ENVIRONMENTAL LAW & POLICY CENTER
Protecting the Midwest's Environment and Natural Heritage

April 17, 2009

Ms. Mary Jo Kunkle
Executive Secretary
Michigan Public Service Commission
6545 Mercantile Way, Ste 7
Lansing, Michigan 48911

Re: MPSC Case Nos. U-15805; U-15889

Dear Ms. Kunkle:

The following is attached for paperless electronic filing:

- Corrected pages from the Testimony of George E. Sansoucy and David A. Wright

- Corrected pages from the Surrebuttal Testimony of George E. Sansoucy

- Exhibits MEC 1-2 of Richard A. Polich's Testimony, Exhibit MEC 3 of David A. Wright's Testimony, Exhibits MEC 4-6 of George E. Sansoucy's Testimony and Exhibits MEC 7-8 of George E. Sansoucy's Surrebuttal Testimony

- Electronic Service List

Very truly yours,

Digitally signed by Bradley D. Klein
DN: cn=Bradley D. Klein, o=Environmental Law & Policy Center, ou, email=bklein@elpc.org, c=US
Date: 2009.04.17 16:29:45 -05'00'

Bradley D. Klein
Environmental Law and Policy Center

cc: All Parties of Interest

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Harry Drucker - Chairperson Howard A. Learner - Executive Director

Q. What materials have you reviewed in preparation of this testimony?

A. I have reviewed all of the testimony and exhibits from Case Nos. U-15805 / U-15889, Consumers Energy's ("Consumers") Renewable Energy and Energy Optimization Plans. I have also reviewed PA 295, the Commission's Order in U-15800, Consumers Annual Reports to the Federal Energy Regulatory Commission, elements of U-15245 and other documents in our files.

II Exhibits

Q. Have you prepared any exhibits for your testimony?

A. Yes. They are the following:

Exhibit MEC-4 ~~Exhibit One~~ – Minimum Plan Savings

- Exhibit MEC-5 ~~Exhibit Two~~ – Annual Report on U.S. Wind Power 2008
- Exhibit MEC-6 ~~Exhibit Three~~ – Delmarva Power

III Purpose of Testimony

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to analyze and make recommendations regarding the renewable energy plan as proposed by Consumers and review the components of the cost of the plan. Also, as part of my testimony, I have prepared recommendations for modifications to the plan which may provide the framework for a more cost effective renewable energy program.

Q. What are your concerns regarding the proposed capital cost projections in the plan?

A. The company projects a current capital cost of $2,500 per kilowatt installed, plus $166 for network transmission upgrades for a total of $2,666 per kilowatt (Swartz direct, page 8). The plan does not provide adequate support for the $2,666 nor does it provide any transparent cost controls and measures to mitigate excess capital costs. A large wind facility in today's dollars should cost approximately $2,000 to $2,500 per kilowatt, installed (Exhibit MEC-5 ~~Sansoucy Exhibit Two,~~ page 20). The company's justification for its costs is based on discussions with developers and its "research" but Consumers has not provided backup documentation. The plan also includes a 3% cost escalator which does not consider the potential downward price pressure of ramping up of manufacturing capability for wind turbines as the industry continues to expand. Furthermore, the breakout of turbines, generators, blades, towers, foundations and balance of plant, land, land rights, etc. is not adequately detailed. Also there are not adequate controls in the plan to require market construction costs and cost caps for the proposed facilities, (Swartz direct testimony, page 8). A reduction in capital cost will have a direct effect on the total plan cost and a reduction of the $198 per megawatt hour.

Q. What are your concerns regarding the plan's cost recovery?

A. The 14.5145% fixed charge rate (D.F. Ronk, Jr., WP-DFR-12, page 15) for this plan reflects the company's request to establish a total return of 9.5509% (Swartz direct testimony, page 7) as approved in case U-15245. While this may have been appropriate in Case U-15245, this total weighted average cost of capital (WACC) may be excessive escalated by the CPI. The levelized cost of electricity for the wind facilities owned or purchased by the company in this plan does not compare to other facilities in the United States. Elsewhere in the United States, wind is costing retail electricity providers less than $l00 per megawatt hour in some instances (Exhibit MEC-6 ~~Sansoucy Exhibit Three,~~ page 7). The capacity factor suggested by the company of 28% (Swartz direct testimony, page 5) is not so much lower than other wind installations around the United States as to account for plan costs which are approximately 100% higher than that experienced by other utilities in the United States.

Q. Should this plan be adopted in its current form?

A. No.

Q. Would you please summarize your opinions and recommendation for the overall structure of this plan?

A. Yes. In summation, the plan should be reduced to 20 years for analysis purposes. The plan should change the depreciation rates, cap the construction costs and change the fixed charge rates. This should reduce the estimated cost to a range of $100 to $140 per megawatt for the plan, as compared to the company's proposed cost of $198 per megawatt (WP-TWS-1A).

Exhibit MEC-3

(~~Attachment EC-1).~~ And, as of March 22, 2009, the 2010 4 MW allotment has also sold out according to the GRU website (http://www.gru.com/OutEnvironment/GreenEnergy/solar.jsp). With well over 1.5 million customers, Consumers' proposed program can be expected to quickly sell out. The program can be expanded with little impact on utility rates and while supporting the development and expansion of solar manufacturing and development in Michigan.

Q. Do you have any recommendations on how to expand the proposed Experimental Advanced Renewable Energy program?

A. After the first systems have been installed and are operational, a review of the proposed program can be performed. The review would be used to determine the cost and benefits of the program and any issues which have been identified by any of the program participants. The review participants need to include Consumers, participating customers, photovoltaic system manufacturers and installers, and the Michigan Public Service Commission (MPSC) staff. The outcome would include an identification and resolution of program issues. The information gained from the program review would be used by Consumers to determine the expanded program's solar purchase price, term of the purchase agreement and an annual solar installation capacity target. On-going reviews would be performed to determine whether the prices and capacity targets are being met. The reviews also would be used to determine the impact of the program on utility rates.

Q. What materials have you reviewed in preparation of this testimony?

A. I have reviewed all of the testimony and exhibits from Case Nos. U-15805 / U-15889, Consumers Energy's ("Consumers") Renewable Energy and Energy Optimization Plans. I have also reviewed PA 295, the Commission's Order in U-15800, Consumers Annual Reports to the Federal Energy Regulatory Commission, elements of U-15245 and other documents in our files. Also I have reviewed the rebuttal testimony of Mr. Cox and Mr. Ronk.

Exhibits

Q. Are you submitting any exhibits in support of your testimony?

A. Yes. I have prepared ~~Exhibit 4~~ Exhibit MEC-7 which consists of excerpts from the early Consumers Energy FERC forms 1's to the Federal Energy Regulatory Commission showing historic lives used by the Company prior to the sale of its transmission lines and towers, and its operation and maintenance costs. I am also submitting ~~Exhibit 5,~~ Exhibit MEC-8 a document filed by The Detroit Edison Company in Michigan PSC Docket Number U-15806.

Purpose of Testimony

Q. What is the purpose of your testimony?

A. My testimony rebuts rebuttal testimony presented by David F. Ronk, Jr., and Mr. Cox.

Testimony

Q. What is your response to Mr. Cox's first rebuttal testimony regarding 20 year depreciation?

A. I disagree with Consumers in relying upon only the wind industry's non-regulated assessment of turbine life to be used as a proxy for the total depreciation of the entire development. Consumers Energy has extensive experience with many of the components that are going to be constructed as part of a wind farm. For example, site development, roads and trails are common items for which the Company has experience in a wide variety of properties. Foundations are common in all types of property depreciated by the Company. The monopole structures are a type of structure familiar to Consumers, as it is similar to monopole transmission line structures that Consumers currently, or in the past, has owned, operated, and depreciated. Wire, conduit, and substations system control are all types of property common to Consumers current or past transmission operations and fully within the ability of Consumers to depreciate. Certain portions of the turbines, housings, mounts, transmission wiring and other non-rotating gear will likely have a service life in excess of the rotating machinery. It is appropriate to consider the lives of site, foundations, heavy steel structures, conduits, substations and other types of long lived items which have been part of both hydroelectric plants and transmission systems owned by Consumers. When Consumers owned its transmission plant, it used lives of 40 to 75 years for different components. For example, towers were 75 years (line 24 , page 337.1, Exhibit MEC-7 ~~exhibit GES-4~~)

Q. Do you wish to rebut Mr. Ronk's rebuttal testimony?

A. Yes. I wish to rebut Mr. Ronk's rebuttal testimony regarding the price of $174.20/MWh as being justifiable for the PPA's in Michigan. As previously stated, credible prices that are sought and discussed by other regulatory authorities are in the budget range of $100/MWh to $150/MWh for the purchase of wind. In the Detroit Edison docket, U-15806, Detroit Edison's Renewable Energy Plan, the company submitted on March 27, 2009 an ex-parte application for the approval of a renewable energy contract, namely a wind contract with Heritage Renewable Energy. (Exhibit MEC-8 ~~Exhibit 5).~~ The pricing of that contract as provided on page 5 of the Executive Summary is $115/MWh. This document also may be found publicly on the Michigan Public Service Commission web site for docket U-15806.

Q. In his rebuttal testimony at page 5, Mr. Ronk claims that the purpose of the 20% fixed charge rate for network upgrade costs is to estimate the impact of these capital investments on the annual expenses that the Company will ultimately have to pay for transmission. Do you agree with this statement?

A. No. The 20% fixed charge rate as referenced by Mr. Ronk is an affiliate transaction and is too much. It penalizes the renewable energy program for new transmission property and jeopardizes the overall success of the program. The fixed charge rate for transmission upgrades should be capped at a total rate of between 15 -16% by the Commission, including all returns, taxes, depreciation, and operations and maintenance. (See historic depreciation and historic operation and maintenance costs prior to Consumers sale of the transmission system in Exhibit MEC-7 ~~Sansoucy Exhibit 4).~~

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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In the matter, on the Commission's own motion regarding the regulatory reviews, revision determinations, and/or approvals necessary for CONSUMERS ENERGY COMPANY to fully comply with Public Acts 286 and 295 of 2008.	))))))	Case No. U-15805
In the matter, on the Commission's own motion, regarding the regulatory reviews, revisions, determinations, and/or approvals necessary for CONSUMERS ENERGY COMPANY to fully comply with Public Acts 286 and 295 of 2008.	))))))	Case No. U-15889

EXHIBITS MEC-1 and MEC-2 OF
RICHARD A. POLICH

ON BEHALF OF
THE ECOLOGY CENTER,
ENVIRONMENTAL LAW & POLICY CENTER,
AND MICHIGAN ENVIRONMENTAL COUNCIL

March 23, 2009

MIDWEST ISO GENERATION INTERCONNECTION QUEUE - 03/17/2009

Project Num	Queue Num	Queue Date	Control Area	Study Zone	County	State	Max Summer Output (MW)	Max Winter Output (MW)	Point of Interconnection	In-Service Date	Inter-Connection Serv. Type	Type of Generating Facility	Fuel Type	Study Status	IA Status	Suspension	Overall Project Status	Feasibility Study Report	Impact Study Report	Facility Study Report	Optional Study Report	FERC ER file	Comments
G934	39430-01	12/14/2007	MECS-CONS		Gratiot	MI	300	0	Nelson-Goss 345 kV line	10/1/2010	NR	WT	Wind	Parked (1 Year Rule)			Active						
G766	39160-02	3/19/2007	MECS-CONS		Hillsdale	MI	300	0	Moore-Dowling 138 kV line	8/30/2010	NR	WT	Wind	Parked (1 Year Rule)			Inactive	FES Report					
G937	39436-01	12/20/2007	WEC		Delta	MI	200	0	tap Indian Lake-Perkins 138kV double-circuit line	12/31/2010	NR	WT	Wind	SIS			Active	FES Report					
G905	39388-02	2/23/2009	MECS-CONS		Gratiot & Saginaw	MI	200	0	Tap Begole-Tittabawassee 138kV line	6/30/2010	NR	WT	Wind	Feasibility Study			Active						
G997	39545-01	4/7/2008	MECS-DECO	0	Huron	MI	200	0	tap Wyatt-Harbor Beach 120kV line	12/31/2012	NR	WT	Wind	SPA			Active						
G750	39140-02	2/27/2007	WEC		Marquette	MI	200	0	Presque Isle - National 138 kV line	9/30/2009	NR	WT	Wind	SIS			Inactive	FES Report	SIS Report				
H030	39588-01	5/20/2008	MECS-DECO	0	Tuscola	MI	200	0	Atlanta Substation 120kV bus	12/1/2012	NR	WT	Wind	Parked (1 Year Rule)			Active						
G503	38425-02	3/14/2005	MECS-DECO		Huron	MI	158	0	Sanduskey-Wyatt 120 kV line	10/30/2006	NR	WT	Wind	Post GIA	GIA Executed		Done	FES Report	SIS Report	FAS Report			
G504	38425-03	3/14/2005	MECS		Sanilac	MI	158	158	ITC 120kV circuit from Sandusky to Lee	10/30/2007	NR		Wind	Withdrawn			inactive	FES Report	SIS Report				
G943	39442-04	12/26/2007	MECS-CONS		Kent, Ottawa	MI	150	0	Kenowa Substation 345kV bus	12/1/2011	NR	WT	Wind	Parked (1 Year Rule)			Active						
G944	39442-05	12/26/2007	MECS-CONS		Kent, Ottawa	MI	150	0	Kenowa Substation 345kV bus	12/1/2011	NR	WT	Wind	Parked (1 Year Rule)			Active						
G854	39335-01	9/10/2007	MECS-CONS		Mason	MI	150	0	Pere Marquette-Stonach 138kV line	12/31/2011	NR	WT	Wind	Parked (1 Year Rule)			Active	FES Report					
G418	38068-02	3/22/2004	MECS-CONS		Oceana/Manistee	MI	140	0	Donaldson Creek 138 kV Substation	10/1/2007	NR	WT	Wind	Post GIA	GIA Filed	Suspended	Done	FES Report	SIS Report	FAS Report			
G918	39413-01	11/27/2007	MECS-CONS		Gratiot	MI	120	0	Begole-Tittabawassee 138 kV line	7/1/2010	NR	WT	Wind	Parked (1 Year Rule)			Active						
G799	39216-02	5/14/2007	UPPC		Houghton	MI	120	0	69kV Atlantic Substation	11/30/2009	NR	WT	Wind	SIS			Inactive	FES Report					
G958	39475-01	1/28/2008	MECS-CONS		Kent & Ottawa	MI	120	0	Kenowa substation 345kV bus	12/31/2010	NR	WT	Wind	Parked (1 Year Rule)			Active						
G742	39129-02	2/16/2007	MECS-CONS		Missaukee	MI	120	0	METC Wexford-Keystone 138kV line	12/31/2010	NR	WT	Wind	Parked (1 Year Rule)			Active	FES Report					
G647	38888-01	6/20/2006	METC		Allegan	MI	102	102	Argenta to Tallmadge 345 kV line	7/1/2008	NR		Wind	Withdrawn			inactive						
G511	38432-01	3/21/2005			Huron/Sanilac	MI	100	100		12/31/2006	NR		Wind	Withdrawn			inactive						
G513	38457-02	4/15/2005	MECS-CONS		Oceana	MI	100	0	White Lake Substation 138kV bus	10/1/2006	NR	WT	Wind	Facilities Study			Active	FES Report	SIS Report				
H076	39618-02	6/19/2008		0	Allegan	MI	74	0	near Consumers 138 kV sub 20 mi. west of Agrenta sub on 138 kV line	1/1/2011	NR	WT	Wind	Parked (1 Year Rule)			Active						
G774	39168-02	3/27/2007	MECS-CONS		Mason	MI	70	0	Pere Marquette-Stronach 138 kV line	6/1/2010	NR	WT	Wind	DPP - System Impact Study			Active	FES Report					
G565	38660-01	11/4/2005	METC		Huron	MI	60	60	Existing 120 kV line near Rapson Rd and Minden Rd.	8/1/2007	ER		Wind	Withdrawn			inactive	FES Report					
H075	39618-01	6/19/2008	ITC	0	Ocean	MI	60	0	At or near the Redwood Substation either on 69 kV (Wolverine) or 138 kV (ITC) lines	12/31/2010	NR	WT	Wind	DPP			Active						
G889	39373-01	10/18/2007	MECS-DECO		Huron	MI	59	0	Cosmo Tap (Bad Axe-Arrowhead) 120kV	12/31/2008	NR	WT	Wind	DPP			Active						
G526	38509-01	6/6/2005	MECS-DECO		Huron	MI	52	0	Cosmo Tap, Bad Axe-Arrowhead 120kV line	10/15/2006	NR	WT	Wind	Post GIA	GIA Filed		Done	FES Report	SIS Report	FAS Report			
G755	39141-02	2/28/2007	MECS-CONS		Osceola	MI	50	0	WPSC LeRoy - Cadillac 69 kV line	6/1/2009	NR	WT	Wind	SIS			Inactive						
G743	39129-03	2/16/2007	MECS-CONS		Missaukee	MI	45	0	WPSC Cadillac-Leroy 69kV line	12/31/2010	NR	WT	Wind	DPP			Active						
G228	37370-01	4/24/2002	MECS		Oceana	MI	30	30		9/1/2002	ER		Wind	Withdrawn			Inactive						
G229	37370-02	4/24/2002	MECS		Oceana	MI	30	30		9/1/2003	ER		Wind	Withdrawn			Inactive						
G566d	39009-02	10/19/2006	MECS-CONS		Missaukee	MI	18	0	Cadillac - Leroy 69 kV line, .5 miles from Cadillac.	12/31/2009	NR	WT	Wind	Post GIA	GIA Executed		Done		SIS Report				
G566	38663-01	11/7/2005	MECS-CONS		Missaukee	MI	3	0	Cadillac - Leroy 69 kV line	12/31/2007	NR	WT	Wind	Post GIA	GIA Filed		Done	FES Report	SIS Report	FAS Report			
				TOTAL WIND GENERATION IN QUEUE			3,839																

Status abbreviations

W	**W**ithdrawn or Cancelled	**FAC**	**F**acility Study **C**ompleted
IP	**I**nterconnection Evaluation Study Agreement **P**ending	**OPP**	**OP**tional Study Agreement **P**ending
IE	**I**nterconnection Evaluation Study Agreement **E**xecuted	**OPE**	**OP**tional Study Agreement **E**xecuted
IC	**I**nterconnection Evaluation Study **C**ompleted	**OPC**	**OP**tional Study **C**ompleted
FEP	**FE**asibility Study Agreement **P**ending	**RSO**	**R**e**S**tudy Ongoing
FEE	**FE**asibility Study Agreement **E**xecuted	**IAP**	**I**nterconnection & Operating **A**greement **P**ending
FEC	**FE**asibility Study **C**ompleted	**IAE**	**I**nterconnection & Operating **A**greement **E**xecuted
SIP	**S**ystem **I**mpact Study Agreement **P**ending	**IAF**	**I**nterconnection & Operating **A**greement **F**iled
SIE	**S**ystem **I**mpact Study Agreement **E**xecuted	**CP**	**C**onstruction of Interconnection Facilities **P**ending
SIC	**S**ystem **I**mpact Study **C**ompleted	**UC**	**I**nterconnection Facilities **U**nder **C**onstruction
FAP	**F**acility Study Agreement **P**ending	**IS**	**I**n-**s**ervice
FAE	**F**acility Study Agreement **E**xecuted	**C**	**C**ancelled

Notes:

*** Deviation from the Tariff standard timeline**

**** Coordinated: Shown for coordination purpose only**

COMPETITIVE INFORMATION REQUESTED IN CONSUMERS RENEWABLE ENERGY REQUEST FOR PROPOSAL

SECTION	RERFP LANGUAGE	COMMENTS
6.4	Bidders of new projects will be required to submit generation interconnection applications to CEC for feasibility, system impact and facilities engineering studies and follow the GEG process to obtain generation interconnection.	This Information is not necessary if the project is connected at the transmission level because the information is already supplied to MISO
8.5	List all lawsuits, regulatory proceedings, or arbitration in which the bidder or its affiliates or predecessors have been or are engaged that could affect bidder's performance of its bid. Identify the parties involved in such lawsuits, proceedings, or arbitration, and the final resolution or present status of such matters.	This information is not relevant to the bid.
8.8.1B	Wind energy proposals must provide the source and basis of the wind speed data used in the development of energy projections for the project. Explain the assumptions for wake losses, line losses, etc., and the location where the data was measured. Also provide the contact information, resume and experience of the consulting meteorologist (if any) engaged for wind measurement and energy projections from the proposed project.	Utility only needs to know if the bidder has meteorological data supporting its projected project output. This evidence can be provided through identification of location of Meteorological tower location and number of years of data collected.
8.8.3	Proposals shall include the project location, the merits of the selected site, and the proposed land rights (including permitting issues). Provide copies or summaries of leases, easements, and/or other ownership documents that demonstrate that the bidder has control of the intended project properties and the legal right to construct, interconnect and operate the project as described.	The information requested in the first sentence is sufficient. Leases contain proprietary information on what landowners are being paid. If necessary for bidder to demonstrate they have land leased, bidder can be required to provide a letter certifying it has site control.
8.8.4	Proposals must show anticipated placement of turbines or engines and other project facilities, including transmission layouts and the Point of Delivery.	Locations of project facilities is unnecessary information. Point of interconnection is the only information the utility needs. All other information is competitive information.
8.8.5	See testimony.	
8.8.8	Also provide the proposed on-going debt-equity ratio to be carried by the project during construction and during operation.	This is competitive information. The information requested in the rest of section will verify bidders ability to finance project.
Appendix B-1 Site Location	Site Geographic Location	Utility only needs point of interconnection. Actual coordinates for the site is competitive information.
Appendix B-1 Site Location	Is there potential for expansion? What is possible additional acreage available?	This is all competitive information and there is not a need for it in the evaluation of the bid.

Appendix B-2	Please attach a copy of the executed interconnection agreement, or if such agreement has not been executed, please attach a copy of all CEC interconnection studies and/or the expected completion date.	Copy of Interconnection Agreement is not necessary and is competitive information. Statement of status of interconnection process should be sufficient. Interconnection status can be verified through the MISO Queue.
Appendix B-2	Please attach a layout that depicts turbines, engines, other collection system facilities, transmission interconnection and the point of delivery.	This is competitive information and is not needed by the utility. Point of delivery is the only necessary information.
Appendix B-2 Permits	On an additional sheet, list and describe all city, county, state and federal permits required for this project. Include: status, duration, planned steps, critical milestones and acquisition timeline.	This is competitive information and is not needed by the utility. Information requested earlier in this section I all that is necessary. Schedule issues can be provided in response to requirement in Section 8.8.7.
Appendix B-2	If yes, provide the major equipment information: Quantity--- Size---- Manufacturer------ Please attach a summary of the equipment warranty terms. If no, please provide the major equipment manufacturer candidates: 1. _ 2. _ Please attach a description of the status and scheduled selection process.	This is all competitive information and discussed in testimony.
Appendix B-2	Consulting Meteorologist Information	Unnecessary competitive information. Bidder is already providing the necessary information earlier in this section. The REPA contract should provide all ready includes a bond in the event bidder is unable to perform, so verification of this data is unnecessary.
Appendix C	All	Bidder should simply be required to provide a certified letter from their financial entity verifying that financing is available should they be awarded the PPA.
Appendix D	Please list Bidder's Affiliate companies:	Why is this information necessary?

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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In the matter, on the Commission's own motion regarding the regulatory reviews, revision determinations, and/or approvals necessary for CONSUMERS ENERGY COMPANY to fully comply with Public Acts 286 and 295 of 2008.	)	Case No. U-15805
In the matter, on the Commission's own motion, regarding the regulatory reviews, revisions, determinations, and/or approvals necessary for CONSUMERS ENERGY COMPANY to fully comply with Public Acts 286 and 295 of 2008.	)	Case No. U-15889

EXHIBIT MEC-3 OF
DAVID A WRIGHT

ON BEHALF OF
THE ECOLOGY CENTER,
ENVIRONMENTAL LAW & POLICY CENTER,
AND MICHIGAN ENVIRONMENTAL COUNCIL

March 23, 2009

Attachment MEC-3

Solar tariff program reaches its limit in only 3 weeks

By Anthony Clark
Business editor

Published: Saturday, February 28, 2009 at 6:01 a.m.
Last Modified: Friday, February 27, 2009 at 11:45 p.m.

Gainesville's solar feed-in tariff reached its 4 megawatt cap in just three weeks — with contracts to buy electricity from 35 businesses and residences — and already has more than 60 percent of next year's cap lined up.

The Gainesville City Commission approved the nation's first feed-in tariff Feb. 5, promising to pay 32 cents per kilowatt hour generated by local solar photovoltaic systems for 20 years for those who sign up during the first two years of the program.

The program starts Sunday and a handful of systems are already installed, said John Crider, strategic planning engineer for Gainesville Regional Utilities. The program will add four megawatts of available electricity per year for 10 years.

Since the $1.5 million program will be subsidized by an increase in utility bills, it was capped at 4 megawatts to limit increases to 3-5 percent, Crider said.

The subsidy would cost an average house 93 cents extra a month once all systems are hooked up, he said.

Those who sign up after the first two years will receive a lesser amount per kilowatt hour at a rate to be determined.

GRU is encouraging anyone interested in putting in a solar PV system to go ahead and apply, since the utility expects that some of those with current contracts and those in line for next year will drop out. Projects have 120 days for completion from the time of the application.

Of the 35 contracts, 27 are for businesses and eight are for residences, ranging in size from 3.85 kilowatts to 1 megawatt, according to Rachel Meek, solar project manager. The largest is for a trust holding company and will be mounted on the ground, she said.

For 2010, 15 contracts are in line for 2.5 megawatts so far. Applicants move up in line as others drop out.

Akira Wood, the first Gainesville business to put in a 25-kilowatt PV system in December 2007 under the former GRU rebate program for businesses, has another 25-kilowatt system installed and ready to plug into the grid as early as next week, and owner Hoch Shitama said he is hoping to add another 25 kilowatts to the system.

