive Committee then met and approved the selection of HGA as Project Manager along with their Project Team. The Project Team consisted of:

- HGA as the Project Manager with Doug Maust, PE as the lead;
- Richardson, Richter & Associates responsible for communication and intergovernmental coordination;
- LLS Resources handling siting and interconnection planning;
- Stoel Rives LLP providing legal and negotiation services; and
- Northland Securities completing the financial modeling and risk assessments.

The Project Team met on June 11, 2008 to determine team members' priorities and how to meet the goals of the Community Wind Initiative. The minutes from that meeting are included as Attachment F. Members of the Project Executive Committee and the Project Team met in Shakopee on June 16, 2008 and included members of both the RMEB and MEPC. The group met to prioritize the efforts of the Project Team. The minutes from this meeting are also included as Attachment G. The next meeting was August 4, 2008, at which time the Project Team was expected to report on the leading options for moving forward with the project. Two scenarios that the Project Team presented are the feasibility and costs of:

- ownership of the turbines by the counties
- private ownership of the turbines

Project Extension

The original timeline is outlined in Attachment D. Representatives from the RMEB, MEPC, and HGA met with staff from LCCMR and Commerce to discuss a request for an extension on July 15, 2009. Commerce and RMEB submitted formal letters of request for an extension to LCCMR on July 20 in order to have the extension request considered by the Commission at the July 28, 2009 meeting.

The extension was necessary due to unforeseen delays in working with transmission owners for interconnection, utilities for acceptable PPA terms, and the U.S. Fish and Wildlife for permitting. An extension was needed for the project team to move forward with a wind resource assessment at the Lyon County landfill site as well as to identify a public/private business model that would enable the project to proceed.

In response to the request for an extension for the Wind Financial Assistance Program in 2009, the Legislature amended ML 2005, First Special Session, Chapter 1, Article 2, Section 11, Subdivision 10 (a), funding for the Community Wind Energy Rebate "The availability of the appropriations for the following projects is extended to June 30, 2010:

2) Laws 2005, First Special Session chapter 1, article 2, section 11, subdivision 10, paragraph (a), clean energy resource teams and community wind energy rebate, as amended by Laws 2006, chapter 243, section 15;" ML 2009, Ch. 143, Subd. 16, paragraph (2).

Siting

The site assessment and selection process began immediately after hiring the project manager. Several proposed sites on county lands from seven RMEB counties were considered as potential sites. Among these, RMEB identified a leading site at the Lyon County Landfill, which has approximately 380 acres of county-owned property that can accommodate two to three turbines. Lyon County was studying the viability of utilizing methane recapture at the landfill to generate electricity, and it was thought that the addition of wind turbines to the site would increase the overall project viability and reduce the interconnection costs for both projects. The Lyon County Landfill location was later decided not to be a cost-effective site for a methane turbine. However, the site was still considered a prime location for the wind development plans, along with a nearby reclaimed, inactive gravel pit, also owned by Lyon County.

Financing

Project consultant HGA entered discussions with the local energy suppliers to determine the best avenue to access the electrical distribution system. Nearby Missouri River Energy was not interested. Another utility contacted was interested, but the purchase price for the energy would not be enough to cash flow the project, especially if the project proceeded as a public project, making it ineligible for the federal Production Tax Credit or Investment Tax Credit. A third utility explored options ranging from a direct power purchase agreement to the possibility of being an equity partner and utilizing the Production Tax Credit. The RMEB and MEPC began to consider which counties would be willing to invest equity in the project in winter 2008-09. The willing counties would have applied for federal Clean Renewable Energy Bonds (CREBs) to aid in financing.

In spring 2009, the RMEB and the MEPC continued to work with their project manager to attempt to secure financing for a wind turbine project at the Lyon County Landfill and gravel pit site. The original project timeline called for the development of the project financial pro-forma and the negotiation with the utility and equity partners to begin in March 2009. When the initial timeline was proposed, finding and negotiating with an equity partner was considered possible in the months from March to June of 2009. However, due to the condition of the economy, equity partners with an appetite for tax credits were not found. Alternative funding sources were considered, but ultimately it was determined that an equity partner was necessary to make the project viable.

The Project Team developed a RFP to send out to potential equity partners. The RMEB made application to the Western Area Power Administration (WAPA) for interconnection, which was eventually approved, allowing negotiations for a Power Purchase Agreement (PPA) to begin. This was necessary for the development of the project financial pro-forma for a 5-10 MW project and to allow the project to seek an equity partner.

The CWI reached a critical decision point, especially for RMEB counties, in December of 2009. Project Engineers HGA presented pro-forma information to a meeting of the interested RMEB counties at the Association of Minnesota Counties Conference in Minneapolis on December 7. Included was information on the formation of an LLC to allow the project to go forward in the most cost-effective manner. Legislation would be needed to allow the counties to form an LLC, which had previously been granted to Winona County, the City of Mountain Iron and to Minnesota School Districts. This was followed by a meeting on December 18 in Marshall where a majority of the commissioners from the interested RMEB counties were present. At this meeting, each of the RMEB counties were requested to go back to their respective County Boards and decide on two issues: 1) Was their county willing to go forward with the project and pursue LLC authorization legislation and commit some county funds to the effort to get the legislation passed, and 2) Was their county willing to invest a specific dollar amount to make the project happen? As it turned out, the answer to both of those questions was "NO" for all RMEB counties involved. MEPC members were not involved in this RMEB process. The next step was to brief the RMEB on February 11, 2010 and arrange a meeting or conference call with the MEPC project committee to discuss closing the project. HGA prepared a final report detailing the steps that were taken and the hurdles that were met along with a financial report. These reports are available as Attachments H and I. Reasons cited included economic conditions, risk, and delayed financial benefits. Project planning stopped.

V. LCMR PROJECT BUDGET—COMMUNITY WIND FINANCIAL ASSISTANCE: TOTAL LCMR PROJECT BUDGET for Community Wind Financial Assistance: $200,000

VI. OTHER FUNDS & PARTNERS:

A. Other Funds being spent during the Project Period:

Community Wind Rebates

a) Community Project: $1,700,000 (estimated) installation costs and in-kind personnel time

b.) Minnesota Department of Commerce: in-kind personnel time

B. Required Match (if applicable): 10%

$21,782 Total Match provided, or 12% of project cost provided

$9,499 RMEB Counties;

$5,000 CERTs grant;

$7,283 Metro Board

C. Past Spending:

Community Wind Rebates:

a) $300,000 LCMR funding FY04 & FY05 (oil overcharge funding)
b) $1,363,500 Carleton College payment for wind turbine equipment (does not include installation/labor)
c) $1,889,608 University of Minnesota-Morris payment for wind turbine equipment and installation

D. Time: n/a

VII. DISSEMINATION:

The final report was approved by both the RMEB and the MEPC. Bob Fox and Jay Trusty gave a presentation on it to the RMEB members. Tony Hainault presented it to the MEPC members. I also presented the results of the project to my Commission members. It is the intention of the Southwest Regional Development Commission to post the report on their website which is undergoing updates. The final pro-formas and other financial information were presented to a number of county boards within the RMEB, including Yellow Medicine, Redwood, Murray, Renville and Cottonwood Counties.

VIII. REPORTING REQUIREMENTS:

Work program progress reports were submitted from January 15, 2006 through January 15, 2010. This final report was submitted August 20, 2010.

IX. RESEARCH PROJECTS: n/a

Attachment A Final Budget

Rural Minnesota Energy Board

Metro - LCCMR Project Totals

Project Report as of June 30, 2010

	Total Project Budget	2008 CYear	2009 CYear to Date	2010 CYear to Date	Project to Date	Under / Over Budget	% of Budget
County Revenue	16,911.00	2,060.77	7,437.77	0.00	9,498.54	7,412.46	56.17%
Metro Board Revenue	12,500.00	150.00	7,133.25	0.00	7,283.25	5,216.75	58.27%
U of MN-SW CERT-RDC grant	5,000.00	0.00	5,000.00	0.00	5,000.00	0.00	100.00%
LCCMR Revenue	200,000.00	71,560.85	99,920.54	6,689.73	178,171.12	21,828.88	89.09%
Total Revenues	234,411.00	73,771.62	119,491.56	6,689.73	199,952.91	34,458.09	85.30%
Board Travel & Expenses	3,031.00	1,030.55	244.52	0.00	1,275.07	1,755.93	42.07%
Board Per Diem	1,335.00	835.22	60.00	0.00	895.22	439.78	67.06%
Consultant	170,000.00	62,500.00	86,000.00	10,750.00	159,250.00	10,750.00	93.68%
Contracted Services-SRDC	14,700.00	9,060.85	13,753.04	480.00	23,293.89	-8,593.89	158.46%
Permit	0.00	0.00	5,000.00	-4,540.27	459.73	-459.73	
Legal	45,345.00	345.00	14,434.00	0.00	14,779.00	30,566.00	32.59%
Total Expenditures	234,411.00	73,771.62	119,491.56	6,689.73	199,952.91	34,458.09	85.30%

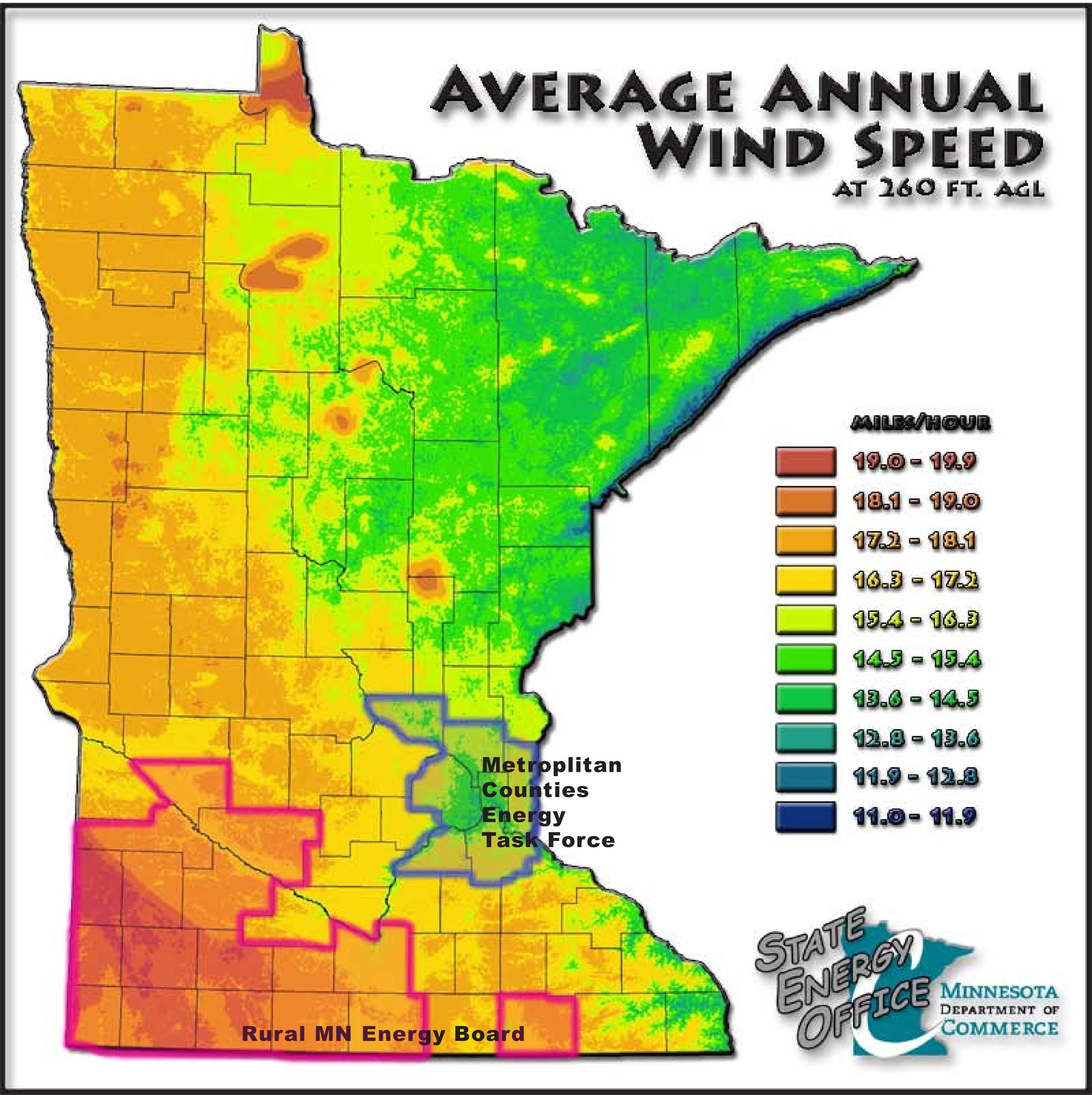
Revenues Over (Under) Expenditures	0.00	0.00	0.00	0.00	0.00

LCCMR update on match **Rural Minnesota Energy Board**

Report Dates		4/28/2008	6/30/2008	9/22/2008	2/23/2009	3/23/2009	6/2/2009	6/30/2009	8/31/2009	10/31/2009	12/31/2009	6/30/2010	GRANT TOTALS	Final Mtg 7/31/2010	TOTALS
Travel															
Travel Inkind		3733.47	1964.45	1593.24	3132.67	988.90	2896.30		913.00	1216.05	1069.75	3416.50	20924.33	764.00	21688.33
Board Travel			591.24	270.83	168.48		244.52						1275.07		1275.07
Board perdiem			655.22	60.00	120.00		60.00						895.22		895.22
	ST	3733.47	3210.91	1924.07	3421.15	988.90	3200.82	0.00	913.00	1216.05	1069.75	3416.50	23094.62	764.00	23858.62
Other Inkind															
Vol. Inkd		1010.40	294.70	631.50	505.20	168.40	252.60		84.20	252.60	84.20	884.10	4167.90	210.50	4378.40
Board Inkind		3055.00	2740.00	1340.00	2320.00	1295.00	3055.00		925.00	1030.00	905.00	2860.00	19525.00	830.00	20355.00
Consultant U-MN								5000.00					5000.00		5000.00
Legal				45.00	300.00			9790.00		1294.00	3182.50		14611.50		14611.50
	ST	4065.40	3034.70	2016.50	3125.20	1463.40	3307.60	14790.00	1009.20	2576.60	4171.70	3744.10	43304.40	1040.50	44344.90
Total Match		7798.87	6245.61	3940.57	6546.35	2452.30	6508.42	14790.00	1922.20	3792.65	5241.45	7160.60	66399.02	1804.50	68203.52
YTD Match		7798.87	14044.48	17985.05	24531.40	26983.70	33492.12	48282.12	50204.32	53996.97	59238.42	66399.02			

G:\...\Finance\RMEB\Request\LCCMR\Match update by category.xls

Attachment B

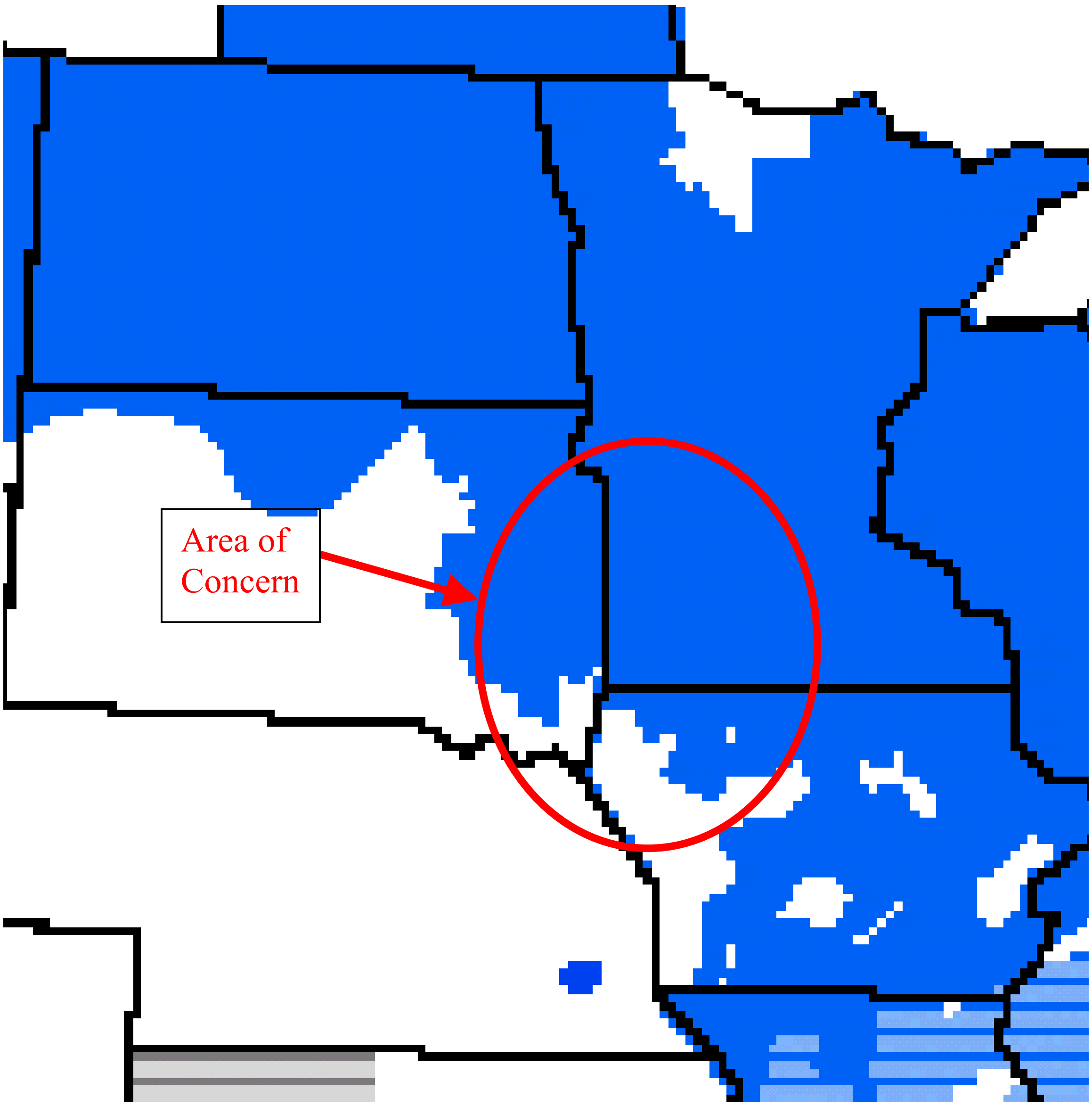


Attachment C

Posted February 10, 2004
Revised May 5, 2004

Notice to Minnesota, South Dakota, and Iowa Energy Developers

If your intentions are to locate a generation project in the area bound by the circle below, please review the following message:



The Midwest ISO has determined that the amount of generation currently proposed in this area exceeds the reliable outlet transmission capacity by several times its value, even taking into consideration planned transmission upgrades that are before regulatory forums. Unfortunately, it will be several years before future upgrades can be determined, approved, and placed into service to allow for more outlet transmission capacity.

The Midwest ISO is taking steps to improve the transmission interconnection queue backlog. We have implemented “Group Studies” that combine multiple interconnection requests into a single study to take advantage of the synergies from studying these generation interconnection projects together. The Midwest ISO and WAPA have recently completed the first Group Study Interconnection Evaluation Study and will begin an Interconnection Facilities Study for these grouped projects. The second Group Study started its Interconnection Evaluation Study in April, with a third group to follow, likely in late 3rd Quarter or early 4th Quarter of 2004. The results of the first Group Study, available at http://www.midwestiso.org/plan_inter/documents/CGS-Group1%20Draft-R2.pdf, show that the available transmission capacity gained by the planned transmission facilities upgrades is exceeded by the currently requested higher queued generation interconnection requests. Any further generation development over that amount will require more extensive facilities upgrades than are currently planned. These facilities upgrades cannot be completed in the time frame that a typical generator wishes to connect to the transmission system.

The Midwest ISO is taking the following steps to address this situation:

1) Group Studies will continue to determine the facilities upgrades necessary to accommodate the proposed development currently in the Midwest ISO transmission interconnection queue.
2) By analyzing the projects as a group, the Midwest ISO utilizes synergies in the study process to improve the time to process the generation projects in the group. The first Group Study took about 6 months to complete but covered 7 projects (Midwest ISO and WAPA).
3) As projects drop out of the interconnection queue prior to the start of a Group Study, remaining projects move into that group.
4) The first group is entering the Facilities Study phase of the process. The Evaluation Study for this group has indicated that more upgrades than those currently planned for the area are necessary for the injection and stable operation of these projects. The nature and timing of these upgrades will be determined in the Facilities Study.
5) Current estimates indicate that the 2nd Group Study will complete its Interconnection Evaluation Study late in the 3rd Quarter of 2004, with the 3rd Group Study starting immediately afterwards. To the extent generation projects drop out of the transmission interconnection queue, lower queued projects with roughly the same size and location may have an opportunity to move up into the 2nd Group Facilities Study as determined by the Midwest ISO.
6) After each group’s Facilities Study is completed, needed facilities upgrades should begin the appropriate regulatory process. The completion date for these upgrades is dependent upon the state regulatory process of the state in which it is located and the size and complexity of the upgrade.

Therefore, it is the position of the Midwest ISO that regardless of any commercial arrangements made by the project developer, for any project over 2 MW and/or connected to facilities greater than 50kV, there will be no expedition of interconnection or facilities studies until the interconnection queue is cleared. Projects under 2 MW connecting to facilities less than 50kV will be evaluated on a case-by-case basis, where the Midwest ISO will take into account the number of small interconnection requests entered into the interconnection queue and how many megawatts are connected to roughly the same point of interconnection. The Midwest ISO will also consider the local load connected to the point of interconnection and other factors, in attempting to expedite the analyses of these projects. If the analyses of these projects cannot be expedited, they will be part of the Group Studies, with the 3rd Group being filled now (estimated study start of 7/15/2004). Out of queue order study requests will be processed only when the Interconnection Customer explicitly acknowledges that any project connecting under an Out of Queue Order Letter Agreement may very well be subject to indefinite disconnection following the commercial operation of higher queued generation projects.

Questions regarding this notice or any of the processes contained therein should be directed to the Midwest ISO Planning Department at (317) 249-5784 or by email at ginterconnection@midwestiso.org

Attachment D

Community Wind Initiative Timeline

	Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09
I. Hire a consultant to manage the CWI project																		
II.Site selections and assessment of technical feasibility																		
A. Consultant will identify a number of potential sites for 5-20 MW of wind development for at least 3 and up to 5 sites																		
B. Consultant performs engineering review of potential sites																		
C. Site Selection & Predevelopment																		
III. Develop project financials and pro forma documents																		
IV. Negotiations with equity and utility partners																		
V. Report to the LCCMR																		

Attachment E

December 5, 2007

Workplan

for Legislative-Citizen Commission on Minnesota Resources (LCCMR) Grant to the Department of Commerce for a Wind Energy Project by the MCETF and RMEB

Introduction

The County Wind Initiative (CWI) is a joint effort by the Rural Minnesota Energy Board (RMEB – seventeen counties in southern Minnesota including Blue Earth, Chippewa, Cottonwood, Faribault, Jackson, Lincoln, Lyon, Martin, Mower, Murray, Nobles, Pipestone, Redwood, Renville, Rock, Watonwan, and Yellow Medicine) and the Metropolitan Counties Energy Task Force (MCETF – Anoka, Dakota, Hennepin, Ramsey, Scott, Sherburne and Washington Counties plus the Metropolitan Council) to develop up to 150 megawatts of wind energy generation in the geographic footprint of the RMEB counties to meet a portion of the electricity needs of the metropolitan governments that opt in. (It is not expected that all 25 counties will ultimately choose to participate in wind development associated with the CWI.) This community-sponsored wind generation on the local distribution system would possibly be the first of its kind in the nation and could serve as a template for other Minnesota governments to utilize.