Factoring in tax credits and depreciation, Shitama said the feed-in program should start paying for itself in five or six years.

"After that, you're just making money," he said. "That would probably come out to a 15, 20 percent return on investment."

GRU rebates are still available for residential PV systems, but not for businesses.

The 50 to sign up for feed-in contracts in three weeks comes after 60 PV systems were installed in three years of the rebate program, Crider said.

"I'm surprised it happened quite this fast," he said. "I think it's a reflection on the state of the general economy. There's just very few places people can put their money to get a positive investment."

Proponents of the tariff are projecting the policy will stimulate millions of dollars in private investment in solar energy.

Meek said GRU is seeing an influx of new solar companies installing projects in Gainesville.

Some are from other areas of the state and even out of state, she said, but even those will use local solar contractors or electricians to install the systems.

Sullivan Solar Power of San Diego located an office in Gainesville about a year ago, drawn by the large number of rebates going to the area relative to other areas of the state, according to John Gurski, eastern regional business manager.

While many people install solar because of environmental concerns, he said the tariff provides an economic motivation he can sell people on.

Gurski said the 4 megawatt cap is a problem, however.

"It's created almost a rat race where everybody's trying to get their fair share as quick as possible," he said. "Every company in the state is trying to get a portion and it's gone in a couple weeks. At that point we don't have a sustainable business. Four megawatts is not enough to attract the kind of investment they're trying to attract."

Gurski said he is still hoping the state Legislature will come through with a renewable energy goal and, when the economy is better, a statewide feed-in tariff.

Ed Regan, GRU assistant general manager for strategic planning, said the City Commission had to consider how much it wanted to add to utility bills in any given year, especially during hard economic times.

"There's an incentive to stay on the list," he said. "It's going to take a long time to build all that."

Contact Anthony Clark at anthony.clark@gvillesun.com.

http://www.gainesville.com/article/20090228/articles/902270894

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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In the matter, on the Commission's own motion regarding the regulatory reviews, revision determinations, and/or approvals necessary for CONSUMERS ENERGY COMPANY to fully comply with Public Acts 286 and 295 of 2008.	))))))	Case No. U-15805
In the matter, on the Commission's own motion, regarding the regulatory reviews, revisions, determinations, and/or approvals necessary for CONSUMERS ENERGY COMPANY to fully comply with Public Acts 286 and 295 of 2008.	))))))	Case No. U-15889

EXHIBITS MEC-4, MEC-5 and MEC-6 OF
GEORGE E. SANSOUCY

ON BEHALF OF
THE ECOLOGY CENTER,
ENVIRONMENTAL LAW & POLICY CENTER,
AND MICHIGAN ENVIRONMENTAL COUNCIL

March 23, 2009

MEC-4

MICHIGAN PUBLIC SERVICE COMMISSION
CONSUMERS ENERGY COMPANY
RENEWABLE ENERGY PLAN
Case No: U-15805/U-15889
Minimum Plan Savings
Sansoucy Exhibit 1

	A	B	C	D	E	F	G	H	I	J
Line	Year	Net Energy Value	Net Capacity Value	Transfer Price	Blended Transfer Price	Total Cost of New Build & PPA Renewable Resources	Value of New Build & PPA Renewable Resources Energy & Capacity	New Cost of New Build & PPA Renewable Resources (Cost Less Value of Energy & Capacity)	Total Transfer Energy from New Build & PPA Renewable Resources	Minimum Proposed Planned Savings Using 20 Year Horizon
		$/MWh	$/MWh	$/MWh	$/MWh	$K	$K	$K	GWh	(Jx$50xMWH)
1	2009	48.52	1.26	49.78	52.25	412,890	114,582	298,309	2,298	114,900,000
2	2010	54.39	1.53	55.92	59.70	412,920	128,879	284,041	2,299	114,950,000
3	2011	56.32	2.04	58.36	63.07	406,100	134,633	271,467	2,300	115,000,000
4	2012	71.73	3.06	74.79	80.96	407,158	172,584	234,574	2,300	115,000,000
5	2013	72.32	4.59	76.91	79.34	407,575	177,726	229,849	2,300	115,000,000
6	2014	73.05	6.37	79.42	81.35	408,011	183,791	224,219	2,300	115,000,000
7	2015	76.01	7.96	83.97	85.44	408,563	194,536	214,027	2,300	115,000,000
8	2016	78.06	8.30	86.35	87.46	409,093	200,082	209,011	2,300	115,000,000
9	2017	79.12	8.63	87.75	88.59	409,596	203,349	206,247	2,300	115,000,000
10	2018	81.20	8.97	90.17	90.59	410,159	208,967	201,192	2,300	115,000,000
11	2019	84.75	9.32	94.07	94.78	410,808	218,006	192,802	2,300	115,000,000
12	2020	88.04	9.68	97.72	98.46	411,466	226,452	185,013	2,300	115,000,000
13	2021	92.34	10.06	102.4	103.17	412,164	237,291	174,873	2,300	115,000,000
14	2022	96.36	10.46	106.81	107.56	412,072	247,193	164,879	2,298	114,900,000
15	2023	101.25	10.87	112.11	112.88	412,575	259,336	153,239	2,298	114,900,000
16	2024	106.78	11.29	118.07	118.86	413,422	273,090	140,332	2,298	114,900,000
17	2025	107.68	11.73	119.41	120.24	414,088	276,250	137,837	2,298	114,900,000
18	2026	111.74	12.20	123.94	124.79	414,918	286,712	128,205	2,298	114,900,000
19	2027	116.34	12.68	129.01	129.9	415,797	298,458	117,339	2,298	114,900,000
20	2028	124.68	13.18	137.86	138.78	416,869	318,855	98,014	2,298	114,900,000
21	2029	129.94	13.68	143.62	144.57				2,298	114,900,000
22	**Total**									**$2,414,050,000**

MEC-5

U.S. Department of Energy
Energy Efficiency and Renewable Energy
Bringing you a prosperous future where energy is clean, abundant, reliable, and affordable

Annual Report on U.S. Wind Power Installation, Cost, and Performance Trends: 2007

May 2008

Annual Report on U.S. Wind Power Installation, Cost, and Performance Trends: 2007

Contents

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Introduction

The U.S. wind industry experienced unprecedented growth in 2007, surpassing even optimistic projections from years past. This rapid pace of development has made it difficult to keep up with trends in the marketplace. Yet, the need for timely, objective information on the industry and its progress has never been greater. This report—the second of an ongoing annual series—attempts to meet this need by providing a detailed overview of developments and trends in the U.S. wind power market, with a particular focus on 2007.

As with the previous edition*, this report begins with an overview of key wind power development and installation-related trends, including trends in capacity growth, in turbine make and model, and among wind power developers, project owners, and power purchasers. It then reviews the price of wind power in the United States, and how those prices compare to the cost of fossil-fueled generation, as represented by wholesale power prices. Next, the report describes trends in installed wind project costs, wind turbine transaction prices, project performance, and operations and maintenance expenses. Finally, the report examines other factors impacting the domestic wind power market, including grid integration costs, transmission issues, and policy drivers. The report concludes with a brief preview of possible developments in 2008.

This version of the Annual Report updates data presented in the previous edition, while highlighting key trends and important new developments from 2007. New to this edition is a section on the contribution of wind power to new capacity additions in the electric sector, data on the amount of wind in utility systems, a summary of trends in wind project size, a discussion of the quantity of wind power capacity in various interconnection queues in the United States, and a section that underscores domestic wind turbine manufacturing investments.

A note on scope: this report concentrates on larger-scale wind applications, defined here as individual turbines or projects that exceed 50 kW in size. The U.S. wind power sector is multifaceted, however, and also includes smaller, customer-sited wind applications used to power the needs of residences, farms, and businesses. Data on these applications are not the focus of this report, though a brief discussion on *Distributed Wind Power* is provided on page 4.

Much of the data included in this report were compiled by Berkeley Lab, and come from a variety of sources, including the American Wind Energy Association (AWEA), the Energy Information Administration (EIA), and the Federal Energy Regulatory Commission (FERC). The Appendix provides a summary of the many data sources used in the report. Data on 2007 wind capacity additions in the United States are based on preliminary information provided by AWEA; some minor adjustments to those data are expected. In other cases, the data shown here represent only a sample of actual wind projects installed in the United States; furthermore, the data vary in quality. As such, emphasis should be placed on overall trends, rather than on individual data points. Finally, each section of this document focuses on historical market information, with an emphasis on 2007; the report does not seek to forecast future trends.

Acronym List

AWEA	American Wind Energy Association
BPA	Bonneville Power Administration
COD	commercial operation date
CREZ	competitive renewable energy zone
DOE	U.S. Department of Energy
EIA	Energy Information Administration
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Commission
IOU	investor-owned utility
IPP	independent power producer
ISO	independent system operator
LBNL	Lawrence Berkeley National Laboratory
MISO	Midwest Independent System Operator
NREL	National Renewable Energy Laboratory
POU	publicly owned utility
PPA	power purchase agreement
PTC	production tax credit
PUC	public utility commission
REC	renewable energy certificate
RPS	renewables portfolio standard
RTO	regional transmission organization
SPP	Southwest Power Pool
TVA	Tennessee Valley Authority
WAPA	Western Area Power Administration

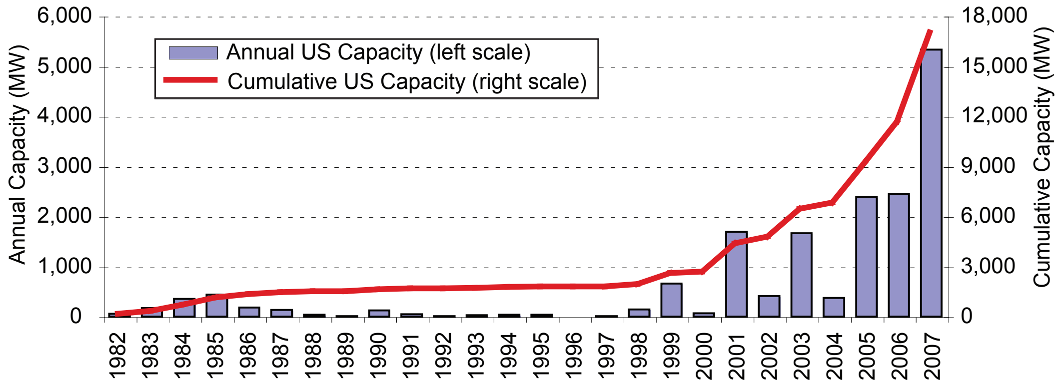
* Wiser, R.; Bolinger, M. (2007). *Annual Report on U.S. Wind Power Installation, Cost, and Performance Trends: 2006*. 24 pp.; NREL Report No. TP-500-41435; DOE/GO-102007-2433, www.nrel.gov/docs/fy07osti/41435.pdf.

U.S. Wind Power Capacity Surged by 46% in 2007, with 5,329 MW Added and $9 Billion Invested

The U.S. wind power market surged in 2007, shattering previous records, with 5,329 MW of new capacity added, bringing the cumulative total to 16,904 MW (Figure 1). This growth translates into roughly $9 billion (real 2007 dollars) invested in wind project installations in 2007, for a cumulative total of nearly $28 billion since the 1980s.[1]

Wind installations in 2007 were not only the largest on record in the United States, but were more than twice the previous U.S. record, set in 2006. No country, in any single year, has added the volume of wind capacity that was added to the United States electrical grid in 2007. Federal tax incentives, state renewables portfolio standards (RPS), concern about global climate change, and continued uncertainty about the future costs and liabilities of natural gas and coal facilities helped spur this intensified growth.

The yearly boom-and-bust cycle that characterized the U.S. wind market from 1999 through 2004—caused by periodic, short-term extensions of the federal production tax credit (PTC)—has now been replaced by three consecutive years of sizable growth. With the PTC currently (as of early-May 2008) set to expire at the end of the year, 2008 is expected to be another year of sizable capacity additions. Unless the PTC is extended before mid-to-late 2008, however, a return to the boom-and-bust cycle can be expected in 2009.



Source: AWEA.

Figure 1. Annual and Cumulative Growth in U.S. Wind Power Capacity

Distributed Wind Power

Wind turbines installed on the distribution side of the electric grid can provide power directly to homes, farms, schools, businesses, and industrial facilities. Distributed wind turbines can also provide power to off-grid sites. Distributed wind turbines generally range in size from a few hundred watts up to 100 kW or more, and growth in this sector has been driven—at least in part—by a variety of state incentive programs.

The table below summarizes sales of distributed wind turbines from 300 W to 100 kW in size into the U.S. market in 2007. As shown, nearly 10 MW of distributed wind turbines were sold in the U.S., with a slight majority (in capacity terms) used in grid-connected applications; 89% of this new capacity came from turbines manufactured by U.S. companies, including (but not limited to) Southwest Windpower, Bergey Windpower, Wind Turbine Industries, Entegrity Wind Systems, and Distributed Energy Systems. These installation figures represent a 14% growth in annual sales—in capacity terms—relative to 2006, yielding a cumulative installed capacity of distributed wind in the United States in this turbine size range of roughly 55-60 MW.

Application	Annual Sales in 2007		
	Number of Turbines	Capacity Additions (MW)	Sales Revenue (million $)
Off-grid	7,800	4.0	14
On-grid	1,292	5.7	28
TOTAL	**9,092**	**9.7**	**42**

Source: AWEA.

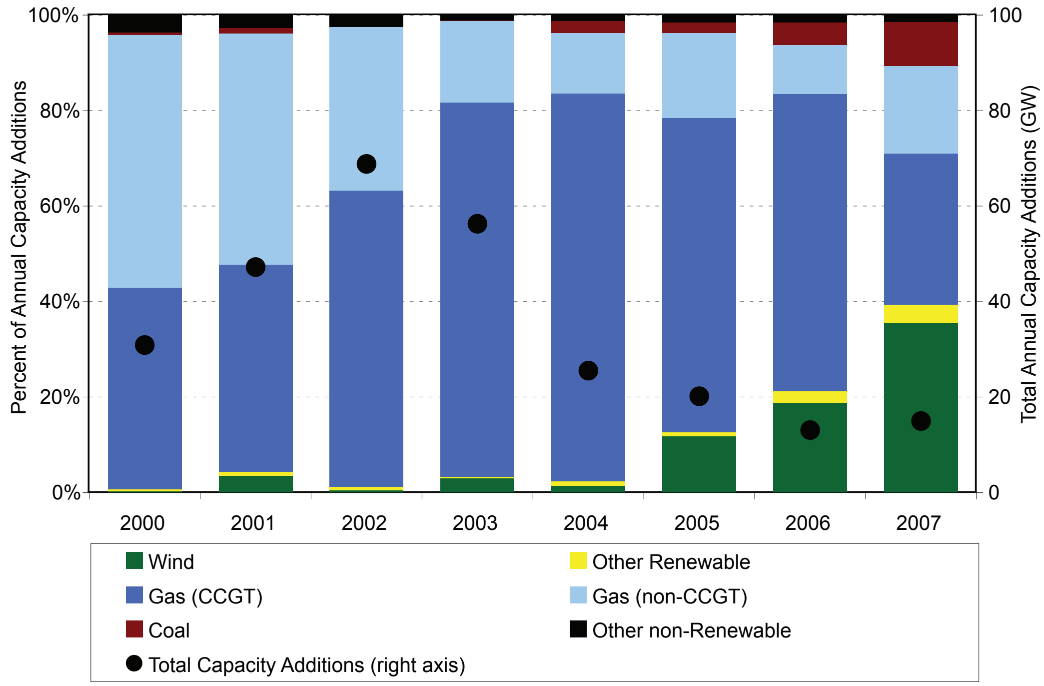
Wind Power Contributed 35% of All New U.S. Electric Generating Capacity in 2007

Wind power now represents one of the largest new sources of electric capacity additions in the United States. For the third consecutive year, wind power was the second-largest new resource added to the U.S. electrical grid in terms of nameplate capacity, behind the 7,500 MW of new natural gas plants, but ahead of the 1,400 MW of new coal. New wind plants contributed roughly 35% of the new nameplate capacity added to the U.S. electrical grid in 2007, compared to 19% in 2006, 12% in 2005, and less than 4% from 2000 through 2004 (see Figure 2).

The EIA projects that total U.S. electricity supply will need to increase at an average pace of 47 TWh per year from 2008 to 2030 in order to meet demand growth. On an energy basis, the annual

[1] These investment figures are based on an extrapolation of the average project-level capital costs reported later in this report. Annual O&M, R&D, and manufacturing expenditures, which are not included here, would add to these figures.

amount of electricity generated by the new wind capacity added in 2007 (~16 TWh) represents roughly 35% of this average annual projected growth in supply.[2] By extension, if wind capacity additions continued through 2030 at the same pace as set in 2007 (5,329 MW per year), then 35% of the nation's projected additional electricity generation needs from 2008 through 2030 would be met with wind electricity. Although future growth trends are hard to predict, it is clear that a significant portion of the country's new generation needs are already being met by wind power.



Source: EIA, Ventyx, AWEA, IREC, Berkeley Lab.

Figure 2. Relative Contribution of Generation Types to Annual Capacity Additions

The United States Continued to Lead the World in Annual Capacity Growth

On a worldwide basis, roughly 20,000 MW of wind capacity was added in 2007, the highest volume achieved in a single year, and up from about 15,000 MW in 2006, bringing the cumulative total to approximately 94,000 MW. For the third straight year, the United States led the world in wind capacity additions (Table 1), capturing roughly 27% of the worldwide market, up from 16% in 2006 (Figure 3). China, Spain, Germany, and India rounded out the top five countries in 2007 for annual wind capacity additions (Table 1).[3]

In terms of cumulative installed wind capacity, the United States ended the year with 18% of worldwide capacity, in second place behind Germany. So far this decade (i.e., over the past eight years), cumulative wind power capacity has grown an average of 27% per year in the United States, equivalent to the same 27% growth rate in worldwide capacity.

Several countries are beginning to achieve relatively high levels of wind power penetration in their electricity grids. Figure 4 presents data on end-of-2007 (and end-of-2006) installed wind capacity, translated into projected annual electricity supply based on assumed country-specific capacity factors, and divided by projected 2008 (and 2007) electricity consumption. Using this rough approximation for the contribution of wind to electricity consumption, and focusing only on the 20 countries with the greatest cumulative installed wind capacity, end-of-2007 installed wind is projected to supply roughly 20% of Denmark's electricity demand (somewhat less than last year), 12% of Spain's (up by 2.2% from last year), 9% of Portugal's (up by 1.6% from last year), 8% of Ireland's (up by 0.4% from last year), and 7% of Germany's (up by 0.4% from last year). In the United States, on the other hand, the cumulative wind capacity installed at the end of 2007 would, in an average year, be able to supply roughly 1.2% of the nation's electricity consumption (up by 0.4% from last year)[4]—the same as wind's estimated 1.2% contribution to electricity consumption on a worldwide basis.

Table 1. International Rankings of Wind Power Capacity

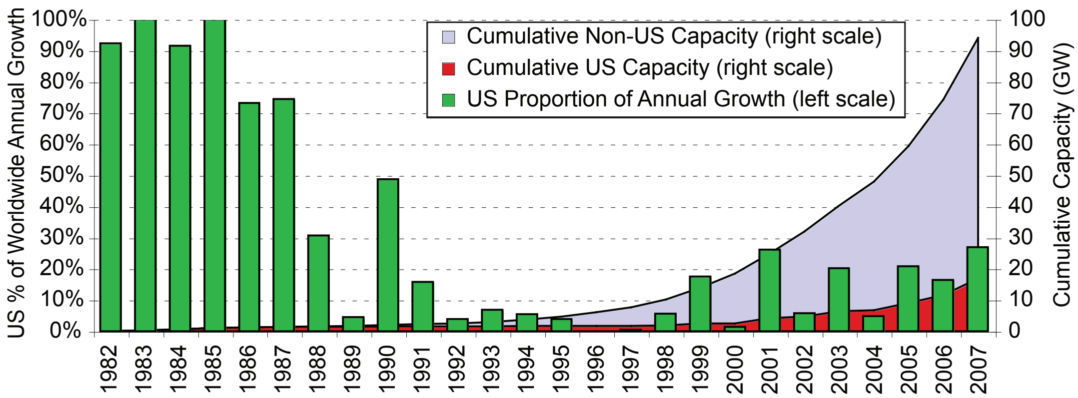
Incremental Capacity (2007, MW)		Cumulative Capacity (end of 2007, MW)	
U.S.	**5,329**	Germany	22,277
China	3,287	**U.S.**	**16,904**
Spain	3,100	Spain	14,714
Germany	1,667	India	7,845
India	1,617	China	5,875
France	888	Denmark	3,088
Italy	603	Italy	2,721
Portugal	434	France	2,471
U.K.	427	U.K.	2,394
Canada	386	Portugal	2,150
Rest of World	2,138	*Rest of World*	13,591
TOTAL	**19,876**	**TOTAL**	**94,030**

Source: BTM Consult; AWEA project database for U.S. capacity.

2 Given the relatively low capacity factor of wind, one might initially expect that wind's percentage contribution on an *energy* basis would be lower than on a *capacity* basis. This is not necessarily the case, in part because even though combined-cycle gas plants can be operated as baseload facilities with high capacity factors, those facilities are often run as intermediate plants with capacity factors that are not dissimilar from that of wind. Combustion turbine facilities run at even lower capacity factors.

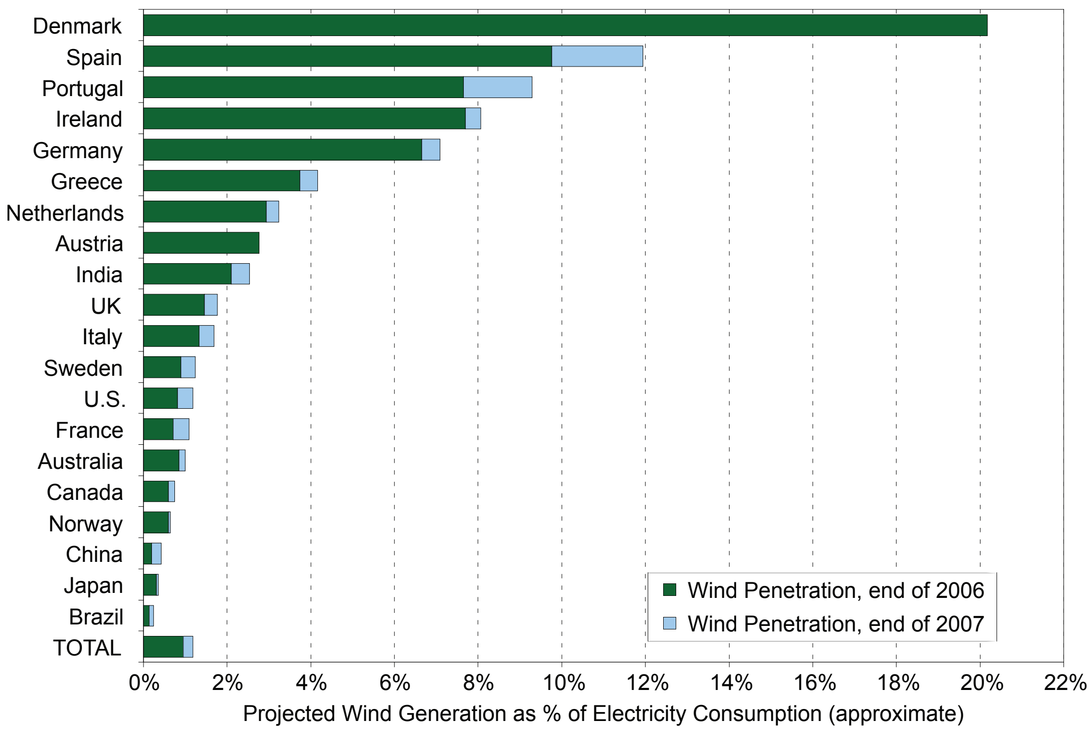
3 Yearly and cumulative installed wind capacity in the United States are from AWEA, while global wind capacity comes from BTM Consult (but updated with the most recent AWEA data for the United States) and, for earlier years, from the Earth Policy Institute. Modest disagreement exists among these data sources and others, e.g., *Windpower Monthly* and the Global Wind Energy Council.

4 In terms of actual 2007 deliveries, wind represented 0.77% of net electricity generation in the United States, and roughly 0.72% of national electricity consumption. These figures are below the 1.2% figure provided above because 1.2% is a projection based on end-of-year 2007 wind capacity.



Source: Earth Policy Institute, BTM Consult, AWEA.

Figure 3. The United States' Contribution to Global Wind Capacity



Source: Berkeley Lab estimates based on data from BTM Consult and elsewhere.

Figure 4. Approximate Wind Power Penetration in the Twenty Countries with the Greatest Installed Wind Capacity

Texas Easily Exceeded Other States in Annual Capacity Growth

New large-scale[5] wind turbines were installed in 18 states in 2007. Texas dominated in terms of new capacity, with 1,708 MW installed in 2007 alone. As shown in Table 2 and Figure 5, other leading states in terms of new capacity include Colorado, Illinois, Oregon, Minnesota, Washington, and Iowa. Ten states added more than 100 MW each.

On a cumulative basis, after surpassing California in 2006, Texas continued to build on its lead in 2007, with a total of 4,446 MW of wind capacity installed by the end of the year. In fact, Texas has more installed wind capacity than all but five countries worldwide. Following Texas are California, Minnesota, Iowa, Washington, and Colorado. Sixteen states had more than 100 MW of wind capacity as of the end of 2007, with nine topping 500 MW. Although all wind projects in the United States to date have been sited on land, offshore development activities continued in 2007, though not without some tribulations (see *Offshore Wind Development Activities*, page 9).

Some states are beginning to realize relatively high levels of wind penetration. Table 2 lists the top-20 states based on an estimate of wind generation from end-of-2007 wind capacity,

[5] "Large-scale" turbines are defined consistently with the rest of this report—over 50 kW.

Table 2. United States Wind Power Rankings: The Top-20 States

Incremental Capacity (2007, MW)		Cumulative Capacity (end of 2007, MW)		Estimated Percentage of In-State Generation	
Texas	1,708	Texas	4,446	Minnesota	7.5%
Colorado	776	California	2,439	Iowa	7.5%
Illinois	592	Minnesota	1,298	Colorado	6.1%
Oregon	444	Iowa	1,271	South Dakota	6.0%
Minnesota	403	Washington	1,163	Oregon	4.4%
Washington	345	Colorado	1,067	New Mexico	4.0%
Iowa	341	Oregon	882	North Dakota	3.8%
North Dakota	167	Illinois	699	Oklahoma	3.0%
Oklahoma	155	Oklahoma	689	Texas	3.0%
Pennsylvania	115	New Mexico	496	Washington	2.8%
California	63	New York	425	California	2.8%
Missouri	57	Kansas	364	Kansas	2.3%
New York	55	North Dakota	345	Hawaii	2.3%
South Dakota	54	Pennsylvania	294	Montana	1.9%
Maine	33	Wyoming	288	Wyoming	1.7%
Hawaii	21	Montana	147	Idaho	1.5%
Massachusetts	2	South Dakota	98	Illinois	0.8%
Montana	2	Idaho	75	Maine	0.8%
		Nebraska	73	New York	0.7%
		West Virginia	66	Nebraska	0.7%
Rest of U.S.	0	*Rest of U.S.*	277	*Rest of U.S.*	0.05%
TOTAL	**5,329**	**TOTAL**	**16,904**	**TOTAL**	**1.1%**

Source: AWEA project database, EIA, Berkeley Lab estimates.

divided by total in-state generation in 2007.[6] By this (somewhat-contrived) metric, two Midwestern states lead the list in terms of estimated wind power as a percentage of total in-state generation. Specifically, wind capacity installed as of the end of 2007 is estimated, in an average year, to generate approximately 7.5% of all in-state electricity generation in both Minnesota and Iowa. Four additional states—Colorado, South Dakota, Oregon, and New Mexico—surpass the 4% mark by this metric, while thirteen states exceed 2%.

Some utilities are achieving even higher levels of wind penetration into their individual electric systems. Table 3 lists the top-20 utilities in terms of aggregate wind capacity on their systems at the end of 2007, based on data provided by AWEA. Included here are wind projects either owned by or under long-term contract with these utilities for use by their own customers; short-term renewable electricity and renewable energy certificate contracts are excluded. The table also lists the top-20 utilities based on an estimate of the percentage of retail sales that wind generation represents, using end-of-2007 wind capacity and wind capacity factors that are consistent with the state or region in which these utilities operate, and EIA-provided aggregate retail electricity sales for each utility in 2006.[7] As shown, three of the listed utility systems are estimated to have achieved in excess of 10% wind penetration based on this metric, while 15 utilities are estimated to have exceeded 5%.

6 To estimate these figures, end-of-2007 wind capacity is translated into estimated annual wind electricity production based on state-specific capacity factors that derive from the project performance data reported later in this report. The resulting state-specific wind production estimates are then divided by the latest data on total in-state electricity generation available from the EIA (i.e., 2007). The resulting wind penetration estimates shown in Table 2 differ from what AWEA provided in its Annual Rankings Report. The most significant source of these differences is that AWEA estimates wind generation based on end-of-2006 wind capacity, while this report uses end-of-2007 capacity. In addition, Berkeley Lab uses state-specific wind capacity factor assumptions that differ from those applied by AWEA.

7 A variety of caveats deserve note with respect to these calculations. First, the utility-specific capacity data that AWEA released in its *Annual Ranking Report* are assumed accurate, and are used without independent verification. Second, only utilities with 50 MW or more of wind capacity are included in the calculation of wind as a proportion of retail sales. Third, projected wind generation based on each utility's installed wind capacity at the end of 2007 is divided by the aggregate national retail sales of that utility in 2006 (which is the latest full year of utility-specific retail sales data provided by EIA). Fourth, in the case of generation and transmission (G&T) cooperatives and power authorities that provide power to other cooperatives and municipal utilities (but do not directly serve retail load themselves), 2006 retail sales from the electric utilities served by those G&T cooperatives and power authorities are used. In some cases, these individual utilities may be buying additional wind power directly from other projects, or may be served by other G&T cooperatives or power authorities that supply wind. In these cases, the penetration percentages shown here may be understated (or at least somewhat misleading). As an example, the "MSR Public Power Agency" (MSR) is a joint powers agency created to procure power for municipal utilities in the California cities of Modesto, Santa Clara, and Redding. The 200 MW of wind capacity associated with MSR in the first column of Table 3 (and the corresponding 8.4% penetration rate shown in the second column) represents MSR's power purchase agreement with the Big Horn wind project in Washington state. However, two of the three municipal utilities participating in MSR purchase additional wind power from California wind projects. The result is that if one were to look at these three municipal utilities individually rather than as a group through MSR, their penetration rates would be considerably higher than the 8.4% shown in Table 3, and all three utilities would be at the top of the rankings: Redding would be roughly 24.2%, Santa Clara 12.3%, and Modesto 11.8%. Finally, some of the entities shown in Table 3 are wholesale power marketing companies that are affiliated with electric utilities. In these cases, estimated wind generation is divided by the retail sales of the power marketing company and any affiliated electric utilities.

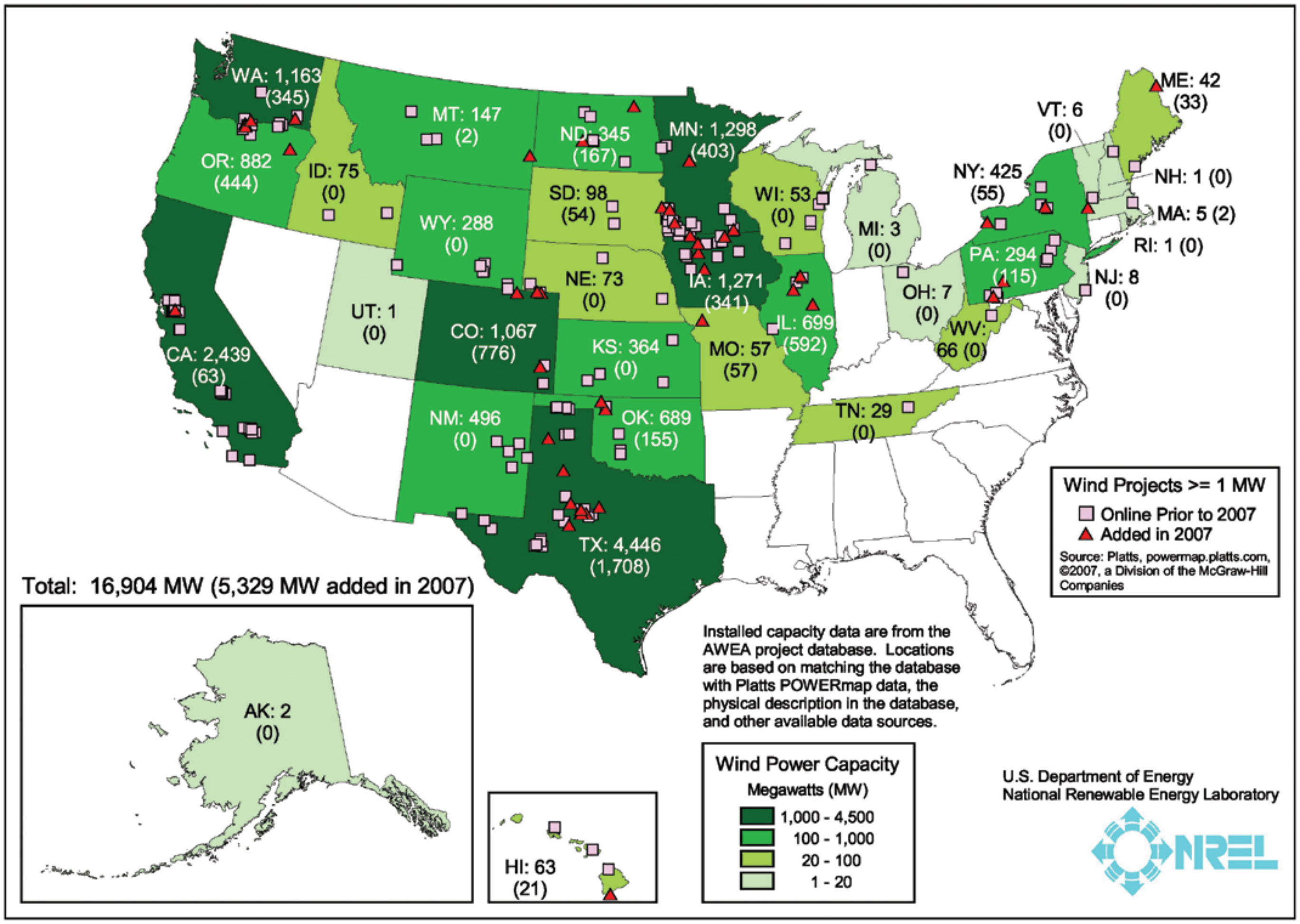


Figure 5. Location of Wind Power Development in the United States

Table 3. Top 20 Utility Wind Power Rankings

Total Wind Capacity (end of 2007, MW)		Estimated Percentage of Retail Sales (for utilities with > 50 MW of wind)	
Xcel Energy	2,635	Minnkota Power Cooperative	11.2%
MidAmerican Energy	1,201	Empire District Electric Company	10.2%
Southern California Edison	1,026	Last Mile Electric Cooperative	10.0%
Pacific Gas & Electric	878	Xcel Energy	9.3%
Luminant	704	MSR Public Power Agency	8.4%
American Electric Power	543	Public Service New Mexico	7.5%
CPS Energy	501	Oklahoma Municipal Power Authority	7.2%
Puget Sound Energy	428	CPS Energy	7.1%
Alliant Energy	378	Northwestern Energy	7.0%
Exelon Energy	342	Austin Energy	6.6%
Austin Energy	274	Otter Tail Power	6.4%
Portland General Electric	225	Great River Energy	6.3%
Great River Energy	218	Nebraska Public Power District	6.0%
Last Mile Electric Cooperative	205	Puget Sound Energy	5.2%
Public Service New Mexico	204	Seattle City Light	5.0%
MSR Public Power Agency	200	MidAmerican Energy	4.7%
Reliant Energy	199	Alliant Energy	4.2%
Seattle City Light	175	Western Farmers' Electric Cooperative	3.8%
Oklahoma Gas & Electric	170	Luminant Energy	3.6%
Empire District Electric Company	150	Minnesota Power	3.5%

Source: AWEA, EIA, Berkeley Lab estimates.

Offshore Wind Development Activities

In Europe, two offshore wind projects, totaling 200 MW, were installed in 2007, bringing total worldwide offshore wind capacity to 1,077 MW. In contrast, all wind projects built in the United States to date have been sited on land. Despite the slow pace of offshore activity, there is some interest in offshore wind in several parts of the United States due to the proximity of offshore wind resources to large population centers, advances in technology, and potentially superior capacity factors. The table on the right provides a listing, by state, of "active" offshore project proposals in the United States as of the end of 2007. Note that these projects are in various stages of development, and a number are either very early-stage proposals or reflect projects that are already in jeopardy of cancellation; clearly, considerable subjectivity is required in creating this list of "active" proposals.

State	Proposed Offshore Wind Capacity
Massachusetts	783 MW
Delaware	450 MW
New Jersey	350 MW
New York	160 MW
Texas	150 MW
Ohio	20 MW
Georgia	10 MW
TOTAL	**1,923 MW**

Source: NREL.

Several events in 2007 demonstrate that progress continues with offshore wind in the United States. Specifically, New Jersey issued a solicitation to provide financial incentives for an offshore wind project up to 350 MW in size, Ohio commissioned a study to investigate the feasibility of a 20-MW wind project in Lake Erie, the Texas General Land Office awarded the first four competitively bid leases for offshore wind power in the nation's history, and the municipal utility serving the town of Hull, Massachusetts filed for (and in February 2008, received) initial state approval for four offshore turbines. More recently, Rhode Island has also issued an RFP for offshore wind. Also in 2007, the Draft Environmental Impact Statement for the highly publicized Cape Wind project in Massachusetts reached conclusions favorable to the project, and the U.S. Minerals Management Service made progress in executing its offshore wind regulatory responsibilities.

Notwithstanding these developments, regulatory delays, turbine supply shortages, high and uncertain project costs, and public acceptance concerns have hampered progress in the offshore wind sector. In 2007 alone, for example, concerns about the high costs of offshore wind resulted in the cancellation of a 500-MW Texas project and the likely cancellation of a 150-MW New York facility, and put a 450-MW Delaware project in jeopardy (the latter two projects are included in the table on the right, as they remain at least somewhat "active").

Data from Interconnection Queues Demonstrate that an Enormous Amount of Wind Capacity Is Under Development

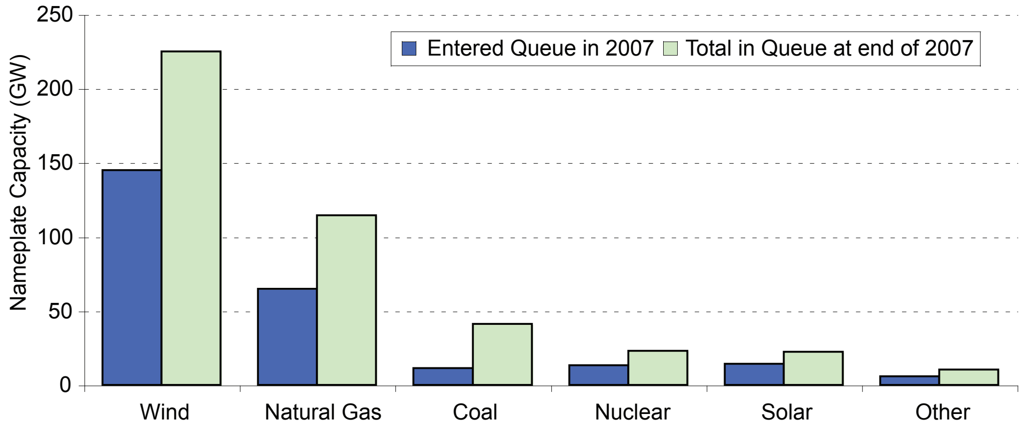
One visible testament to the surging interest in wind is the amount of wind power capacity currently working its way through the major interconnection queues across the country. Figure 6 provides this information, for wind and other resources, aggregated across eleven wind-relevant independent system operators (ISOs), regional transmission organizations (RTOs), and utilities.[8] These data should be interpreted with caution: though placing a project in the interconnection queue is a necessary step in project development, being in the queue does not guarantee that a project will actually be built. In fact, there is a growing recognition that many of the projects currently in interconnection queues are very early in the development process, and that a large number of these projects are unlikely to achieve commercial operations any time soon, if at all.[9]

Even with this important caveat, the amount of wind capacity in the nation's interconnection queues is astounding, and provides some indication of the number and capacity of projects that are in the planning phase. At the end of 2007, there were 225 GW of wind power capacity within the eleven interconnection queues reviewed for this report—more than 13 times the installed wind capacity in the United States at the end of 2007. This wind capacity represents roughly *half* of all generating capacity within these queues at that time, and is *twice as much* capacity as the next-largest resource in these queues (natural gas). Moreover, wind's prominent position is a relatively recent phenomenon: 64% of the total wind capacity in these eleven queues at the end of 2007 first entered the queue in 2007 (for the non-wind projects, in aggregate, the comparable figure is 52%).

Much of this wind capacity is planned for the Midwest, Texas, and PJM regions: wind in the interconnection queues of MISO (66 GW), ERCOT (41 GW), and PJM (35 GW) account for nearly two-thirds of the aggregate 225 GW of wind in all eleven queues. At the other end of the spectrum, the Northeast exhibits the least amount of wind capacity in the pipeline, with the New York ISO (7 GW) and ISO-New England (2 GW) together accounting for about 4% of the aggregate 225 GW. The remaining six queues include SPP (21 GW), California ISO (19 GW), WAPA (10 GW), BPA (10 GW), PacifiCorp (9 GW), and Xcel's Colorado service area (4 GW).

8 The queues surveyed include PJM Interconnection, Midwest Independent System Operator (MISO), New York ISO, ISO-New England, California ISO, Electricity Reliability Council of Texas (ERCOT), Southwest Power Pool (SPP), Western Area Power Administration (WAPA), Bonneville Power Administration (BPA), PacifiCorp, and Xcel Energy (Colorado). To provide a sense of sample size and coverage, roughly 60% of the total installed generating capacity (both wind and non-wind) in the United States is located within these ISOs, RTOs, and utility service territories. Figure 6 only includes projects that were active in the queue at the end of 2007 but that had not yet been built; suspended projects are not included.

9 FERC held a technical conference in November 2007 focusing on the burgeoning interconnection queues and potential reforms.



Source: Exeter Associates review of interconnection queues.

Figure 6. Nameplate Resource Capacity in Eleven Major Interconnection Queues

GE Wind Remained the Dominant Turbine Manufacturer, but a Growing Number of Other Manufacturers Are Capturing Market Share

GE Wind remained the dominant manufacturer of wind turbines supplying the U.S. market in 2007, with 44% of domestic turbine installations (down from 47% in 2006 and 60% in 2005).[10] Vestas (18%) and Siemens (16%) vied for second place in 2007, with Gamesa (11%), Mitsubishi (7%), and Suzlon (4%) playing significant, but lesser, roles (Figure 7).

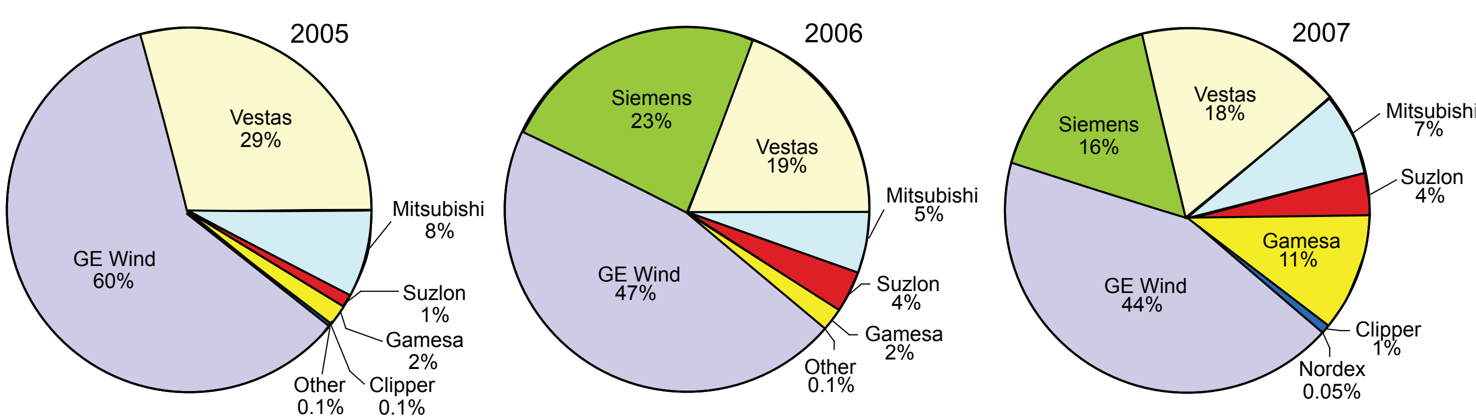
Noteworthy developments in 2007 include the growth in Gamesa's market share, from just 2% in 2005 and 2006 to 11% in 2007, and Siemens' loss of market share after a banner year in 2006. Also significant is that newcomer Clipper installed 48 MW in New York, Illinois, and Iowa in 2007, marking the start of serial production of that firm's 2.5-MW "Liberty" turbine. Nordex also re-entered the U.S. market in 2007, after a several-year hiatus, with 2.5 MW installed in Minnesota. Interestingly, though not reflected in the data shown here, U.S. developer GreenHunter announced in late 2007 an order for 108 1.5-MW Chinese-made turbines from Mingyang Wind Power Technology, for delivery in 2008.

Table 4. Annual Turbine Installations, by Manufacturer

Manufacturer	Turbine Installations (MW)		
	2005	2006	2007
GE Wind	1,433	1,146	2,342
Vestas	700	463	948
Siemens	0	573	863
Gamesa	50	50	574
Mitsubishi	190	128	356
Suzlon	25	92	197
Clipper	2.5	0	47.5
Nordex	0	0	2.5
Other	2	2	0
TOTAL	**2,402**	**2,454**	**5,329**

Source: AWEA project database.

Market share, delineated in percentage terms, can be misleading in rapidly growing markets. As shown in Table 4, every manufacturer active in the U.S. market saw installations of their turbines grow between 2006 and 2007, in many cases dramatically. The most significant growth was experienced by GE (1,196 MW), Gamesa (524 MW), and Vestas (485 MW).



Source: AWEA project database.

Figure 7. Annual U.S. Market Share of Wind Manufacturers by MW, 2005-2007

10 Market share reported here is in MW terms, and is based on project installations—not turbine shipments or orders—in the year in question.

Soaring Demand for Wind Spurs Expansion of U.S. Wind Turbine Manufacturing

The manufacturing of wind turbines and components in the United States remains somewhat limited, in part because of the continued uncertain availability of the federal PTC. As domestic demand for wind turbines continues to surge, however, a growing number of foreign turbine and component manufacturers have begun to localize operations in the United States, and manufacturing by U.S.-based companies is starting to expand.

Figure 8 presents a (non-exhaustive) list of domestic wind turbine and component manufacturing facilities announced or opened in 2007, and identifies the location of those facilities as well as the location of manufacturing facilities that opened prior to 2007. Included in the figure are not only turbine assembly and component manufacturing facilities, but also facilities that meet the needs of other segments of the wind industry's supply chain, such as wind project construction companies, anemometer suppliers, and crane and rigging providers.

Among the list of facilities opened or announced in 2007 are three owned by major international turbine manufacturers: Vestas (blades in Windsor, Colorado), Acciona (turbine assembly in West Branch, Iowa), and Siemens (blades in Fort Madison, Iowa).[11] Vestas is also known to be exploring sites for a U.S. R&D center. These plants are in addition to facilities opened by several other international turbine manufacturers in previous years, including: Gamesa (blades, towers, and nacelle assembly in Ebensburg and Fairless Hills, Pennsylvania), Suzlon (blades and nose cones in Pipestone, Minnesota), and Mitsubishi (gearboxes in Lake Mary, Florida).

Among U.S.-based wind turbine manufacturers, GE remains dominant, and has maintained a significant domestic turbine manufacturing presence, in addition to its international facilities that serve both the U.S. and global markets. GE's wind turbine manufacturing facilities in the United States include Tehachapi, California (turbine manufacturing); Pensacola, Florida (blade technology development, component assembly); Erie, Pennsylvania and Salem, Virginia (components); and Greenville, South Carolina (turbine assembly).

Signaling the emergence of new players in the U.S. wind turbine industry, three other U.S.-based turbine manufacturers continued to scale-up their activities in 2007.

- **Clipper Windpower** is in the process of significant expansion, with 137 of its 2.5-MW Liberty turbines produced in 2007, up from eight in 2006. Clipper expects to produce over 300 turbines in 2008 at its Cedar Rapids, Iowa, manufacturing facility, and cumulative firm turbine orders equaled 825 at the end of January, 2008.
- **CTC/DeWind** commissioned its first 2-MW D8.2 turbine in the United States in March, 2008. CTC acquired DeWind in 2006, and turbine production commenced in December, 2007 at a TECO Westinghouse manufacturing facility in Round Rock, Texas, with an initial capacity of 400 turbines per year and an order backlog of $140 million by the end of January, 2008.
- **Nordic Windpower**, a manufacturer of two-bladed turbines, announced that Goldman Sachs made a significant investment in the company in 2007. Nordic subsequently announced the opening of its North American headquarters in Berkeley, California, and in early 2008 announced the location of a planned manufacturing facility in Pocatello, Idaho.