A CWI Executive Committee will be formed and made up of designees from both RMEB and MCETF. Representatives of both groups have been involved in the development of this workplan, and formation of a joint executive committee will ensure that both groups of counties will continue to be represented. The Executive Committee members will serve as the designated liaisons for the counties and governments they represent and will be responsible for overseeing completion of the tasks outlined in this workplan. Representatives or designees of the Executive Committee will confer with the Department of Commerce.

Initial Phase. The initial phase of the project will result in the technical and governmental framework for constructing 5-20 MW of wind generation capacity through a collaborative effort between the interested rural and metro governments. The initial 5-20 MW project(s) will provide valuable experience to the participants and the state in developing the balance of the planned CWI capacity. Due to the very constrained transmission infrastructure in the high wind resource areas of the RMEB, this initial phase will be placed in area(s) that minimize transmission needs and MISO involvement.

The Department of Commerce intends to grant up to $200,000 of the LCCMR funds allocated to the Department by the Minnesota Legislature in 2005 (amended in 2006) to promote the development of community wind to the intensive planning work necessary to allow this initial phase of the CWI to become a reality. That appropriation language is as follows:

Appropriation Language:

Clean Energy Resource Teams and **Community Wind Energy Rebate and Financial Assistance Programs**

- *$350,000 the first year and $350,000 the second year are from the trust fund to the commissioner of commerce. $300,000 of this appropriation is to provide technical assistance to implement cost-effective conservation, energy efficiency, and renewable energy projects.* ***$400,000 of this appropriation is to assist Minnesota communities in developing locally owned wind energy projects by offering financial assistance and rebates. This appropriation is available until June***

30, 2009, at which time the project must be completed and final products delivered, unless an earlier date is specified in the work program.[1]

Citation: ML 2005, First Special Session, Chapter 1, Article 2, Section, 11, Subd. 10 (a), as amended by ML 2006, Chapter 243, Section 15, subdivision 10 (a).

Parties. The Rural Minnesota Energy Board is a Joint Powers of seventeen (17) counties in southern Minnesota formed to provide policy guidance on issues surrounding energy development in rural Minnesota. It originally formed in 1996 as the Ridge Counties Task Force and later developed into the Wind Task Force, Southwest Minnesota Energy Task Force, and Rural Minnesota Energy Task Force as both the membership and policy issues expanded. In January 2004, the group became a Joint Powers Board. The counties have been working together to resolve many energy related issues, including the barriers to local wind energy generation and development and have recently been engaged with the Metro County Energy Task Force in developing a plan for the CWI.

The Metro Counties Energy Task Force was formed to work on energy issues and joint projects that are greater than the sum of what they could do individually. In response to the ongoing changes in the electric utility industry and other energy markets, Hennepin County initiated a Metropolitan Counties Energy Task Force in late 1999. The Task Force consists of commissioners from each of seven metro area counties and the Metropolitan Council. The MCETF is exploring ways that it can become more active in guiding policy and initiating forward thinking partnerships as a means of implementing energy efficiency and renewable energy and addressing climate concerns. The CWI is an opportunity to help achieve these goals.

Under the CWI, the RMEB will serve as the grant recipient and will be responsible for hiring a project manager and overseeing progress of the development plan in consultation with the joint county wind initiative Executive Committee. The parties commit to providing a 10% cash and/or in-kind match to the grant, over the course of the workplan.

This workplan details the steps the counties and the Department will need to take, from the time the grant is issued to the project completion date of June 30, 2009, in order to get the Community Wind Initiative to the point where the multitude of boards participating in the planning stages of the CWI can decide whether to commit resources to the construction and operation of the wind turbines, and to provide the Department and the LCCMR with a detailed report on the CWI and lessons learned. Specifically, the LCCMR grant funds would be used to identify and assess potential wind sites, make all necessary technical evaluations, develop project financial assumptions and documents based on those technical evaluations, and to fund initial negotiations with electric utilities and potential equity partners. All contracts will be done by competitive bids or proposals. All project developments will meet the criteria for community-based energy development projects under Minnesota Statutes, section 216B.1612.

The ultimate goal of this grant is to develop a procurement approach by which other public institutions in situations similar to the participants involved with the CWI can develop and benefit from community-owned wind energy projects. This community wind project will culminate in a report by the participants and the Minnesota Department of Commerce that will be designed as a guide to other governmental entities considering similar projects. The report will detail lessons learned in areas related to project development, creation of governance structures and bylaws, and recommendations regarding the sharing

[1] The material in bold was added in 2006. The language was changed to allow Minnesota entities interested in wind development time to formulate a workplan and to conduct the technical studies necessary to evaluate the feasibility of the proposed wind projects.

of project risks, costs and revenues. Under the legislation enacted in 2006 and quoted above, this report must be completed and final products delivered by June 30, 2009.

Total estimated budget:

	Estimated Uses	
Grant Activity	**LCCMR**	**Other**
Hire a consultant to manage project	5,000	
Site Selection and Assessment of Technical Feasibility	145,000	10,000
Development of Project Financials and Pro Forma Documents	35,000	5,000
Negotiations with Equity and Utility Partners	15,000	5,000
Total Estimated Uses*	$200,000	$20,000

	Estimated Sources
Total grant award	200,000
Cash and/or In-kind match by RMEB/MCETF (10% of total grant)	20,000
Total project budget	$220,000

I. Hire a consultant to manage the CWI project

- Time budget: 3 months
- Estimated LCCMR budget: $5,000

A consultant will be hired through an RFP process to manage the overall project and assure completion of Parts II, III and IV (in substantially the form described below). The consultant will adhere to the budget and timeline proposed in this workplan unless an amendment to the budget is requested from and approved by LCCMR.

The consultant will identify optimal areas for wind projects, as well as specific sites, within the geographic footprint of the 17 Rural Minnesota Energy Board (RMEB) counties where significant wind resource coincides with appropriate substation capacity and load. The feasibility study will provide the technical guidance necessary for stakeholders to consider opportunities for integrating, distributing, and selling electricity generated from County Wind Project developments.

RFP process to contract with a knowledgeable consulting firm:

A. Develop draft RFP for consultant based on budget estimates and workplan

B. Schedule a public "Proposers' Meeting" to brief potential proposers, to stimulate interest in the project from well qualified consultants, and to solicit advice from experienced consultants about the proposed workplan and budget estimates.

C. CWI Executive Committee will meet to evaluate the responses and select a most advantageous proposer. RMEB will approve award.

II. Site Selections and Assessment of Technical Feasibility

- Time budget: 15 months from date grant is awarded
- Estimated LCCMR budget: $145,000

A. Consultant (with Executive Committee input) will identify a number of potential sites for 5-20 MW of wind development for at least 3 and up to 5 sites

- Time budget: 4 months from date project manager is selected
- Estimated budget: $45,000 (This amount includes project management costs throughout the assessment and predevelopment phases)

1. Using generally available information resources, the project manager will develop a list of potential sites within the RMEB counties. The consultant will do so by collecting and overlaying information for these counties including, but not limited to:
    - an initial assessment of available wind resources
    - amount of available substation and distribution capacity
    - load centers in the various counties
    - the sites within the RMEB counties that optimize the above criteria
    - information from consultations with electric utilities in the area
2. Conduct preliminary review of potential site factors for wind projects
    - Define appropriate factors and process for CWI to select final sites
    - create ranking mechanism for fair and adequate comparisons among sites
    - review with CWI Executive Committee

B. Consultant will perform engineering review of potential sites

- Time budget: 3 months from initial site identification (Item A)

- Estimated budget: $5,000 per site x 5 sites = $25,000

1. An engineering review will be performed by the consultant to identify problems with proposed plan. The engineering review should specifically address line loading issues and identify potential thermal hot spots

2. Conduct preliminary analysis of potential power flows by substation

3. Compute distance from proposed sites to substations

4. Describe necessary interconnection requirements, keeping in mind the intention to minimize transmission needs and Midwest Independent System Operator (Midwest ISO)* involvement.

   * Midwest Independent System Operator, a non-profit regional transmission organization, assures industry consumers of unbiased regional grid management and open access to the transmission facilities under Midwest ISO's functional supervision. However, Midwest ISO has established a queue for proposed electric generation projects in Minnesota since the current number of proposed projects greatly exceeds available transmission capacity. To the extent that the CWI can minimize Midwest ISO oversight, wind development resulting from this effort can potentially be realized years sooner. See the attached message from MISO to energy developers in Minnesota for more information about the queue.

C. Site Selection and Predevelopment

- Time budget: 5 months from completion of engineering review of potential sites (Item B)
- Estimated budget: $75,000

1. Project manager will order detailed resource assessments for specific sites

   - Estimated budget: $10,000 per site x 5 sites = $50,000

   a) Individual site reports from a resource assessment service like WindLogics will model the 30 year average wind speeds based on a comprehensive set of references.

   b) Perform 12 months of on-site meteorological data to document wind resource if required by private lenders.

2. Project manager will select sites and negotiate business terms for options for wind rights
   - Estimated budget: $10,000

3. Negotiate business terms for the local interconnection with distribution utility identifying specific interconnection points

   - Estimated budget: $15,000

III. Development of Project Financials and Pro Forma Documents

- Time budget: 3 months (time overlapping with site selection process)
- Estimated LCCMR budget: $35,000

  - Project manager will develop project financial analyses and pro forma documents, including explicit statement of all financial assumptions and specification of all project costs (including reasonable governance and administrative costs), potential project per kilowatt-hour generation revenues, project risks, potential value of renewable energy credits, etc.
  - If needed, the Executive Committee will obtain advice of bond counsel related to the issuance of county bonds to finance a development.
  - A summary of the financial feasibility will include:
    - i) under what assumptions and conditions is this aggregated wind project financially feasible;
    - ii) discussion of the advantages and disadvantages of the aggregation model, of public involvement, and possible ownership and financing models;
    - iii) identification of any recommended alternatives; and
    - iv) identification of project risks to CWI sponsor/participants.

IV. Negotiations with Equity & Utility Partners

- Time budget: 6 months (time overlapping with previous work)
- Estimated LCCMR budget: $15,000

  - The consultant shall negotiate business terms for favorable Power Purchase Agreement(s) with interested utilities for the chosen sites.

V. Report to the LCCMR June 30, 2009

- Time budget: 6 months

  - The consultant will draft a preliminary report of all of the above tasks, any other activities performed under this contract, and a general assessment of the business concept for review by April 1, 2009.
  - The consultant shall make a final report incorporating the changes of the RMEB, MCETF, and Dept of Commerce. The CWI Executive Committee shall resolve any substantive conflicts among the comments.
  - The consultant will make presentations of the final results to the RMEB, MCETF, Department of Commerce and LCCMR (if requested).

Grant complete with issuance of final report.

HGA.

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Meeting Minutes

PROJECT: **RMEB/MEPC County Wind Initiative**
HGA Commission Number 2998-001-00

FROM: Ken Peterson WRITER'S DIRECT DIAL 612-758-4574

DATE: June 13, 2008

MEETING
Purpose: **Consultant Team Kickoff Meeting**
Date: June 11, 2008 Time: 9:00 a.m.
Location: HGA

ATTENDEES
PRESENT:

LLS Resources
Larry Schedin

Richardson Richter & Assoc.
Michael Reed

Stoel Rives
Bill Holmes
Kevin Johnson
Sarah Johnson Phillips

HGA
Doug Maust
Ken Peterson

COPIES: Those Present

Northland Securities
Dan O'Niell

REVIEW OF AGENDA:

1. Roundtable brainstorming session
    - Define project drivers
    - Categorize statements
    - Name categories
    - Vote for key priorities
2. Client meeting materials and agenda
3. Project schedule and workplan
4. Review work scopes, roles, and responsibilities
5. Project directory list
6. Deliverables

Hammel, Green and Abrahamson, Inc.
HGA Architects and Engineers, LLC
HGA Architects and Engineers, LLP

701 Washington Avenue North • Minneapolis, Minnesota USA 55401-1180

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Visit our Website: www.hga.com

MEETING MINUTES:

Item	Votes
GROUP BRAINSTORMING SESSION	
QUESTION: What do counties need to know to execute project?	
1. **UTILITY RELATIONSHIPS – BUSINESS/TECHNICAL**	
• Understand distribution interconnection rules/tariffs	5
• How cooperative are various utilities?	3
• PPA form & terms	3
• Utility purchase tariffs and standby requirements	1
• Utility(ies) involved	
2. **FINANCE COST**	
• Cost and finance scenarios – capital cost	4
• Availability of incentives	3
• Met Tower data versus computer modeling and how it impacts financing	1
• MISO rate history	1
• How is purchase by metro counties being allocated?	1
• Development costs beyond LCCMR Grant	1
• Project risks to counties	1
• Operational and Maintenance costs	1
• Meet RFC mandates (who gets the REC's?)	
3. **APPROVAL/AUTHORITY**	
• RMEB/MEPC – governance structure and roles	3
• Legislative and legal authority	3
• Who are the primary decision makers?	2
• What public contracting rules apply?	2
• Internal approval process	1
• What does the RFP process look like?	
4. **TECH CHOICES**	
• Wind turbine availability	3
• Technologies available	1
• What renewable resource – solar or wind?	
• Understand the differences between small turbines and wind farms	
• Future technology trends	
5. **PERMITTING LOGISTICS**	
• What does the permit process look like?	1
• Is it important to use Minnesota suppliers?	
• What is the process of erecting wind turbines?	
• Do you have equipment manufacturer preferences?	
• Do you have construction contractor preferences?	
6. **PUBLIC RELATIONS**	
• Benefits for metro counties	3

- Benefits for rural counties 3
- Tangible benefits and who gets them 3
- Whether there are objections to counties acting like wind developers 1
- What does the newspaper report about the project say? 1
- Information needs being communicated back to counties/constituents 1
- What do you need to sell this on the home front? 1
- NIMBY (not in my back yard) arguments 1
- Major/minor opposition 1
- Turf issues between members 1

7. **PRODUCTION LOCATIONS**
   - How good is the wind resource at high county load sites? 5
   - Scale of the projects 3
   - Implementation timeframes 2
   - Dispersed generation opportunities (new study) 2
   - Behind the meter options; getting electricity from point A to point B 1
   - Transmission restrictions 1
   - Site selection criteria 1
   - Land lease terms
   - Locations of county facilities (loads)
   - MISO queue restrictions and process
   - Substation locations
   - Is there a location in mind? Will government property be used?
   - Infrastructure parameters for wind farms
   - Sweet spots
   - Geographic limitations – state parks, wildlife management areas, etc.
   - Install generators on buildings or stand alone?

8. **WHY DO THE PROJECT?** 1
   - Ownership structure 4
   - Is reducing or hedging counties' power costs a major goal? 2
   - Are certain approaches more amenable to future expansion? 1
   - Do our goals match up? 1
   - Alternatives via Xcel (Windsource), Connexus, City of Anoka, Dakota Co-op 1
   - Does county want to own/control? 1
   - Model or stand alone?
   - Decrease tax collections?
   - Public/private synergies already identified?
   - Mitigate increasing energy costs?
   - Is local private ownership a goal?
   - Is job creation a goal?
   - How do these projects fit with larger wind projects?
   - Is physical evidence of renewables an important goal?

Meeting Materials for Monday, June 16, 2008

Name Tents
Post-It Notes & color coded voting dots
RMEB/MEPC Counties Map
Minnesota Electric Transmission Planning Zone Maps
WindLogics Wind Resource Maps
MISO Queue Locations Map
New legislative information
Directions to Minnesota Electric Transmission Planning website
Directions to DRG Transmission Study Webinar

The next meeting is scheduled for Monday, June 16, 1:30-4:30 p.m. at Scott County Government Center (200 4th Avenue West, Shakopee, Minnesota)

The foregoing represents HGA's understanding of the discussions and decisions made during this meeting. If anyone has any changes or comments, please notify the author within seven days of the date of this document.

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Meeting Minutes

PROJECT: **RMEB/MEPC County Wind Initiative**
HGA Commission Number 2998-001-00

FROM: Ken Peterson — WRITER'S DIRECT DIAL 612-758-4574

DATE: June 24, 2008

MEETING
Purpose: **Project Kickoff Meeting**
Date: June 16, 2008 Time: 1:30 p.m.
Location: Scott County Government Center (200 Fourth Avenue West, Shakopee, Minnesota)

ATTENDEES
PRESENT:

RMEB
David Benson
Brian Kletscher
Jay Trusty
Tom Warmka

MEPC
Tony Hainault
Peter McLaughlin
Chuck Salter
Felix Schmiesing
Margaret Schriener
Jason Willet

Stoel Rives LLP
Bill Holmes
Kevin Johnson

LLS Resources
Larry Schedin

Richardson Richter & Assoc.
Michael Reed

Northland Securities
Dan O'Neill

HGA
Doug Maust
Ken Peterson

COPIES: Those Present

RMEB
Annette Bair
Bob Fox

MEPC
Luci Botzek
Lisa Geister
Sue Harder
Joseph Harris
Georgeanne Hilker
Lisa Kohner
Dave Lucas
Carl Michaud
Dorothy Rucker

Stoel Rives LLP
Sarah Johnson Phillips

HGA
Joe Witchger

REVIEW OF AGENDA

	Item
1.	Introductions
2.	Roundtable brainstorming session to establish project goals • Define project drivers • Categorize statements • Name categories • Vote for key priorities
3.	Review of key issues
4.	Meeting schedule
5.	Deliverables

GROUP BRAINSTORMING SESSION

QUESTION: What objectives does the "BOARD" foresee as defining success for this Project? Upon completion of listing ideas, items were grouped and assigned categories, and each member present was allowed to vote for top 10 key priorities.

CATEGORY	RMEB Score	MEPC Score	Total Score
1. Regulatory & Political	**11**	**12**	**23**
• Good relationship support from power companies	2	3	5
• Create Minnesota jobs	2	3	5
• Relationship with utilities	1	2	3
• Congruence of political will	2	1	3
• State agencies willingness to cooperate	1	1	2
• Educate legislators	2		2
• Net good will		2	2
• Broadly held development	1		1
• Level playing field for public sector development			
• More buy-in from legislators			
• Local ownership			
• Break new ground			
• Model for other forms of distributed generation			
2. Governance	**6**	**12**	**18**
• Model that can be replicated	3	3	6
• Meet LCCMR obligations	2	2	4
• Near-term project (sooner vs. later)	1	2	3
• Define distinctive capabilities of counties/Met Council		2	2

	• Lawsuit free		1	1
	• Management structure of 25 entities (17 RMEB counties, 7 metro counties, Met Council)		1	1
	• Carbon flexibility		1	1
	• Define unique niche of opportunity			
	• Get ahead of shift in opinion on renewables			
3.	**Financials**	**6**	**9**	**15**
	• Good financial deal	3	3	6
	• Demonstrable pro forma for sub-optimal sites	2	4	6
	• Stable reliable pricing	1	1	2
	• Avoid cost-shifting between rate payers		1	1
	• Reduce county dependence on property tax			
4.	**Collaboration**	**7**	**6**	**13**
	• Prove that counties can work together	3	2	6
	• Demonstrate local government can deliver project with value	2	2	4
	• Green energy project in place		2	2
	• Partner with metro counties to meet energy demands	2		2
	• Expand coalition			
	• Successful long term			
5.	**Interconnect Infrastructure**	**5**	**4**	**9**
	• Promote distributed generation	1	3	4
	• Change regulatory barriers	2		2
	• Connect production with consumption	2		2
	• Transmission infrastructure that allows larger interconnect		1	1
	• Spur change in utility distribution / generation process			
6.	**Geography**	**3**	**4**	**7**
	• Identify best locations	3	2	5
	• Define good backup supply		2	2
	• Identify productive energy sites			
	• Take advantage of "sweet spots"			
7.	**Promote Renewable Energy**	**2**	**2**	**4**
	• Promote renewables across state	1	2	3
	• Increase utilization of green energy	1		1
	• Demonstrate volume of renewable energy			

DISCUSSION ITEMS

	Item	Action
1.	Statutory differences between Dispersed Generation, Distributed Generation, and Net Metering for small-scale wind energy systems were reviewed.	Refer to attached Stoel Rives LLP Memorandum dated June 13, 2008.
2.	The Dispersed Renewable Generation (DRG) Transmission Study, due to be released by the Minnesota Department of Energy, was mentioned. This study analyzes the impact of the addition of 600 MW of dispersed generation around the state.	Follow link to Dispersed Renewable Generation Transmission Study to download the full study and presentation slides.
3.	None of the LCCMR Grant money should be spent on studying governance structure at this stage of the project.	
4.	Project feasibility will determine business model of ownership structure (aggregate resources vs. individual entities). • Options explored should include evaluation of risk vs. reward.	
5.	It is anticipated that seven to nine counties might put money into the project.	
6.	The past legislative session did not adopt language desired for general obligations bonds.	
7.	Utility companies are the only purchasers in the wholesale market. • Current legislative definition of wholesale power is ambiguous.	
8.	Aggregating resources and selling wind generated power in open MISO market might outperform conventional PPAs.	
9.	Carbon Credits and Renewable Energy Credits (RECs) might provide added value to the project depending upon the business model. • Neither the state nor counties have explicitly identified goals for carbon credits. • It is hard to unbundle and monetize the value of carbon credits from RECs if power is sold to the utilities. • Selling power directly into the open MISO market makes it easier to identify CCs and RECs.	

10. Financial models discussed as possibilities included selling to utilities through conventional PPAs, selling in open MISO market, or Net Metering.

    - Net Metering would require on-site load that can consume power as well as a standby tariff with utilities to provide required load when wind turbines can not meet demand.
    - MISO market is harder to predict cash flow compared to PPA, but appears to be an attractive option worth exploring. Counties would act as Independent Power Producers (IPPs), also referred to as Non-Utility Generators (NUGs). Third party service providers would serve as agents to sell generated power.

The next meeting is scheduled for Monday, August 4, 8:00 a.m. -11:00 a.m., at Scott County Government Center (200 Fourth Avenue West, Shakopee, Minnesota)

The foregoing represents HGA's understanding of the discussions and decisions made during this meeting. If anyone has any changes or comments, please notify the author within seven days of the date of this document.