Figure 8 also shows a considerable number of new component manufacturing facilities announced or opened in 2007, from both

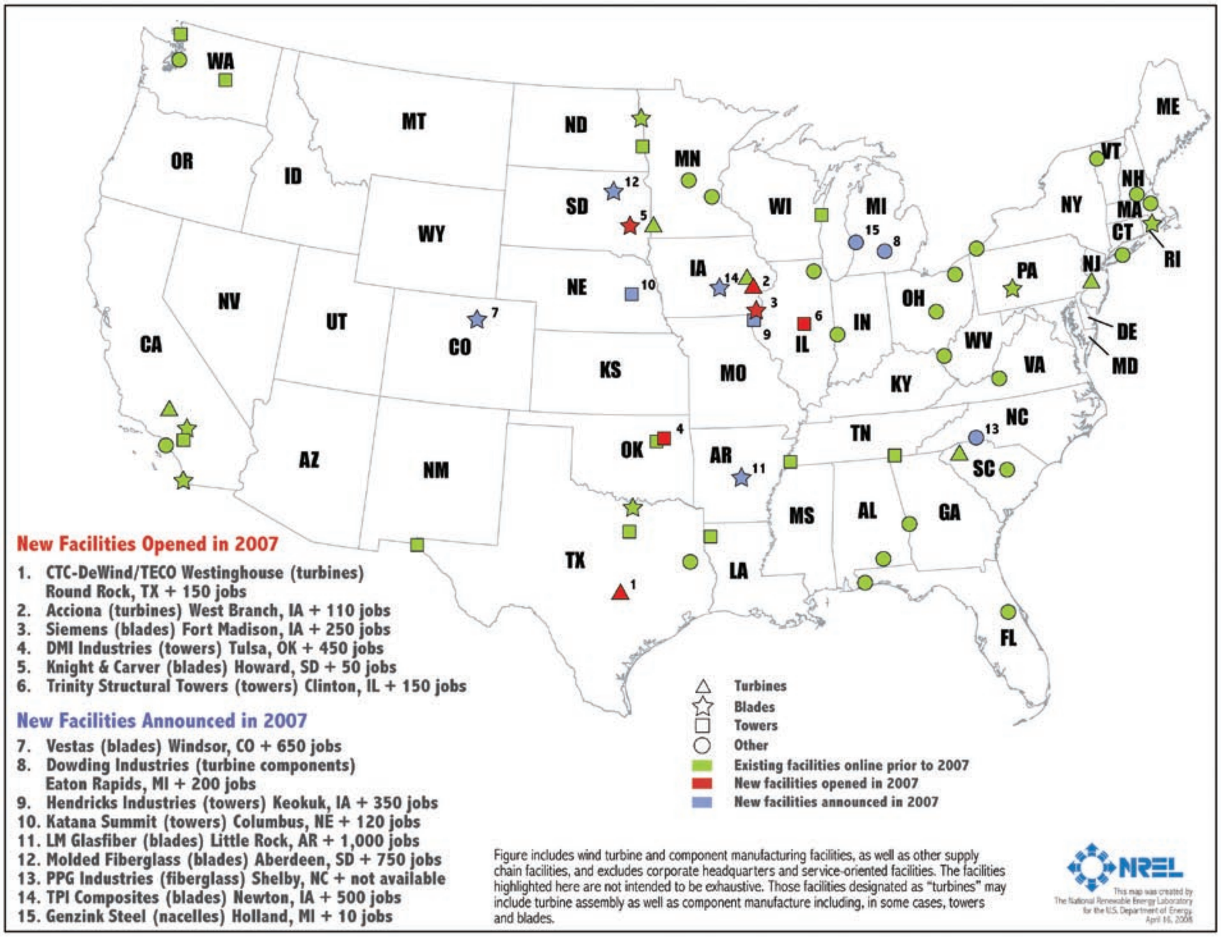


Figure 8. Location of Existing and New Wind Manufacturing Facilities

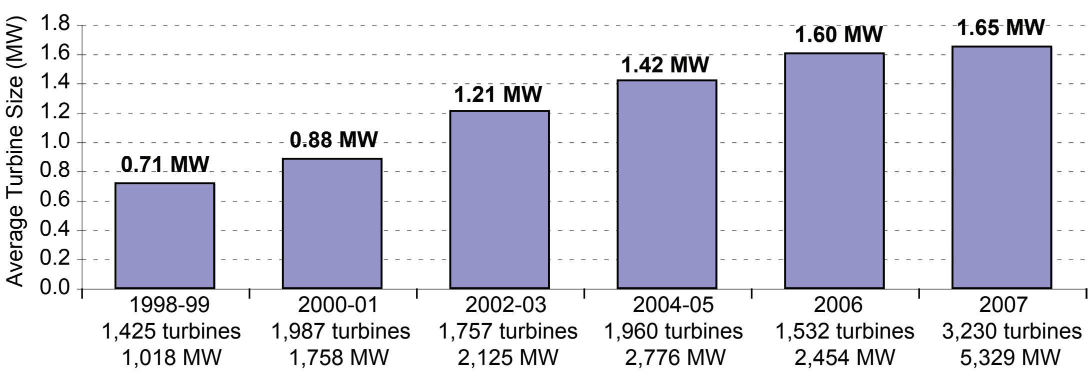
[11] In addition, in 2008, Fuhrlander announced its decision to build a turbine assembly plant in Butte, Montana, with an expected 150 jobs.

foreign and domestic firms. All told, the new turbine and component manufacturing facilities opened or announced in 2007 and listed in Figure 8 will, if fully implemented as planned, create more than 4,700 jobs.

Notwithstanding the generally positive outlook for the turbine manufacturing sector, however, impediments faced by manufacturers due to rapid scale-up are apparent. Clipper Windpower, for example, has had to reinforce some blades, and has experienced problems with some of its drivetrains, slowing shipments in 2007. Blade quality and tower manufacturing problems also surfaced at Gamesa's Pennsylvania manufacturing facilities in 2007 and early 2008; Suzlon has also recently faced blade problems. Turbine manufacturing by CTC/DeWind, meanwhile, has faced some delay, at least relative to that company's initial expectations.

Average Turbine Size Continued to Grow, Albeit at a Slower Pace

The average size of wind turbines installed in the United States in 2007 increased to roughly 1.65 MW (Figure 9), from 1.60 MW in 2006. Since 1998-99, average turbine size has increased by 130%.[12]



Source: AWEA project database.

Figure 9. Average Turbine Size Installed During Period

Table 5. Size Distribution of Number of Turbines Over Time

Turbine Size Range	1998-99	2000-01	2002-03	2004-05	2006	2007
	1,018 MW	1,758 MW	2,125 MW	2,776 MW	2,454 MW	5,329 MW
	1,425 turbines	1,987 turbines	1,757 turbines	1,960 turbines	1,532 turbines	3,230 turbines
0.05-0.5 MW	1.3%	0.4%	0.5%	1.8%	0.7%	0.0%
0.51-1.0 MW	98.5%	73.9%	43.4%	18.5%	10.7%	11.0%
1.01-1.5 MW	0.0%	25.4%	43.5%	56.0%	54.2%	48.6%
1.51-2.0 MW	0.3%	0.4%	12.5%	23.6%	17.6%	24.1%
2.01-2.5 MW	0.0%	0.0%	0.0%	0.1%	16.3%	15.0%
2.51-3.0 MW	0.0%	0.0%	0.1%	0.0%	0.5%	1.3%

Source: AWEA project database.

Table 5 shows how the distribution of turbine size has shifted over time; 40% of all turbines installed in 2007 had a nameplate capacity in excess of 1.5 MW, compared to 34% in 2006, 24% in 2004-2005, and 13% in 2002-2003. GE's 1.5-MW wind turbine remained by far the nation's most-popular turbine in 2007, with more than 1,500 units installed.

The Average Size of Wind Projects Expanded Significantly

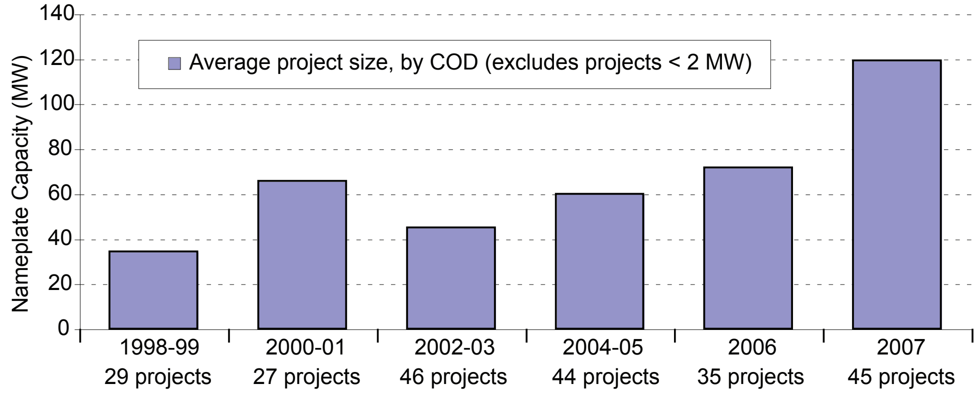
As the U.S. wind industry has matured and installations have increased, so too has the average size of installed wind projects. Projects installed in 2007 averaged nearly 120 MW, roughly double that seen in the 2004-05 period and nearly quadruple that seen in the 1998-99 period.[13]

This marked increase in average project size may reflect a number of interrelated trends highlighted elsewhere in this report: growing demand for wind driven by economics and policy; the upward march in turbine size; the large turbine orders that have become standard practice; consolidation among wind project developers to support these orders; and increasing turbine and project costs, which may require taking full advantage of any and all economies of scale. Whatever the specific cause, larger project sizes reflect an increasingly mature energy source that is beginning to penetrate into the domestic electricity market in a significant way.

Taking this trend towards larger project size to a new level, several gigawatt-scale projects were announced in 2007. In Texas, Shell WindEnergy and Luminant are jointly planning a 3,000-MW wind project, while oilman T. Boone Pickens announced plans for a project of up to 4,000 MW. While these projects should be considered speculative at this early stage, a 1,500-MW wind project being developed by Allco and Oak Creek Energy Systems in Tehachapi, California, has already secured a power purchase agreement with Southern California Edison.

12 Except for 2006 and 2007, Figure 9 (as well as a number of the other figures and tables included in this report) combines data into two-year periods in order to avoid distortions related to small sample size in the PTC lapse years of 2000, 2002, and 2004. Though not a PTC lapse year, 1998 sample size is also small, and is therefore combined with 1999.

13 Projects less than 2 MW in size are excluded from Figure 10 so that a large number of single-turbine "projects" (that, in practice, may have been developed as part of a larger, aggregated project) do not end up skewing the average. For projects defined in phases, each phase is considered to be a separate project. Projects that are partially constructed in two different years are counted as coming online in the year in which a clear majority of the capacity was completed. If roughly equal amounts of capacity are built in each year, then the full project is counted as coming online in the later year.



Source: Berkeley Lab analysis of AWEA project database.

Figure 10. Average Project Size, by Commercial Operation Date (COD)

Developer Consolidation Continued at a Torrid Pace

Consolidation on the development end of the wind business continued the strong trend that began in 2005, and has been motivated, in part, by the increased globalization of the wind sector and the need for capital to manage wind turbine supply constraints. Table 6 provides a listing of major acquisition and investment activity among U.S. wind developers in the 2002 through 2007 timeframe.[14]

As shown, at least 11 significant transactions involving roughly 37,000 MW of in-development wind projects (also called the development "pipeline") were announced in 2007, consistent with 2006 acquisition and investment activity of 12 transactions with a total 34,000 MW in the pipeline. In 2005, eight transactions totaling nearly 12,000 MW were announced, while only four transactions totaling less than 4,000 MW were completed from 2002 through 2004.

A number of large companies have entered the U.S. wind development business in recent years, some through acquisitions, and others through their own development activity or through joint development agreements with others. Particularly striking in recent years has been the entrance of large European energy companies into the U.S. market. The two largest developer acquisitions in 2007, for example, were the purchase of Horizon Wind by Energias de Portugal (from Portugal) and the acquisition of Airtricity North America by E.ON AG (from Germany), summing to nearly $4 billion in aggregate.

Table 6. Acquisition and Investment Activity Among Wind Developers*

Investor	Transaction Type	Developer	Announced
EDF (SIIF Energies)	Acquisition	enXco	May-02
Gamesa	Investment	Navitas	Oct-02
AES	Investment	US Wind Force	Sep-04
PPM (Scottish Power)	Acquisition	Atlantic Renewable Energy Corp.	Dec-04
AES	Acquisition	SeaWest	Jan-05
Goldman Sachs	Acquisition	Zilkha (Horizon)	Mar-05
JP Morgan Partners	Investment	Noble Power	Mar-05
Arclight Capital	Investment	CPV Wind	Jul-05
Diamond Castle	Acquisition	Catamount	Oct-05
Pacific Hydro	Investment	Western Wind Energy	Oct-05
EIF U.S. Power Fund II	Investment	Tierra Energy, LLC	Dec-05
Airtricity	Acquisition	Renewable Generation Inc.	Dec-05
Babcock & Brown	Acquisition	G3 Energy LLC	Jan-06
Iberdrola	Acquisition	Community Energy Inc.	Apr-06
Shaw/Madison Dearborn	Investment	UPC Wind	May-06
NRG	Acquisition	Padoma	Jun-06
CPV Wind	Acquisition	Disgen	Jul-06
BP	Investment	Clipper	Jul-06
BP	Acquisition	Greenlight	Aug-06
Babcock & Brown	Acquisition	Superior	Aug-06
Enel	Investment	TradeWind	Sep-06
Iberdrola	Acquisition	Midwest Renewable Energy Corp.	Oct-06
Iberdrola	Acquisition	PPM (Scottish Power)	Dec-06
BP	Acquisition	Orion Energy	Dec-06
Naturener	Acquisition	Great Plains Wind & Energy, LLC	Feb-07
HSH Nordbank	Investment	Ridgeline Energy	Feb-07
Energias de Portugal	Acquisition	Horizon	Mar-07
Iberdrola	Acquisition	CPV Wind	Apr-07
Duke Energy	Acquisition	Tierra Energy, LLC	May-07
Acciona	Acquisition	EcoEnergy, LLC	Jun-07
Babcock & Brown	Acquisition	Bluewater Wind	Sep-07
Good Energies	Investment	EverPower	Sep-07
E.ON AG	Acquisition	Airtricity North America	Oct-07
Wind Energy America	Acquisition	Boreal	Oct-07
Marubeni	Investment	Oak Creek Energy Systems	Dec-07

* Select list of announced transactions; excludes joint development activity.
Source: Berkeley Lab.

14 Only transactions that are known to involve 500 MW or more of in-development wind projects are included.

Comfort With and Use of Innovative Financing Structures Increased

A variety of innovative financing structures have been developed by the U.S. wind industry in recent years to allow projects to fully access federal tax incentives. The two most common structures at the present time are corporate balance-sheet finance (e.g., historically used by FPL Energy) and the "institutional investor flip" structure involving institutional "tax equity" investors.[15] With the record-shattering amount of new wind capacity installed in 2007 and the growing presence of foreign developers and owners with little appetite for U.S. tax incentives,[16] the need to attract institutional tax equity to the U.S. wind sector has never been greater. The past year has brought both good and bad news on this front.

The wind industry received welcome news in October 2007, when the IRS issued "safe harbor" guidelines (i.e., Revenue Procedure 2007-65) for wind projects utilizing special-allocation partnership flip structures. Although various permutations of these types of structures have been used for a number of years to monetize the tax benefits provided to wind projects, tax equity investors have had to absorb the risk that these deals would be challenged by the IRS. Revenue Procedure 2007-65 effectively removed this structural tax risk for projects that adhere to the prescribed investment and allocation limits, and has, through numerical example, legitimized the institutional investor flip structure.[17]

Comfort with this structure has grown to the point where even FPL Energy—which has financed the largest fleet of wind projects in the United States primarily on its balance sheet—conducted its first ever project refinancing using third-party tax equity in late 2007. While this event sparked rumors that the U.S. wind giant was running out of tax credit appetite, FPL's own explanation is more benign: the institutional investor flip structure allows FPL to focus on its core strengths—developing and operating wind projects—while capitalizing on the relatively lower cost of institutional tax equity (pre-flip) and retaining long-term upside potential (post-flip).

The year 2007 also saw the closing of a first-of-its-kind tax equity structure suitable for municipalities and cooperatives interested in long-term wind project ownership. The 205-MW White Creek Wind project was developed by four publicly owned, tax-exempt utilities in the Pacific Northwest, in cooperation with several institutional tax investors. By serving as power purchasers and pre-paying (up-front) for the minimum projected electricity output of the project over its initial 20 years of project operations, these four publicly owned utilities effectively enabled the project to take advantage of low-cost tax-exempt debt (used to finance the pre-payments) as well as the traditional tax benefits afforded to wind projects (available to the institutional tax investors). A post-flip buyout option allows for long-term ownership by the publicly owned utilities.

Although institutional tax investors were plentiful in 2007, with more than a dozen active in the market,[18] the growing dependence on such third-party investors has left the U.S. wind sector vulnerable to the broader credit crisis that began in earnest towards the end of 2007. As a result of the large losses incurred by the banking industry, institutional tax investors have less taxable income to shelter. This shortage is already being felt in the affordable housing sector—one of the wind sector's main competitors for tax equity—where the yields on affordable housing credits have been driven sharply higher by lack of demand.

It remains to be seen whether lackluster tax investor demand will spill over into the wind sector, but at the very least it seems unlikely that the cost of tax equity provided to wind projects will continue to fall in 2008. This is particularly notable because the sizable decline in the cost of tax equity over the past four or five years has partially offset (by roughly 45%, according to Berkeley Lab analysis) the impact of rising turbine and installed project costs on wind power prices. To the extent that the cost of tax equity has bottomed out or begins to rise, any further project cost increases will be felt more immediately and severely in wind power prices.

Finally, project-level debt staged a comeback of sorts in 2007, with a number of projects announcing the use of term (as opposed to just construction) debt, even alongside institutional tax equity (this combination of term debt and tax equity has heretofore been quite rare), and in some cases, in quasi-merchant wind projects. One such deal involved three projects in New York State (scheduled for completion in 2008), aggregated into a single debt facility by the project sponsor. Other deals have featured increasingly aggressive terms, with debt providers willing to extend maturities 5 years or more into a project's "merchant tail" (i.e., the period beyond which the project's power sales have been contracted), and at least one deal featuring a 20-year loan term (including a 5-year merchant tail).

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15 For more information on these and other structures, see *Wind Project Financing Structures: A Review & Comparative Analysis*, downloadable from http://eetd.lbl.gov/ea/ems/reports/63434.pdf.

16 In a telling move, Spanish wind giant Iberdrola announced in June 2007 that it intended to buy Energy East—an investor-owned utility holding company in the Northeastern United States—in part to generate U.S. income tax liability that would better enable it to use the production tax credits and depreciation deductions generated by its U.S. wind project investments.

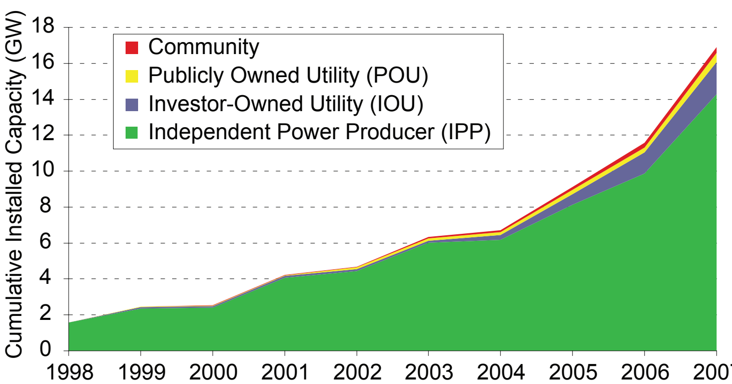
17 In contrast to its favorable implications for the institutional investor flip structure, Revenue Procedure 2007-65 is less-favorable to the pay-as-you-go (PAYGO) structure, under which the tax investor injects equity into the project over time, but only as PTCs are generated. Specifically, the Revenue Procedure limits the amount of PTC-contingent equity to 25% of the total anticipated tax equity (prior to the Revenue Procedure, the general assumption was that up to 50% of the tax equity could be PTC-contingent).

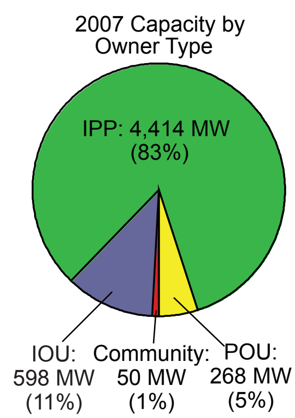
18 Institutional tax investors active in the wind market include GE Financial Services, JP Morgan Capital, Morgan Stanley, Lehman Brothers, Fortis Capital, Wachovia, Wells Fargo, Union Bank of California, Prudential Capital, Northwestern Mutual, New York Life, Babcock & Brown, Meridian Clean Fuels, and AEGON USA Realty Advisors.

IPP Project Ownership Remained Dominant, but Utility Interest in Ownership Continued, While Community Wind Faltered

Private independent power producers (IPPs) continued to dominate the wind industry in 2007, owning 83% of all new capacity (Figure 11). In a continuation of the trend begun several years ago, however, 16% of total wind additions in 2007 are owned by local electrical utilities, split between investor-owned utilities (IOUs) and publicly owned utilities (POUs) roughly two-to-one.[19] Community wind power projects—defined here as projects using turbines over 50 kW in size and completely or partly owned by towns, schools, commercial customers, or farmers, but excluding publicly owned utilities—constitute the remaining 1% of 2007 projects.

Of the cumulative 16,904 MW of installed wind capacity at the end of 2007, IPPs owned 84% (14,280 MW), with utilities contributing 14% (1,790 MW for IOUs and 526 MW for POUs), and community ownership just 2% (308 MW). The community wind sector, in particular, has found it difficult to make much headway in the last couple of years, in part due to the difficulty of securing smaller turbine orders amidst the current turbine shortage. That said, state policies specifically targeting community wind and USDA Section 9006 grants may help boost the community wind numbers in future years.





Source: Berkeley Lab estimates based on AWEA project database.

Figure 11. Cumulative and 2007 Wind Capacity Categorized by Owner Type

Though Long-Term Contracted Sales to Utilities Remained the Most Common Off-Take Arrangement, Merchant Plants and Sales to Power Marketers Are Becoming More Prevalent

Investor-owned utilities continued to be the dominant purchasers of wind power, with 48% of new 2007 capacity and 55% of cumulative capacity selling power to IOUs under long-term contracts (see Figure 12). Publicly owned utilities have also taken an active role, purchasing the output of 17% of new 2007 capacity and 15% of cumulative capacity. For both IOUs and POUs, power purchase agreement (PPA) terms for projects built in 2007 range from 15 to 25 years, with 20 years being the most common.

The role of power marketers—defined here as corporate intermediaries that purchase power under contract and then re-sell that power to others, sometimes taking some merchant risk[20]– in the wind power market has increased dramatically since 2000, when such entities first entered the wind sector. In 2007, power marketers purchased the output of 20% of new wind power capacity and 17% of cumulative capacity. Among projects built in 2007, PPAs with power marketers range from 5 to 23 years in length, somewhat shorter than the range of utility PPAs.

Increasingly, owners of wind projects are taking on some merchant risk, meaning that a portion of their electricity sales revenue is tied to short-term contracted and/or spot market prices (with the resulting price risk commonly hedged over a 5- to 10-year period via financial transactions rather than through PPAs[21]). The owners of 15% of the wind power capacity added in 2007, for example, are accepting some merchant risk, bringing merchant/quasi-merchant ownership to 12% of total cumulative U.S. wind capacity. The majority of this activity exists in Texas and New York—both states in which wholesale spot

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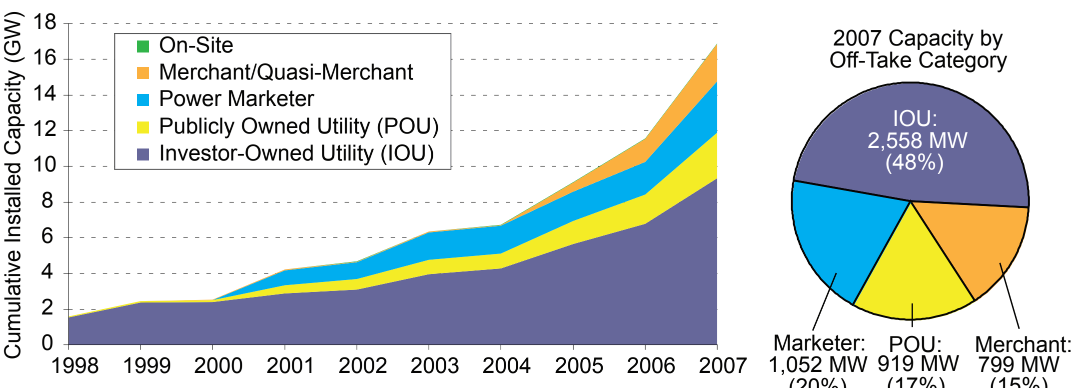
19 Compared to the recent past, the growth in publicly owned utility ownership in 2007 is striking. This growth is, arguably, inflated by the categorization of the 205-MW White Creek Wind project as a POU-owned project. Although the four POUs involved with the White Creek project do not technically own any part of the project unless and until they exercise their purchase option (after the project's tenth year), by pre-paying for a substantial portion of the project's power, these utilities have nevertheless contributed roughly half of the capital required to build the project. This, plus the fact that the financing structure is specifically designed to result in long-term POU ownership (through the buyout option), favors the categorization of this project as POU-owned.

20 Power marketers are defined here to include not only traditional marketers such as PPM Energy, but also the wholesale power marketing affiliates of large investor-owned utilities (e.g., PPL Energy Plus or FirstEnergy Solutions), which may buy wind power on behalf of their load-serving affiliates.

21 Hedge providers active in the market in 2007 include Fortis, Credit Suisse, Barclay's, J. Aron & Company, and Coral Energy Holding (a division of Shell). These hedges are often structured as a "fixed-for-floating" power price swap—a purely financial arrangement whereby the wind project swaps the "floating" revenue stream that it earns from spot power sales for a "fixed" revenue stream based on an agreed-upon strike price. For at least one project in Texas (where natural gas is virtually always the marginal supply unit), the hedge has been structured in the natural gas market rather than the power market, in order to take advantage of the greater liquidity and longer terms available in the forward gas market.



Source: Berkeley Lab estimates based on AWEA project database.

Figure 12. Cumulative and 2007 Wind Capacity Categorized by Power Off-Take Arrangement

markets exist, where wind power may be able to compete with these spot prices, and where additional revenue is possible from the sale of renewable energy certificates (RECs).

Another interesting development in 2007 was the initiation of cross-border sales of wind electricity into the United States, despite the fact that those facilities are not eligible for U.S. tax incentives. A portion of the West Cape wind project, located in Price Edward Island (New Brunswick), began exporting power and renewable energy certificates (RECs) to New England in mid-2007. Later that year, Hydro-Quebec received permission to sell into New England from two of its wind facilities. Finally, San Diego Gas & Electric announced a 20-year contract with the proposed 250-MW La Rumorosa wind project in Baja, Mexico.

Upward Pressure on Wind Power Prices Continued in 2007

Although the wind industry appears to be on solid footing, the weakness of the dollar, rising materials costs, a concerted movement towards increased manufacturer profitability, and a shortage of components and turbines continued to put upward pressure on wind turbine costs, and therefore wind power prices, in 2007.

Berkeley Lab maintains a database of wind power sales prices, which currently contains price data for 128 projects installed between 1998 and the end of 2007. These wind projects total 8,303 MW, or 55% of the wind capacity brought on line in the United States over the 1998-2007 period. The prices in this database reflect the price of electricity as sold by the project owner, and might typically be considered busbar energy prices.[22] The prices are suppressed by the receipt of any available state and federal incentives (e.g., the PTC), as well as by the value that might be received through the separate sale of renewable energy certificates (see *REC Markets Remain Fragmented and Prices Volatile*, page 18).[23] The prices reported here would therefore be higher if wind projects did not have access to these state and federal incentives and, as a result, these prices do not represent wind energy generation costs.