Enclosures

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Attachment H

RMEB / MEPC County Wind Initiative

Review and Conclusion


June 7th, 2010

HGA Commission Number 2998-001-00

LLS RESOURCES, LLC

NORTHLAND SECURITIES

STOEL RIVES

TABLE OF CONTENTS

Authors:

Doug Maust, PE	Principal-In-Charge	HGA
Ken Peterson, PE	Project Manager	HGA

ENVIRONMENT AND NATURAL RESOURCES TRUST FUND

Funding for this project was provided by the Minnesota Environment and Natural Resources Trust Fund as recommended by the Legislative-Citizen Commission on Minnesota Resources (LCCMR). The Trust Fund is a permanent fund constitutionally established by the citizens of Minnesota to assist in the protection, conservation, preservation, and enhancement of the state’s air, water, land, fish, wildlife, and other natural resources.

HGA Comm. No. 2998-001-00

A. EXECUTIVE SUMMARY

Wind resources in the southwest part of Minnesota are robust as is the demand for energy in the Minneapolis-Saint Paul metropolitan area. Discussion between leaders of counties in both areas of the state led to the pursuit of a project that might benefit both. The concept of developing wind-to-energy conversion systems (wind farms) that would produce power in the southwest for consumption in the metro area offered the benefit of economic development where the wind farm would be located and cost effective renewable energy for the consumption of metro area county government. The goal was to create opportunity to develop wind energy power production having economic benefit for the counties. However, as described in earlier meetings and reports, the effort required some combination of enabling legislation, the commitment of assets/resources that the various parties managed or controlled and working with the rules and forces that shape the electric market. While it was and is our opinion that this group could develop a utility scale generating project, the effort was abandoned as too risky in this economic environment.

The counties established several goals early in the process:

- Develop the project in collaboration with the electric utilities with the goal of maintaining and enhancing the relationship
- Develop a project with positive economic benefit.
- Demonstrate that county governments can work together and get things done.
- Promote renewable energy.

Wind energy production demands working closely with the utilities who are encouraged, through regulation and customer pressure to produce low cost, responsible and reliable electricity. The interest in developing wind energy has created unprecedented growth in distributed generation and has presented technical and business challenges for the electric utilities responsible for electric transmission and distribution. Furthermore, the governance and management of the electrical system is complicated by intersecting market and technical issues that challenge the operation and development of the system with the growth of variable energy resources. This is characterized in a Notice of Inquiry published by the Federal Energy Regulatory Commission in January 2010.

Our process started by examining enabling legislation to understand what constraints the counties would face in developing the project. Our second step was to estimate the market price of wind power and how the counties could bring it to market. The third step was to identify land that would enable the group to develop a 5-20 MW wind farm and simplify the development process. Fourth was the estimated cost of construction to test whether or not operating costs would be lower than generated income. Finally, as the economy recessed, we polled the counties to see who was still willing to risk investment.

Earlier engrossments of the bill in the Minnesota House of Representatives enabling county owned renewable energy projects had explicit language regarding joint purchase and acquisition of projects and the issuance of general obligation bonds of the county to pay their respective shares of the cost of the projects. This language did not make it into the final legislative language. The Counties may wish to continue working with the legislature to get explicit authority to issue bonds to finance renewable energy projects and the authority to develop corporate structures that allow them use of federal programs to develop projects.

Legislative constraints are significant, but not disabling. Key requirements include working with the utilities to bring the power to market and modifications to the rules to enable county financing. Bond counsel has determined that the Metropolitan Council has authority to issue bonds for this type of project. Given development constraints for all developers, we focused on a project size of 5-10 MW. It is a project size that is manageable technically and financially.

Siting the project in a RMEB county almost assures a productive wind farm, yet it can also complicate selection of a single site. Two counties have contiguous property that they control, and development on either of those sites simplifies the selection process. The counties can simply work together to accomplish the project.

We established pricing parameters that needed to be satisfied for the project to have a positive cash flow. These scenarios for financing can be found attached as Appendices 1-4. Recent history suggests the project could be successful; however, it was dependent upon a favorable power purchase agreement to establish a strong top line and federal grants to reduce development costs. Price and subsidy are inextricably linked in renewable energy development because market prices claim the value of federal grants and subsidies for electric rate payers. While there were opportunities created by the federal government to compete for grants during this development effort, the application windows were too short for the counties to react to and compete for the funding. Each opportunity caused county boards to examine their willingness and ability to participate in the development of the project and accept the associated risks. It became clear that the economic climate together with individual board member's need to understand, scrutinize and exercise their fiduciary responsibility on behalf of their constituents created a level of risk tolerance that made quick decision making impossible.

This project allowed the participants to examine the issues associated with the complex process of renewable energy development. It occurred during a period when the market crested in frenzied activity and fell into a lull that cost factory and construction workers their jobs. Equipment and materials went from scarce to plentiful and the market price of electricity fluctuated as well.

B. PROJECT BACKGROUND AND OBJECTIVES

PROJECT BACKGROUND

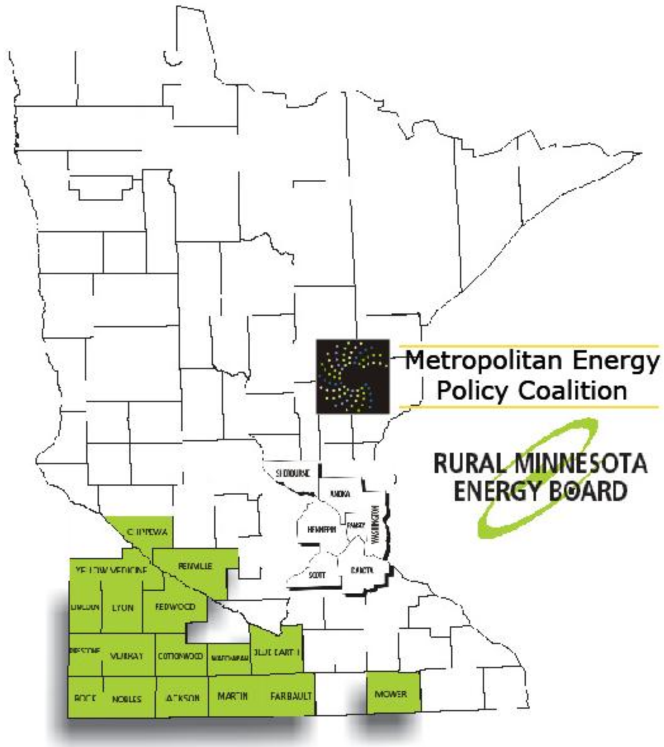
The County Wind Initiative (CWI) was the result of discussions among RMEB and MEPC commissioners who wanted to assist rural counties in developing local projects that had the potential to provide Metro counties with clean renewable electricity. After initial discussions the group hired a legal and technical team to help get to the heart of how a project would be developed. In the early stages of the project, commissioners spoke of win-win strategies to provide development assistance to rural counties and meet growing energy demand in the metro area. The Rural Minnesota Energy Board (RMEB) and the Metropolitan Energy Policy Coalition (MEPC) decided to pursue this goal and were granted authority by the State of Minnesota Department of Commerce and Legislative-Citizen Commission on Minnesota Resources (LCCMR) to pursue the development of a wind-to-energy project by means of grant funding through Clean Energy Resource Teams and Community Wind Energy Rebate and Financial Assistance Programs.

The Rural Minnesota Energy Board is a Joint Powers of seventeen (17) counties in southern Minnesota formed to provide policy guidance on issues surrounding energy development in rural Minnesota. The Rural Minnesota Energy Board is committed to cooperating in a joint venture to provide the greatest public service benefit possible for the 17 county area encompassed by the Counties in policy, planning, management, and implementation of methods to deal with energy and transmission in rural Minnesota.[1]

The Metropolitan Energy Policy Coalition is a member group of seven (7) metro area counties and the Metropolitan Council whose name reflects the“ long term interest of its members in the use of secure, safe, reliable, sustainable, economical and environmentally responsible energy for constituents. The MEPC seeks to lead by example by practicing energy conservation, using renewable energy sources in an effective manner, and taking steps to reduce greenhouse gas emissions.” The goal of MEPC is to become more active in guiding policy and initiating forward-thinking partnerships as a means of implementing energy efficiency and renewable energy, and addressing climate concerns. The long-term interest of its members is the use of secure, safe, reliable, sustainable, economical and environmentally responsible energy for constituents. The MEPC seeks to lead by example, by practicing energy conservation, using renewable energy sources in an effective manner, and taking steps to reduce greenhouse gas emissions.[2]

[1] Reference: RMEB; http://www.mncounties2.org/rmeb/about_rmeb.htm

[2] Reference: MEPC; http://www.mepc-mn.org/



PROJECT DESCRIPTION[3]

The initial phase of the project was intended to result in the technical and governmental framework for constructing 5-20 MW of wind generation capacity through a collaborative effort between the interested rural and metro governments. Due to the very constrained transmission infrastructure in the high wind resource areas of the RMEB, it was preferable to install this initial phase in area(s) that minimize transmission needs and MISO involvement.

The ultimate goal was to develop a procurement approach by which other public institutions in situations similar to participants involved with the CWI could develop and benefit from community-owned wind energy projects.

[3] Reference: Draft Workplan for Legislative-Citizen Commission on Minnesota Resources (LCCMR) Grant to the Department of Commerce for a Wind Energy Project by the MCETF and RMEB.

TABLE 1 – Primary Objectives of CWI Executive Committee Defining Project Success[4]

CATEGORY		RMEB Score	MEPC Score	Total Score
1.	**Regulatory & Political**	**11**	**12**	**23**
	• Good relationship support from power companies	2	3	5
	• Create Minnesota jobs	2	3	5
	• Relationship with utilities	1	2	3
	• Congruence of political will	2	1	3
	• State agencies willingness to cooperate	1	1	2
	• Educate legislators	2		2
	• Net good will		2	2
	• Broadly held development	1		1
	• Level playing field for public sector development			
	• More buy-in from legislators			
	• Local ownership			
	• Break new ground			
	• Model for other forms of distributed generation			
2.	**Governance**	**6**	**12**	**18**
	• Model that can be replicated	3	3	6
	• Meet LCCMR obligations	2	2	4
	• Near-term project (sooner vs. later)	1	2	3
	• Define distinctive capabilities of counties/Met Council		2	2
	• Lawsuit free		1	1
	• Management structure of 25 entities (17 RMEB counties, 7 metro counties, Met Council)		1	1
	• Carbon flexibility		1	1
	• Define unique niche of opportunity			
	• Get ahead of shift in opinion on renewables			
3.	**Financials**	**6**	**9**	**15**
	• Good financial deal	3	3	6
	• Demonstrable pro forma for sub-optimal sites	2	4	6
	• Stable reliable pricing	1	1	2
	• Avoid cost-shifting between rate payers		1	1
	• Reduce county dependence on property tax			
4.	**Collaboration**	**7**	**6**	**13**
	• Prove that counties can work together	3	2	6
	• Demonstrate local government can deliver project with value	2	2	4
	• Green energy project in place		2	2
	• Partner with metro counties to meet energy demands	2		2
	• Expand coalition			
	• Successful long term			
5.	**Interconnect Infrastructure**	**5**	**4**	**9**
	• Promote distributed generation	1	3	4
	• Change regulatory barriers	2		2
	• Connect production with consumption	2		2
	• Transmission infrastructure that allows larger interconnect		1	1
	• Spur change in utility distribution / generation process			
6.	**Geography**	**3**	**4**	**7**
	• Identify best locations	3	2	5
	• Define good backup supply		2	2
	• Identify productive energy sites			
	• Take advantage of "sweet spots"			
7.	**Promote Renewable Energy**	**2**	**2**	**4**
	• Promote renewables across state	1	2	3
	• Increase utilization of green energy	1		1

[4] Reference: RMEB/MEPC County Wind Initiative June 16, 2008 Project Kickoff Meeting Minutes. See Timeline Event #3 for explanation of Table 1.

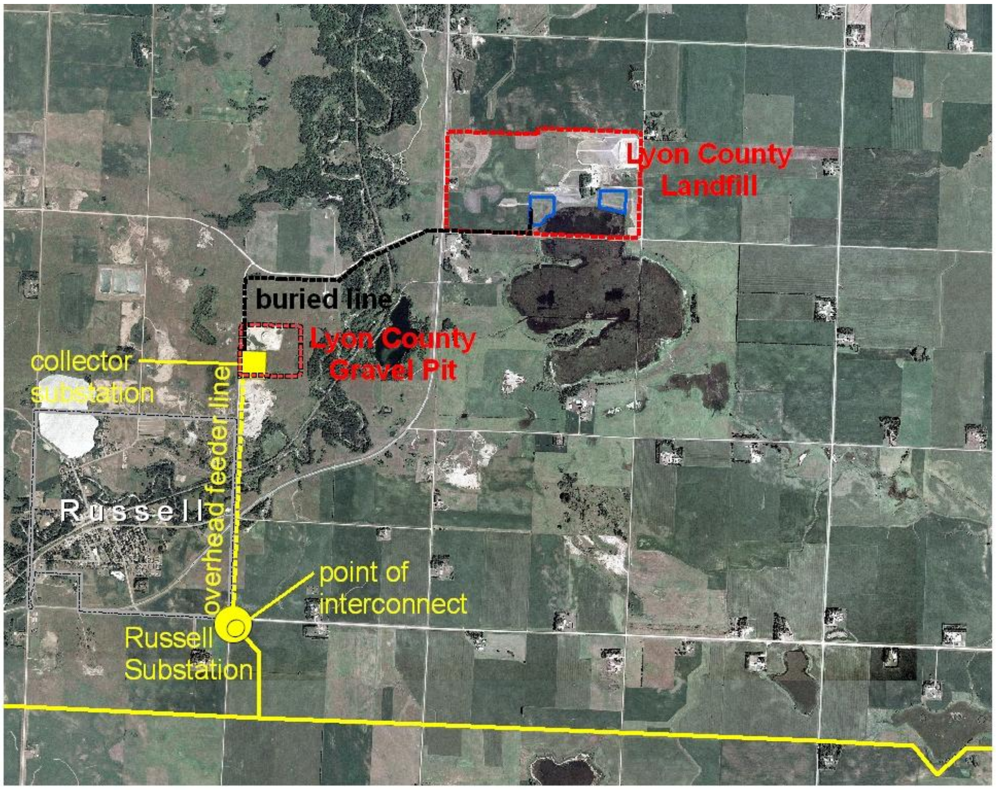
- Demonstrate volume of renewable energy

C. TIMELINE OF EVENTS

1. **December 3, 2007** – The RMEB and MEPC submitted a draft workplan for the Legislative-Citizen Commission on Minnesota Resources (LCCMR) Grant to the Department of Commerce for a Wind Energy Project
2. **January 28, 2008** – The RMEB and MEPC solicited statements of qualifications for a Project Manager to oversee the development of a 5-20 MW wind energy project.
3. **June 16, 2008** – Project Kick-Off meeting held with the RMEB, MEPC, and HGA consulting team to define goals and success factors for project. The goals of the RMEB and MEPC were explored in this meeting and voting by the commissioners in attendance was recorded in Table 1. The priorities of the two groups were recorded separately and it was observed that the priorities of the two groups were closely aligned.
4. **June 16, 2008** – The Dispersed Renewable Generation (DRG) Transmission Study was issued by the Minnesota Transmission Owners for the Minnesota Department of Commerce – Office of Energy Security.
5. **July 28, 2008** – HGA formally entered into Professional Services Agreement with the Rural Minnesota Energy Board as a consultant to evaluate the feasibility for the counties to undertake a wind energy development project.
6. **August 25, 2008** – The HGA consulting team submitted a Business Concept Assessment Draft Report to the RMEB and MEPC.
7. **February, 2009** – American Recovery and Reinvestment Act of 2009 signed into law along with incentive provisions applicable to renewable energy projects.
8. **April 1, 2009** – HGA submitted a memo outlining next steps for counties to pursue development that could benefit from federal tax incentives or grant opportunities being created from the stimulus package.
9. **April 2, 2009** – The Minnesota State Legislature granted The Winona County economic development authority the ability to form or become a member of a limited liability company organized under Minnesota Statutes, chapter 322B, for the purpose of developing a community-based energy development project pursuant to Minnesota Statutes, section 216B.
10. **May 22, 2009** –Effective date for Minnesota Senate File 657 regarding appropriations for Federal Stimulus Funds, including State Energy Programs and Energy Efficiency and Conservation Block Grant Programs.
    - Chapter 138, Article 3, Section 5 identifies the grant program for local government renewable energy projects. For wind projects greater than 40 kW, the grant is the lesser of 35% of project costs or $150,000. Each local government body may be able to severally apply and jointly invest in a single project under this program. This options was explored, however, this is a competitive grant program that did not appear to have a great deal of funding and the counties decided not to pursue it.
    - The limited funding availability from these programs did not appear to be enough to adequately leverage for grant equity on this project. With project capital costs anticipated to be approximately $2.0-2.1 million/MW, the total costs were estimated to be $7.5 million. Therefore, $2.625 million would have needed to be awarded in total to all the participating entities. Since individual awards are limited to $150,000, at least 18 participating entities would have had to been awarded a grant in order to make energy sales competitive with private development.
11. **June 2, 2009** – The Lyon County Commissioners provided a letter to the Rural Minnesota Energy Board authorizing approval for development exploration to site up to two utility scale Wind Turbine Generators on land owned by the county.
12. **June 3, 2009** – A Small Generator Interconnect Application (SGIA) for 3.6 MW was subsequently prepared and submitted to Western Area Power Administration (WAPA) along with a $5,000 non-refundable deposit, one-line electrical diagram, and the Lyon County Commissioners' approval letter for the project which is required as part of the application process to document site control of the intended

development area. A scheduled in-service date of **June 1, 2010** for operations was requested in the application.

13. **June 2009** – Preliminary discussions occurred with the Lyon County Public Works Department to coordinate suitable locations to explore micrositing wind turbines on the land parcel without impeding the landfill operations, maintaining required setbacks, and avoiding disturbance to the wetland areas.



The U.S. Fish & Wildlife service was contacted regarding siting of the wind turbines on the landfill site relative to the adjacent wetlands, and concerns were expressed about the potential negative ecological impact that utility scale wind generators might have on the surrounding avian habitat . The USFWS land immediately adjacent to the landfill is categorized as a Waterfowl Production Area. Therefore, a 50 acre gravel pit owned by Lyon County and located in Section 17 of Lyons Township was identified as an alternative location for siting a wind turbine.

14. **June 11, 2009** – WindLogics was engaged by HGA to study a detailed regime of information for the Area of Interest in Lyon County. Their wind resource assessment included wind speed, energy production, and capacity factor maps at an 80 meter AGL height for the AOI and a gridded spatial resolution of 50 meters using the GE 1.5 SLE Normal Turbulence turbine. Additionally, they included statistics for one virtual met tower location within the AOI. The statistics package included graphs of monthly and annual wind speed frequency and distribution, as well as prediction values and capacity factors.

15. **June 22, 2009** – A Pre-Scoping meeting was held to discuss the interconnection request and the project was assigned SGIA-0914 by WAPA. Participants in this discussion were Dirk Shulund – WAPA, Jay Trusty – SWRDC, Bob Fox – Renville County, and Ken Peterson – HGA. The point of interconnect options discussed were in order of preference – Lyon-Lincoln Electric's distribution line running by the landfill site; East River Electric's Russell substation; East River Electric's 69-kV subtransmission line. Voltage regulation will need to be managed if tying directly into the distribution system, so this will need to be closely studied and controlled to work. Otherwise, a feeder line taken back to the distribution

substation could be developed to manage power flow fluctuations. It was requested by HGA that the interconnection be in accordance with Minnesota Statute 216B.1611 for distributed generation.

16. **June 24, 2009** – The Minnesota Department of Commerce's Office of Energy Security announced that Minnesota has been awarded $21.7 million in federal stimulus funds for retrofitting existing public buildings and homes, **renewable energy** and energy efficiency programs and to develop new training opportunities. The funding represents the first installment of the $54.1 million set aside for Minnesota in the American Recovery and Reinvestment Act (ARRA).
17. **June 30, 2009** – HGA submitted an updated Business Concept Assessment Report in light of specifici project development efforts and state and federal funding opportunities.
18. **July 15, 2009** – The RMEB presented the case for an extension through June 30, 2010 to the LCCMR and HGA was directed to stop work until this request was approved.
19. **July 15, 2009** – The U.S. Department of Energy issued a Financial Assistance Funding Opportunity Announcement (Number DE-FOA-0000122) with stated anticipated award amounts in $5-7 million range. Eligibility for award was restricted to state and local governments, Indian Tribes and Tribal Energy Resource Development Organizations or Groups. The counties elected to pass up this opportunity due to their inability to obtain the necessary county board approvals to proceed in the time required and meet the September 3, 2009 Application Due Date.
20. **July 28, 2009** – The LCCMR granted the extension requested by the RMEB.
21. **November 3, 2009** – HGA submitted a memo outlining three basic options for consideration to the RMEB and MEPC in order to keep development efforts moving forward.
22. **December 21, 2009** – Stoel Rives submitted a resolution document to the counties for review to commit to pursuing ongoing development efforts and to work with the state legislature to allow the counties to form taxable “blocker” corporations.
23. **January 21, 2010** – WAPA submitted the System Impact Study Agreement (SISA) to the RMEB for consideration along with an additional $5,000 payment requirement to complete the study for the Interconnect Agreement. The RMEB was obligated to execute this agreement with invoice paid within 30 business days after receipt.
24. **February 11, 2010 –** The RMEB decided not to pursue continuing with the WAPA System Impact Study since none of the rural counties were willing to invest in the project. This resulted in the interconnect request being withdrawn and the practicality of advancing any further development efforts was lost.
25. **February 26, 2010 –** HGA submitted a memo again outlining the importance of obtaining legislative authority
26. **March 4, 2010** – During the monthly MEPC meeting, Commissioner Peter McLaughlin (Hennepin) explained that the Rural MN Energy Board (RMEB) decided that the capital investment to continue the joint wind initiative was not worthwhile.

D. IMPEDIMENTS TO COUNTY WIND INITIATIVE

MISO [5]

The MISO interconnection queue data shows that literally thousands of megawatts of new wind projects are under various stages of development in Southwestern Minnesota, Northwestern Iowa, and Eastern South Dakota. MISO has reformed their interconnection queue process, but projects that are not yet in the queue and wish to move forward with development on a tight timeline should avoid any hurdles that require MISO interconnection studies. There still remains numerous areas of congested transmission constraints in the MISO market which continue to impede new energy resource development efforts for the foreseeable future.

[5] Midwest ISO; Generator Interconnection
http://www.midwestiso.org/page/Generator+Interconnection

Our business concept efforts recognized these risks and honed in on the opportunity to develop a near term project at distribution level capacity (ie – 69 kV and under) on the Western Area Power Administration (WAPA) transmission system to overcome this impediment due to the overwhelming transmission constraints and regulatory approvals process that currently exists within MISO for the southwest region of the state. A Small Generator Interconnect Application was filed with WAPA on June 3, 2009 with a request to have the project studied out-of-queue.