Based on this database, the capacity-weighted average power sales price from the sample of post-1997 wind projects remains low by historical standards. Figure 13 shows the cumulative capacity-weighted average wind power price (plus or minus one standard deviation around that price) in each calendar year from 1999 through 2007. Based on the limited sample of seven projects built in 1998 or 1999 and totaling 450 MW, the weighted-average price of wind in 1999 was nearly $63/MWh (expressed in 2007 dollars). By 2007, in contrast, the cumulative sample of projects built from 1998 through 2007 had grown to 128 projects totaling 8,303 MW, with an average price of just under $40/MWh (with the one standard deviation range extending from $24/MWh to $55/MWh).[24] Although Figure 13 does show a modest increase in the weighted-average wind power price in 2006 and 2007, reflecting rising prices from new projects, the cumulative nature of the graphic mutes the degree of increase.

To better illustrate changes in the price of power from newly built wind projects, Figure 14 shows average wind power sales prices in 2007, grouped by each project's initial commercial operation date (COD).[25] Although the limited project sample and the considerable variability in price across projects installed in a given time period complicate analysis of national price trends (with averages subject to regional and other factors), the general trend exhibited by the capacity-weighted-average prices (i.e., the blue columns) nevertheless suggests that, following a general decline since 1998, prices bottomed out for projects built in 2002 and 2003, and have since risen significantly.[26] Given the year-on-year increase in project-level installed costs from 2006 to 2007 (see a later section of this report), however, it comes as some surprise that prices from projects installed in 2007 were, on average, somewhat lower than from projects installed in 2006.

22 These prices will typically include interconnection costs and, in some cases, transmission expansion costs that are needed to ensure delivery of the energy to the purchaser.

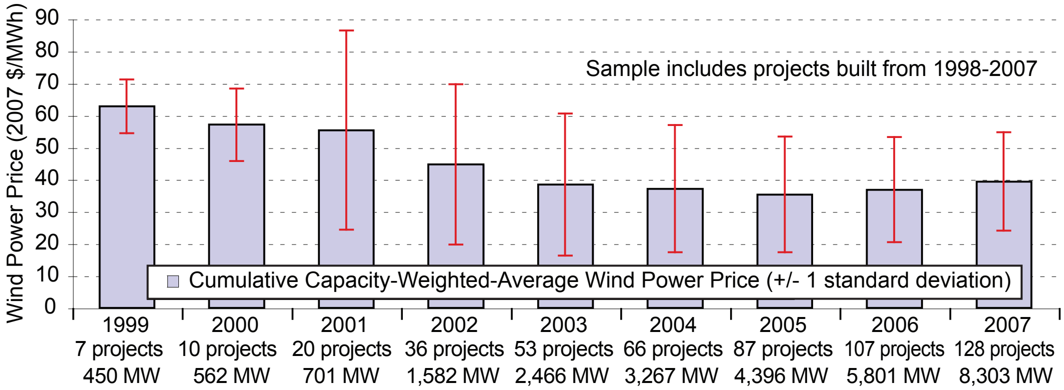
23 For most of the wind power sales prices reported here, the wind generator is selling electricity and RECs in a bundled fashion, and the price reported here therefore reflects the delivery of that bundled product. For at least 10 of the 128 projects in the sample, however, the wind project appears to receive additional revenue (beyond the power price reported) from the separate sale of RECs. The prices provided in this report do not include this separate REC revenue stream, and therefore understate total sales revenue for these projects. Because a minority of projects (10 out of 128) fall in this category, however, this factor is unlikely to significantly bias the overall results presented in this report.

24 All wind power pricing data presented in this report exclude the few projects located in Hawaii. Such projects are considered outliers in that they are significantly more expensive to build than projects in the continental United States, and receive a power sales price that is significantly higher than normal, in part because it is linked to the price of oil. For example, the three major wind projects located in Hawaii (totaling 62 MW) earned revenue in 2007 that ranged from $112/MWh to $177/MWh on average, which is considerably higher than the price received by most wind projects built on the mainland.

25 Prices from two individual projects built during the 2000-2001 period are not shown in Figure 14 (due to the scale of the y-axis), but are included in the capacity-weighted average for that period. The omitted prices are roughly $91/MWh and $150/MWh.

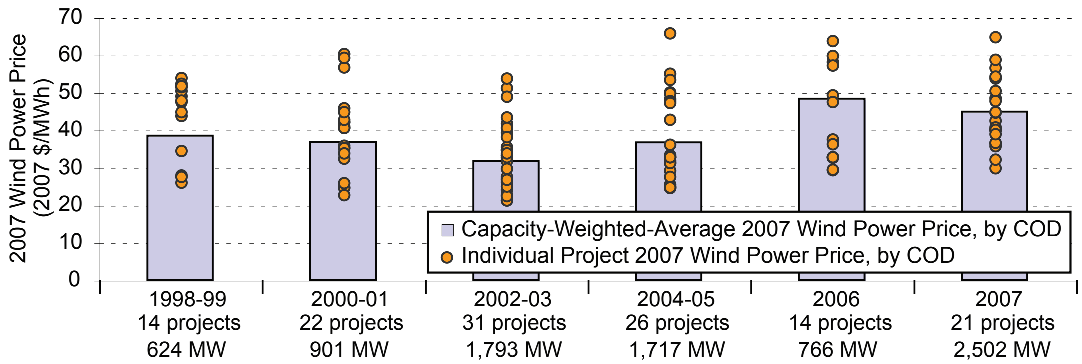
Specifically, the capacity-weighted average 2007 sales price for projects in the sample built in 2007 was roughly \$45/MWh (with a range of \$30 to \$65/MWh).[27] Although this price is (somewhat surprisingly) slightly less than the average of \$48/MWh for the sample of projects built in 2006, it is still higher than the average price of \$37/MWh for the sample of projects built in 2004 and 2005, as well as the \$32/MWh for the sample of projects built in 2002 and 2003. Moreover, because ongoing turbine price increases are not fully reflected in 2007 wind project prices—many of these projects had locked in turbine prices and/or negotiated power purchase agreements as much as 18 to 24 months earlier—prices from projects being built in 2008 and beyond may be higher still.

The underlying variability in the price sample is caused in part by regional factors, which may affect not only project capacity factor (depending on the strength of the wind resource in a given region), but also development and installation costs (depending on a region's physical geography, population density, or even regulatory processes).[28] Figure 15 shows individual project and average 2007 wind power prices by region for just those wind projects installed in 2006 and 2007 (a period of time in which pricing was reasonably consistent), with regions as defined in Figure 16. Although sample size is extremely problematic in numerous regions,[29] Texas and the Heartland region appear to be among the lowest cost on average, while the East, California, and New England are among the higher cost areas.



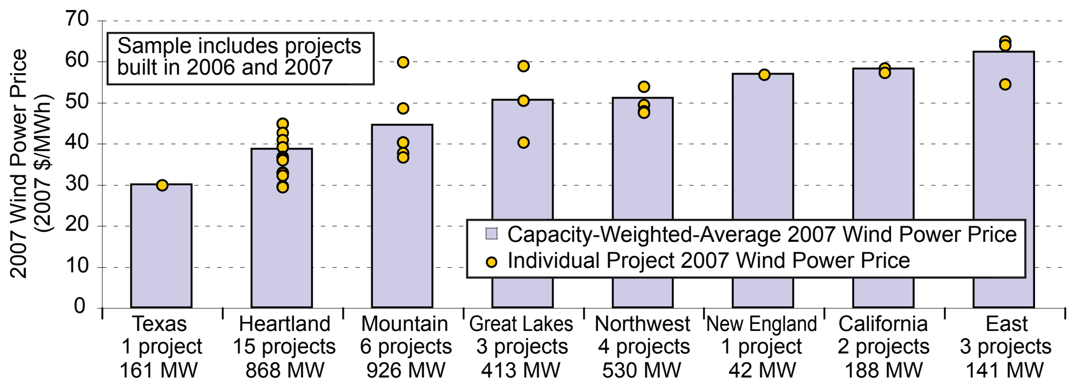
Source: Berkeley Lab database.

Figure 13. Cumulative Capacity-Weighted-Average Wind Power Prices Over Time



Source: Berkeley Lab database.

Figure 14. 2007 Wind Power Prices by Commercial Operation Date (COD)



Source: Berkeley Lab database.

Figure 15. 2007 Wind Power Prices by Region: 2006-2007 Projects Only

26 Although it may seem counterintuitive, the weighted-average price in 1999 for projects built in 1998 and 1999 (shown in Figure 13 to be about \$63/MWh) is significantly higher than the weighted-average price in 2007 for projects built in 1998 and 1999 (shown in Figure 14 to be \$39/MWh) for three reasons: (1) the sample size is larger in Figure 14, due to the fact that 2007 prices are presented, rather than 1999 prices as in Figure 13 (i.e., we were unable to obtain early-year pricing for some of the projects built in 1998-1999); (2) two of the larger projects built in 1998 and 1999 (for which both 1999 and 2007 prices are available, meaning that these projects are represented within both figures) have nominal PPA prices that actually *decline*, rather than remaining flat or escalating, over time; and (3) inflating all prices to constant 2007 dollar terms impacts older (i.e., 1999) prices more than it does more recent (i.e., 2007) prices.

27 If the federal PTC was not available, wind power prices for 2007 projects would range from approximately \$50/MWh to \$85/MWh, with an average of roughly \$65/MWh.

28 It is also possible that regions with higher wholesale power prices will, in general, yield higher wind contract prices due to arbitrage opportunities on the wholesale market.

29 It may be surprising to some that relatively little pricing data are available for Texas, despite the enormous growth in wind capacity in that state. The reason is simple: because ERCOT is not electrically connected to the remainder of the U.S. grid, generators located within ERCOT are not required to file pricing information with FERC. The pricing information for Texas provided in this report comes primarily from projects located in the Texas panhandle, which is covered by the Southwest Power Pool rather than ERCOT.

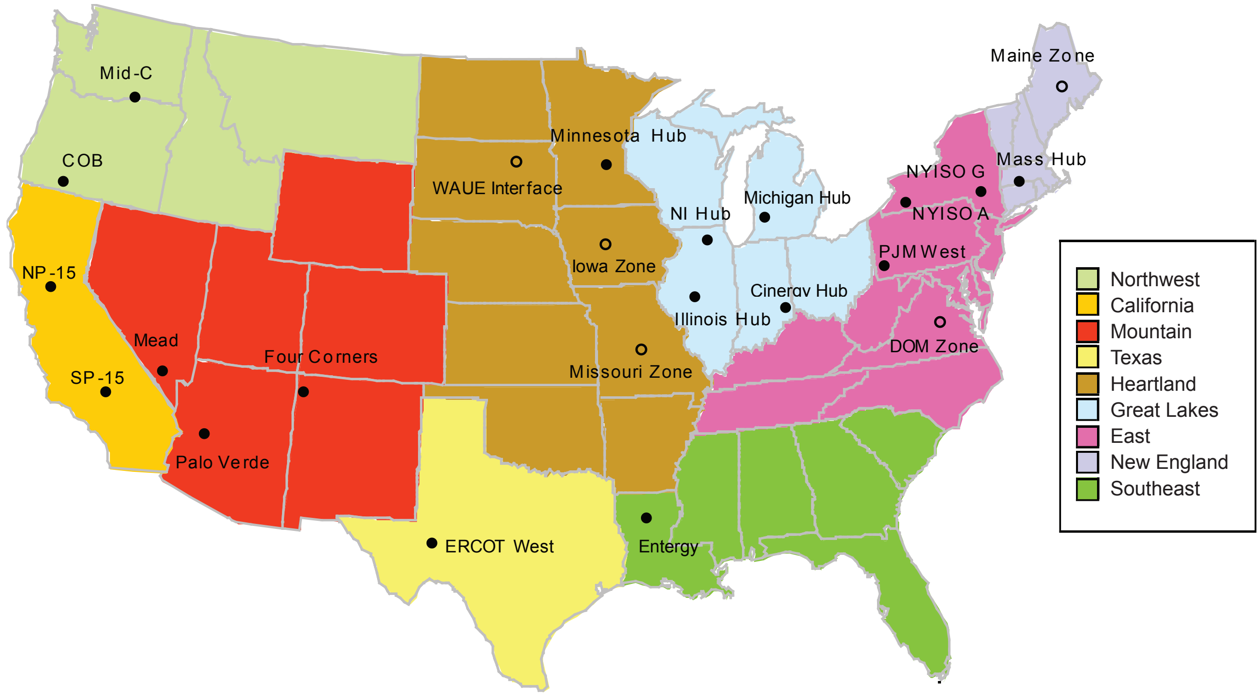


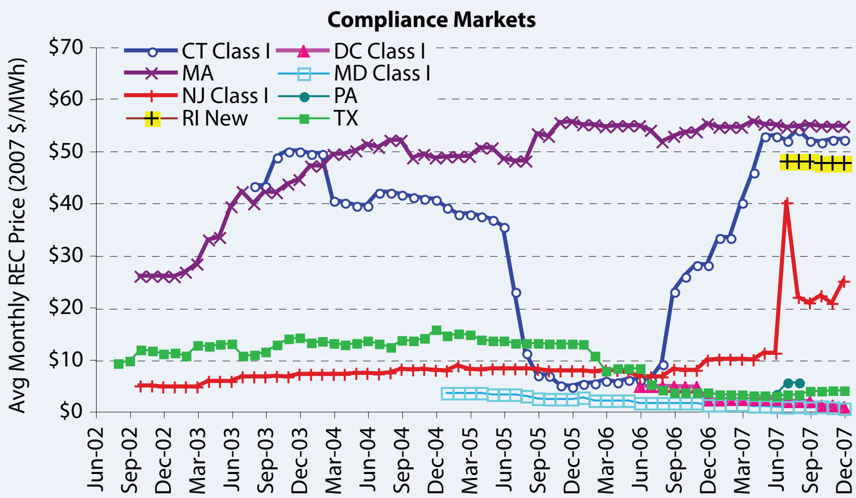
Figure 16. Map of Regions and Wholesale Price Hubs Used in Analysis

REC Markets Remain Fragmented and Prices Volatile

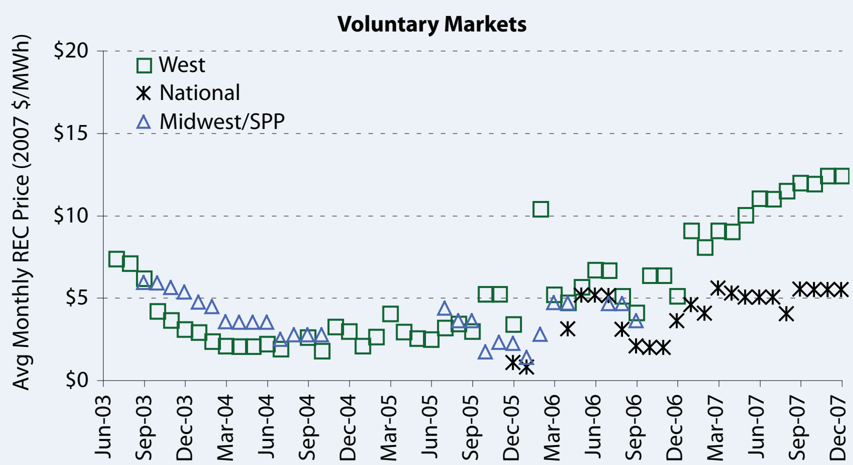
Most of the wind power transactions identified in Figures 13 through 15 reflect the bundled sale of both electricity and RECs, but for at least 10 of these projects, RECs may be sold separately to earn additional revenue. REC markets are highly fragmented in the United States, but consist of two distinct segments: compliance markets in which RECs are purchased to meet state RPS obligations, and green power markets in which RECs are purchased on a voluntary basis.

The year 2007 saw the completion of two new regional electronic REC tracking systems: the Western Renewable Energy Generation Information System (WREGIS) and the Midwest Renewable Energy Tracking System (MRETS). As such, electronic REC tracking systems are now widespread, with operational systems in New England, the PJM Interconnection, Texas, the Western Electricity Coordinating Council, and the upper Midwest, and another system under development in New York.

The figures to the right present indicative monthly data on spot-market REC prices in both compliance and voluntary markets; data for compliance markets focus on the "Class I" or "Main Tier" of the RPS policies. Clearly, spot REC prices have varied substantially, both among states and over time within individual states. Key trends in 2007 compliance markets include continued high prices to serve the Massachusetts RPS, dramatically increasing prices under the Connecticut RPS, high initial prices to serve the Rhode Island RPS, and a large spike in the price for Class I certificates under the New Jersey RPS. Prices remained relatively low in Texas, Maryland, Pennsylvania, and Washington D.C. due to a surplus of eligible renewable energy supply relative to RPS-driven demand in those markets. Despite low REC prices in Texas, the combination of high wholesale power prices and the possibility of additional REC revenue increased merchant wind activity in that state in 2007. RECs offered in voluntary markets ranged from less than $5/MWh to more than $10/MWh in 2007, with strong upward movement in Western REC prices.



Source: Evolution Markets.



Source: Evolution Markets.

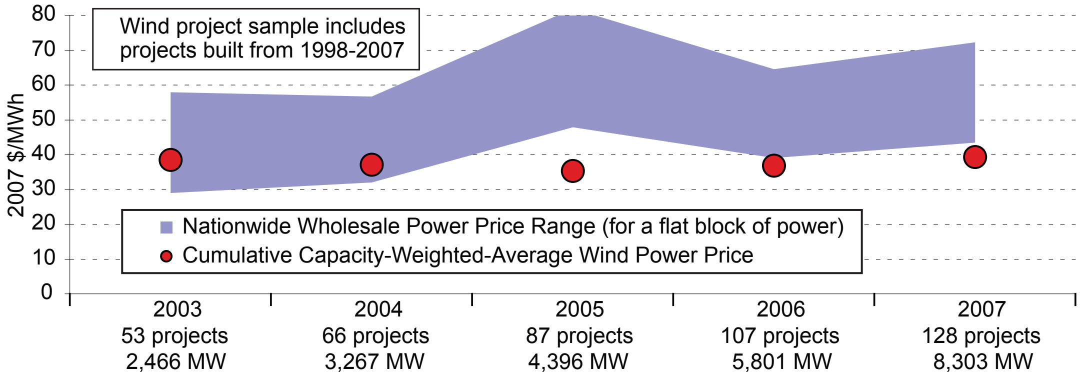
Wind Remained Competitive in Wholesale Power Markets

A simple comparison of the wind prices presented in the previous section to recent wholesale power prices throughout the United States demonstrates that wind power prices have been competitive with wholesale power market prices over the past few years. Figure 17 shows the range (minimum and maximum) of average annual wholesale power prices for a flat block of power[30] going back to 2003 at twenty-three different pricing nodes located throughout the country (refer to Figure 16 for the names and approximate locations of the twenty-three pricing nodes represented by the blue-shaded area[31]). The red dots show the cumulative capacity-weighted-average price received by wind projects in each year among those projects in the sample with commercial operation dates of 1998 through 2007 (consistent with the data first presented in Figure 13). At least on a cumulative basis within the sample of projects reported here, average wind power prices have consistently been at or below the low end of the wholesale power price range.

Though Figure 17 shows that—on average—wind projects installed from 1998 through 2007 have, since 2003 at least, been priced at or below the low end of the wholesale power price range on a nationwide basis, there are clearly regional differences in wholesale power prices and in the average price of wind power. These variations are reflected in Figure 18, which focuses on 2007 wind and wholesale power prices in the same regions as shown earlier, based on the entire sample of wind projects installed from 1998 through 2007.[32] Although there is quite a bit of variability within some regions, in most regions the average wind power price was below the range of average wholesale prices in 2007.

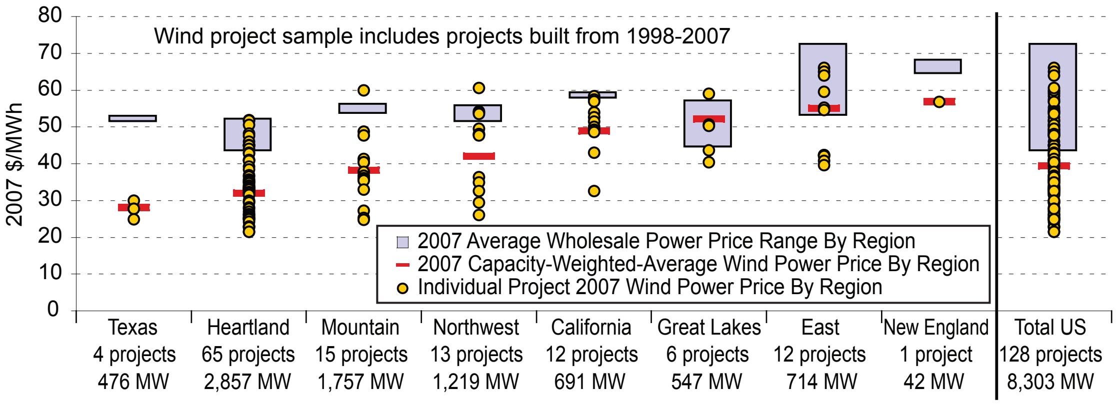
To try to control for the fact that wind power prices have risen in recent years, Figure 19 focuses just on those projects in the sample that were built in 2006 and 2007 (as opposed to 1998 through 2007). At this level of granularity, sample size is clearly an issue in most regions. Nevertheless, while there is greater convergence between wind and wholesale prices in this instance, power prices from wind projects built in 2006 and 2007 still appear, for the most part, to be either within or below the range of 2007 wholesale power prices. Rising wholesale power prices since earlier in the decade have, to a degree, mitigated the impact of rising wind power prices on wind's competitive position.

Notwithstanding the comparisons made in Figures 17-19, it should be recognized that neither the wind nor wholesale power prices presented in this section reflect the full social costs of power generation and delivery. Specifically, the wind power prices are suppressed by virtue of federal and, in some cases, state tax and financial incentives (a few



Source: FERC 2006 and 2004 "State of the Market" reports, Berkeley Lab database, Ventyx.

Figure 17. Average Cumulative Wind and Wholesale Power Prices Over Time



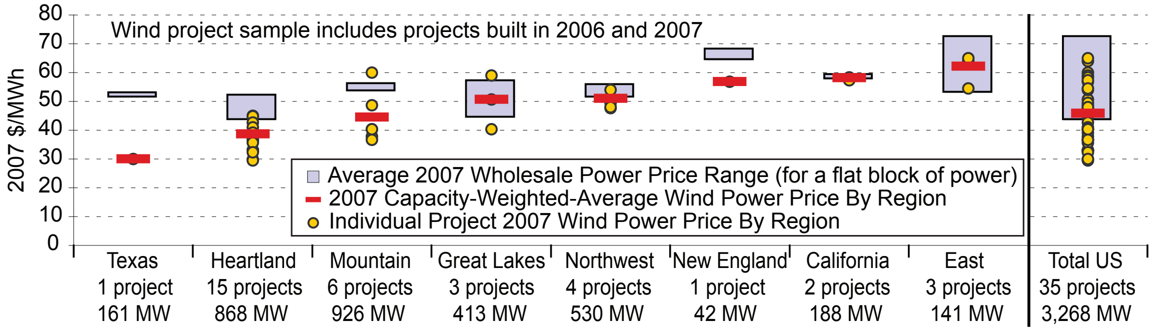
Source: Berkeley Lab database, Ventyx.

Figure 18. Wind and Wholesale Power Prices by Region: 1998-2007 Projects

30 Though wind projects do not provide a perfectly flat block of power, as a common point of comparison, a flat block is not an unreasonable starting point. In other words, the time-variability of wind generation is often such that its wholesale market value is not too dissimilar from that of a flat block of (non-firm) power.

31 The five pricing nodes represented in Figure 16 by an open rather than closed bullet do not have complete pricing history back through 2003.

32 Although their prices are factored into the capacity-weighted-average wind power price (depicted by the red dash), two individual projects are not shown in Figure 18, due to scale limitations: one in the Great Lakes region, at roughly $91/MWh; and one in the East, at roughly $150/MWh.



Source: Berkeley Lab database, Ventyx.

Figure 19. Wind and Wholesale Power Prices by Region: 2006-2007 Projects Only

projects also receive additional revenue from unbundled REC sales). Furthermore, these prices do not fully reflect integration, resource adequacy, or transmission costs. At the same time, wholesale power prices do not fully reflect transmission costs, may not fully reflect capital and fixed operating costs, and are suppressed by virtue of any financial incentives provided to fossil-fueled generation and by not fully accounting for the environmental and social costs of that generation. In addition, wind power prices—once established—are typically fixed and known, whereas wholesale power prices are short-term and therefore subject to change over time. Finally, the location of the wholesale pricing nodes and the assumption of a flat block of power are not perfectly consistent with the location and output profile of the sample of wind projects.