Behind-The-Meter Energy Sales and Incentives
No county owned facilities within the RMEB territory are large enough to consume the load from a 5-10 MW wind development project. These factors cause Behind-The-Meter wind generation to be limited in their applicability to county owned facilities within the RMEB territory.

Investor Equity Production Tax Credit (PTC) Incentives
The counties can not leverage the added value of the PTC if they intend to wholly own a renewable energy development. To monetize the value of the PTCs, the counties would need to pursue the private developer hedging model, potentially with a “flip” structure that would allow a tax equity investor with sufficient passive income to own the project and receive the full value of the PTCs for a period of ten years or more (until a target ROI was achieved). After the equity investor achieves their target ROI, the ownership structure would flip so that the Counties and/or Metropolitan Council would then own the project. This hedging scenario has significant risk and does not appear to match the goals of the RMEB/MEPC CWI.

Renewable Energy Production Incentives (REPIs)
Qualifying projects are eligible to receive payments of $0.015/kWh (indexed for inflation) for the first ten years of operation. Since REPI funds must be appropriated every year, this incentive is unreliable for financing and budgeting purposes, but could provide some additional revenue for a county-owned project.

Small Generator Interconnect Agreement
In February, 2010, the RMEB opted not to pursue continuing with the WAPA System Impact Study since none of the rural counties were willing to invest in the project. This resulted in the interconnect request being withdrawn and the practicality of advancing any further development efforts was lost.

E. GOVERNANCE ISSUES

Governance of this project was complicated for the counties. The project involved 24 county governments and the Metropolitan Council that were part of two groups, the RMEB and the MEPC The two groups worked toward agreement of a common set of goals (see Table 1.) to affirm and guide the groups decisions. The RMEB worked under a Joint Powers Agreement, however, it was relatively weak and plagued the RMEB’s to commit its members throughout the development effort. Similarly, while the MEPC emerged in early 2008 from potential governance issues by recognizing that the MEPC does not operate as a JPA. It sought to engage only its members who were interested in the project, so it could proceed as a "coalition of the willing". It also developed a position that the willing should keep the full membership informed of project developments and that if the project appeared to have momentum that a coalition of the willing could be re-defined (members at that point would have the opportunity to opt in). The RMEB took a similar position with its counties allowing the ability to opt in at any point. Each had the notion that once there was a clearly defined wind project, a single governance model would be adopted under a JPA or some other structure comprised only of interested participants (and that this would reflect the success of the group rather than threaten it).

F. FINANCING ISSUES

Renewable energy projects are not cost competitive with fossil fuels. To encourage their development two broad approaches have been taken: 1) Renewable Portfolio Standards (RPS) where competition is created among similar renewable projects and 2) subsidies that off-set the higher cost of the projects and reduce the cost of renewable projects. The subsidies also help reduce the cost of meeting RPS requirements. Federal law created renewable energy subsidies through the Department of Treasury in two broad categories, the first was for taxable entities in the form of investment tax credits, the second was for production tax credits. The program has been expanded to allow grants to taxable entities as well. Non-taxable entities were provided with zero interest bond program (Clean Renewable Energy Bonds CREBs), where the interest was paid by the federal government.

Clean Renewable Energy Bonds (CREBs)
CREBs remain a viable financing option under current statutory authority for the counties as long as the continue to be renewed by Congress and the state grants counties the authority to borrow under the program. However, the low-cost financial incentive of CREBs still is not equal to the competitive cost advantages available from the Production Tax Credits, Investment Tax Credits, or US Treasury Grant in lieu of ITCs.

Federal Renewable Energy Production Incentive (REPI)
Qualifying projects are eligible to receive payments of $0.015/kWh (indexed for inflation) for the first ten years of operation. The payments are subject to the availability of funds based on annual appropriations by Congress. The Energy Policy Act authorized appropriations through fiscal year 2026 for facilities that become eligible before Oct. 1, 2016. Wind is an eligible technology. Since REPI funds must be appropriated every year, this incentive is unreliable for financing and budgeting purposes, but could provide some additional revenue for a county-owned project.

State law describes the purpose and amount of money county governments can bond for. It also limits the role county government and the formation of specific structures under which they may work. Both the state and the counties recognized this and the state demonstrated a willingness to work with the counties to enable them to promote renewable energy projects by allowing them to participate in their development under specific guidelines and limits. For example, the state gave the counties the authority to own projects under the C-BED Statute in 2008 and Winona was allowed to form an LLC in 2009 to allow it to make use of federal programs that are limited to taxable entities. However, the state did not give the counties the authority to bond for these projects, leaving them without a mechanism to pay for the projects with anything other than cash. Meaningful legislation to permit competitive financing of renewable projects was taken by the state, but it was narrow in scope, only apply to Winona county's economic development authority.

It seems that the federal government provided cost effective debt that was made unuseable by state statutes that establish debt financing boundaries. However, the electric utilities offer price for the purchase of the power not consumed behind the meter reflects the value of federal subsidies made to taxable entities. The value of the interest payments is not as generous as the tax credits so non-tax paying entities can not participate in the competitive wholesale electric market. This limits non-profits to behind the meter projects or projects above market wholesale rates. The restrictions proved significant, and to develop a meaningful project would have required federal participation to reach economic parity with the private sector. Seeking legislative authority for these agencies to create a "blocker" corporation with an operating agreement, fiscal budget, and board of managers that have the authority to make financial go or no-go decisions based on predetermined metrics would provide the necessary dexterity for the counties to advance development efforts quickly if and when new opportunities arise.

G. OWNERSHIP ISSUES

Project Ownership structure was intended to meet the requirements for the project to qualify for Community Based Energy Development (C-BED) power purchase agreements. The legal work to create this structure was not completed, nor did the counties do the work to assemble a operating agreement that would govern the membership rights and obligations of an ownership organization. Earlier in this report the flexibility to opt in and out of the project was described as a coalition of the willing that was relatively fluid. We also broadly discussed the fact that we would work toward a return on investment that was proportional to each parties investment in the project. More normal to many ventures like this, early investment while the project is most risky, earns the greatest return and subsequent investment is judged as more secure and is compensated at lower rates. This business model was not adopted during the exploration of the project. Below is a summary of the general characteristics of C-BED projects.

C-BED Model Qualification
Authority for Minnesota political subdivisions and local governments to own C-BED projects is unambiguously provided in 2008 amendment to the C-BED statute. Minn. Stat. § 216B.1612 subd. 9 now states that a county may "plan, develop, purchase, acquire, construct, and own a C-BED project" and the sell the output as provided for under the C-BED statute.

C-BED Tariffs
Minnesota utilities must adopt C-BED tariffs in accordance with the requirements in the C-BED statute. § 216B.1612 subd. 4. Public utilities file their tariffs with the Minnesota Public Utilities Commission. However, at "the discretion of the developer, a community-based project developer and a utility may negotiate a power purchase agreement with terms different from the tariff..." Thus, C-BED project developers are not bound to the terms of the tariffs if a utility is willing to agree to other terms.

C-BED Advantages
Utilities have made voluntary commitments to buying power from C-BED projects and Governor Pawlenty has set a voluntary target of having 800 MW of C-BED projects in Minnesota by 2010. Utilities are required to consider C-BED projects for meeting their statutory renewable energy obligations and report to regulators about their efforts to buy power from C-BED projects. § 216B.1612 subd. 5. Further, utilities including Xcel Energy, specifically agreed to and publicly supported the new legislation giving counties authority to own C-BED projects. Utilities are unlikely to object to counties acting as C-BED developers and might even be inclined to work with them as part of their voluntary C-BED goals.

C-BED Disadvantages
The terms of the C-BED tariffs are not advantageous, unless the utility is willing to negotiate different terms. Public utilities must receive approval from the Minnesota Public Utilities Commission for C-BED project power purchase agreements. § 216B.1612 subd. 7(e). The purpose of this provision is to give utility ratepayers an opportunity to address the reasonableness of the agreements.

H. MISSED OPPORTUNITIES

Pairing with landfill gas recovery project
As discussed by the Counties Wind Initiative consulting team at the July 15, 2008 meeting and subsequent correspondence, there is an MSW landfill in Lyon County near Marshall with some potential for Landfill Gas to Energy (LFGTE). Lyon County decided not to pursue this project independently , and the RMEB also opted to pass up consideration for coupling this project with the wind project. This site could still provide an opportunity for pairing a wind project with a LFGTE project.

U.S. DOE Financial Assistance Funding Opportunity Announcement
The U.S. Department of Energy issued a Financial Assistance Funding Opportunity Announcement (Number DE-FOA-0000122) on July 15, 2009 with stated anticipated award amounts in $5-7 million range. Eligibility for award was restricted to state and local governments, Indian Tribes and Tribal Energy Resource

Development Organizations or Groups. The counties elected to pass up this opportunity due to their inability to obtain the necessary county board approvals to proceed in the time required and meet the September 3, 2009 Application Due Date.)

Blocker Corporation Statutory Authority

Efforts to pursue explicit legislative authority of counties to form taxable “blocker” corporations as drafted in a resolution document by Stoel Rives for consideration by the counties during the 2010 legislative session were not pursued. This status would give the counties the authority to pursue other federal incentive programs that they are currently not eligible for.

I. LEGACY ENERGY STRUCTURES

Minnesota's utilities generate electricity, move it over long distances and distribute it to their customers in a regulated environment. They have organized their companies and developed expectations to perform these tasks efficiently, reliably and at low cost. They have owned their own generating assets and transmission and distribution system. The companies and their rates are scrutinized in a public review process. Over the course of their corporate history they have developed pride in their work and traditions in their work place that reflect their historic role of owning and operating all electric generating assets in their service territories.

Some states have moved to deregulate electricity in an effort to improve the efficiency and lower costs by creating a competitive environment. As states explored this option, policy makers weighed the advantages and disadvantages of moving from a regulated to a competitive market. Over the past decade the PUC has required uitilities to identify their costs in three areas, generation, transmission and distribution. This accounting process is intended to allow investors to determine if they are in a position to compete for the development of generation and transmission systems.

Distributed generation has stood out as a recognized element of electric service where economy could be achieved in both regulated and deregulated markets To one degree or another, utilities with exclusive service territories have made the development of distributed generation a difficult process and have assigned significant cost to the interface of distributed generators with the utilities distribution system.

The issues surrounding distributed generation present both technical and business challenges as both utility customers search for ways to reduce operating costs and merchant plant developers search for ways to participate in the electric market. Renewable energy has presented new opportunities and new challenges. January 10, 2010 the Federal Energy Regulatory Commission issued a Notice of Inquiry titled, "Integration of Variable Energy Resources" to structure the discussion of the impact energy sources like wind, solar and hydro have on electric service. In their words:

"In this proceeding, the Commission seeks to explore whether existing rules, regulations, tariffs, or industry practices within the Commission's jurisdiction may hinder the reliable and efficient integration of Variable Energy Resources (VERs are wind, solar and some hydro generators), resulting in rates that are unjust and unreasonable and/or terms of service that unduly discriminate against certain types of resources. The Commission seeks comment on how best to reform any such rules, regulations, tariffs, or industry practices."

FERC states, "Under sections 205 and 206 of the Federal Power Act, the Commission has a responsibility to remedy undue discrimination with respect to transmission of electric energy and sales of electric energy for resale in interstate commerce and to ensure that rates for these services are just and reasonable.16 U.S.C. 824d, 824e. " This presents the conundrum of what is just and reasonable treatment of fossil fuel generators vs. renewable energy generators. It is clear that government is working toward a national energy policy that displaces some of our fossil fuel fired generating assets with clean, renewable energy sources. The cost of integrating these resources is greater than the low cost generating solutions that we built our country on for the last 100 years and rate payers will incur the cost. The issue is who in the supply chain, VERs or the fossil fuel utilities, will be assigned the added cost of bringing renewable energy into our energy portfolio. However, history has shown that whoever is faced with higher costs in the merchant market has a harder time developing new capacity.

The assignment of costs associated with the development of renewable energy generating assets may have a significant impact on its future development. Simply put, all the cost of integrating wind power into our electrical system could be assigned to the wind developer or to the coal fired power plants with one side arguing that without variable attributes of wind energy in the system the cost of electricity is lower. The other side of the argument is that wind is less damaging to the environment and should be treated as the preferred method of power production and all of the cost of accommodation should be assigned to the dirtiest producers to discourage their continued use.

J. CHALLENGES OF WORKING WITH LIMITED INFORMATION

The RMEB and MEPC both struggled at times with the conundrum of needing to protect potentially sensitive information needing some level of confidential protection and having enough information that they could present to their respective county board constituents in order for them to make informed decisions as to whether or not to pursue opportunities as they arose.

K. ENERGY LANDSCAPE

Diversifying and expanding our supply of energy is becoming a national priority. Universities and industry are responding to government funding and increasing market prices for electricity by exploring how to make use of low grade and or intermittent energy sources like solar radiation, wind and biomass to meet a portion of our demand for energy.

The transportation industry is also responding by exploring alternates to petroleum products by looking at electricity, hydrogen and natural gas to propel our cars. Using electricity for cars opens up the possibility of a broad range of fuel sources to make the electricity that will in turn propel our fleet of vehicles.

The effect of developing low grade energy to generate electricity and consuming more electricity with cars changes how we use our electric transmission and distribution grid. To capture low grade energy sources distributed generation plays a greater role in the production of electricity. Rather than operating large coal fired plants, energy is gathered from roof-tops and farm fields spread out across our state. Since many of the new sources are intermittent, additional firma capacity needs to be developed that can be operated to compliment the renewable-intermittent resources. This presents a technical and business change to the way we operate and pay for the transmission and distribution of power.

Similarly, the addition of cars to the load side of the equation presents a load growth to the utilities. An opportunity presents itself using smart grid technology to match some loads with the peak production of intermittent resources. This is a way to maximize the value of the existing wire infrastructure.

These goals have cluttered the landscape with questions, both technical and economic. The work has been started and has relied primarily on government funding. Together the industry and its regulators are sorting through their choice of economic levers that will drive efficient development of clean intermittent energy sources and a diversified energy portfolio that is less dependent upon fossil fuels.

L. CONCLUSIONS

The ultimate goal was to develop a procurement approach by which other public institutions in situations similar to participants involved with the CWI could develop and benefit from community-owned wind energy projects. The counties were interested in the concept of developing a wind farm in the part of the state where it could be most productive and then using the energy in the metropolitan area, where there was a significant demand for electricity. State law enabling the counties recognized this concept by defining the maximum amount of power the counties could develop, but the legislation was mute regarding other barriers to implementation.

- Current tariffs do not allow this concept. Instead, the counties needed to produce and sell the energy to a utility with facilities in the area of the wind farm at a wholesale price and repurchase the power at retail from the utility serving the metro area. Under the direction of the legislature, the Office of Energy Security investigated the concept of establishing a tariff for Contract Renewable Distributed Generation with a multiparty workgroup during Xcel's last general rate case. The goal of the tariff is to allow wind assets operated in the most productive parts of the state to serve loads in other areas of the state, while paying transmission fees similar to or lower than the fee one utility pays to another for similar service. The rate that was proposed within the workgroup was unacceptably high and the Minnesota Chamber of Commerce continues to encourage the establishment of a favorable tariff. The University of Minnesota remains interested and Xcel agreed to continue discussions, however, its resolution did not stand in the way of the rate case.

- Current state law does not allow most counties to form special purpose companies to own generating assets and make use of federal tax incentives. (Hennepin County, Winona County and the City of Mountain Iron were granted limited authority to form special purpose companies.) Work at the federal level may make this a non-issue by making the investment tax credit grant or similarly generous grants available to non-profits and units of government. Alternatively, the state could authorize the counties to create and own for-profit entities.(reference Stoel Rives letter.)
- Current law does not allow counties to bond for the purpose of producing power. It is within the power of the state legislature to offer this authority.

As outlined in HGA's memo to the RMEB and MEPC on February 26, 2010, recommendations going forward are simple and shaped by the renewable energy market, the overall economy and the federal government's willingness to work with units of government who have authority to own taxable entities.

Gaining authority from the legislature to form a corporation is the single best initiative the state's units of government could work to achieve. The purpose of the corporation would be to allow units of government to own a taxable entity and to establish a management board with the authority to make development decisions quickly if and when opportunities to advance a project arise. Federal law may or may not change. Grants may or may not be made available. However, under current law and programs, dollars are available.

Without the authority and the value of treasury grants to buy down the project costs, the projects we have modeled do not have adequate return on investment for the counties to move forward. While this may not have been true at the project's outset, the renewable energy market has changed enough (downward price pressure) and the financial strength of county government has changed enough to make the proposed renewable energy projects too risky to most of the participants. At last count, only one of 17 rural counties was interested in moving forward.

We worked our way through the changing economic conditions this project experienced. We expected to realize a successful project and explored options as they became available. Our team was extremely creative and kept our collective ears to the ground for the opportunity that could make this endeavor successful.

While the result of the effort is disappointing, it is clear that if a project like this is taken up by the counties in the future, they would be well served by making sure they secure as much statutory, financial and leadership agility as possible early in the project. The group learned about the impediments and barriers to bring the project to fruition over the course of the two year effort and likely would have approached some issues differently with the benefit of hindsight. The lessons learned have informed the group so they are better positioned to respond to future opportunities with both speed and strength.

RMEB/MEPC JWI
Project costs
Treasury Grant Scenario
11/6/2009

	Project Total	Per Turbine	Per MW	Dep. or Amo.	Dep.	Amo.
Hard Costs						
Construction						
Turbines	5,850,000	1,950,000	1,300,000	D	5,850,000	-
Towers		-	-	D	-	-
Shipping / Freight	525,000	175,000	116,667	D	525,000	-
Balance of Plant						
General Conditions / Mob-Demob	225,000	75,000	50,000	D	225,000	-
Foundation, conduit & transfer pad	450,000	150,000	100,000	D	450,000	-
Crane, rigging, erection labor	525,000	175,000	116,667	D	525,000	-
Turbine electrical installations	150,000	50,000	33,333	D	150,000	-
Man lift	-	-	-	D	-	-
FAA Obstruction Light	18,000	6,000	4,000	D	18,000	-
Access roads	100,000	33,333	22,222	D	100,000	-
Excavation and site restoration	75,000	25,000	16,667	D	75,000	-
Transformers	150,000	50,000	33,333	D	150,000	-
High voltage collection systems	90,000	30,000	20,000	D	90,000	-
Substation / Interconnection	900,000	300,000	200,000	D	900,000	-
Transmission	150,000	50,000	33,333	D	150,000	-
Contingency	100,000	33,333	22,222	D	100,000	-
(open)		-	-	D	-	-
(open)		-	-	D	-	-
(open)		-	-	D	-	-
(open)		-	-	D	-	-
(open)		-	-	D	-	-
Soft Costs						
WAPA Interconnect Studies	5,000	1,667	1,111	A	-	5,000
Planning & Development	300,000	100,000	66,667	A	-	300,000
(open)		-	-	A	-	-
(open)		-	-	A	-	-
(open)		-	-	A	-	-
(open)		-	-	A	-	-
(open)		-	-	A	-	-
(open)		-	-	A	-	-
Other Costs						
Construction Loan Closing Costs	30,000	10,000	6,667	A	-	30,000
Construction Bridge Closing Costs		-	-	A	-	-
Equity Closing Costs	5,000	1,667	1,111	A	-	5,000
Construction Interest	80,000	26,667	17,778	A	-	80,000
Construction Loan Finance Fee	48,890	16,297	10,864		-	-
Equity & Bridge Financing Fee	-	-	-		-	-
Rounding	1,110	370	247	A	-	1,110
TOTAL	**9,778,000**	**3,259,333**	**2,172,889**		**9,308,000**	**421,110**

RMEB/MEPC JWI

Wind Energy Conversion System

Turbine Warranty, Insurance and OM&S Cost Allocation Assumptions

WIND TURBINE EX-WORKS PRICE	
GE 1.5SLE	$ 1,950,000
Industry average ex-works price	$ 2,250,000
ex-works cost factor adjustment	**1.15**

TOTAL ANNUAL OPERATING EXPENSES	% of ex-works price		Annual Expense Allocation		Total Project Cost Allocation	
	Range		Range		Range	
OM&S Contract	0.8%	1.0%	$ 18,000	$ 22,500	$ 360,000	$ 450,000
Repair reserves	1.0%	1.5%	$ 22,500	$ 33,750	$ 450,000	$ 675,000
Insurance	0.5%	0.8%	$ 11,250	$ 18,000	$ 225,000	$ 360,000
Land Lease	0.2%	0.4%	$ 4,500	$ 9,000	$ 90,000	$ 180,000
Misc. (tax, energy use, accounting, site maintenance)	0.3%	0.4%	$ 6,750	$ 9,000	$ 135,000	$ 180,000
SUBTOTAL	**2.8%**	**4.1%**	**$ 63,000**	**$ 92,250**	**$ 1,260,000**	**$ 1,845,000**

TURBINE INSURANCE BREAKDOWN	% of ex-works price		Annual Expense Allocation		Total Project Cost Allocation	
	Range		Range		Range	
Liability Insurance	0.06%	0.12%	$ 1,350	$ 2,700	$ 27,000	$ 54,000
Insurance against machine breakage	0.30%	0.60%	$ 6,750	$ 13,500	$ 135,000	$ 270,000
Loss-of-profit insurance	0.04%	0.06%	$ 900	$ 1,350	$ 18,000	$ 27,000
Force Majeure insurance ("Act of God")	0.04%	0.06%	$ 900	$ 1,350	$ 18,000	$ 27,000
SUBTOTAL			**$ 9,900**	**$ 18,900**	**$ 198,000**	**$ 378,000**

MAJOR EQUIPMENT REPLACEMENT ALLOCATION	% of ex-works price					
	Range					
	20%	30%			**$ 450,000**	**$ 675,000**
	Estimated Frequency		Estimated Replacement Cost		Project Life Cost	
Typical Replacement Items	Range		Range		Range	
gearbox - bearings and gearing	4 years	6 years	$ 40,000	$ 50,000	$ 120,000	$ 200,000
roller bearings in generator	10 years	15 years	$ 40,000	$ 50,000	$ 40,000	$ 50,000
clutch	10 years	15 years	$ 40,000	$ 50,000	$ 40,000	$ 50,000
nacelle mounting - yaw drives / contactors	10 years	15 years	$ 120,000	$ 150,000	$ 120,000	$ 150,000
rotor blades/ shaft	10 years	15 years	$ 120,000	$ 150,000	$ 120,000	$ 150,000
electronics	5 years	6 years	$ 2,000	$ 3,000	$ 6,000	$ 9,000
fuses	2 years	3 years	$ 1,000	$ 2,000	$ 6,000	$ 18,000
fan housings	5 years	6 years	$ 4,000	$ 5,000	$ 12,000	$ 15,000
sensors	5 years	6 years	$ 2,000	$ 4,000	$ 6,000	$ 12,000
wind vanes/anemometers	2 years	3 years	$ 1,000	$ 2,000	$ 6,000	$ 18,000
phantom faulting	1 years	2 years	$ 1,000	$ 1,500	$ 9,000	$ 28,500
SUBTOTAL					**$ 485,000**	**$ 700,500**

RMEB/MEPC JWI
Depreciation & Amortization
Treasury Grant Scenario
11/6/2009

DEPRECIATION

Depreciation Basis	9,308,000
Depreciation Schedule	MACRS
Years	5
Bonus Depreciation in Year 1	50%
Basis Reduction (half of grant)	15%

Year	1	2	3	4	5	6	7	8	9	10
Basis Reduction	15%									
Reduction in Basis Value	(1,396,200)									
Reduced Basis	7,911,800									
Bonus Depreciation	50%									
Bonus Depreciation Value	3,955,900									
Basis After Bonus Depreciation	3,955,900									
5 Year MACRS (Half-year convention)										
Depreciation Schedule	0.2	0.32	0.192	0.1152	0.1152	0.0576				
5 Year MACRS Depreciation Value	$ 791,180	$ 1,265,888	$ 759,533	$ 455,720	$ 455,720	$ 227,860				
Total Depreciation	$ 4,747,080	$ 1,265,888	$ 759,533	$ 455,720	$ 455,720	$ 227,860				
5 Year MACRS (4th Quarter convention)										
(assumes 40% or more of the project was put in place during 4th quarter)										
Depreciation Schedule	0.05	0.38	0.228	0.1368	0.1094	0.0958				
5 Year MACRS Depreciation Value	$ 197,795	$ 1,503,242	$ 901,945	$ 541,167	$ 432,775	$ 378,975				
Total Depreciation	$ 4,153,695	$ 1,503,242	$ 901,945	$ 541,167	$ 432,775	$ 378,975				
7 Year MACRS										
Depreciation Schedule	0.1429	0.2449	0.1749	0.1249	0.0893	0.0892	0.0893	0.0446		
7 Year MACRS Depreciation Value	$ 565,298	$ 968,800	$ 691,887	$ 494,092	$ 353,262	$ 352,866	$ 353,262	$ 176,433		
Total Depreciation	$ 4,521,198	$ 968,800	$ 691,887	$ 494,092	$ 353,262	$ 352,866	$ 353,262	$ 176,433		

RMEB/MEPC JWI
Summary
Treasury Grant Scenario
11/06/09

Lyon County, MN
4.5 MW Nameplate Capacity

Turbine Manufacturer:	GE 1.5SLE
Number of Turbines:	3
Turbine Size (MW):	1.50 MW
Project Nameplate Capacity	**4.50 MW**
Net Capacity Factor (Year 1)	38.3%
Energy Production (Year 1)	15,096 MWh/yr
PPA Term	20 Years
1st Year Energy Payment (w/ RECs)	$0.0475/kWh
NPV PPA	$0.0257/kWh
Debt	**50%**
Equity	**50%**
Minimum DSCR	**1.09**
Average DSCR	**1.41**

Total Development Cost:	$9,778,000
Price per MW	$2,172,889 / MW
Development Incentive Utilized:	**Grant**
3rd Party Equity Investor Returns	
Equity	$ 4,669,000
Investment Tax Credit	$ -
XIRR	**16.45%**
Local Investor Returns	
Equity	$ -
IRR	**NA**

RMEB/MEPC JWI
Pro Forma Assumptions
Treasury Grant Scenario
11/6/2009

PROJECT SUMMARY									
		Turbine Size (MW)	Total Project Size (MW)						
Project Name	RMEB/MEPC JWI								
Project Location	Lyon County, MN								
Scenario Name	Treasury Grant Scenario								
Scenario Date	November 6, 2009								
Developer	RMEB Wind								
Number of Turbines	3	1.50	4.50						
Make of Turbines	GE 1.5SLE								
	Gross Capacity Factor	Operational Availability	Wind Park Array Losses	Net Capacity Factor (Year 1)	kWh Produced per turbine	Total kWh produced by project	Annual Loss in Operational Availability	Loss Distributed "Monthly" or "Annually"	Annual Loss Beginning in Year
Capacity Factor	45%	92%	7.5%	38.30%	5,031,963	15,095,889	0.25%	Annually	5
Start Date (spinning)	04/01/11								
Construction Period Length (months)	6								
Terminal Value	0								

FINANCING & OWNERSHIP								
	Investment %	Ownership post-flip	Rate / Required Return	Tax Rate	Amortization (Years)	Term (Years)	Payments per year	Financing Fee (%)
Total Initial Debt (% of project cost for construction)	50%							
Total Initial Equity (% of project cost for construction)	50%							
Construction Debt (% of project cost)	50%		6.50%			0.5		1%
Construction Bridge for Grant (% of project cost, tied to Grant (below))	0%		6.50%			0.75		2%
Permanent Debt (% of project cost)	50%		6.50%		20	20	12	
Tax Equity (% of equity)	100%	100%	12%	35%				0%
Local Equity (% of equity)	0%	0%						
Construction & Permanent Debt provided by local bank? ("Yes" or "No")	Yes							
	Value	% to Tax Equity Investor	% to Local Group		Dep/Amo (Years)	Depreciation Convention		
Equity Flip at Beginning of Year:	11							
PTC, ITC or Grant ("PTC", "ITC", "Grant")	Grant							
Federal Grant % (30% max)	30%	100%	0%					
Grant applied towards ("Debt" or "Equity")	Equity							
Date grant received (number of days after start of spinning)	90							
Depreciation Schedule ("MACRS" or "Straight")	MACRS				5	Half-year		
Bonus Depreciation (50%)	50%							
Amortization Schedule ("Straight" only)	Straight				7			
LCCMR Grant	220,000							

RMEB/MEPC JWI
Pro Forma Assumptions
Treasury Grant Scenario
11/6/2009

OPERATIONS	Initial Value (Annual)	Escalation Rate	Step-up Value (Annual)	Step-up In Year	Escalation Rate After Step-up	% to Local Community, for CBED Calculation
REVENUES						
Electricity Sold through PPA (%)	100%		100%	11		
Electricity Sold on Spot Market (%)	0%		0%	11		
Green Tags Sold	100%		100%	11		
PPA Rate	0.04250	2.5%			0%	
PPA Balloon Payment						
Spot Market Rate						
Green Tags Price ($/kWh)	0.0050	2.5%				
PTC Rate	0.0210	2.0%				
EXPENSES						
Operations / Mgmt (% of revenues, per MW; "Flat" or "Variable")	0.00%	Flat				
OM&S Warranty (per MW)	22,222	0.00%		6		
(open)	-					
Service Agreement (per MW)			22,222	6	3.00%	
Insurance (per MW)	4,889	2.00%				
Power Use (per MW)	667	3.00%				
Management Fee (per MW)	3,333	2.00%				
Accounting, Admin & Legal (per MW)	1,111	2.00%				
PPA Revenue Royalty Payments (per MW)						
PPA Revenue Royalty Payments (% of revenues)	4.00%					
Property Tax ($/kWh)						
Production Tax ($/kWh)	0.00036	2.00%				
RESERVES	Initial Value (Annual)	Escalation Rate	Step-up Value (Annual)	Step-up In Year	Escalation Rate After Step-up	Interest Rate Received on Reserve
Addition to Contingency Fund (per MW)	13,333		14,667	2		
Addition to Decommissioning Fund (per MW)	667	0.00%				
Addition to Operating Reserves (per MW)						

RMEB/MEPC JWI
Project Pro Forma (Annual)
Treasury Grant Scenario
11/6/2009

Year	0	1	2	3	4	5	6	7	8	9	10
Date	3/31/2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
TOTAL DEVELOPMENT COST											
Project Capital Required	$9,778,000										
POWER PRODUCTION											
Total Electricity Production (kWh/yr)		15,095,889	15,095,889	15,095,889	15,095,889	15,058,149	15,020,504	14,982,953	14,945,495	14,908,132	14,870,861
Electricity Sold through PPA		15,095,889	15,095,889	15,095,889	15,095,889	15,058,149	15,020,504	14,982,953	14,945,495	14,908,132	14,870,861
Electricity Sold to Day-ahead and Spot Markets		-	-	-	-	-	-	-	-	-	-
Green Tags Sold		15,095,889	15,095,889	15,095,889	15,095,889	15,058,149	15,020,504	14,982,953	14,945,495	14,908,132	14,870,861
Electricity Qualifying for PTC		-	-	-	-	-	-	-	-	-	-
Electricity Rate through PPA ($/kWh)		$0.0425/kWh	$0.0436/kWh	$0.0447/kWh	$0.0458/kWh	$0.0469/kWh	$0.0481/kWh	$0.0493/kWh	$0.0505/kWh	$0.0518/kWh	$0.0531/kWh
Electricity Revenue in Day-ahead and Spot Markets ($/kWh)		$0.0000/kWh	$0.0000/kWh	$0.0000/kWh	$0.0000/kWh	$0.0000/kWh	$0.0000/kWh	$0.0000/kWh	$0.0000/kWh	$0.0000/kWh	$0.0000/kWh
Green Tags Rate ($/kWh)		$0.0050/kWh	$0.0051/kWh	$0.0053/kWh	$0.0054/kWh	$0.0055/kWh	$0.0057/kWh	$0.0058/kWh	$0.0059/kWh	$0.0061/kWh	$0.0062/kWh
PTC Rate		$0.0210/kWh	$0.0214/kWh	$0.0218/kWh	$0.0223/kWh	$0.0227/kWh	$0.0232/kWh	$0.0236/kWh	$0.0241/kWh	$0.0246/kWh	$0.0251/kWh
REVENUES											
Revenues from PPA		$ 641,575	$ 657,615	$ 674,055	$ 690,906	$ 706,409	$ 722,259	$ 738,464	$ 755,034	$ 771,975	$ 789,296
Revenues from PPA Balloon Payment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Revenues from Day-ahead and Spot Markets		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Green Tags		$ 75,479	$ 77,366	$ 79,301	$ 81,283	$ 83,107	$ 84,972	$ 86,878	$ 88,827	$ 90,821	$ 92,858
Interest Revenues											
Total Revenues		$ 717,055	$ 734,981	$ 753,356	$ 772,190	$ 789,516	$ 807,230	$ 825,342	$ 843,861	$ 862,795	$ 882,154
EXPENSES											
Operations / Management		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
OM&S Warranty (per MW)		$ 100,000	$ 100,000	$ 100,000	$ 100,000	$ 100,000	$ -	$ -	$ -	$ -	$ -
Service Agreement		$ -	$ -	$ -	$ -	$ -	$ 100,000	$ 103,000	$ 106,090	$ 109,273	$ 112,551
Insurance		$ 22,000	$ 22,440	$ 22,889	$ 23,347	$ 23,814	$ 24,290	$ 24,776	$ 25,271	$ 25,777	$ 26,292
Power Use		$ 3,000	$ 3,090	$ 3,183	$ 3,278	$ 3,377	$ 3,478	$ 3,582	$ 3,690	$ 3,800	$ 3,914
Management Fee		$ 15,000	$ 15,300	$ 15,606	$ 15,918	$ 16,236	$ 16,561	$ 16,892	$ 17,230	$ 17,575	$ 17,926
Accounting, Admin & Legal		$ 5,000	$ 5,100	$ 5,202	$ 5,306	$ 5,412	$ 5,520	$ 5,631	$ 5,743	$ 5,858	$ 5,975
PPA Revenue Royalty Payments		$ 28,682	$ 29,399	$ 30,134	$ 30,888	$ 31,581	$ 32,289	$ 33,014	$ 33,754	$ 34,512	$ 35,286
Property Tax		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Production Tax		$ 5,435	$ 5,543	$ 5,654	$ 5,767	$ 5,868	$ 5,970	$ 6,074	$ 6,180	$ 6,288	$ 6,398
		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Expenses		$ 179,117	$ 180,872	$ 182,668	$ 184,504	$ 186,287	$ 188,109	$ 192,969	$ 197,959	$ 203,083	$ 208,343
EBITDA (Operating Cash)		$ 537,938	$ 554,109	$ 570,688	$ 587,686	$ 603,228	$ 619,122	$ 632,373	$ 645,902	$ 659,713	$ 673,811

RMEB/MEPC JWI
Project Pro Forma (Annual)
Treasury Grant Scenario
11/6/2009

Year	0	1	2	3	4	5	6	7	8	9	10
DEBT SERVICE & RESERVES											
Interest Expense		$ 314,156	$ 305,901	$ 297,094	$ 287,696	$ 277,669	$ 266,971	$ 255,556	$ 243,377	$ 230,382	$ 216,517
Depreciation Expense		$ 4,747,080	$ 1,265,888	$ 759,533	$ 455,720	$ 455,720	$ 227,860	$ -	$ -	$ -	$ -
Amortization Expense		$ 60,159	$ 60,159	$ 60,159	$ 60,159	$ 60,159	$ 60,159	$ 60,159	$ -	$ -	$ -
Total Non-Cash Expenses		$ 4,807,239	$ 1,326,047	$ 819,691	$ 515,878	$ 515,878	$ 288,018	$ 60,159	$ -	$ -	$ -
EBT (Income Distributed to Partners)		$ (4,269,301)	$ (771,938)	$ (249,004)	$ 71,808	$ 87,350	$ 331,103	$ 572,215	$ 645,902	$ 659,713	$ 673,811
Addition to Contingency Fund		$ 60,000	$ 66,000	$ 66,000	$ 66,000	$ 66,000	$ 66,000	$ 66,000	$ 66,000	$ 66,000	$ 66,000
Addition to Decommissioning Fund		$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000
Addition to Operating Reserves		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Terminal Value											
Cash for Debt Service & Distribution (EBITDA - Reserves)		$ 474,938	$ 485,109	$ 501,688	$ 518,686	$ 534,228	$ 550,122	$ 563,373	$ 576,902	$ 590,713	$ 604,811
Debt Service (P&I)		$ 437,413	$ 437,413	$ 437,413	$ 437,413	$ 437,413	$ 437,413	$ 437,413	$ 437,413	$ 437,413	$ 437,413
Debt Service Coverage Ratio		1.09	1.11	1.15	1.19	1.22	1.26	1.29	1.32	1.35	1.38
Net Cash (Cash Distributed to Partners)		$ 37,525	$ 47,696	$ 64,275	$ 81,273	$ 96,816	$ 112,709	$ 125,961	$ 139,489	$ 153,300	$ 167,398
TAX CREDITS AND GRANTS											
Federal Production Tax Credit (PTC)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Federal Investment Tax Credit (ITC)	$ -										
Tax Credits (Tax Credits Distributed to Partners)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Federal Grant		$ 2,933,067	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Grants (Grants Distributed to Partners)		$ 2,933,067	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TAX INVESTOR RETURNS											
Income Distribution		$ (4,583,457)	$ (1,077,839)	$ (546,097)	$ (215,889)	$ (190,319)	$ 64,132	$ 316,659	$ 402,525	$ 429,330	$ 457,294
Income from Sale (Termination Value) Distribution											
Tax Rate		35%	35%	35%	35%	35%	35%	35%	35%	35%	35%
Tax Savings (Obligation) from Earnings		$ 1,604,210	$ 377,244	$ 191,134	$ 75,561	$ 66,612	$ (22,446)	$ (110,831)	$ (140,884)	$ (150,266)	$ (160,053)
Tax Credits	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cash Savings (Obligation) from Taxes[2]	$ -	$ 1,604,210	$ 377,244	$ 191,134	$ 75,561	$ 66,612	$ (22,446)	$ (110,831)	$ (140,884)	$ (150,266)	$ (160,053)
Cash Distributed from Net Cash		$ 40,525	$ 50,696	$ 67,275	$ 84,273	$ 99,816	$ 115,709	$ 128,961	$ 142,489	$ 156,300	$ 170,398
Cash Distributed from Grant	$ -	$ 2,933,067	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Cash Distributed from Sale (Terminal Value)											
Total Cash Distribution & Tax Savings	$ -	$ 4,577,802	$ 427,939	$ 258,409	$ 159,834	$ 166,427	$ 93,263	$ 18,130	$ 1,605	$ 6,034	$ 10,345
LOCAL INVESTOR RETURNS											
Income Distribution		-	-	-	-	-	-	-	-	-	-
Income from Sale (Termination Value) Distribution											
Tax Rate		0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Tax Savings (Obligation) from Earnings		-	-	-	-	-	-	-	-	-	-
Tax Credits	-	-	-	-	-	-	-	-	-	-	-
Total Cash Savings (Obligation) from Taxes[2]	-	-	-	-	-	-	-	-	-	-	-
Cash Distributed from Net Cash		-	-	-	-	-	-	-	-	-	-
Operations / Management		-	-	-	-	-	-	-	-	-	-
Cash Distributed from Grant	-	-	-	-	-	-	-	-	-	-	-
Cash Distributed from Sale (Terminal Value)											
Total Cash Distribution & Tax Savings	-	-	-	-	-	-	-	-	-	-	-

RMEB/MEPC JWI
Project Pro Forma (Annual)
Treasury Grant Scenario
11/6/2009

Year	11	12	13	14	15	16	17	18	19	20	TOTALS
Date	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	
TOTAL DEVELOPMENT COST											
Project Capital Required											
POWER PRODUCTION											
Total Electricity Production (kWh/yr)	14,833,684	14,796,600	14,759,608	14,722,709	14,685,903	14,649,188	14,612,565	14,576,033	14,539,593	14,503,244	296,848,778
Electricity Sold through PPA	14,833,684	14,796,600	14,759,608	14,722,709	14,685,903	14,649,188	14,612,565	14,576,033	14,539,593	14,503,244	296,848,778
Electricity Sold to Day-ahead and Spot Markets	-	-	-	-	-	-	-	-	-	-	-
Green Tags Sold	14,833,684	14,796,600	14,759,608	14,722,709	14,685,903	14,649,188	14,612,565	14,576,033	14,539,593	14,503,244	296,848,778
Electricity Qualifying for PTC	-	-	-	-	-	-	-	-	-	-	-
Electricity Rate through PPA ($/kWh)	$0.0544/kWh	$0.0558/kWh	$0.0572/kWh	$0.0586/kWh	$0.0601/kWh	$0.0616/kWh	$0.0631/kWh	$0.0647/kWh	$0.0663/kWh	$0.0679/kWh	
Electricity Revenue in Day-ahead and Spot Markets ($/kWh)	$0.0000/kWh	$0.0000/kWh	$0.0000/kWh	$0.0000/kWh	$0.0000/kWh	$0.0000/kWh	$0.0000/kWh	$0.0000/kWh	$0.0000/kWh	$0.0000/kWh	
Green Tags Rate ($/kWh)	$0.0064/kWh	$0.0066/kWh	$0.0067/kWh	$0.0069/kWh	$0.0071/kWh	$0.0072/kWh	$0.0074/kWh	$0.0076/kWh	$0.0078/kWh	$0.0080/kWh	
PTC Rate	$0.0000/kWh	$0.0000/kWh	$0.0000/kWh	$0.0000/kWh	$0.0000/kWh	$0.0000/kWh	$0.0000/kWh	$0.0000/kWh	$0.0000/kWh	$0.0000/kWh	
REVENUES											
Revenues from PPA	$ 807,006	$ 825,113	$ 843,626	$ 862,555	$ 881,909	$ 901,697	$ 921,928	$ 942,614	$ 963,764	$ 985,389	$ 16,083,188
Revenues from PPA Balloon Payment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Revenues from Day-ahead and Spot Markets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Green Tags	$ 94,942	$ 97,072	$ 99,250	$ 101,477	$ 103,754	$ 106,082	$ 108,462	$ 110,896	$ 113,384	$ 115,928	$ 1,892,140
Interest Revenues											
Total Revenues	$ 901,948	$ 922,185	$ 942,877	$ 964,032	$ 985,663	$ 1,007,779	$ 1,030,391	$ 1,053,510	$ 1,077,148	$ 1,101,317	$ 17,975,328
EXPENSES											
Operations / Management	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
OM&S Warranty (per MW)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 500,000
Service Agreement	$ 115,927	$ 119,405	$ 122,987	$ 126,677	$ 130,477	$ 134,392	$ 138,423	$ 142,576	$ 146,853	$ 151,259	$ 1,859,891
Insurance	$ 26,818	$ 27,354	$ 27,901	$ 28,459	$ 29,029	$ 29,609	$ 30,201	$ 30,805	$ 31,421	$ 32,050	$ 534,542
Power Use	$ 4,032	$ 4,153	$ 4,277	$ 4,406	$ 4,538	$ 4,674	$ 4,814	$ 4,959	$ 5,107	$ 5,261	$ 80,611
Management Fee	$ 18,285	$ 18,651	$ 19,024	$ 19,404	$ 19,792	$ 20,188	$ 20,592	$ 21,004	$ 21,424	$ 21,852	$ 364,461
Accounting, Admin & Legal	$ 6,095	$ 6,217	$ 6,341	$ 6,468	$ 6,597	$ 6,729	$ 6,864	$ 7,001	$ 7,141	$ 7,284	$ 121,487
PPA Revenue Royalty Payments	$ 36,078	$ 36,887	$ 37,715	$ 38,561	$ 39,427	$ 40,311	$ 41,216	$ 42,140	$ 43,086	$ 44,053	$ 719,013
Property Tax	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Production Tax	$ 6,510	$ 6,623	$ 6,739	$ 6,856	$ 6,976	$ 7,098	$ 7,222	$ 7,348	$ 7,476	$ 7,606	$ 129,631
	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Expenses	$ 213,744	$ 219,290	$ 224,985	$ 230,832	$ 236,836	$ 243,001	$ 249,332	$ 255,833	$ 262,509	$ 269,364	$ 4,309,636
EBITDA (Operating Cash)	$ 688,203	$ 702,895	$ 717,892	$ 733,201	$ 748,827	$ 764,778	$ 781,059	$ 797,677	$ 814,639	$ 831,952	$ 13,665,692