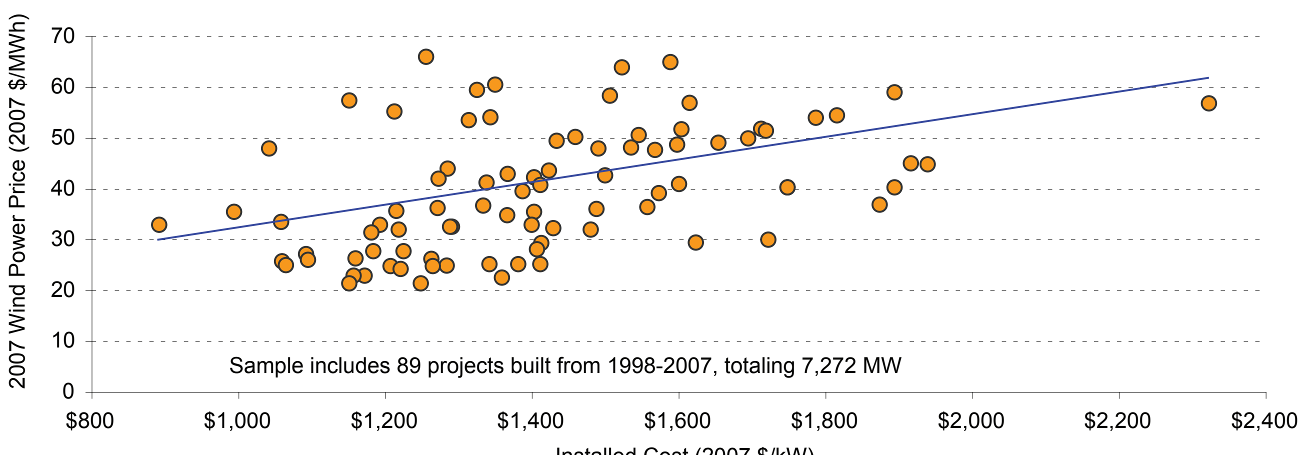
In short, comparing wind and wholesale power prices in this manner is spurious, if one's goal is to fully account for the costs and benefits of wind relative to its competition. Another way to think of Figures 17-19, however, is as loosely representing the decision facing wholesale power purchasers—i.e., whether to contract long-term for wind power or buy a flat block of (non-firm) spot power on the wholesale market. In this sense, the costs represented in Figures 17-19 are reasonably comparable in that they represent (to some degree, at least) what the power purchaser would actually pay.

Project Performance and Capital Costs Drive Wind Power Prices

Wind power sales prices are affected by a number of factors, two of the most important of which are installed project costs and project performance.[33] Figures 20 and 21 illustrate the importance of these two variables.

Figure 20 shows the relationship between project-level installed costs and power sales prices in 2007 for a sample of more than 7,200 MW of wind projects installed in the United States from 1998 through 2007.[34] Though the scatter is considerable, in general, projects with higher installed costs also have higher wind power prices. Figure 21 illustrates the relationship between project-level capacity factors in 2007 and power sales prices in that same year for a sample of more than 5,700 MW of wind projects installed from 1998 through 2006. The inverse relationship shows that projects with higher capacity factors generally have lower wind power prices, though considerable scatter is again apparent.

The next few sections of this report explore trends in installed costs and project performance in more detail, as both factors can have significant effects on wind power prices.

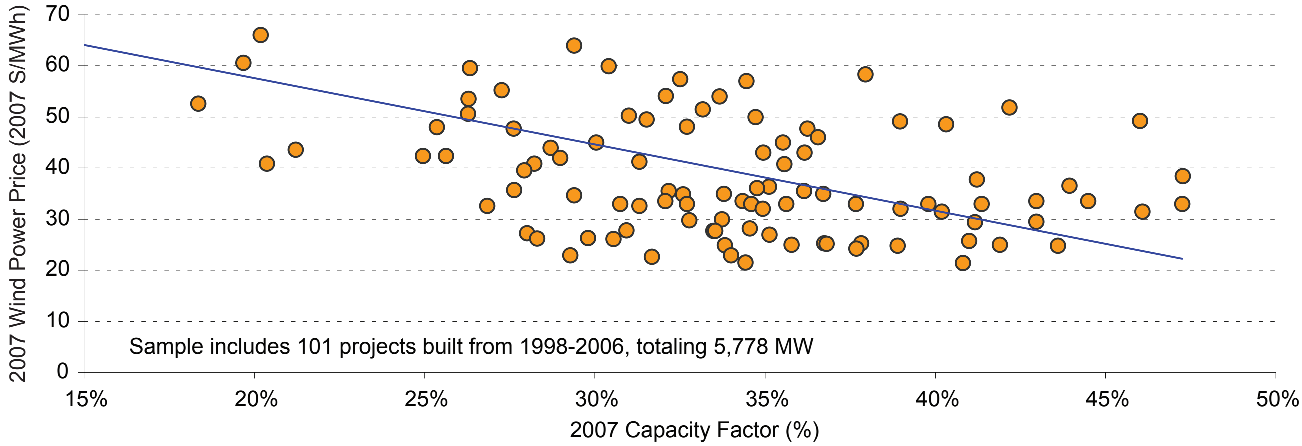


Source: Berkeley Lab database.

Figure 20. 2007 Wind Power Price as a Function of Installed Project Costs

33 Operations and maintenance (O&M) costs are another important variable that affects wind power prices. A later section of this report covers trends in project-level O&M costs.

34 In both Figures 20 and 21, two project outliers (the same two described earlier) are obscured by the compressed scales, yet still influence the trend lines.



Source: Berkeley Lab database.

Figure 21. 2007 Wind Power Price as a Function of 2007 Capacity Factor

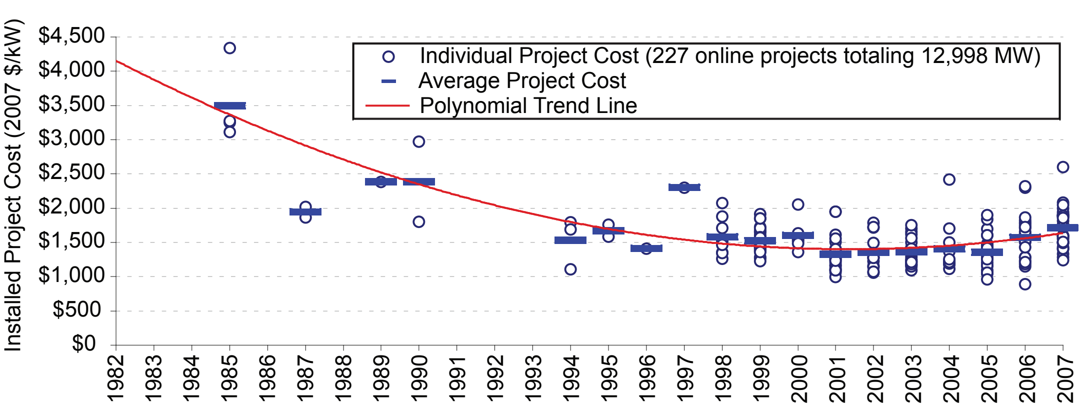
Installed Project Costs Continued to Rise in 2007, After a Long Period of Decline

Berkeley Lab has compiled a sizable database of the installed costs of wind projects in the United States, including data on 36 projects completed in 2007 totaling 4,079 MW, or 77% of the wind power capacity installed in that year. In aggregate, the dataset includes 227 completed wind projects in the continental United States totaling 12,998 MW, and equaling roughly 77% of all wind capacity installed in the United States at the end of 2007. The dataset also includes cost projections for a sample of proposed projects. In general, reported project costs reflect turbine purchase and installation, balance of plant, and any substation and/or interconnection expenses. Data sources are diverse, however, and are not all of equal credibility, so emphasis should be placed on overall trends in the data, rather than on individual project-level estimates.

As shown in Figure 22, wind project installed costs declined dramatically from the beginnings of the industry in California in the 1980s to the early 2000s, falling by roughly $2,700/kW over this period.[35] More recently, however, costs have increased. Among the sample of projects built in 2007, reported installed costs ranged from $1,240/kW to $2,600/kW, with an average cost of $1,710/kW. This average is up $140/kW (9%) from the average cost of installed projects in 2006 ($1,570/kW), and up roughly $370/kW (27%) from the average cost of projects installed from 2001 through 2003. Project costs are clearly on the rise.

Moreover, there is reason to believe that recent increases in turbine costs did not fully work their way into installed project costs in 2007, and therefore that even higher installed costs are likely in the near future. The average cost estimate for 2,950 MW of proposed projects in the dataset (not shown in Figure 22, but most of which are expected to be built in 2008), for example, is $1,920/kW, or $210/kW higher than for projects completed in 2007.

Project costs may be influenced by a number of factors, including project size. Focusing only on those projects completed in 2006 and 2007 (to try to remove the confounding effect of rising costs over the past few years), Figure 23 tries to identify the existence of project-level economies of scale. There is clearly a wider spread in project-level costs among smaller wind projects than among larger projects, but Figure 23 does not show strong evidence of economies of scale.[36] Given the wide spread in the data, it is clear that other factors must play a major role in determining installed project costs.



Source: Berkeley Lab database (some data points suppressed to protect confidentiality).

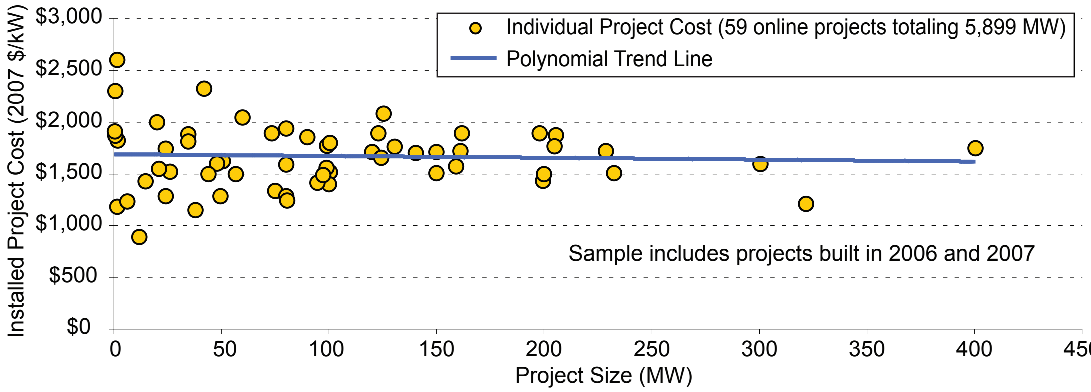
Figure 22. Installed Wind Project Costs Over Time

35 Limited sample size early on – particularly in the 1980s – makes it difficult to pin down this number with a high degree of confidence.

36 This may simply be an artifact of the limited quantity and quality of available data, and the influence of other confounding factors. Alternatively, it may be that economies of scale are evident in turbine transactions (larger turbine orders yielding lower prices), but those economies do not necessarily correspond with project size because a large turbine order could be used for either one large project or allocated among multiple smaller projects.

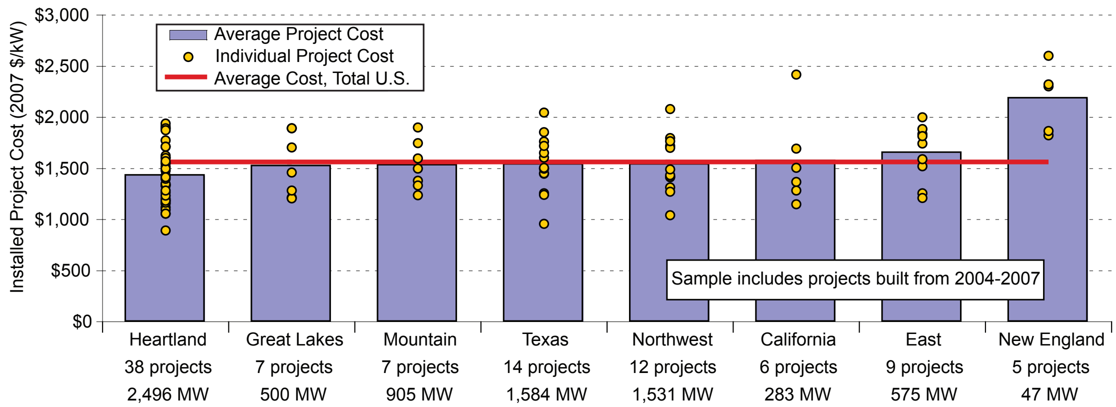
Differences in installed costs exist regionally due to variations in development costs, transportation costs, siting and permitting requirements and timeframes, and balance-of-plant and construction expenditures. Considering projects in the sample installed in 2004 through 2007, Figure 24 shows that average costs equaled $1,540/kW nationwide over this period, but varied somewhat by region. New England was the highest cost region, while the Heartland was the lowest.[37]

Finally, it is important to recognize that wind is not alone in seeing upward pressure on project costs—other types of power plants have seen similar increases in capital costs in recent years. In September 2007, for example, the Edison Foundation published a report showing increases in the installed cost of both natural gas and coal power plants that rival that seen in the wind industry.[38]



Source: Berkeley Lab database.

Figure 23. Installed Wind Project Costs as a Function of Project Size: 2006-2007 Projects



Source: Berkeley Lab database.

Figure 24. Installed Wind Project Costs by Region: 2004-2007 Projects

Project Cost Increases Are a Function of Turbine Prices, and Turbine Prices Have Increased Dramatically

Increases in wind power prices and overall installed project costs mirror increases in the cost of wind turbines. Berkeley Lab has gathered data on 49 U.S. wind turbine transactions totaling 16,600 MW, including 16 transactions summing to 7,600 MW in 2007 alone. Figure 25 depicts these reported wind turbine transaction prices.

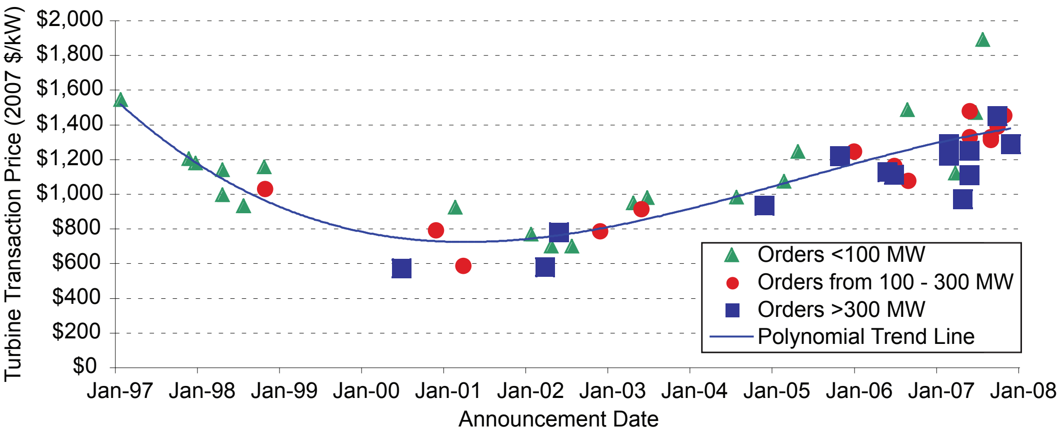
Sources of transaction price data vary, but most derive from press releases and press reports. Wind turbine transactions differ in the services offered (e.g., whether towers and installation are provided, the length of the service agreement, etc.) and on the timing of future turbine delivery, driving some of the observed intra-year variability in transaction prices. Nonetheless, most of the transactions included in the Berkeley Lab dataset likely include turbines, towers, erection, and limited warranty and service agreements; unfortunately, because of data limitations, the precise content of many of the individual transactions is not known.

Since hitting a nadir of roughly $700/kW in the 2000-2002 period, turbine prices appear to have increased by approximately $600/kW (85%), on average. Between 2006 and 2007, capacity-weighted-average turbine prices increased by roughly $115/kW (10%), from $1,125/kW to $1,240/kW. Recent increases in turbine prices have likely been caused by several factors, including the declining value of the U.S. dollar relative to the Euro, increased materials and energy input prices (e.g., steel and oil), a general move by manufacturers to improve their profitability, shortages in certain turbine components, an up-scaling of turbine size (and hub height), and improved sophistication of turbine design (e.g., improved grid interactions). The shortage of turbines has also led to a secondary market in turbines, through which prices may be even higher than those shown in Figure 25.

Though by no means definitive, Figure 25 also suggests that larger turbine orders (> 300 MW) may have generally yielded somewhat lower pricing than smaller orders (< 100 MW) at any given point in time. This is reflected in the fact that most of the larger turbine orders shown in Figure 25 are located below the polynomial trend line, while the majority of the smaller orders are located above that line.

37 Graphical presentation of the data in this way should be viewed with some caution, as numerous factors influence project costs (e.g., whether projects are repowered vs. "greenfield" development, etc.). As a result, actual cost differences among some regions may be more (or less) significant than they appear in Figure 24.

38 See: www.edisonfoundation.net/Rising_Utility_Construction_Costs.pdf



Source: Berkeley Lab database.

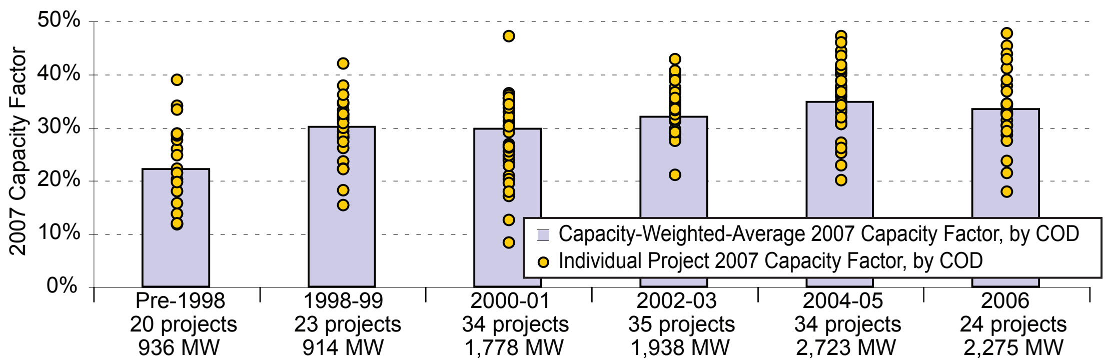
Figure 25. Reported U.S. Wind Turbine Transaction Prices Over Time

This trend of increasing turbine prices suggests that virtually the entire recent rise in installed project costs reported earlier has come from turbine price increases (recognizing that these prices reflect the cost of turbines, towers, and erection). In fact, because project-level installed costs have increased, on average, by roughly $370/kW during the last several years, while turbine prices appear to have increased by $600/kW over the same time span, further increases in project costs should be expected in the near future as the increases in turbine prices flow through to project costs.

Wind Project Performance Has Improved Over Time

Though recent turbine and installed project cost increases have driven wind power prices higher, improvements in wind project performance have mitigated these impacts to some degree. In particular, capacity factors have increased for projects installed in recent years, driven by a combination of higher hub heights, improved siting, and technological advancements.

Figures 26 and 27, as well as Table 7, present excerpts from a Berkeley Lab compilation of wind project capacity-factor data. The sample consists of 170 projects built between 1983 and 2006, and totaling 10,564 MW (91% of nationwide installed wind capacity at the end of 2006).[39] Though capacity factors are not an ideal metric of project performance due to variations in the design and rating of wind turbines, absent rotor diameter data for each project, this report is unable to present the arguably more-relevant metric of electricity generation per square meter of swept rotor area. Both figures and the table summarize project-level capacity factors in the year 2007, thereby limiting the effects of inter-annual fluctuations in the nationwide wind resource.[40]



Source: Berkeley Lab database.

Figure 26. 2007 Project Capacity Factors by Commercial Operation Date

Figure 26 shows individual project as well as capacity-weighted average 2007 capacity factors broken out by each project's commercial operation date. The capacity-weighted-average 2007 capacity factors in the Berkeley Lab sample increased from 22% for wind projects installed before 1998 to roughly 30%-32% for projects installed from 1998-2003, and to roughly 33%-35% for projects installed in 2004-2006. [41]

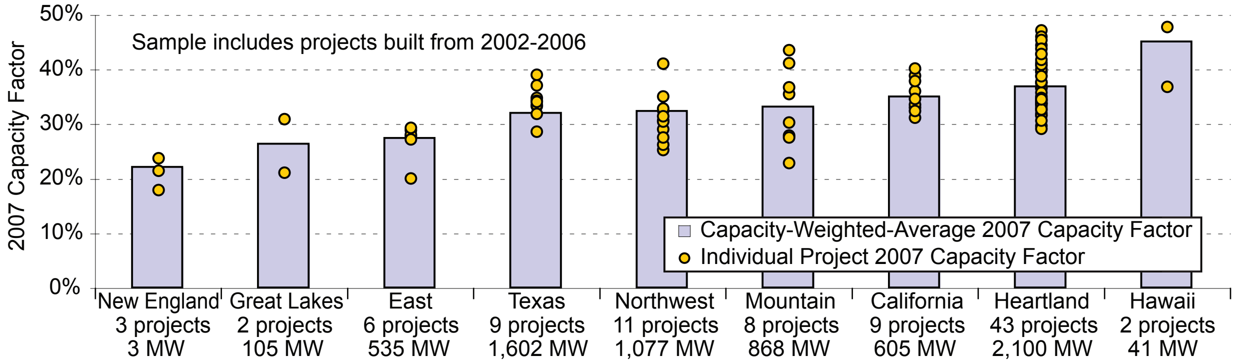
In the best wind resource areas, capacity factors in excess of 40% are increasingly common. Of the 112 projects in the sample installed prior to 2004, for example, only 4 (3.6%) had capacity factors in excess of 40% in 2007 (in capacity terms, 56 MW, or 1%, exceeded 40%). Of the 58 projects installed from 2004 through 2006, on the other hand, 15 (25.9%) achieved capacity factors in excess of 40% in 2007 (in capacity terms, 836 MW, or 16.7%, exceeded 40%).

These increases in capacity factors over time suggest that improved turbine designs, higher hub heights, and/or improved siting are outweighing the otherwise-presumed trend towards

[39] Though some performance data for wind projects installed in 2007 are available, those data do not span an entire year of operations. As such, for the purpose of this section, the focus is on project-level 2007 capacity factors for projects with commercial online dates in 2006 and earlier.

[40] Focusing just on 2007 means that the *absolute* capacity factors shown in Figure 26 may not be representative if 2007 was not a representative year in terms of the strength of the wind resource. Note also that by including only 2007 capacity factors, variations in the quality of the wind resource year in 2007 across regions could skew the regional results presented in Figure 27 and Table 7.

[41] The capacity-weighted-average 2007 capacity factor for projects installed in 2006 (33.4%) is down slightly from that for projects installed in 2004-2005 (34.8%), in large part due to the impact of a single large project. Specifically, a very large 2006 project in Texas achieved a capacity factor of just 28.7% in 2007; if this single project were excluded from the sample, the capacity-weighted-average 2007 capacity factor from projects built in 2006 would rise to 35.7% (up from 34.8% for projects built in 2004-2005). The impact of this single project is also evident in Figure 27 (where the capacity-weighted-average for Texas is at the low end of the individual project range) and Table 7 (where the steady upward march of average capacity factors in Texas is abruptly reversed in 2006).



Source: Berkeley Lab database.

Figure 27. 2007 Project Capacity Factors by Region: 2002-2006 Projects Only

Table 7. Capacity-Weighted-Average 2007 Capacity Factors by Region and COD

Capacity Factor	Heartland	Texas	California	Northwest	Mountain	East	Great Lakes	Hawaii	New England
Pre-1998	28.9%	11.9%	22.3%	—	—	—	—	—	19.8%
1998-99	30.2%	28.2%	29.8%	32.1%	34.4%	—	23.4%	—	—
2000-01	33.4%	29.6%	34.5%	28.7%	29.3%	22.5%	23.5%	—	27.0%
2002-03	34.4%	33.5%	32.6%	30.5%	30.3%	28.5%	21.2%	—	—
2004-05	36.8%	34.5%	37.5%	34.0%	38.9%	26.7%	31.0%	—	—
2006	40.8%	30.4%	36.9%	31.3%	34.7%	29.4%	—	45.0%	22.1%

Sample	#	MW	#	MW	#	MW	#	MW	#	MW	#	MW	#	MW	#	MW	#	MW
Pre-1998	1	26	1	34	17	870	—	—	—	—	—	—	—	—	—	—	1	6
1998-99	8	470	3	139	5	190	1	25	3	68	—	—	3	22	—	—	—	—
2000-01	10	229	7	911	1	67	3	388	4	123	6	78	2	32	—	—	1	1
2002-03	20	628	2	198	4	287	2	105	3	510	3	161	1	50	—	—	—	—
2004-05	16	1,086	4	461	3	130	5	434	3	208	2	349	1	54	—	—	—	—
2006	7	386	3	944	2	188	4	538	2	150	1	26	—	—	2	41	3	3
Total	**62**	**2,825**	**20**	**2,686**	**32**	**1,732**	**15**	**1,440**	**15**	**1,059**	**12**	**613**	**7**	**158**	**2**	**41**	**5**	**10**

lower-value wind resource sites as the best locations are developed. Further analysis would be needed to determine the relative importance of the variables influencing performance improvements.

Although the overall trend is towards higher capacity factors, the project-level spread shown in Figure 26 is enormous, with capacity factors ranging from 18% to 48% among projects built in the same year, 2006. Some of this spread is attributable to regional variations in wind resource quality. Figure 27 shows the regional variation in 2007 capacity factors, based on a sub-sample of wind projects built from 2002 through 2006. For this sample of projects, capacity factors are the highest in Hawaii (though just two projects) and the Heartland (above 35% on average), and lowest in New England, the Great Lakes, and the East (below 30% on average). Given the small sample size in some regions, however, as well as the possibility that certain regions may have experienced a particularly good or bad wind resource year in 2007, care should be taken in extrapolating these results.

Though limited sample size is again a problem for many regions, Table 7 illustrates trends in 2007 capacity factors for projects with different commercial operation dates, by region. In the Heartland region, with the largest sample of projects in terms of installed capacity, the average capacity factor of projects installed in 2006 (40.8%) is approximately 35% greater than that of the 1998-1999 vintage projects in the sample (30.2%).

Operations and Maintenance Costs Are Affected by the Age and Size of the Project, Among Other Factors

Operations and maintenance (O&M) costs are a significant component of the overall cost of wind projects, but can vary widely among projects. Market data on actual project-level O&M costs for wind plants are scarce. Even where these data are available, care must be taken in extrapolating historical O&M costs given the dramatic changes in wind turbine technology that have occurred over the last two decades, not least of which has been the up-scaling of turbine size (see Figure 9, earlier).