RMEB/MEPC JWI
Project Pro Forma (Annual)
Treasury Grant Scenario
11/6/2009

Year	11	12	13	14	15	16	17	18	19	20	TOTALS
DEBT SERVICE & RESERVES											
Interest Expense	$ 201,723	$ 185,938	$ 169,097	$ 151,127	$ 131,954	$ 111,497	$ 89,670	$ 66,381	$ 41,532	$ 15,019	$ 3,859,257
Depreciation Expense	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,911,800
Amortization Expense	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 421,110
Total Non-Cash Expenses	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 8,332,910
EBT (Income Distributed to Partners)	$ 688,203	$ 702,895	$ 717,892	$ 733,201	$ 748,827	$ 764,778	$ 781,059	$ 797,677	$ 814,639	$ 831,952	$ 5,332,782
Addition to Contingency Fund	$ 66,000	$ 66,000	$ 66,000	$ 66,000	$ 66,000	$ 66,000	$ 66,000	$ 66,000	$ 66,000	$ 66,000	$ 1,314,000
Addition to Decommissioning Fund	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 60,000
Addition to Operating Reserves	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Terminal Value										$ -	$ -
Cash for Debt Service & Distribution (EBITDA - Reserves)	$ 619,203	$ 633,895	$ 648,892	$ 664,201	$ 679,827	$ 695,778	$ 712,059	$ 728,677	$ 745,639	$ 762,952	$ 12,291,692
Debt Service (P&I)	$ 437,413	$ 437,413	$ 437,413	$ 437,413	$ 437,413	$ 437,413	$ 437,413	$ 437,413	$ 437,413	$ 437,413	$ 8,748,257
Debt Service Coverage Ratio	1.42	1.45	1.48	1.52	1.55	1.59	1.63	1.67	1.70	1.74	
Net Cash (Cash Distributed to Partners)	$ 181,790	$ 196,482	$ 211,479	$ 226,788	$ 242,414	$ 258,365	$ 274,646	$ 291,264	$ 308,227	$ 325,539	$ 3,543,435
TAX CREDITS AND GRANTS											
Federal Production Tax Credit (PTC)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Federal Investment Tax Credit (ITC)											
Tax Credits (Tax Credits Distributed to Partners)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Federal Grant	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,933,067
Total Grants (Grants Distributed to Partners)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,933,067
TAX INVESTOR RETURNS											
Income Distribution	$ 486,480	$ 516,956	$ 548,795	$ 582,074	$ 616,873	$ 653,281	$ 691,389	$ 731,297	$ 773,107	$ 816,933	$ 1,473,525
Income from Sale (Termination Value) Distribution											
Tax Rate	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	
Tax Savings (Obligation) from Earnings	$ (170,268)	$ (180,935)	$ (192,078)	$ (203,726)	$ (215,906)	$ (228,648)	$ (241,986)	$ (255,954)	$ (270,588)	$ (285,927)	$ (515,734)
Tax Credits	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cash Savings (Obligation) from Taxes[2]	$ (170,268)	$ (180,935)	$ (192,078)	$ (203,726)	$ (215,906)	$ (228,648)	$ (241,986)	$ (255,954)	$ (270,588)	$ (285,927)	$ (515,734)
Cash Distributed from Net Cash	$ 184,790	$ 199,482	$ 214,479	$ 229,788	$ 245,414	$ 261,365	$ 277,646	$ 294,264	$ 311,227	$ 328,539	$ 3,603,435
Cash Distributed from Grant	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,933,067
Cash Distributed from Sale (Terminal Value)										$ -	$ -
Total Cash Distribution & Tax Savings	$ 14,522	$ 18,547	$ 22,401	$ 26,062	$ 29,509	$ 32,717	$ 35,660	$ 38,311	$ 40,639	$ 42,613	$ 6,020,769
LOCAL INVESTOR RETURNS											
Income Distribution	-	-	-	-	-	-	-	-	-	-	-
Income from Sale (Termination Value) Distribution											
Tax Rate	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	
Tax Savings (Obligation) from Earnings	-	-	-	-	-	-	-	-	-	-	
Tax Credits	-	-	-	-	-	-	-	-	-	-	-
Total Cash Savings (Obligation) from Taxes[2]	-	-	-	-	-	-	-	-	-	-	-
Cash Distributed from Net Cash	-	-	-	-	-	-	-	-	-	-	-
Operations / Management	-	-	-	-	-	-	-	-	-	-	-
Cash Distributed from Grant	-	-	-	-	-	-	-	-	-	-	-
Cash Distributed from Sale (Terminal Value)										-	-
Total Cash Distribution & Tax Savings	-	-	-	-	-	-	-	-	-	-	-

RMEB/MEPC JWI
Summary
ITC Scenario
11/06/09

Lyon County, MN
4.5 MW Nameplate Capacity

Turbine Manufacturer:	GE 1.5SLE
Number of Turbines:	3
Turbine Size (MW):	1.50 MW
Project Nameplate Capacity	**4.50 MW**
Net Capacity Factor (Year 1)	38.3%
Energy Production (Year 1)	15,096 MWh/yr
PPA Term	20 Years
1st Year Energy Payment (w/ RECs)	$0.0475/kWh
NPV PPA	$0.0238/kWh
Debt	**50%**
Equity	**50%**
Minimum DSCR	**1.09**
Average DSCR	**1.22**

Total Development Cost:	$9,778,000
Price per MW	$2,172,889 / MW
Development Incentive Utilized:	**ITC**
3rd Party Equity Investor Returns	
Equity	$ 4,669,000
Investment Tax Credit	$ 2,933,067
XIRR	**14.98%**
Local Investor Returns	
Equity	0
IRR	**NA**

RMEB/MEPC JWI
Pro Forma Assumptions
ITC Scenario
11/6/2009

PROJECT SUMMARY									
		Turbine Size (MW)	Total Project Size (MW)						
Project Name	RMEB/MEPC JWI								
Project Location	Lyon County, MN								
Scenario Name	ITC Scenario								
Scenario Date	November 6, 2009								
Developer	RMEB Wind								
Number of Turbines	3	1.50	4.50						
Make of Turbines	GE 1.5SLE								
	Gross Capacity Factor	Operational Availability	Wind Park Array Losses	Net Capacity Factor (Year 1)	kWh Produced per turbine	Total kWh produced by project	Annual Loss in Operational Availability	Loss Distributed "Monthly" or "Annually"	Annual Loss Beginning in Year
Capacity Factor	45%	92%	7.5%	38.30%	5,031,963	15,095,889	0.25%	Annually	5
Start Date (spinning)	04/01/11								
Construction Period Length (months)	6								
Terminal Value	0								

FINANCING & OWNERSHIP								
	Investment %	Ownership, post-flip	Rate / Required Return	Tax Rate	Amortization (Years)	Term (Years)	Payments per year	Financing Fee (%)
Total Initial Debt (% of project cost for construction)	50%							
Total Initial Equity (% of project cost for construction)	50%							
Construction Debt (% of project cost)	50%		6.50%			0.5		1%
Construction Bridge for Grant (% of project cost, tied to Grant (below))	0%		6.50%			0.75		2%
Permanent Debt (% of project cost)	50%		6.50%		20	20	12	
Tax Equity (% of equity)	100%	100%	12%	35%				0%
Local Equity (% of equity)	0%	0%						
Construction & Permanent Debt provided by local bank? ("Yes" or "No")	Yes							
	Value	% to Tax Equity Investor	% to Local Group		Dep/Amo (Years)	Depreciation Convention		
Equity Flip at Beginning of Year:	11							
PTC, ITC or Grant ("PTC", "ITC", "Grant")	ITC							
Federal Grant % (30% max)	30%	100%	0%					
Grant applied towards ("Debt" or "Equity")	Equity							
Date grant received (number of days after start of spinning)	90							
Depreciation Schedule ("MACRS" or "Straight")	MACRS				5	Half-year		
Bonus Depreciation (50%)	50%							
Amortization Schedule ("Straight" only)	Straight				7			
LCCMR Grant	220,000							

RMEB/MEPC JWI
Pro Forma Assumptions
ITC Scenario
11/6/2009

OPERATIONS	Initial Value (Annual)	Escalation Rate	Step-up Value (Annual)	Step-up In Year	Escalation Rate After Step-up	% to Local Community, for CBED Calculation
REVENUES						
Electricity Sold through PPA (%)	100%		100%	11		
Electricity Sold on Spot Market (%)	0%		0%	11		
Green Tags Sold	100%		100%	11		
PPA Rate	0.04250	1.5%			0%	
PPA Balloon Payment						
Spot Market Rate						
Green Tags Price ($/kWh)	0.0050	1.5%				
PTC Rate	0.0210	2.0%				
EXPENSES						
Operations / Mgmt (% of revenues, per MW; "Flat" or "Variable")	0.00%	Flat				
OM&S Warranty (per MW)	22,222	0.00%		6		
(open)	-					
Service Agreement (per MW)			22,222	6	3.00%	
Insurance (per MW)	4,889	2.00%				
Power Use (per MW)	667	3.00%				
Management Fee (per MW)	3,333	2.00%				
Accounting, Admin & Legal (per MW)	1,111	2.00%				
PPA Revenue Royalty Payments (per MW)						
PPA Revenue Royalty Payments (% of revenues)	4.00%					
Property Tax ($/kWh)						
Production Tax ($/kWh)	0.00036	2.00%				
RESERVES	Initial Value (Annual)	Escalation Rate	Step-up Value (Annual)	Step-up In Year	Escalation Rate After Step-up	Interest Rate Received on Reserve
Addition to Contingency Fund (per MW)	13,333		14,667	2		
Addition to Decommissioning Fund (per MW)	667	0.00%				
Addition to Operating Reserves (per MW)						

RMEB/MEPC JWI
Project Pro Forma (Annual)
ITC Scenario
11/6/2009

Year	0	1	2	3	4	5	6	7	8	9	10
Date	3/31/2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
TOTAL DEVELOPMENT COST											
Project Capital Required	$9,778,000										
POWER PRODUCTION											
Total Electricity Production (kWh/yr)		15,095,889	15,095,889	15,095,889	15,095,889	15,058,149	15,020,504	14,982,953	14,945,495	14,908,132	14,870,861
Electricity Sold through PPA		15,095,889	15,095,889	15,095,889	15,095,889	15,058,149	15,020,504	14,982,953	14,945,495	14,908,132	14,870,861
Electricity Sold to Day-ahead and Spot Markets		-	-	-	-	-	-	-	-	-	-
Green Tags Sold		15,095,889	15,095,889	15,095,889	15,095,889	15,058,149	15,020,504	14,982,953	14,945,495	14,908,132	14,870,861
Electricity Qualifying for PTC		-	-	-	-	-	-	-	-	-	-
Electricity Rate through PPA ($/kWh)		$0.0425/kWh	$0.0431/kWh	$0.0438/kWh	$0.0444/kWh	$0.0451/kWh	$0.0458/kWh	$0.0465/kWh	$0.0472/kWh	$0.0479/kWh	$0.0486/kWh
Electricity Revenue in Day-ahead and Spot Markets ($/kWh)		$0.0000/kWh	$0.0000/kWh	$0.0000/kWh	$0.0000/kWh	$0.0000/kWh	$0.0000/kWh	$0.0000/kWh	$0.0000/kWh	$0.0000/kWh	$0.0000/kWh
Green Tags Rate ($/kWh)		$0.0050/kWh	$0.0051/kWh	$0.0052/kWh	$0.0052/kWh	$0.0053/kWh	$0.0054/kWh	$0.0055/kWh	$0.0055/kWh	$0.0056/kWh	$0.0057/kWh
PTC Rate		$0.0210/kWh	$0.0214/kWh	$0.0218/kWh	$0.0223/kWh	$0.0227/kWh	$0.0232/kWh	$0.0236/kWh	$0.0241/kWh	$0.0246/kWh	$0.0251/kWh
REVENUES											
Revenues from PPA		$ 641,575	$ 651,199	$ 660,967	$ 670,881	$ 679,242	$ 687,707	$ 696,278	$ 704,955	$ 713,741	$ 722,636
Revenues from PPA Balloon Payment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Revenues from Day-ahead and Spot Markets		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Green Tags		$ 75,479	$ 76,612	$ 77,761	$ 78,927	$ 79,911	$ 80,907	$ 81,915	$ 82,936	$ 83,969	$ 85,016
Interest Revenues											
Total Revenues		$ 717,055	$ 727,811	$ 738,728	$ 749,809	$ 759,153	$ 768,614	$ 778,193	$ 787,891	$ 797,710	$ 807,652
EXPENSES											
Operations / Management		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
OM&S Warranty (per MW)		$ 100,000	$ 100,000	$ 100,000	$ 100,000	$ 100,000	$ -	$ -	$ -	$ -	$ -
Service Agreement		$ -	$ -	$ -	$ -	$ -	$ 100,000	$ 103,000	$ 106,090	$ 109,273	$ 112,551
Insurance		$ 22,000	$ 22,440	$ 22,889	$ 23,347	$ 23,814	$ 24,290	$ 24,776	$ 25,271	$ 25,777	$ 26,292
Power Use		$ 3,000	$ 3,090	$ 3,183	$ 3,278	$ 3,377	$ 3,478	$ 3,582	$ 3,690	$ 3,800	$ 3,914
Management Fee		$ 15,000	$ 15,300	$ 15,606	$ 15,918	$ 16,236	$ 16,561	$ 16,892	$ 17,230	$ 17,575	$ 17,926
Accounting, Admin & Legal		$ 5,000	$ 5,100	$ 5,202	$ 5,306	$ 5,412	$ 5,520	$ 5,631	$ 5,743	$ 5,858	$ 5,975
PPA Revenue Royalty Payments		$ 28,682	$ 29,112	$ 29,549	$ 29,992	$ 30,366	$ 30,745	$ 31,128	$ 31,516	$ 31,908	$ 32,306
Property Tax		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Production Tax		$ 5,435	$ 5,543	$ 5,654	$ 5,767	$ 5,868	$ 5,970	$ 6,074	$ 6,180	$ 6,288	$ 6,398
		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Expenses		$ 179,117	$ 180,586	$ 182,083	$ 183,608	$ 185,073	$ 186,564	$ 191,083	$ 195,720	$ 200,479	$ 205,363
EBITDA (Operating Cash)		$ 537,938	$ 547,225	$ 556,645	$ 566,200	$ 574,081	$ 582,050	$ 587,110	$ 592,171	$ 597,231	$ 602,289

RMEB/MEPC JWI
Project Pro Forma (Annual)
ITC Scenario
11/6/2009

Year	0	1	2	3	4	5	6	7	8	9	10
DEBT SERVICE & RESERVES											
Interest Expense		$ 314,156	$ 305,901	$ 297,094	$ 287,696	$ 277,669	$ 266,971	$ 255,556	$ 243,377	$ 230,382	$ 216,517
Depreciation Expense		$ 4,747,080	$ 1,265,888	$ 759,533	$ 455,720	$ 455,720	$ 227,860	$ -	$ -	$ -	$ -
Amortization Expense		$ 60,159	$ 60,159	$ 60,159	$ 60,159	$ 60,159	$ 60,159	$ 60,159	$ -	$ -	$ -
Total Non-Cash Expenses		$ 4,807,239	$ 1,326,047	$ 819,691	$ 515,878	$ 515,878	$ 288,018	$ 60,159	$ -	$ -	$ -
EBT (Income Distributed to Partners)		$ (4,269,301)	$ (778,822)	$ (263,046)	$ 50,322	$ 58,202	$ 294,032	$ 526,951	$ 592,171	$ 597,231	$ 602,289
Addition to Contingency Fund		$ 60,000	$ 66,000	$ 66,000	$ 66,000	$ 66,000	$ 66,000	$ 66,000	$ 66,000	$ 66,000	$ 66,000
Addition to Decommissioning Fund		$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000
Addition to Operating Reserves		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Terminal Value											
Cash for Debt Service & Distribution (EBITDA - Reserves)		$ 474,938	$ 478,225	$ 487,645	$ 497,200	$ 505,081	$ 513,050	$ 518,110	$ 523,171	$ 528,231	$ 533,289
Debt Service (P&I)		$ 437,413	$ 437,413	$ 437,413	$ 437,413	$ 437,413	$ 437,413	$ 437,413	$ 437,413	$ 437,413	$ 437,413
Debt Service Coverage Ratio		1.09	1.09	1.11	1.14	1.15	1.17	1.18	1.20	1.21	1.22
Net Cash (Cash Distributed to Partners)		$ 37,525	$ 40,812	$ 50,232	$ 59,787	$ 67,668	$ 75,637	$ 80,697	$ 85,758	$ 90,818	$ 95,876
TAX CREDITS AND GRANTS											
Federal Production Tax Credit (PTC)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Federal Investment Tax Credit (ITC)	$ 2,933,067										
Tax Credits (Tax Credits Distributed to Partners)	$ 2,933,067	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Federal Grant		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Grants (Grants Distributed to Partners)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TAX INVESTOR RETURNS											
Income Distribution		$ (4,583,457)	$ (1,084,723)	$ (560,140)	$ (237,374)	$ (219,467)	$ 27,061	$ 271,395	$ 348,794	$ 366,849	$ 385,772
Income from Sale (Termination Value) Distribution											
Tax Rate		35%	35%	35%	35%	35%	35%	35%	35%	35%	35%
Tax Savings (Obligation) from Earnings		$ 1,604,210	$ 379,653	$ 196,049	$ 83,081	$ 76,813	$ (9,471)	$ (94,988)	$ (122,078)	$ (128,397)	$ (135,020)
Tax Credits	$ 2,933,067	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cash Savings (Obligation) from Taxes[2]	$ 2,933,067	$ 1,604,210	$ 379,653	$ 196,049	$ 83,081	$ 76,813	$ (9,471)	$ (94,988)	$ (122,078)	$ (128,397)	$ (135,020)
Cash Distributed from Net Cash		$ 40,525	$ 43,812	$ 53,232	$ 62,787	$ 70,668	$ 78,637	$ 83,697	$ 88,758	$ 93,818	$ 98,876
Cash Distributed from Grant	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Cash Distributed from Sale (Terminal Value)											
Total Cash Distribution & Tax Savings	$ 2,933,067	$ 1,644,735	$ 423,465	$ 249,281	$ 145,868	$ 147,481	$ 69,166	$ (11,291)	$ (33,320)	$ (34,579)	$ (36,144)
LOCAL INVESTOR RETURNS											
Income Distribution		-	-	-	-	-	-	-	-	-	-
Income from Sale (Termination Value) Distribution											
Tax Rate		0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Tax Savings (Obligation) from Earnings		-	-	-	-	-	-	-	-	-	-
Tax Credits		-	-	-	-	-	-	-	-	-	-
Total Cash Savings (Obligation) from Taxes[2]		-	-	-	-	-	-	-	-	-	-
Cash Distributed from Net Cash		-	-	-	-	-	-	-	-	-	-
Operations / Management		-	-	-	-	-	-	-	-	-	-
Cash Distributed from Grant		-	-	-	-	-	-	-	-	-	-
Cash Distributed from Sale (Terminal Value)											
Total Cash Distribution & Tax Savings		-	-	-	-	-	-	-	-	-	-

RMEB/MEPC JWI
Project Pro Forma (Annual)
ITC Scenario
11/6/2009

Year	11	12	13	14	15	16	17	18	19	20	TOTALS
Date	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	
TOTAL DEVELOPMENT COST											
Project Capital Required											
POWER PRODUCTION											
Total Electricity Production (kWh/yr)	14,833,684	14,796,600	14,759,608	14,722,709	14,685,903	14,649,188	14,612,565	14,576,033	14,539,593	14,503,244	296,848,778
Electricity Sold through PPA	14,833,684	14,796,600	14,759,608	14,722,709	14,685,903	14,649,188	14,612,565	14,576,033	14,539,593	14,503,244	296,848,778
Electricity Sold to Day-ahead and Spot Markets	-	-	-	-	-	-	-	-	-	-	-
Green Tags Sold	14,833,684	14,796,600	14,759,608	14,722,709	14,685,903	14,649,188	14,612,565	14,576,033	14,539,593	14,503,244	296,848,778
Electricity Qualifying for PTC	-	-	-	-	-	-	-	-	-	-	-
Electricity Rate through PPA ($/kWh)	$0.0493/kWh	$0.0501/kWh	$0.0508/kWh	$0.0516/kWh	$0.0523/kWh	$0.0531/kWh	$0.0539/kWh	$0.0547/kWh	$0.0556/kWh	$0.0564/kWh	
Electricity Revenue in Day-ahead and Spot Markets ($/kWh)	$0.0000/kWh	$0.0000/kWh	$0.0000/kWh	$0.0000/kWh	$0.0000/kWh	$0.0000/kWh	$0.0000/kWh	$0.0000/kWh	$0.0000/kWh	$0.0000/kWh	
Green Tags Rate ($/kWh)	$0.0058/kWh	$0.0059/kWh	$0.0060/kWh	$0.0061/kWh	$0.0062/kWh	$0.0063/kWh	$0.0063/kWh	$0.0064/kWh	$0.0065/kWh	$0.0066/kWh	
PTC Rate	$0.0000/kWh	$0.0000/kWh	$0.0000/kWh	$0.0000/kWh	$0.0000/kWh	$0.0000/kWh	$0.0000/kWh	$0.0000/kWh	$0.0000/kWh	$0.0000/kWh	
REVENUES											
Revenues from PPA	$ 731,642	$ 740,760	$ 749,991	$ 759,338	$ 768,801	$ 778,383	$ 788,083	$ 797,905	$ 807,849	$ 817,916	$ 14,569,849
Revenues from PPA Balloon Payment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Revenues from Day-ahead and Spot Markets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Green Tags	$ 86,075	$ 87,148	$ 88,234	$ 89,334	$ 90,447	$ 91,574	$ 92,716	$ 93,871	$ 95,041	$ 96,225	$ 1,714,100
Interest Revenues											
Total Revenues	$ 817,717	$ 827,908	$ 838,226	$ 848,672	$ 859,249	$ 869,957	$ 880,799	$ 891,776	$ 902,890	$ 914,142	$ 16,283,949
EXPENSES											
Operations / Management	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
OM&S Warranty (per MW)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 500,000
Service Agreement	$ 115,927	$ 119,405	$ 122,987	$ 126,677	$ 130,477	$ 134,392	$ 138,423	$ 142,576	$ 146,853	$ 151,259	$ 1,859,891
Insurance	$ 26,818	$ 27,354	$ 27,901	$ 28,459	$ 29,029	$ 29,609	$ 30,201	$ 30,805	$ 31,421	$ 32,050	$ 534,542
Power Use	$ 4,032	$ 4,153	$ 4,277	$ 4,406	$ 4,538	$ 4,674	$ 4,814	$ 4,959	$ 5,107	$ 5,261	$ 80,611
Management Fee	$ 18,285	$ 18,651	$ 19,024	$ 19,404	$ 19,792	$ 20,188	$ 20,592	$ 21,004	$ 21,424	$ 21,852	$ 364,461
Accounting, Admin & Legal	$ 6,095	$ 6,217	$ 6,341	$ 6,468	$ 6,597	$ 6,729	$ 6,864	$ 7,001	$ 7,141	$ 7,284	$ 121,487
PPA Revenue Royalty Payments	$ 32,709	$ 33,116	$ 33,529	$ 33,947	$ 34,370	$ 34,798	$ 35,232	$ 35,671	$ 36,116	$ 36,566	$ 651,358
Property Tax	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Production Tax	$ 6,510	$ 6,623	$ 6,739	$ 6,856	$ 6,976	$ 7,098	$ 7,222	$ 7,348	$ 7,476	$ 7,606	$ 129,631
	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Expenses	$ 210,375	$ 215,519	$ 220,799	$ 226,217	$ 231,779	$ 237,488	$ 243,348	$ 249,363	$ 255,538	$ 261,877	$ 4,241,981
EBITDA (Operating Cash)	$ 607,342	$ 612,389	$ 617,427	$ 622,455	$ 627,469	$ 632,469	$ 637,451	$ 642,412	$ 647,351	$ 652,264	$ 12,041,968