Berkeley Lab has compiled O&M cost data for 95 installed wind plants in the United States, totaling 4,319 MW of capacity, with commercial operation dates of 1982 through 2006. These data cover facilities owned by both independent power producers and utilities, though data since 2004 is exclusively from utility-owned plants. A full-time series of O&M cost data, by year, is available for only a small number of projects; in all other cases, O&M cost data are available for just a subset of years of project operations. Although the data sources do not all clearly define what items are included in O&M costs, in most cases the reported values appear to include the costs of wages and materials associated with operating and maintaining the facility, as well as rent (i.e., land lease payments). Other ongoing expenses, including taxes, property insurance, and workers' compensation insurance, are generally not included. Given the scarcity and varying quality of the data, caution should be taken when interpreting the results shown below. Note also that the available data are presented in $/MWh terms, as if O&M represents a variable cost. In fact, O&M costs are in part variable and in part fixed. [42]

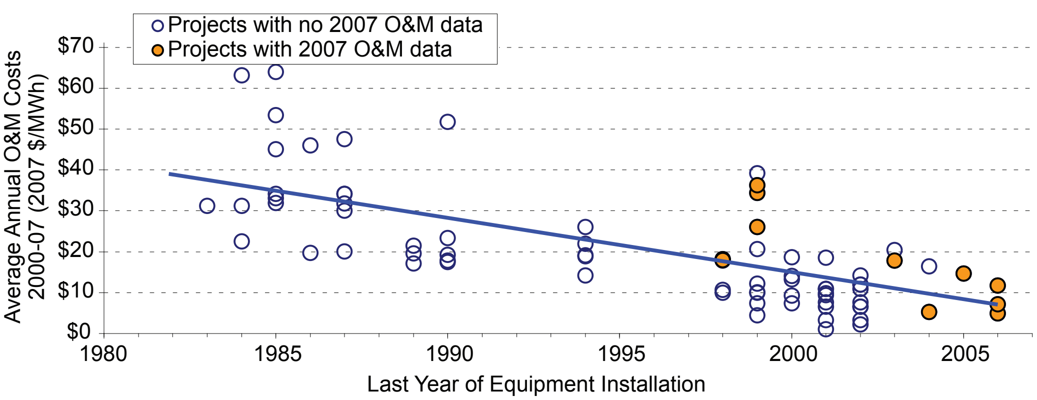
Figure 28 shows project-level O&M costs by year of project installation (i.e., the last year that original equipment was installed, or the last year of project repowering). Here, O&M costs represent an average of annual project-level data available for the years 2000 through 2007. For example, for projects that reached commercial operations in 2006, only year 2007 data are available, and that is what is shown in the figure.[43] Many other projects only have data for a subset of years during the 2000-2007 period, either because they were installed after 2000 or because a full-time series is not available, so each data point in the chart may represent a different averaging period over the 2000-07 timeframe. The chart also identifies which of the data points contain the most-updated data, from 2007.

The data exhibit considerable spread, demonstrating that O&M costs are far from uniform across projects. However, Figure 28 suggests that projects installed more recently have, on average, incurred much lower O&M costs. Specifically, capacity-weighted-average 2000-2007 O&M costs for projects in the sample constructed in the 1980s equal $30/MWh, dropping to $20/MWh for projects installed in the 1990s, and to $9/MWh for projects installed in the 2000s. This drop in O&M costs may be due to a combination of at least two factors: (1) O&M costs generally increase as turbines age, component failures become more common, and as manufacturer warranties expire[44]; and (2) projects installed more recently, with larger turbines and more sophisticated designs, may experience lower overall O&M costs on a per-MWh basis.

To help tease out the possible influence of these two factors, Figure 29 shows annual O&M costs over time, based on the number of years since the last year of equipment installation. Annual data for projects of similar vintages are averaged together, and data for projects under 5 MW in size are excluded (to help control for the confounding influence of economies of scale). Note that, for each group, the number of projects used to compute the average annual values shown in the figure is limited, and varies substantially (from 3 to 21 data points per project-year for projects installed in 1998 through 2000; 10 data points per project-year for projects installed in 2001 through 2003; and from 3 to 6 data points for projects installed in 2004 through 2006). With this limitation in mind, the figure appears to show that projects installed in 2001 and later have had lower O&M costs than those installed from 1998 through 2000, at least during the initial two years of operation. In addition, the data for projects installed from 1998 through 2000 show a quite modest upward trend in project-level O&M costs after the third year of project operation, though the sample size after year four is quite limited.

Another variable that may impact O&M costs is project size. Figure 30 presents average O&M costs for 2000 through 2007 (as in Figure 28) relative to project size. Though substantial spread in the data exists and the sample is too small for definite conclusions, project size does appear to have some impact on average O&M costs, with higher costs typically experienced by smaller projects. More data would be needed to confirm this inference.

Though interesting, the trends noted above are not necessarily useful predictors of long-term O&M costs for the latest turbine models. The U.S. DOE, in collaboration with the wind industry, is currently funding additional efforts to better understand the drivers for O&M costs and component failures, and to develop models to project future O&M costs and failure events.



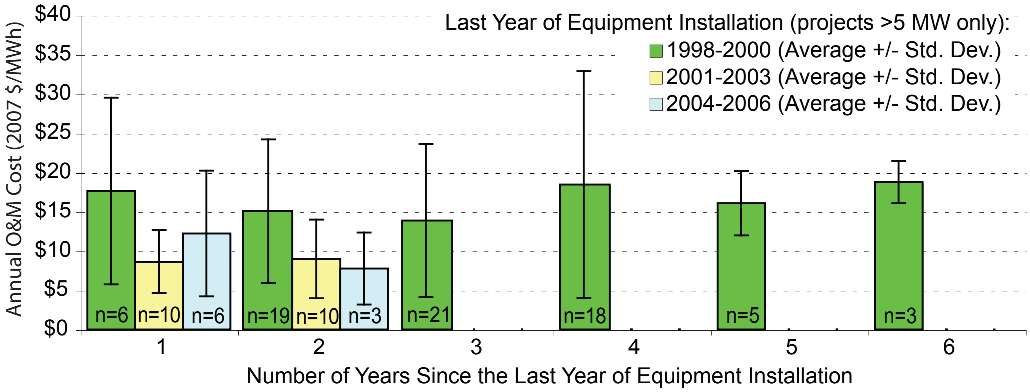
Source: Berkeley Lab database; five data points suppressed to protect confidentiality.

Figure 28. Average O&M Costs for Available Data Years from 2000-2007, by Last Year of Equipment Installation

42 Although not presented here, expressing O&M costs in units of $/kW-yr was found to yield qualitatively similar results.

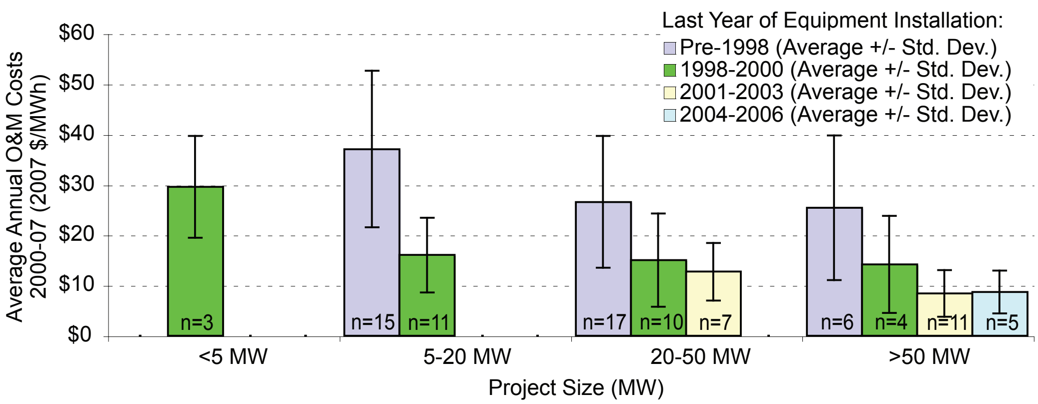
43 Projects installed in 2007 are not shown because only data from the first full year of project operations (and afterwards) are used, which in the case of projects installed in 2007 would be year 2008 (for which data are not yet available).

44 Many of the projects installed more recently may still be within their turbine manufacturer warranty period, in which case the O&M costs reported here may or may not include the costs of the turbine warranty, depending on whether the warranty is paid up-front as part of the turbine purchase, or is paid over time.



Source: Berkeley Lab database; averages shown only for groups of three or more projects.

Figure 29. Annual Average O&M Costs, by Project Age and Last Year of Equipment Installation



Source: Berkeley Lab database; averages shown only for groups of three or more projects.

Figure 30. Average O&M Costs for Available Data Years from 2000-2007, by Project Size

New Studies Continued to Find that Integrating Wind into Power Systems Is Manageable, but Not Costless

During the past several years, there has been a considerable amount of analysis on the potential impacts of wind energy on power systems, typically responding to concerns about whether the electrical grid can accommodate significant new wind additions, and at what cost. The sophistication of these studies has increased in recent years, resulting in a better accounting of wind's impacts and costs. Key trends among some of the more recent studies include evaluating even higher levels of wind penetration, evaluating the integration of wind within larger electricity market areas, and identifying approaches to mitigate integration concerns.

Table 8 provides a selective listing of results from major wind integration studies completed from 2003 through 2007.[45] Because methods vary and a consistent set of operational impacts has not been included in each study, results from the different analyses are not entirely comparable. Nonetheless, key conclusions that continue to emerge from the growing body of integration literature include: (1) wind integration costs are well below $10/MWh—and typically below $5/MWh—for wind capacity penetrations[46] of as much as 30% of the peak load of the system in which the wind power is delivered[47]; (2) regulation impacts are often found to be relatively small, whereas the impacts of wind on load-following and unit commitment are typically found to be more significant; (3) larger balancing areas, such as those found in RTOs and ISOs, make it possible to integrate wind more easily and at lower cost than is the case in small balancing areas[48]; and (4) the use of wind power forecasts can significantly reduce integration challenges and costs.

Additional wind integration research is planned for 2008. Perhaps of greatest import is that the National Renewable Energy Laboratory is in the process of examining higher levels of wind penetration in larger electrical footprints. The Western Wind and Solar Integration Study (WWSIS), in collaboration with GE and WestConnect, is analyzing wind penetration levels of up to 30% on an energy basis in the WestConnect footprint, which includes parts of Wyoming, Colorado, New Mexico, Arizona, and Nevada. The Eastern Wind Integration Study, to be conducted in collaboration

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45 Some of the studies included in the table also address capacity valuation for resource adequacy purposes; those results are not presented here. Two major integration studies for California were also completed in 2007: one conducted by the California ISO and another by the California Energy Commission's Intermittency Analysis Project. Neither of these studies sought to comprehensively calculate integration costs, however, so neither is listed in the table.

46 Wind penetration on a capacity basis (defined as nameplate wind capacity serving a region divided by that region's peak electricity demand) is frequently used in integration studies. For a given amount of wind capacity, penetration on a capacity basis is typically higher than the comparable wind penetration in energy terms.

47 The relatively low cost estimate in the 2006 Minnesota study, despite an aggressive level of wind penetration, is partly a result of relying on the overall Midwest Independent System Operator (MISO) market to accommodate certain elements of integrating wind into system operations. The low costs found in the 2006 California study arise because of the large electrical market in which wind power is integrated, as well as the relatively low penetration level analyzed. Conversely, the higher integration costs found by Avista and Idaho Power are, in part, caused by the relatively smaller markets in which the wind is being absorbed and, in part, by those utilities' operating practices (specifically, that sub-hourly markets are not used, as is common in ISOs and RTOs). Note also that the rigor with which the various studies have been conducted has varied, as has the degree of peer review.

48 Even outside of ISOs and RTOs, there is increasing interest in collaborative system control actions among balancing areas to address market operations inefficiencies, including helping to mitigate the impact of wind variability on systems operation and cost. In the West, for example, the Area Control Error (ACE) Diversity Interchange project has sought to pilot the pooling of individual ACEs to take advantage of control error diversity.

Table 8. Key Results from Major Wind Integration Studies Completed 2003-2007

Date	Study	Wind Capacity Penetration	Cost ($/MWh)				
			Regulation	Load Following	Unit Commitment	Gas Supply	TOTAL
2003	Xcel-UWIG	3.5%	0	0.41	1.44	na	1.85
2003	We Energies	29%	1.02	0.15	1.75	na	2.92
2004	Xcel-MNDOC	15%	0.23	na	4.37	na	4.60
2005	PacifiCorp	20%	0	1.60	3.00	na	4.60
2006	CA RPS (multi-year)*	4%	0.45	trace	trace	na	0.45
2006	Xcel-PSCo	15%	0.20	na	3.32	1.45	4.97
2006	MN-MISO**	31%	na	na	na	na	4.41
2007	Puget Sound Energy	10%	na	na	na	na	5.50
2007	Arizona Public Service	15%	0.37	2.65	1.06	na	4.08
2007	Avista Utilities***	30%	1.43	4.40	3.00	na	8.84
2007	Idaho Power	20%	na	na	na	na	7.92

** regulation costs represent 3-year average*
*** highest over 3-year evaluation period*
**** unit commitment includes cost of wind forecast error*

Source: Berkeley Lab based, in part, on data from NREL.

with the Joint Coordinated System Plan (whose participants include MISO, SPP, TVA, and PJM), will examine a similar wind penetration in the combined footprint of these RTOs and ISOs.[49] Finally, in 2008, ERCOT will issue a study by GE on the potential impact of wind development on ERCOT's ancillary service requirements.

Solutions to Transmission Barriers Began to Emerge, but Constraints Remain

After a prolonged period of relatively little transmission investment, expenditures on new transmission are on the rise. The Edison Electric Institute, for example, projects that its member companies will invest $37 billion in transmission from 2007-2010, a 55% increase from the 2003-2006 period.

Nonetheless, lack of transmission availability remains a primary barrier to wind development. New transmission facilities are particularly important for wind power because wind projects are constrained to areas with adequate wind speeds, which are often located at a distance from load centers. In addition, there is a mismatch between the short lead time needed to develop a wind project and the lengthier time often needed to develop new transmission lines. Moreover, the relatively low capacity factor of wind can lead to underutilization of new transmission lines that are intended to only serve this resource. The allocation of costs for new transmission investment is also of critical importance for wind development, as are issues of transmission rate "pancaking" when power is wheeled across multiple utility systems, charges imposed for inaccurate scheduling of wind generation, and interconnection queuing procedures.

A number of federal, state, and regional developments occurred in 2007 that may help ease the transmission barrier for wind over time. At the federal level, the U.S. DOE issued its *National Electric Transmission Congestion Report*, which designates two constrained corridors: the Southwest Area National Interest Electric Transmission Corridor and the Mid-Atlantic Area National Interest Electric Transmission Corridor. Under the Energy Policy Act of 2005, FERC can approve proposed new transmission facilities in these corridors if states fail to do so within one year, among other conditions. The U.S. DOE's designations have proven controversial, however, and multiple efforts to reverse these designations have occurred or are underway.

Also at the federal level, in February 2007, FERC issued Order 890, which includes several provisions of importance to wind. First, the order adopts a cost-based energy imbalance policy that replaces the penalty-based energy imbalance charges that applied under FERC Order 888 and that were much more punitive for wind. Second, the order requires transmission providers to participate in an open transmission planning process at the local and regional level. Third, if transmission capacity is unavailable to service a firm point-to-point transmission application, then the transmission provider is required to examine redispatch and conditional firm service as alternative transmission service options. More recently, FERC has begun to investigate ways to ease barriers imposed by current interconnection queuing procedures; more activity on this topic is expected in 2008.

States and grid operators are also increasingly taking more proactive steps to encourage transmission investment, often

[49] Note that the two NREL studies are not expected to be complete until 2009.

within the context of growing renewable energy demands. Several examples of these initiatives are presented below:

- **Texas**: In October 2007, the Texas public utilities commission (PUC) issued an interim order designating five competitive renewable energy zones (CREZ), defined as areas of high-quality renewable resources to which transmission could be built in advance of installed generation. These CREZs could stimulate as much as 22,806 MW of new wind power capacity, and ERCOT has subsequently completed a transmission study for these areas.
- **Colorado**: Legislation enacted in January 2007 requires utilities to submit biennial reports designating energy resource zones (ERZs) and to submit applications for certificates of public convenience and necessity (CPCN) for these areas. In October 2007, Xcel Energy identified four potential ERZ areas, created in large measure to support renewable energy development, and the Colorado PUC recently approved Xcel's application for a 345-kV line in northeastern Colorado.[50]
- **California**: In late 2007, the California ISO received FERC approval for a new transmission interconnection category for location-constrained resources, such as renewable energy facilities. Once a resource area has been identified, transmission would be built in advance of generation being developed, and costs would be initially recovered through the California ISO transmission charge. California also started the Renewable Energy Transmission Initiative to help define renewable energy zones in and around the state, and to prepare transmission plans for those zones.

Progress was also made in 2007 on a number of specific transmission projects that are designed to, in part, support wind power. In March 2007, for example, the California PUC approved the first three of ultimately 11 segments of Southern California Edison's Tehachapi transmission project. Fully developed, the project will transmit up to 4,500 MW of wind power. In Minnesota, meanwhile, utilities that are part of the CapX 2020 statewide transmission planning group filed applications at the Minnesota PUC for four 345-kV lines that will collectively increase transmission capacity in southwestern Minnesota by 800 MW, to about 2,000 MW total. Finally, a number of states have created transmission infrastructure authorities to support new transmission investment;[51] two of these states—Colorado and New Mexico—created transmission authorities in 2007 in large measure to support renewable energy.

Policy Efforts Continued to Affect the Amount and Location of Wind Development

A variety of policy drivers have been important to the recent expansion of the wind power market in the United States. Most obviously, the continued availability of the federal PTC has sustained industry growth. First established by the Energy Policy Act of 1992, the PTC provides a 10-year credit at a level that equaled 2.0¢/kWh in 2007 (adjusted annually for inflation). The importance of the PTC to the U.S. wind industry is illustrated by the pronounced lulls in wind capacity additions in the three years—2000, 2002, and 2004—in which the PTC lapsed (see Figure 1). With the PTC currently (as of early-May 2008) scheduled to expire at the end of 2008, the U.S. wind industry may experience another quiet year in 2009 absent an imminent extension.

A number of other federal policies also support the wind industry. Wind power property, for example, may be depreciated for tax purposes over an accelerated 5-year period, with bonus depreciation allowed for certain projects completed in 2008. Because tax-exempt entities are unable to take direct advantage of tax incentives, the Energy Policy Act of 2005 created the Clean Renewable Energy Bond (CREB) program, effectively offering interest-free debt to eligible renewable projects (though not without certain additional transaction costs).[52] Finally, the USDA provides grants to certain renewable energy applications.

State policies also continue to play a substantial role in directing the location and amount of wind development. From 1999 through 2007, for example, more than 55% of the wind power capacity built in the U.S. was located in states with RPS policies; in 2007 alone, this proportion was more than 75%. Utility resource planning requirements in Western and Midwestern states have also helped spur wind additions in recent years, as has growing voluntary customer demand for "green" power, especially among commercial customers. State renewable energy funds provide support for wind projects, as do a variety of state tax incentives. Finally, concerns about the possible impacts of global climate change are fueling interest by states, regions, and the federal government to implement carbon reduction policies, a trend that is likely to increasingly underpin wind power expansion in the years ahead.

Key policy developments in 2007 included:

- In February 2008, the IRS announced the distribution of roughly $400 million in CREBs, based on applications received in 2007, including $170 million for 102 wind power projects.
- In September 2007, a total of more than $18 million in grant and loan awards were announced under the USDA's Section 9006 grant program, including $2.7 million for 7 "large wind" projects totaling 8.2 MW in capacity.
- Illinois, New Hampshire, North Carolina, and Oregon enacted mandatory RPS policies in 2007, while Ohio established an RPS in early 2008, bringing the total to 26 states and Washington D.C. (see Figure 31). A large number of additional states strengthened previously established RPS programs in 2007.
- A variety of states and regions continued to make progress in implementing carbon reduction policies, and a rising number of electric utilities considered the possible implementation of carbon regulation in their resource planning and selection processes.
- State renewable energy funds, state tax incentives, utility resource planning requirements, and green power markets all helped contribute to wind expansion in 2007.

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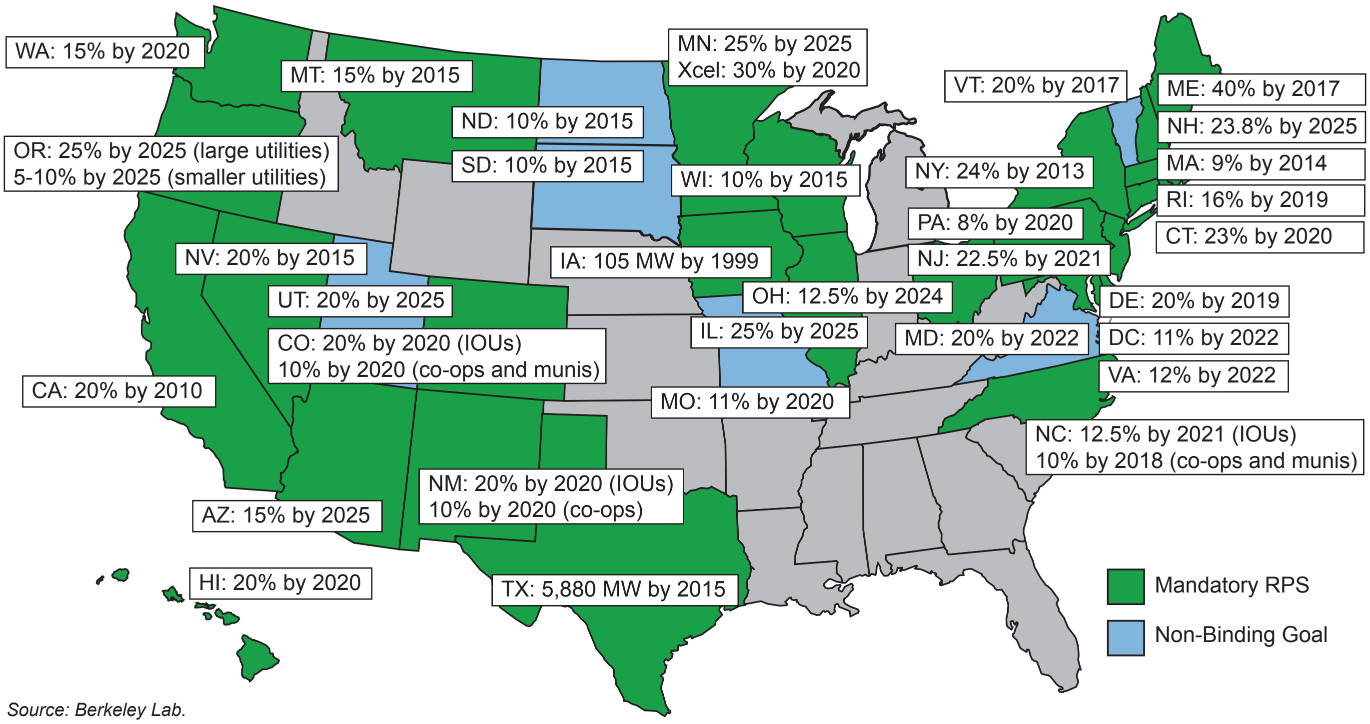
50 In 2008, Xcel Energy reached a settlement with interveners to submit CPCN applications for new transmission facilities in all four ERZ areas by March 2009.

51 These include Colorado, Idaho, Kansas, North Dakota, New Mexico, South Dakota, and Wyoming.

52 Such entities have also been eligible to receive the Renewable Energy Production Incentive (REPI), which offers a 10-year cash payment equal in face value to the PTC, but the need for annual appropriations and insufficient funding have limited the effectiveness of the REPI.



Source: Berkeley Lab.

Figure 31. State RPS Policies and Non-Binding Renewable Energy Goals (as of May 2008)

Coming Up in 2008

Though transmission availability, siting and permitting conflicts, and other barriers remain, 2008 is, by all accounts, expected to be another banner year for the U.S. wind industry. Another year of capacity growth in excess of 5,000 MW appears to be in the offing, and past installation records may again fall. Local manufacturing of turbines and components is also anticipated to continue to grow, as announced manufacturing facilities come on line and existing facilities reach capacity and expand.

And all of this is likely to occur despite the fact that wind power pricing is projected to continue its upwards climb in the near term, as increases in turbine prices make their way through to wind power purchasers. Supporting continued market expansion, despite unfavorable wind pricing trends, are the rising costs of fossil generation, the mounting possibility of carbon regulation, and the growing chorus of states interested in encouraging wind power through policy measures.

If the PTC is not extended, however, 2009 is likely to be a difficult year of industry retrenchment. The drivers noted above should be able to underpin some wind capacity additions even in the absence of the PTC, and some developers may continue to build under the assumption that the PTC will be extended and apply retroactively. Nonetheless, most developers are expected to "wait it out," re-starting construction activity only once the fate of the PTC is clear.

Appendix: Sources of Data Presented in this Report

Wind Installation Trends

Data on wind power additions in the United States come from AWEA. Annual wind capital investment estimates derive from multiplying these wind capacity data by weighted-average capital cost data, provided elsewhere in the report. Data on non-wind electric capacity additions come primarily from the EIA (for years prior to 2007) and Ventyx's Energy Velocity database (for 2007), except that solar data come from the Interstate Renewable Energy Council (IREC) and Berkeley Lab. Data on the distributed wind segment come primarily from AWEA and, to a lesser extent, NREL. Information on offshore wind development activity in the United States was compiled by NREL.

Global cumulative (and 2007 annual) wind capacity data come from BTM Consult, but are revised to include the most recent AWEA data on U.S. wind capacity. Historical cumulative and annual worldwide capacity data come from BTM Consult and the Earth Policy Institute. Wind as a percentage of country-specific electricity consumption is based on end-of-2007 wind capacity data and country-specific assumed capacity factors that primarily come from BTM Consult's *World Market Update 2007*. For the United States, the performance data presented in this report are used to estimate wind production. Country-specific projected wind generation is then divided by projected electricity consumption in 2008 (and 2007), based on actual 2005 consumption and a country-specific growth rate assumed to be the same as the rate of growth from 2000 through 2005 (these data come from the EIA's *International Energy Annual*).