RMEB/MEPC JWI
Project Pro Forma (Annual)
ITC Scenario
11/6/2009

Year	11	12	13	14	15	16	17	18	19	20	TOTALS
DEBT SERVICE & RESERVES											
Interest Expense	$ 201,723	$ 185,938	$ 169,097	$ 151,127	$ 131,954	$ 111,497	$ 89,670	$ 66,381	$ 41,532	$ 15,019	$ 3,859,257
Depreciation Expense	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,911,800
Amortization Expense	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 421,110
Total Non-Cash Expenses	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 8,332,910
EBT (Income Distributed to Partners)	$ 607,342	$ 612,389	$ 617,427	$ 622,455	$ 627,469	$ 632,469	$ 637,451	$ 642,412	$ 647,351	$ 652,264	$ 3,709,058
Addition to Contingency Fund	$ 66,000	$ 66,000	$ 66,000	$ 66,000	$ 66,000	$ 66,000	$ 66,000	$ 66,000	$ 66,000	$ 66,000	$ 1,314,000
Addition to Decommissioning Fund	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 60,000
Addition to Operating Reserves	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Terminal Value										$ -	$ -
Cash for Debt Service & Distribution (EBITDA - Reserves)	$ 538,342	$ 543,389	$ 548,427	$ 553,455	$ 558,469	$ 563,469	$ 568,451	$ 573,412	$ 578,351	$ 583,264	$ 10,667,968
Debt Service (P&I)	$ 437,413	$ 437,413	$ 437,413	$ 437,413	$ 437,413	$ 437,413	$ 437,413	$ 437,413	$ 437,413	$ 437,413	$ 8,748,257
Debt Service Coverage Ratio	1.23	1.24	1.25	1.27	1.28	1.29	1.30	1.31	1.32	1.33	
Net Cash (Cash Distributed to Partners)	$ 100,929	$ 105,976	$ 111,014	$ 116,042	$ 121,057	$ 126,056	$ 131,038	$ 136,000	$ 140,938	$ 145,851	$ 1,919,711
TAX CREDITS AND GRANTS											
Federal Production Tax Credit (PTC)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Federal Investment Tax Credit (ITC)											
Tax Credits (Tax Credits Distributed to Partners)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Federal Grant	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Grants (Grants Distributed to Partners)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TAX INVESTOR RETURNS											
Income Distribution	$ 405,619	$ 426,450	$ 448,330	$ 471,328	$ 495,515	$ 520,972	$ 547,781	$ 576,032	$ 605,819	$ 637,245	$ (150,199)
Income from Sale (Termination Value) Distribution											
Tax Rate	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	
Tax Savings (Obligation) from Earnings	$ (141,967)	$ (149,258)	$ (156,916)	$ (164,965)	$ (173,430)	$ (182,340)	$ (191,723)	$ (201,611)	$ (212,037)	$ (223,036)	$ 52,569
Tax Credits	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,933,067
Total Cash Savings (Obligation) from Taxes[2]	$ (141,967)	$ (149,258)	$ (156,916)	$ (164,965)	$ (173,430)	$ (182,340)	$ (191,723)	$ (201,611)	$ (212,037)	$ (223,036)	$ 2,985,636
Cash Distributed from Net Cash	$ 103,929	$ 108,976	$ 114,014	$ 119,042	$ 124,057	$ 129,056	$ 134,038	$ 139,000	$ 143,938	$ 148,851	$ 1,979,711
Cash Distributed from Grant	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Cash Distributed from Sale (Terminal Value)										$ -	$ -
Total Cash Distribution & Tax Savings	$ (38,038)	$ (40,282)	$ (42,901)	$ (45,923)	$ (49,374)	$ (53,284)	$ (57,685)	$ (62,612)	$ (68,098)	$ (74,184)	$ 4,965,348
LOCAL INVESTOR RETURNS											
Income Distribution	-	-	-	-	-	-	-	-	-	-	-
Income from Sale (Termination Value) Distribution											
Tax Rate	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	
Tax Savings (Obligation) from Earnings	-	-	-	-	-	-	-	-	-	-	-
Tax Credits	-	-	-	-	-	-	-	-	-	-	-
Total Cash Savings (Obligation) from Taxes[2]	-	-	-	-	-	-	-	-	-	-	-
Cash Distributed from Net Cash	-	-	-	-	-	-	-	-	-	-	-
Operations / Management	-	-	-	-	-	-	-	-	-	-	-
Cash Distributed from Grant	-	-	-	-	-	-	-	-	-	-	-
Cash Distributed from Sale (Terminal Value)										-	-
Total Cash Distribution & Tax Savings	-	-	-	-	-	-	-	-	-	-	-

RMEB/MEPC JWI
Summary
PTC Scenario
11/06/09

Lyon County, MN
4.5 MW Nameplate Capacity

Turbine Manufacturer:	GE 1.5SLE
Number of Turbines:	3
Turbine Size (MW):	1.50 MW
Project Nameplate Capacity	**4.50 MW**
Net Capacity Factor (Year 1)	38.3%
Energy Production (Year 1)	15,096 MWh/yr
PPA Term	20 Years
1st Year Energy Payment (w/ RECs)	$0.0500/kWh
NPV PPA	$0.0272/kWh
Debt	**50%**
Equity	**50%**
Minimum DSCR	**1.17**
Average DSCR	**1.51**

Total Development Cost:	$9,778,000
Price per MW	$2,172,889 / MW
Development Incentive Utilized:	PTC
3rd Party Equity Investor Returns	
Equity	$ 4,669,000
Investment Tax Credit	$ -
XIRR	**12.46%**
Local Investor Returns	
Equity	0
IRR	**NA**

RMEB/MEPC JWI
Pro Forma Assumptions
PTC Scenario
11/6/2009

PROJECT SUMMARY									
		Turbine Size (MW)	Total Project Size (MW)						
Project Name	RMEB/MEPC JWI								
Project Location	Lyon County, MN								
Scenario Name	PTC Scenario								
Scenario Date	November 6, 2009								
Developer	RMEB Wind								
Number of Turbines	3	1.50	4.50						
Make of Turbines	GE 1.5SLE								
	Gross Capacity Factor	Operational Availability	Wind Park Array Losses	Net Capacity Factor (Year 1)	kWh Produced per turbine	Total kWh produced by project	Annual Loss in Operational Availability	Loss Distributed "Monthly" or "Annually"	Annual Loss Beginning in Year
Capacity Factor	45%	92%	7.5%	38.30%	5,031,963	15,095,889	0.25%	Annually	5
Start Date (spinning)	04/01/11								
Construction Period Length (months)	6								
Terminal Value	0								

FINANCING & OWNERSHIP								
	Investment %	Ownership, post-flip	Rate / Required Return	Tax Rate	Amortization (Years)	Term (Years)	Payments per year	Financing Fee (%)
Total Initial Debt (% of project cost for construction)	50%							
Total Initial Equity (% of project cost for construction)	50%							
Construction Debt (% of project cost)	50%		6.50%			0.5		1%
Construction Bridge for Grant (% of project cost, tied to Grant (below))	0%		6.50%			0.75		2%
Permanent Debt (% of project cost)	50%		6.50%		20	20	12	
Tax Equity (% of equity)	100%	100%	12%	35%				0%
Local Equity (% of equity)	0%	0%						
Construction & Permanent Debt provided by local bank? ("Yes" or "No")	Yes							
	Value	% to Tax Equity Investor	% to Local Group		Dep/Amo (Years)	Depreciation Convention		
Equity Flip at Beginning of Year:	11							
PTC, ITC or Grant ("PTC", "ITC", "Grant")	PTC							
Federal Grant % (30% max)	30%	100%	0%					
Grant applied towards ("Debt" or "Equity")	Equity							
Date grant received (number of days after start of spinning)	90							
Depreciation Schedule ("MACRS" or "Straight")	MACRS				5	Half-year		
Bonus Depreciation (50%)	50%							
Amortization Schedule ("Straight" only)	Straight				7			
LCCMR Grant	220,000							

RMEB/MEPC JWI
Pro Forma Assumptions
PTC Scenario
11/6/2009

OPERATIONS	Initial Value (Annual)	Escalation Rate	Step-up Value (Annual)	Step-up In Year	Escalation Rate After Step-up	% to Local Community, for CBED Calculation
REVENUES						
Electricity Sold through PPA (%)	100%		100%	11		
Electricity Sold on Spot Market (%)	0%		0%	11		
Green Tags Sold	100%		100%	11		
PPA Rate	0.04500	2.5%			0%	
PPA Balloon Payment						
Spot Market Rate						
Green Tags Price ($/kWh)	0.0050	2.5%				
PTC Rate	0.0210	2.0%				
EXPENSES						
Operations / Mgmt (% of revenues, per MW; "Flat" or "Variable")	0.00%	Flat				
OM&S Warranty (per MW)	22,222	0.00%		6		
(open)	-					
Service Agreement (per MW)			22,222	6	3.00%	
Insurance (per MW)	4,889	2.00%				
Power Use (per MW)	667	3.00%				
Management Fee (per MW)	3,333	2.00%				
Accounting, Admin & Legal (per MW)	1,111	2.00%				
PPA Revenue Royalty Payments (per MW)						
PPA Revenue Royalty Payments (% of revenues)	4.00%					
Property Tax ($/kWh)						
Production Tax ($/kWh)	0.00036	2.00%				
RESERVES	Initial Value (Annual)	Escalation Rate	Step-up Value (Annual)	Step-up In Year	Escalation Rate After Step-up	Interest Rate Received on Reserve
Addition to Contingency Fund (per MW)	13,333		14,667	2		
Addition to Decommissioning Fund (per MW)	667	0.00%				
Addition to Operating Reserves (per MW)						

RMEB/MEPC JWI
Project Pro Forma (Annual)
PTC Scenario
11/6/2009

Year	0	1	2	3	4	5	6	7	8	9	10
Date	3/31/2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
TOTAL DEVELOPMENT COST											
Project Capital Required	$9,778,000										
POWER PRODUCTION											
Total Electricity Production (kWh/yr)		15,095,889	15,095,889	15,095,889	15,095,889	15,058,149	15,020,504	14,982,953	14,945,495	14,908,132	14,870,861
Electricity Sold through PPA		15,095,889	15,095,889	15,095,889	15,095,889	15,058,149	15,020,504	14,982,953	14,945,495	14,908,132	14,870,861
Electricity Sold to Day-ahead and Spot Markets		-	-	-	-	-	-	-	-	-	-
Green Tags Sold		15,095,889	15,095,889	15,095,889	15,095,889	15,058,149	15,020,504	14,982,953	14,945,495	14,908,132	14,870,861
Electricity Qualifying for PTC		15,095,889	15,095,889	15,095,889	15,095,889	15,058,149	15,020,504	14,982,953	14,945,495	14,908,132	14,870,861
Electricity Rate through PPA ($/kWh)		$0.0450/kWh	$0.0461/kWh	$0.0473/kWh	$0.0485/kWh	$0.0497/kWh	$0.0509/kWh	$0.0522/kWh	$0.0535/kWh	$0.0548/kWh	$0.0562/kWh
Electricity Revenue in Day-ahead and Spot Markets ($/kWh)		$0.0000/kWh	$0.0000/kWh	$0.0000/kWh	$0.0000/kWh	$0.0000/kWh	$0.0000/kWh	$0.0000/kWh	$0.0000/kWh	$0.0000/kWh	$0.0000/kWh
Green Tags Rate ($/kWh)		$0.0050/kWh	$0.0051/kWh	$0.0053/kWh	$0.0054/kWh	$0.0055/kWh	$0.0057/kWh	$0.0058/kWh	$0.0059/kWh	$0.0061/kWh	$0.0062/kWh
PTC Rate		$0.0210/kWh	$0.0214/kWh	$0.0218/kWh	$0.0223/kWh	$0.0227/kWh	$0.0232/kWh	$0.0236/kWh	$0.0241/kWh	$0.0246/kWh	$0.0251/kWh
REVENUES											
Revenues from PPA		$ 679,315	$ 696,298	$ 713,705	$ 731,548	$ 747,962	$ 764,744	$ 781,903	$ 799,447	$ 817,385	$ 835,725
Revenues from PPA Balloon Payment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Revenues from Day-ahead and Spot Markets		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Green Tags		$ 75,479	$ 77,366	$ 79,301	$ 81,283	$ 83,107	$ 84,972	$ 86,878	$ 88,827	$ 90,821	$ 92,858
Interest Revenues											
Total Revenues		$ 754,794	$ 773,664	$ 793,006	$ 812,831	$ 831,069	$ 849,716	$ 868,782	$ 888,275	$ 908,206	$ 928,583
EXPENSES											
Operations / Management		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
OM&S Warranty (per MW)		$ 100,000	$ 100,000	$ 100,000	$ 100,000	$ 100,000	$ -	$ -	$ -	$ -	$ -
Service Agreement		$ -	$ -	$ -	$ -	$ -	$ 100,000	$ 103,000	$ 106,090	$ 109,273	$ 112,551
Insurance		$ 22,000	$ 22,440	$ 22,889	$ 23,347	$ 23,814	$ 24,290	$ 24,776	$ 25,271	$ 25,777	$ 26,292
Power Use		$ 3,000	$ 3,090	$ 3,183	$ 3,278	$ 3,377	$ 3,478	$ 3,582	$ 3,690	$ 3,800	$ 3,914
Management Fee		$ 15,000	$ 15,300	$ 15,606	$ 15,918	$ 16,236	$ 16,561	$ 16,892	$ 17,230	$ 17,575	$ 17,926
Accounting, Admin & Legal		$ 5,000	$ 5,100	$ 5,202	$ 5,306	$ 5,412	$ 5,520	$ 5,631	$ 5,743	$ 5,858	$ 5,975
PPA Revenue Royalty Payments		$ 30,192	$ 30,947	$ 31,720	$ 32,513	$ 33,243	$ 33,989	$ 34,751	$ 35,531	$ 36,328	$ 37,143
Property Tax		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Production Tax		$ 5,435	$ 5,543	$ 5,654	$ 5,767	$ 5,868	$ 5,970	$ 6,074	$ 6,180	$ 6,288	$ 6,398
		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Expenses		$ 180,626	$ 182,420	$ 184,254	$ 186,129	$ 187,949	$ 189,808	$ 194,707	$ 199,736	$ 204,899	$ 210,200
EBITDA (Operating Cash)		$ 574,168	$ 591,245	$ 608,752	$ 626,702	$ 643,120	$ 659,908	$ 674,075	$ 688,539	$ 703,306	$ 718,383

RMEB/MEPC JWI
Project Pro Forma (Annual)
PTC Scenario
11/6/2009

Year	0	1	2	3	4	5	6	7	8	9	10
DEBT SERVICE & RESERVES											
Interest Expense		$ 314,156	$ 305,901	$ 297,094	$ 287,696	$ 277,669	$ 266,971	$ 255,556	$ 243,377	$ 230,382	$ 216,517
Depreciation Expense		$ 5,584,800	$ 1,489,280	$ 893,568	$ 536,141	$ 536,141	$ 268,070	$ -	$ -	$ -	$ -
Amortization Expense		$ 60,159	$ 60,159	$ 60,159	$ 60,159	$ 60,159	$ 60,159	$ 60,159	$ -	$ -	$ -
Total Non-Cash Expenses		$ 5,644,959	$ 1,549,439	$ 953,727	$ 596,299	$ 596,299	$ 328,229	$ 60,159	$ -	$ -	$ -
EBT (Income Distributed to Partners)		$ (5,070,790)	$ (958,194)	$ (344,974)	$ 30,402	$ 46,820	$ 331,679	$ 613,916	$ 688,539	$ 703,306	$ 718,383
Addition to Contingency Fund		$ 60,000	$ 66,000	$ 66,000	$ 66,000	$ 66,000	$ 66,000	$ 66,000	$ 66,000	$ 66,000	$ 66,000
Addition to Decommissioning Fund		$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000
Addition to Operating Reserves		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Terminal Value											
Cash for Debt Service & Distribution (EBITDA - Reserves)		$ 511,168	$ 522,245	$ 539,752	$ 557,702	$ 574,120	$ 590,908	$ 605,075	$ 619,539	$ 634,306	$ 649,383
Debt Service (P&I)		$ 437,413	$ 437,413	$ 437,413	$ 437,413	$ 437,413	$ 437,413	$ 437,413	$ 437,413	$ 437,413	$ 437,413
Debt Service Coverage Ratio		1.17	1.19	1.23	1.28	1.31	1.35	1.38	1.42	1.45	1.48
Net Cash (Cash Distributed to Partners)		$ 73,755	$ 84,832	$ 102,339	$ 120,289	$ 136,707	$ 153,495	$ 167,662	$ 182,126	$ 196,894	$ 211,970
TAX CREDITS AND GRANTS											
Federal Production Tax Credit (PTC)		$ 317,014	$ 323,354	$ 329,821	$ 336,417	$ 342,288	$ 348,261	$ 354,338	$ 360,521	$ 366,812	$ 373,213
Federal Investment Tax Credit (ITC)	$										
Tax Credits (Tax Credits Distributed to Partners)	$ -	$ 317,014	$ 323,354	$ 329,821	$ 336,417	$ 342,288	$ 348,261	$ 354,338	$ 360,521	$ 366,812	$ 373,213
Federal Grant		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Grants (Grants Distributed to Partners)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TAX INVESTOR RETURNS											
Income Distribution		$ (5,384,946)	$ (1,264,095)	$ (642,068)	$ (257,294)	$ (230,849)	$ 64,708	$ 358,360	$ 445,162	$ 472,924	$ 501,866
Income from Sale (Termination Value) Distribution											
Tax Rate		35%	35%	35%	35%	35%	35%	35%	35%	35%	35%
Tax Savings (Obligation) from Earnings		$ 1,884,731	$ 442,433	$ 224,724	$ 90,053	$ 80,797	$ (22,648)	$ (125,426)	$ (155,807)	$ (165,524)	$ (175,653)
Tax Credits	$ -	$ 317,014	$ 323,354	$ 329,821	$ 336,417	$ 342,288	$ 348,261	$ 354,338	$ 360,521	$ 366,812	$ 373,213
Total Cash Savings (Obligation) from Taxes[2]	$ -	$ 2,201,745	$ 765,787	$ 554,545	$ 426,470	$ 423,085	$ 325,613	$ 228,912	$ 204,714	$ 201,289	$ 197,560
Cash Distributed from Net Cash		$ 76,755	$ 87,832	$ 105,339	$ 123,289	$ 139,707	$ 156,495	$ 170,662	$ 185,126	$ 199,894	$ 214,970
Cash Distributed from Grant	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Cash Distributed from Sale (Terminal Value)											
Total Cash Distribution & Tax Savings	$ -	$ 2,278,500	$ 853,619	$ 659,884	$ 549,759	$ 562,792	$ 482,108	$ 399,574	$ 389,841	$ 401,182	$ 412,530
LOCAL INVESTOR RETURNS											
Income Distribution		-	-	-	-	-	-	-	-	-	-
Income from Sale (Termination Value) Distribution											
Tax Rate		0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Tax Savings (Obligation) from Earnings		-	-	-	-	-	-	-	-	-	-
Tax Credits	-	-	-	-	-	-	-	-	-	-	-
Total Cash Savings (Obligation) from Taxes[2]	-	-	-	-	-	-	-	-	-	-	-
Cash Distributed from Net Cash		-	-	-	-	-	-	-	-	-	-
Operations / Management		-	-	-	-	-	-	-	-	-	-
Cash Distributed from Grant	-	-	-	-	-	-	-	-	-	-	-
Cash Distributed from Sale (Terminal Value)											
Total Cash Distribution & Tax Savings	-	-	-	-	-	-	-	-	-	-	-

RMEB/MEPC JWI
Project Pro Forma (Annual)
PTC Scenario
11/6/2009

Year	11	12	13	14	15	16	17	18	19	20	TOTALS
Date	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	
TOTAL DEVELOPMENT COST											
Project Capital Required											
POWER PRODUCTION											
Total Electricity Production (kWh/yr)	14,833,684	14,796,600	14,759,608	14,722,709	14,685,903	14,649,188	14,612,565	14,576,033	14,539,593	14,503,244	296,848,778
Electricity Sold through PPA	14,833,684	14,796,600	14,759,608	14,722,709	14,685,903	14,649,188	14,612,565	14,576,033	14,539,593	14,503,244	296,848,778
Electricity Sold to Day-ahead and Spot Markets	-	-	-	-	-	-	-	-	-	-	-
Green Tags Sold	14,833,684	14,796,600	14,759,608	14,722,709	14,685,903	14,649,188	14,612,565	14,576,033	14,539,593	14,503,244	296,848,778
Electricity Qualifying for PTC	-	-	-	-	-	-	-	-	-	-	-
Electricity Rate through PPA ($/kWh)	$0.0576/kWh	$0.0590/kWh	$0.0605/kWh	$0.0620/kWh	$0.0636/kWh	$0.0652/kWh	$0.0668/kWh	$0.0685/kWh	$0.0702/kWh	$0.0719/kWh	
Electricity Revenue in Day-ahead and Spot Markets ($/kWh)	$0.0000/kWh	$0.0000/kWh	$0.0000/kWh	$0.0000/kWh	$0.0000/kWh	$0.0000/kWh	$0.0000/kWh	$0.0000/kWh	$0.0000/kWh	$0.0000/kWh	
Green Tags Rate ($/kWh)	$0.0064/kWh	$0.0066/kWh	$0.0067/kWh	$0.0069/kWh	$0.0071/kWh	$0.0072/kWh	$0.0074/kWh	$0.0076/kWh	$0.0078/kWh	$0.0080/kWh	
PTC Rate	$0.0000/kWh	$0.0000/kWh	$0.0000/kWh	$0.0000/kWh	$0.0000/kWh	$0.0000/kWh	$0.0000/kWh	$0.0000/kWh	$0.0000/kWh	$0.0000/kWh	
REVENUES											
Revenues from PPA	$ 854,477	$ 873,649	$ 893,251	$ 913,294	$ 933,786	$ 954,738	$ 976,160	$ 998,062	$ 1,020,456	$ 1,043,353	$ 17,029,258
Revenues from PPA Balloon Payment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Revenues from Day-ahead and Spot Markets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Green Tags	$ 94,942	$ 97,072	$ 99,250	$ 101,477	$ 103,754	$ 106,082	$ 108,462	$ 110,896	$ 113,384	$ 115,928	$ 1,892,140
Interest Revenues											
Total Revenues	$ 949,418	$ 970,721	$ 992,502	$ 1,014,771	$ 1,037,540	$ 1,060,820	$ 1,084,622	$ 1,108,958	$ 1,133,840	$ 1,159,281	$ 18,921,398
EXPENSES											
Operations / Management	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
OM&S Warranty (per MW)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 500,000
Service Agreement	$ 115,927	$ 119,405	$ 122,987	$ 126,677	$ 130,477	$ 134,392	$ 138,423	$ 142,576	$ 146,853	$ 151,259	$ 1,859,891
Insurance	$ 26,818	$ 27,354	$ 27,901	$ 28,459	$ 29,029	$ 29,609	$ 30,201	$ 30,805	$ 31,421	$ 32,050	$ 534,542
Power Use	$ 4,032	$ 4,153	$ 4,277	$ 4,406	$ 4,538	$ 4,674	$ 4,814	$ 4,959	$ 5,107	$ 5,261	$ 80,611
Management Fee	$ 18,285	$ 18,651	$ 19,024	$ 19,404	$ 19,792	$ 20,188	$ 20,592	$ 21,004	$ 21,424	$ 21,852	$ 364,461
Accounting, Admin & Legal	$ 6,095	$ 6,217	$ 6,341	$ 6,468	$ 6,597	$ 6,729	$ 6,864	$ 7,001	$ 7,141	$ 7,284	$ 121,487
PPA Revenue Royalty Payments	$ 37,977	$ 38,829	$ 39,700	$ 40,591	$ 41,502	$ 42,433	$ 43,385	$ 44,358	$ 45,354	$ 46,371	$ 756,856
Property Tax	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Production Tax	$ 6,510	$ 6,623	$ 6,739	$ 6,856	$ 6,976	$ 7,098	$ 7,222	$ 7,348	$ 7,476	$ 7,606	$ 129,631
	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Expenses	$ 215,643	$ 221,232	$ 226,970	$ 232,861	$ 238,911	$ 245,123	$ 251,501	$ 258,051	$ 264,776	$ 271,683	$ 4,347,479
EBITDA (Operating Cash)	$ 733,775	$ 749,489	$ 765,532	$ 781,910	$ 798,629	$ 815,697	$ 833,121	$ 850,907	$ 869,064	$ 887,598	$ 14,573,920

RMEB/MEPC JWI
Project Pro Forma (Annual)
PTC Scenario
11/6/2009

Year	11	12	13	14	15	16	17	18	19	20	TOTALS
DEBT SERVICE & RESERVES											
Interest Expense	$ 201,723	$ 185,938	$ 169,097	$ 151,127	$ 131,954	$ 111,497	$ 89,670	$ 66,381	$ 41,532	$ 15,019	$ 3,859,257
Depreciation Expense	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 9,308,000
Amortization Expense	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 421,110
Total Non-Cash Expenses	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 9,729,110
EBT (Income Distributed to Partners)	$ 733,775	$ 749,489	$ 765,532	$ 781,910	$ 798,629	$ 815,697	$ 833,121	$ 850,907	$ 869,064	$ 887,598	$ 4,844,810
Addition to Contingency Fund	$ 66,000	$ 66,000	$ 66,000	$ 66,000	$ 66,000	$ 66,000	$ 66,000	$ 66,000	$ 66,000	$ 66,000	$ 1,314,000
Addition to Decommissioning Fund	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 60,000
Addition to Operating Reserves	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Terminal Value										$ -	$ -
Cash for Debt Service & Distribution (EBITDA - Reserves)	$ 664,775	$ 680,489	$ 696,532	$ 712,910	$ 729,629	$ 746,697	$ 764,121	$ 781,907	$ 800,064	$ 818,598	$ 13,199,920
Debt Service (P&I)	$ 437,413	$ 437,413	$ 437,413	$ 437,413	$ 437,413	$ 437,413	$ 437,413	$ 437,413	$ 437,413	$ 437,413	$ 8,748,257
Debt Service Coverage Ratio	1.52	1.56	1.59	1.63	1.67	1.71	1.75	1.79	1.83	1.87	
Net Cash (Cash Distributed to Partners)	$ 227,362	$ 243,077	$ 259,119	$ 275,497	$ 292,216	$ 309,284	$ 326,708	$ 344,494	$ 362,651	$ 381,185	$ 4,451,663
TAX CREDITS AND GRANTS											
Federal Production Tax Credit (PTC)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,452,040
Federal Investment Tax Credit (ITC)											
Tax Credits (Tax Credits Distributed to Partners)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,452,040
Federal Grant	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Grants (Grants Distributed to Partners)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TAX INVESTOR RETURNS											
Income Distribution	$ 532,052	$ 563,551	$ 596,435	$ 630,783	$ 666,675	$ 704,200	$ 743,451	$ 784,527	$ 827,532	$ 872,579	$ 985,553
Income from Sale (Termination Value) Distribution											
Tax Rate	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	
Tax Savings (Obligation) from Earnings	$ (186,218)	$ (197,243)	$ (208,752)	$ (220,774)	$ (233,336)	$ (246,470)	$ (260,208)	$ (274,584)	$ (289,636)	$ (305,403)	$ (344,943)
Tax Credits	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,452,040
Total Cash Savings (Obligation) from Taxes[2]	$ (186,218)	$ (197,243)	$ (208,752)	$ (220,774)	$ (233,336)	$ (246,470)	$ (260,208)	$ (274,584)	$ (289,636)	$ (305,403)	$ 3,107,096
Cash Distributed from Net Cash	$ 230,362	$ 246,077	$ 262,119	$ 278,497	$ 295,216	$ 312,284	$ 329,708	$ 347,494	$ 365,651	$ 384,185	$ 4,511,663
Cash Distributed from Grant	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Cash Distributed from Sale (Terminal Value)										$ -	$ -
Total Cash Distribution & Tax Savings	$ 44,144	$ 48,834	$ 53,367	$ 57,723	$ 61,880	$ 65,814	$ 69,500	$ 72,910	$ 76,015	$ 78,782	$ 7,618,759
LOCAL INVESTOR RETURNS											
Income Distribution	-	-	-	-	-	-	-	-	-	-	-
Income from Sale (Termination Value) Distribution											
Tax Rate	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	
Tax Savings (Obligation) from Earnings	-	-	-	-	-	-	-	-	-	-	-
Tax Credits	-	-	-	-	-	-	-	-	-	-	-
Total Cash Savings (Obligation) from Taxes[2]	-	-	-	-	-	-	-	-	-	-	-
Cash Distributed from Net Cash	-	-	-	-	-	-	-	-	-	-	-
Operations / Management	-	-	-	-	-	-	-	-	-	-	-
Cash Distributed from Grant	-	-	-	-	-	-	-	-	-	-	-
Cash Distributed from Sale (Terminal Value)										-	-
Total Cash Distribution & Tax Savings	-	-	-	-	-	-	-	-	-	-	-

Trust Fund 2005 Work Program Final Report
Date of Report: August 15, 2010
Final Report
Project Completion Dates:
Project A Clean Energy Resource Teams: June 30, 2007
Project B Community Wind Energy Rebate: June 30, 2010
Project C Community Wind Financial Assistance Programs: June 30, 2010

I. PROJECT TITLE: Community Wind Energy Rebate Program

Project Manager: Stacy Miller
Affiliation: Minnesota Department of Commerce
Mailing Address: 85 7th Place East, Suite 500
City / State / Zip: Saint Paul, MN 55101
Telephone Number: 651-282-5091
E-mail Address: stacy.miller@state.mn.us
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Web Page address: www.energy.mn.gov

Total LCMR Project Budget C (Community Wind Rebate)	**LCMR Appropriation:**	**$ 200,000**
	Minus Amount Spent:	**$ 0**
	Equal Balance:	**$ 200,000**

Legal Citation: ML 2005, First Special Session, Chapter 1, Article 2, Section, 11, Subd. 10 (a), as amended by ML 2006, Chapter 243, Section 15, subdivision 10 (a) and as amended by ML 2009, Ch. 143, Subd. 16, paragraph (2).

Appropriation Language:
Clean Energy Resource Teams and **Community Wind Energy Rebate and Financial Assistance Programs**
10 (a) $350,000 the first year and $350,000 the second year are from the trust fund to the commissioner of commerce. $300,000 of this appropriation is to provide technical assistance to implement cost-effective conservation, energy efficiency, and renewable energy projects. $400,000 of this appropriation is to assist Minnesota communities in developing locally owned wind energy projects by offering financial assistance and rebates. This appropriation is available until June 30, 2010, at which time the project must be completed and final products delivered, unless an earlier date is specified in the work program.

This appropriation has been divided into three separate work programs, **Work Program A** for **Clean Energy Resource Teams** (CERTs) and **Work Program B** for **Community Wind Energy Rebates** and **Work Program C** for the **Community Wind Financial Assistance Program**. This document, **Work Program B**, addresses the Community Wind Rebate Program.

II. and III. FINAL PROJECT SUMMARY

The **Community Wind Energy Rebate Program** was designed to competitively select proposed community-owned wind energy projects to receive financial assistance and rebates of $200,000 for the successful completion of megawatt-scale, grid-connected wind turbines. The goal behind the program was to demonstrate how a local government could use local resources to utilize renewable energy development as a means to direct funding to the public and to help contribute to local renewable energy goals. Two local government projects were competitively selected to receive a rebate through this program including Winona County Economic Development Authority (EDA) and a collaborative effort by the Rural Minnesota Energy Board (RMEB) and the Metropolitan Energy Policy Coalition (MEPC), formerly known as the Metro County Energy Task Force (MCETF). Both entities found that publicly owned megawatt-scale wind projects are difficult to develop without private partnerships that allow for federal financial support. Winona County successfully sought legislation to allow for the sale of power during the 2007 legislative session. (*Minn Laws 2007 Ch. 57, art. 2, § 39)*

While in the end the Winona County EDA was the only entity that sought a community wind rebate, its project was determined to be ineligible due to the project ownership structure necessary to allow eligibility for federal grants. Under the proposal received in January 2010, the Winona County EDA would have entered into a partnership with private investors to create a limited liability corporation. Winona County EDA proposed receiving the LCCMR grant and in turn, lending the funds to the project partners. However, this structure was deemed not to fit the requirements of the grant that the project be owned by a public entity. In a letter dated April 28, 2010, the Department of Commerce officially requested that the $200,000 in funds reserved for Winona County EDA be returned to the Trust Fund.

While this program did not contribute financial assistance to a local government to support the development of a megawatt-scale local wind project, the grant opportunity was helpful in obtaining the legal authorization to own interest in a wind generation project and to do so on a timeline that will allow for the contribution of federal funds. The lessons learned through this exercise are included in the final report and may be valuable to other public entities seeking to participate in public-private partnerships.

IV. OUTLINE OF PROJECT RESULTS*:*

Result 4: Community Wind Energy Rebate Program Description
$200,000 was committed to the Winona County EDA wind turbine project that was competitively selected. Since the project was not completed, the funding remains in the appropriation.

The Community Wind Energy Rebate Program solicited community-oriented wind energy projects to install a grid-connected wind turbine(s). One project was competitively selected, and $200,000 in rebates was obligated for the project upon completion. Community-oriented projects were defined as owned by non-taxable entities, including but not limited to counties or municipalities, educational institutions, or non-profit community or nature centers, and involving multi-stakeholder coalitions in the non-technical/non-construction portions of planning, construction, operation, and ongoing management and utilization of the wind project.

The Department of Commerce coordinated the project by:

- Issuing a request for proposals for community project to apply for a $200,000 rebate by September 30, 2005;
- Selecting a project that would maximize non-LCMR funds, promote local community involvement, provide geographic diversity across Minnesota, provide ongoing educational opportunities and curriculum, and show technical expertise and capabilities to complete the project by June 30, 2010;
- Working with selected communities to develop project parameters and provide technical assistance in project development where applicable; and
- Awarding a financial rebate for a completed wind turbine project. (Task not completed.)

Summary Budget Information for Result 4:		
	Budget	$200,000
	- Spent	0
	Balance	$200,000

Completion Date: June 30, 2010

Program Description

A request for proposals was issued on August 1, 2005 for a community wind project, and the Department of Commerce (Department) received one proposal by the October 6, 2005 deadline. Winona County's application was accepted and the award reservation was announced on November 1, 2005. Several parties had indicated a strong interest in the rebate and were informally surveyed to determine how to potentially restructure the rebate for a second issuance. These parties expressed two common concerns: ownership structure and the deadline.

Regarding ownership, the Department originally required 100% community (public) ownership. However, many financial incentives are only available to taxable entities. An alternative for the second Request for Proposals (and as an option for Winona County) was chosen that corresponds with new statutory language regarding community wind energy development.

Qualifying applicants included local/regional governments, educational institutions, or tribal governments (216B.1612, Subd 2, part c, numbers 5 & 6) who maintain decision-making authority over the project's development. Qualifying owners could be Minnesota residents, limited liability corporations, non-profits, cooperatives, local/regional government, educational institutions, or tribal government (216B.1612, Subd 2, part c, numbers 1-6), but at least 51% of the financial benefits must accrue to the community applicant over the project's life (216B.1612, Subd 2, part f, numbers 2).

Additionally, interested parties indicated that the project completion deadline of June 30, 2007 was an impediment to an application because of a wind turbine supply shortage affecting the industry, and applicants were hesitant to commit to such a short construction schedule. The Department requested a no-cost two-year work program extension to June 30, 2009 to allow additional time for rebate recipients to complete projects, and the extension was approved.

Siting

The site selected for turbine development was located on County Road 114 in Altura, Minnesota. The Department erected a 40-meter wind monitoring tower at the proposed site in Winona County on March 29, 2006 to measure local wind speeds. Data was collected and analyzed. This step was necessary in order to ensure good wind resource and to secure project financing.

Financing and Procurement

Winona County EDA began negotiations with Xcel Energy for a power purchase agreement in 2006 and reconvened negotiations in mid-2007 in an effort to receive a higher rate than initially offered. The county also successfully applied for a Clean Renewable Energy Bond (CREBs) for its proposed community wind project and was approved for $3.2 million in federal Clean Renewable Energy Bond dollars. This was the largest amount awarded to any single project nationwide. However, the CREBs allocation expired in late 2008 unused.

By winter 2008-09, the following steps were completed:

- JWI filed a new Interconnection Application to Xcel Energy to update information that was previously submitted. There were no problems with the interconnection status and specifications for the Altura Substation.
- A new underground wire collection system was designed for the site.
- An acceptable power purchase agreement was negotiated with Xcel Energy, while interconnection was still being negotiated.
- JWI solidified a frame agreement with the turbine manufacturers.
- Multiple equity partners were explored. However, the PPA needed to be approved and executed prior to selection of the equity investor.

Hurdles

Finding a turbine supplier was among the bigger challenges for Winona County as suppliers generally avoid contracts for a single turbine. Suzlon Energy, LTD, a wind turbine manufacturer with facilities in Pipestone, Minnesota, informed the County that the company could not make delivery of a wind turbine until 2009; this was in conflict with the project completion deadline of June 30, 2009. Winona County explored options to determine if there was a way to arrive at an acceptable timeframe for delivery and installation, including engaging in discussions with German manufacturer, Vensys.

The County also had difficulty in finding a project manager to see the project through due to the complexity of the development process and the length of time required to negotiate a satisfactory PPA, secure turbines, identify financing, etc.

Additionally, a year into the project, Winona County discovered the need for statutory authority permitting the county to sell power produced by its proposed community wind project. The County sought and obtained legislation to allow for the sale of power during the 2007 legislative session.

> *Within the boundaries of the county, Winona County may own, construct, acquire, purchase, issue bonds and certificates of indebtedness for, maintain, and operate a wind energy conversion system, or a portion of a system, and sell the output at wholesale. Minn Laws 2007 Ch. 57, art. 2 § 39, effective upon local approval.*

On December 10, 2008, the County submitted a formal request to the Department and LCCMR to extend the project completion date beyond the June 30, 2009 expiration date. The County cited the following reasons for pursuing an extension from the Department and LCCMR:

- In August of 2008, the Winona County Economic Development Authority entered into an agreement with Juhl Wind, Inc. as a developer. The company had the experience to help structure the ownership, bring private equity investors to the project, complete negotiations for the Power Purchase Agreement, and source a turbine supplier.
- Since so much groundwork had been completed, Juhl Wind, Inc. estimated that construction would be completed before the end of 2009.

Based on the County's request and discussion with the project developer, Dan Juhl of Juhl Wind, the Department supported the County's request for an extension. The successful outcome of the unique public project would have been a noteworthy milestone in community-based energy development, both in the state and nationwide. The request was approved by LCCMR and the Legislature as well.

The following reasons for the delay in project completion were identified in December 2008:

- The community wind project would be the first of its kind nationwide;
- Single turbine availability was limited;
- The County lacked statutory authority to own a wind turbine, and it was necessary to pursue special legislation to allow ownership by the County;
- The County's educational partners decided not to enter into joint powers agreements as originally proposed;
- The 51% ownership requirements of CBED made companies reluctant to work with a unit of government as the majority owner due to bureaucratic red tape;
- The time required to negotiate a PPA with Xcel Energy was too long to allow the County to secure a down payment on a turbine in a timely manner, and the bid and turbine availability expired by the time the County approved a down payment.

Conclusions and Lessons Learned

The Winona County EDA was authorized by legislation to create a limited liability corporation (LLC) for this project, and potential investors attended a meeting in Winona at the end of June 2009. New federal tax benefits offered additional incentives for partners that could help make the project viable, particularly with depreciation.

Given the value of the new federal tax incentives, on January 22, 2010 Winona County requested that the agreement with Commerce be amended to allow for ownership by a newly created LLC, Winona County Wind, LLC (WCW) to be responsible for designing, constructing and operating the project. WCW's membership interests would be owned by a taxable third party in return for financing the equity of the project and to permit the project and WCW to qualify for funding pursuant to Section 1603 of the American Recovery and Reinvestment Act of 2009. Winona County requested an extension from OES through June 30, 2010 to commission the wind project to allow time to establish WCW and construction scheduling around weather conditions. The request for an extension was approved to allow time for staff legal counsel and LCCMR staff to review whether Winona County EDA would be eligible for the grant funds. After deliberation, it was decided that the newly formed LLC did not meet the requirements of the grant and that the project could not be co-funded with LCCMR funding. The County had to decide which source of funding to pursue and in the end chose to proceed with the LLC in order to realize the significant federal tax incentives. In a letter dated April 28, 2010, and in consultation with Winona County EDA, the Department of Commerce officially requested that the $200,000 in funds reserved for Winona County EDA be returned to the Trust Fund. The project is expected to be completed by the end of 2010 with support from federal tax incentives under the LLC structure.

While it was disappointing to all parties involved during the past four and a half years to forgo the LCCMR funding, the project is well positioned to take advantage of the federal dollars due to the amount of work invested in pursuing the LCCMR grant. The project will qualify as a Community Based Energy Development (CBED) project, which means that at a minimum, the County and its surrounding community will receive benefits from the project equal to no less than 1/3 the revenues. The County's legal consultant for the project, Jeffrey Paulson, indicated that even after leases, local bank interest, and other qualifying expenses, the County should still see a substantial amount of benefits over the project life.

Other public entities seeking to do community wind projects should remember that projects take years to develop. Project managers and others involved should keep expectations manageable and be prepared for delays. Some lessons learned include:

- **Select a consultant/developer very carefully.** Much money and time can be wasted working with consultants who lack experience in project development.
- **Build political support early and often.** "Doing the right thing" is not always seen as valuable by the public – especially when using taxpayer dollars.
- **Control the release of information as much as possible.** Projects are fluid and change frequently during the development stages. It's difficult for the public to understand how and why a public entity changes to a different turbine model or ownership structure, for example. Timing the release of information is important to build confidence and support for a project.
- **Talk to other communities who have tried or completed similar projects.** Winona County EDA did not have other models to follow as they undertook this project. The staff involved indicates that they would be pleased to share experiences with others and to offer guidance to move public projects forward more quickly.

V. LCMR PROJECT BUDGET—COMMUNITY WIND REBATES:

TOTAL LCMR PROJECT BUDGET for Community Wind: $200,000

VI. OTHER FUNDS & PARTNERS:

A. Other Funds being spent during the Project Period:

Community Wind Rebates

a) Community Project: $1,700,000 (estimated) installation costs and in-kind personnel time

b.) Minnesota Department of Commerce: in-kind personnel time

B. Required Match (if applicable): n/a

C. Past Spending:

Community Wind Rebates:

a) $300,000 LCMR funding FY04 & FY05 (oil overcharge funding)
b) $1,363,500 Carleton College payment for wind turbine equipment (does not include installation/labor)
c) $1,889,608 University of Minnesota-Morris payment for wind turbine equipment and installation

E. Time: n/a

VII. DISSEMINATION: n/a

VIII. REPORTING REQUIREMENTS:

Work program progress reports were submitted from January 15, 2006 through January 15, 2010. This final report was submitted August 20, 2010.

IX. RESEARCH PROJECTS: n/a

Attachment A: Budget Detail for 2005 Projects

Proposal Title: *Community Wind Energy Rebate and Financial Assistance Programs - Part 3: Winona County Wind Rebate*

Project Manager Name: *Stacy A. Miller*

LCMR Requested Dollars: $ *400,000.00*

2005 LCMR Proposal Budget	**Result 4 Budget:**	**Amount Paid** *(12/31/2009)*	**Balance** *(12/31/2009)*
	Community Wind Energy Rebate and Financial Assistance		
BUDGET ITEM			
Winona County Wind Project	**$200,000**	**$0.00**	**$200,000.00**
COLUMN TOTAL	**$200,000.00**	**$0.00**	**$200,000.00**

office of energy security

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April 28, 2010

Susan Thornton, Director
Legislative-Citizen Commission on Minnesota Resources (LCCMR)
100 Rev. Dr. Martin Luther King Jr. Blvd.
State Office Building, Room 65
St. Paul, MN 55155

Dear Ms. Thornton:

Pursuant to Minnesota Laws (ML) 2005, First Special Session, Chapter 1, Article 2, Section 11, Subd. 10(a) as amended by ML 2006, Chapter 243, Section 15, Subd. 10(a) and as amended by ML 2009, Chapter 143, Subd. 16, paragraph (2) appropriated $350,000 for the first year and $350,000 for the second year are from the trust fund to the Commissioner of Commerce. $300,000 of this appropriation is to provide technical assistance to implement cost-effective conservation, energy efficiency, and renewable energy projects. $400,000 of this appropriation is to assist Minnesota communities in developing locally owned wind energy projects by offering financial assistance and rebates. This appropriation is available until June 30, 2010, at which time the project must be completed and final products delivered.

The Department of Commerce designated $200,000 of the appropriation to assist Winona County Economic Development Authority (EDA) in developing a locally owned wind energy project. A grant agreement was not fully executed for this funding.

On April 12, 2010, the Winona County EDA confirmed that they do not wish to receive these funds. The circumstances surrounding this community-based wind project have changed since the initial grant application in various and unexpected ways. Given new opportunities for federal incentives that conflict with the community ownership requirements for utilizing the LCCMR funding, the Winona County EDA has decided to pursue the federal funding exclusively.

While the LCCMR funds will not be used directly to support this project, we are pleased that the Winona County EDA intends to complete the installation of a utility-scale, community-based wind project. We appreciate LCCMR's willingness to work with the Department of Commerce and Winona County EDA while we pursued this unique community-based model. Certainly, without the support of LCCMR and its staff, this project would not have advanced to the stage that would have allowed it to receive federal assistance.

office of energy security

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Both the Department of Commerce and Winona County EDA appreciate the support of LCCMR and staff in helping to make this project a reality.

Sincerely,

Jeremy de Fiebre, SEP/EECBG Programs Supervisor
Minnesota Department of Commerce