The wind project installation map of the United States was created by NREL, based in part on AWEA's database of wind power projects and in part on data from Platts on the location of individual wind power plants. Effort was taken to reconcile the AWEA project database and the Platts-provided project locations, though some discrepancies remain. Wind as a percentage contribution to statewide electricity generation is based on AWEA installed capacity data for the end of 2007 and the underlying wind project performance data presented in this report. Where necessary, judgment was used to estimate state-specific capacity factors. The resulting state wind generation is then divided by in-state total electricity generation in 2007, based on EIA data.

Data on wind capacity in various interconnection queues come from a review of publicly available data provided by each ISO, RTO, or utility. Only projects that were active in the queue at the end of 2007, but that had not yet been built, are included. Suspended projects are not included in these listings.

Wind Capacity Serving Electric Utilities

The listing of wind capacity serving specific electric utilities comes from AWEA's *2008 Annual Rankings Report*. To translate this capacity to projected utility-specific annual electricity generation, regionally appropriate wind capacity factors are used. The resulting utility-specific projected wind generation is then divided by the aggregate national retail sales of each utility in 2006 (based on EIA data). Only utilities with 50 MW or more of wind capacity are included in these calculations. In the case of G&T cooperatives and power authorities that provide power to other cooperatives and municipal utilities (but do not directly serve load themselves), this report uses 2006 retail sales from the electric utilities served by those G&T cooperatives and power authorities. In some cases, these individual utilities may be buying additional wind directly from other projects, or may be served by other G&T cooperatives or power authorities that supply wind. In these cases, the penetration percentages shown in the report may be understated. Finally, some of the entities shown in Table 3 are wholesale power marketing companies that are affiliated with electric utilities. In these cases, estimated wind generation is divided by the retail sales of the power marketing company and any affiliated electric utilities.

Turbine Manufacturing, Turbine Size, and Project Size

Turbine manufacturer market share, average turbine size, and average project size are derived from the AWEA wind project database. Information on wind turbine and component manufacturing come from NREL, AWEA, and Berkeley Lab, based on a review of press reports, personal communications, and other sources. The listings of manufacturing and supply chain facilities are not intended to be exhaustive. Information on wind developer consolidation and financing trends were compiled by Berkeley Lab. Wind project ownership and power purchaser trends are based on a Berkeley Lab analysis of the AWEA project database.

Wind Power Prices and Wholesale Market Prices

Wind power price data are based on multiple sources, including prices reported in FERC's Electronic Quarterly Reports (in the case of non-qualifying-facility projects), FERC Form 1, avoided cost data filed by utilities (in the case of some qualifying-facility projects), pre-offering research conducted by Standard & Poor's and other bond rating agencies, and a Berkeley Lab collection of power purchase agreements.

Wholesale power price data were compiled by Berkeley Lab from FERC's *2006 State of the Markets Report* and *2004 State of the Markets Report*, as well as from Ventyx's Energy Velocity database of wholesale power prices (which itself derives data from the IntercontinentalExchange—ICE—and the various ISOs).

REC price data were compiled by Berkeley Lab based on a review of Evolution Markets' monthly REC market tracking reports.

Installed Project and Turbine Costs

Berkeley Lab used a variety of public and some private sources of data to compile capital cost data for a large number of U.S. wind power projects. Data sources range from pre-installation corporate press releases to verified post-construction cost data. Specific sources of data include: EIA Form 412, FERC Form 1, various Securities and Exchange Commission filings, various filings with state public utilities commissions, *Windpower Monthly* magazine, AWEA's *Wind Energy Weekly*, DOE/EPRI's Turbine Verification Program, *Project Finance* magazine, various analytic case studies, and general web searches for news stories, presentations, or information from project developers. Some data points are suppressed in the figures to protect data confidentiality. Because the data sources are not equally credible, little emphasis should be placed on individual project-level data; instead, it is the trends in those underlying data that offer insight. Only wind power cost data from the contiguous lower-48 states are included.

Wind turbine transaction prices were compiled by Berkeley Lab. Sources of transaction price data vary, but most derive from press releases and press reports. In part because wind turbine transactions vary in the services offered, a good deal of intra-year variability in the cost data is apparent.

Wind Project Performance

Wind project performance data are compiled overwhelmingly from two main sources: FERC's *Electronic Quarterly Reports* and EIA Form 906. Additional data come from FERC Form 1 filings and, in several instances, other sources. Where discrepancies exist among the data sources, those discrepancies are handled based on the judgment and experience of Berkeley Lab staff.

Wind Project Operations and Maintenance Costs

Wind project operations and maintenance costs come primarily from two sources: EIA Form 412 data from 2001-2003 for private power projects and projects owned by POUs, and FERC Form 1 data for IOU-owned projects. Some data points are suppressed in the figures to protect data confidentiality.

Wind Integration, Transmission, and Policy

The wind integration, transmission, and policy sections were written by staff at Berkeley Lab, NREL, and Exeter Associates, based on publicly available information.

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Wind Energy Web Sites

U.S. DEPARTMENT OF ENERGY WIND AND HYDROPOWER TECHNOLOGIES PROGRAM
www1.eere.energy.gov/windandhydro/

AMERICAN WIND ENERGY ASSOCIATION
www.awea.org

LAWRENCE BERKELEY NATIONAL LABORATORY
eetd.lbl.gov/ea/ems/re-pubs.html

NATIONAL RENEWABLE ENERGY LABORATORY NATIONAL WIND TECHNOLOGY CENTER
www.nrel.gov/wind/

NREL WIND SYSTEMS INTEGRATION
www.nrel.gov/wind/systemsintegration/

SANDIA NATIONAL LABORATORIES
www.sandia.gov/wind/

NATIONAL WIND COORDINATING COMMITTEE
www.nationalwind.org/

UTILITY WIND INTEGRATION GROUP
www.uwig.org

WIND POWERING AMERICA
www.eere.energy.gov/windandhydro/windpoweringamerica/

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PHOTO CREDITS: Cover: PIX14820, GE wind turbines near Blairsburg, Iowa. This is MidAmerican Energy's Century Wind Site.

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A PHI Company

Delaware Energy Plan and Economic Development Working Group

August 26, 2008

Mark Finfrock

Managing the Future Energy Supply Needs of Delmarva's Customers

The Company's Integrated Resource Planning (IRP)[1] has concluded that there is no single "silver bullet" to resolve future electrical supply needs.

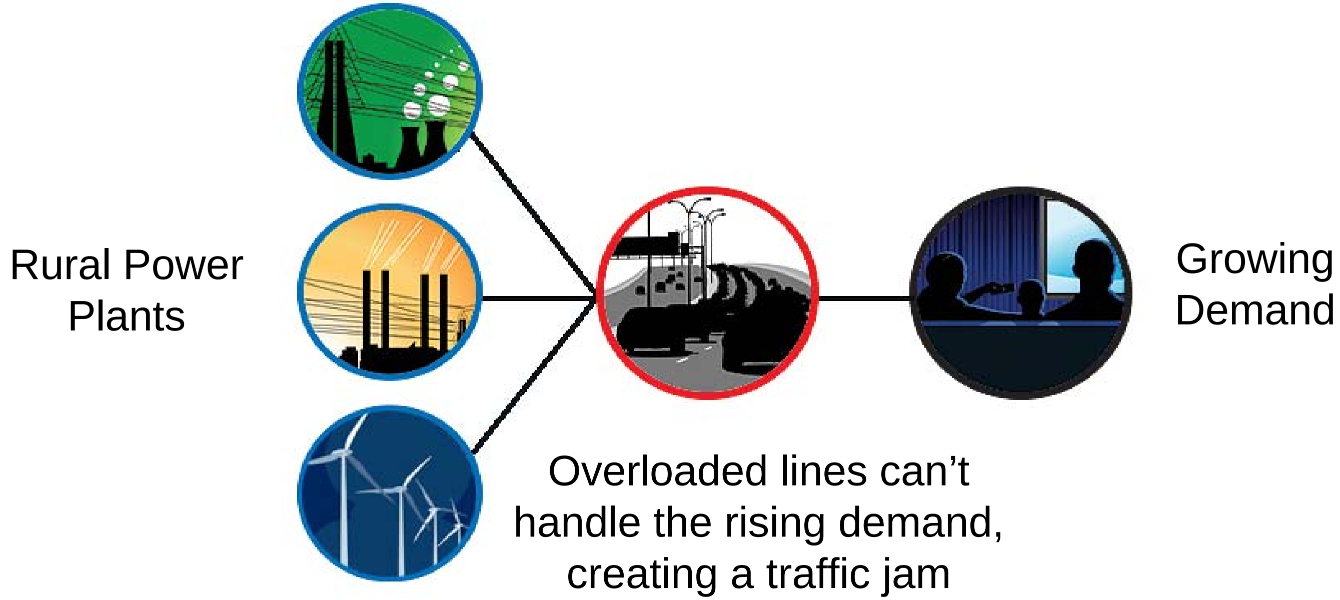
A balance of energy efficiency and demand response programs, market resources, transmission enhancements, and renewable resources must all come together to manage our future needs.

[1] IRP is required under the Electric Utility Retail Customer Supply Act of 2006 (HB 6). The Company's IRP can be found at www.depsc.delaware.gov

Managing the Future Energy Supply Needs of Delmarva's Customers

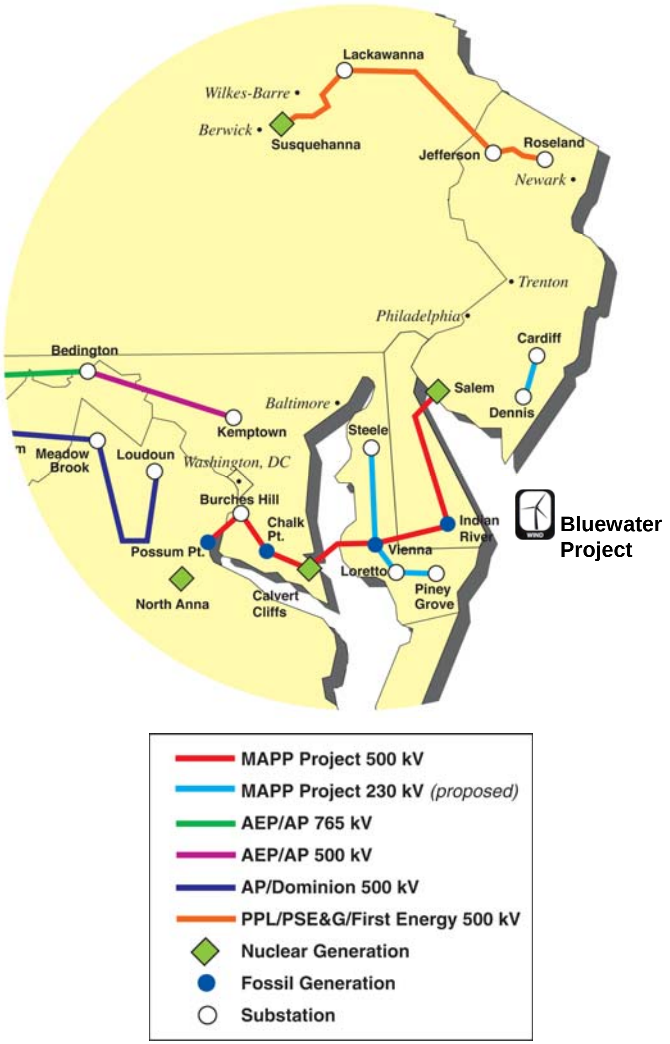
Energy Efficiency and Demand Response Programs	Various programs identified in Company's IRP supported by the build-out of an advanced meter infrastructure and an appropriate revenue decoupling mechanism
Market Resources	Portfolio management approach including load following contracts, short and long-term block contracts, and spot market purchases
Transmission Enhancements	
Renewable Resources	 

- It’s been 25 years since the last major interstate transmission line was built in the Mid-Atlantic Region (New York to Washington D.C.).
- Demand for electricity is rapidly increasing in urban centers. At the same time older coal plants are nearing retirement.
- It is difficult to build new power plants close to these high-demand areas. This means power must be imported from rural power plants.
- Mid-Atlantic off-shore wind growth will be dependant on the ability to export power in times of low local demand and high generation.
- The existing transmission system cannot move enough power to meet future demand needs, creating an electricity traffic jam and leading to possible power shortages in the future.



Benefits for Delaware

- Ensures a safe, reliable supply of electricity over the long-term by improving the flow of electricity in the Mid-Atlantic Region
- Removing import barriers will allow the system to access new generation including new nuclear, wind power and other planned renewable power projects
- Increases power import/export capability within the Delmarva Peninsula by more than 1,000 MW giving the State access to less expensive power and providing more transportation access for new in-State or near-State generation (i.e., off-shore wind), supporting economic growth and employment
- The cost for these benefits will be shared across the entire PJM system of 51 million customers. We estimate the cost to be less the 40 cents per 1000 kwh's
- Reduces the cost of delivered power by reducing congestion



Meeting our Renewable Energy Needs Into the Future for Delaware – Wind Power

Delmarva Power has entered into four long term wind contracts with three developers for providing renewable energy to our Delaware customers:

- **Synergics 100 MW** (two land-based wind farms for SOS customers only)
- **AES 70 MW** (one land-based wind farm for SOS customers only)
- **Bluewater Wind 200 MW** (offshore, 100 MW SOS, 100 for non-SOS)

Wind Power – Size and Pricing Terms

Contract	Location	MWs	Products Purchased	Initial Delivery Date*	Guaranteed Initial Delivery Date**	Annual Forecasted Output	Price
						(Gwh)	
Synergics Roth Rock Wind Energy, LLC	Garrett County, MD	40	Energy and an equivalent level of RECs	June 1, 2009	December 31, 2009	122	$81/Mwh at the Initial Delivery Date increasing annually at the lesser of: (a) a factor equal to fifty percent 50% of the CPI; or (b) 2.5%.
Synergics Eastern Wind Energy, LLC	Garrett County, MD	30 to 60	Energy and an equivalent level of RECs	June 1, 2009	December 31, 2010	**30 MW:** 92 **60 MW:** 184	Identical pricing as Synergics Roth Rock
AES Armenia Mountain Wind, LLC	Tioga and Bradford Counties, PA	70	Energy and an equivalent level of RECs	November 1, 2009	April 30, 2010	171	$94/Mwh fixed throughout contract term.
Bluewater Wind DE, LLC	11.5 miles East of Rehoboth Beach, DE	200	Capacity, energy and 29% equivalent level of RECs***	N.A.	December 31, 2014	558	In 2008 dollars, $117.10/Mwh for energy and RECs, and capacity priced at $71.99/kw-year. All increasing annually at 2.5%.

* "Initial Delivery Date" means the date, which shall be the earliest start date.

** "Guaranteed Initial Delivery Date" means the date, which shall be the latest start date before damages accrue and are paid.

*** Senate Bill 328 permits Delmarva to receive 350% credit for the RECs received from the Bluewater contract to meet RPS requirements. The multiplier results in Delmarva receiving a "REC equivalent" equal to the level of energy supplied by Bluewater.

Each of the four contracts can be found on Delmarva's website at www.delmarva.com

A Portfolio of Wind Resources for Delmarva Power Delaware SOS Customers - Cost Comparison

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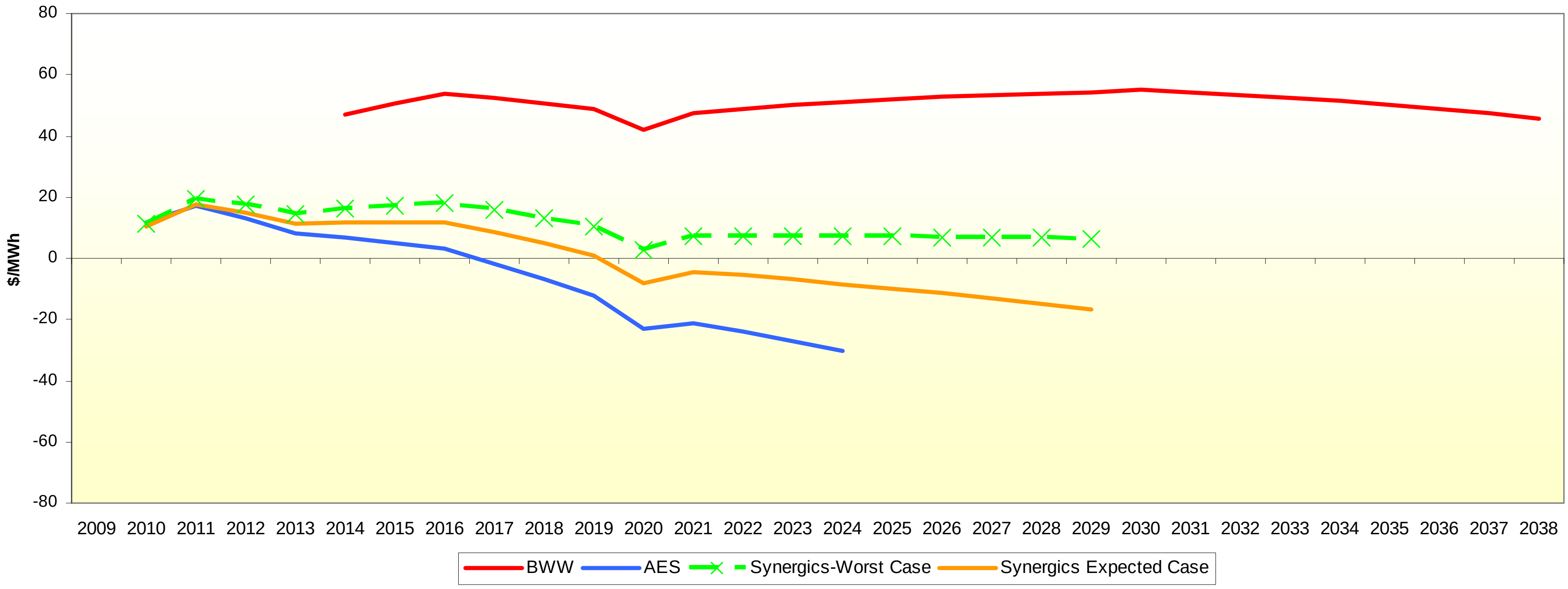
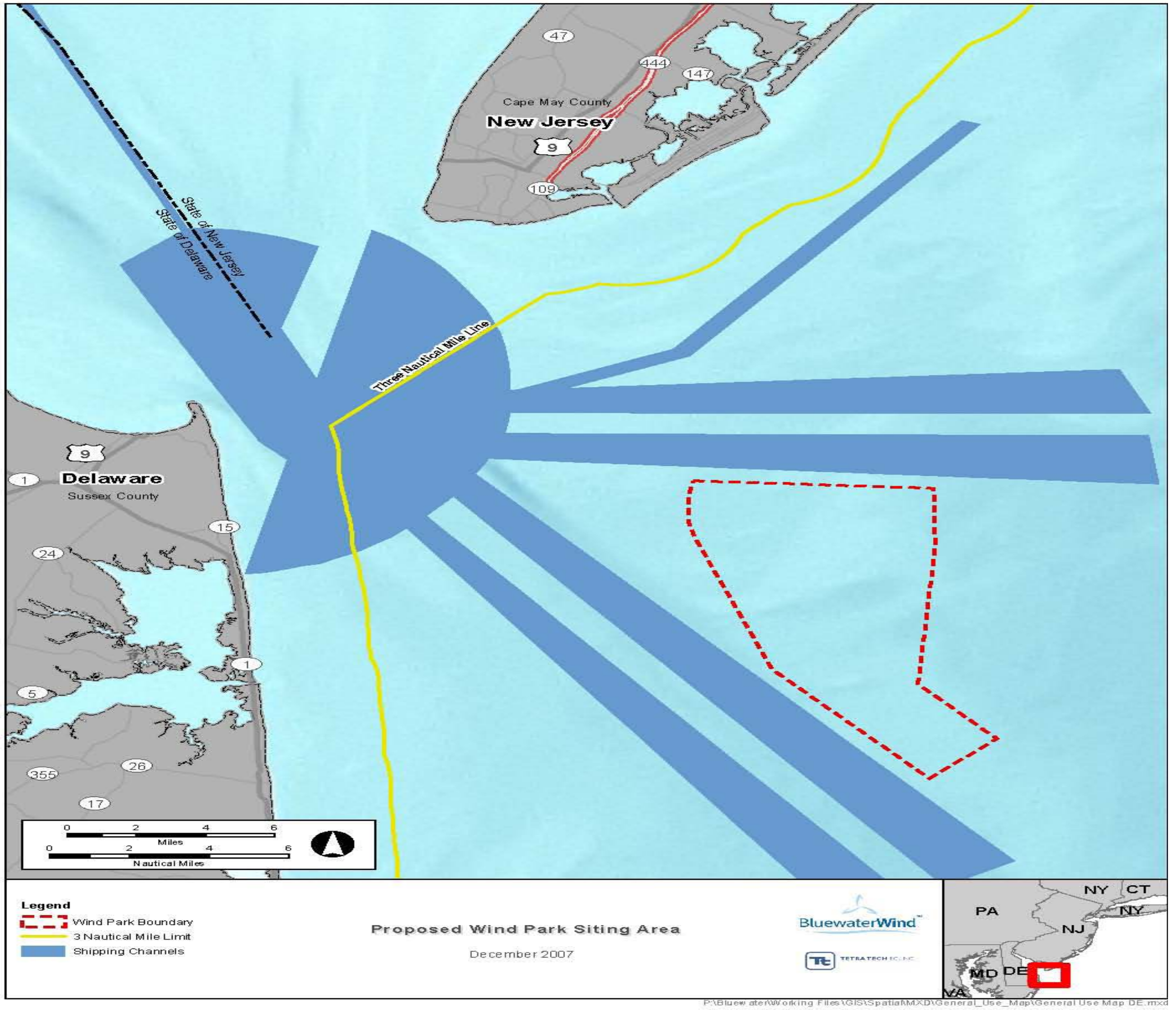
Incremental Cost per Megawatthour to Delmarva over Market Value of Land Based and Bluewater Wind Price Offers



Note: Prices reflect the delta from the market price in Delmarva in comparable hours. Prices do not reflect customer rates.
For land-based wind, capacity was valued at the market price.
Synergics line shown above reflects Eastern Energy offer. Synergics Roth Rock has the same price offer and term, but starts one year earlier.
Market value reflects firm power price while the bid prices are unit contingent and hence not firm.

Location of Bluewater Facility



Description of Bluewater Facility

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- Bluewater Wind, owned by Australian Babcock and Brown, is planned to be an ocean-based wind farm with a capacity not less than 200 MW and not more than 600 MW.

- It is to be located in the Atlantic Ocean approximately 11.5 nautical miles East of Rehoboth Beach, DE, between the northern and southern shipping channels into the Delaware Bay.

- The Site includes the seafloor corridor through which electrical interconnection cables transit from this ocean area to Delmarva Power's Indian River Substation.

- Turbine size is not yet determined.

Description of Bluewater Facility

- It is proposed that Bluewater Wind may interconnect to Delmarva Power's transmission system near the Bethany substation, and planned that the energy will then be transmitted approximately 12 miles to Delmarva Power's Indian River Substation.

- Bluewater Wind will pay for any needed transmission facilities up to the Indian River Substation, but those facilities will be operated by Delmarva Power.

- Start dates are subject to various contingencies, but permitting currently is projected to be completed in 2012.

Bluewater/Delmarva Agreement

- Delmarva Power will buy 200 megawatts of power from the Bluewater wind farm, which can be sized as large as 600 MW. Regardless of the final size, Delmarva Power will purchase a proportion of power equal in amount to that generated by a 200 megawatt nameplate facility.

- The purchase includes energy, capacity that clears the PJM auction process, ancillary services, if applicable, and most environmental attributes associated with the energy or capacity, such as RECs.

- BWW assumes costs of constructing interconnection facilities, and is responsible for transmission service and facilities to deliver the energy to Delmarva Power's Indian River substation. Delmarva Power is responsible for certain network upgrades at and after the point of delivery unless PJM assigns those costs to someone else.

- Delmarva Power will work with Babcock & Brown to establish an optional program whereby any Delmarva Power Delaware customer may choose to purchase more electricity supply from the wind farm.

What made this agreement work?

- Key enabling legislations passed; 1) spread costs and benefits across all Delmarva's Delaware customers, and 2) give 350% multiplier for offshore RECs towards meeting state goals.
- The size was greatly reduced from earlier discussions based on the needs of Delmarva Power customers.
- The total and unit cost was reduced from earlier discussions.
- Strong desire across the state supporting above market cost for this off-shore renewable project.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

****

In the matter, on the Commission's own motion regarding the regulatory reviews, revision determinations, and/or approvals necessary for CONSUMERS ENERGY COMPANY to fully comply with Public Acts 286 and 295 of 2008.	))))))	Case No. U-15805
In the matter, on the Commission's own motion, regarding the regulatory reviews, revisions, determinations, and/or approvals necessary for CONSUMERS ENERGY COMPANY to fully comply with Public Acts 286 and 295 of 2008.	))))))	Case No. U-15889

EXHIBITS MEC-7 and MEC-8 OF
GEORGE E. SANSOUCY

ON BEHALF OF
THE ECOLOGY CENTER,
ENVIRONMENTAL LAW & POLICY CENTER,
AND MICHIGAN ENVIRONMENTAL COUNCIL

April 9, 2009

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Consumers Energy Company	(1) [ ] An Original (2) [X] A Resubmission	08/27/2002	End of 2000/Q4

MEC-7

ACCUMULATED PROVISION FOR DEPRECIATION OF ELECTRIC UTILITY PLANT (Account 108)

1. Explain in a footnote any important adjustments during year.
2. Explain in a footnote any difference between the amount for book cost of plant retired, Line 11, column (c), and that reported for electric plant in service, pages 204-207, column 9d), excluding retirements of non-depreciable property.
3. The provisions of Account 108 in the Uniform System of accounts require that retirements of depreciable plant be recorded when such plant is removed from service. If the respondent has a significant amount of plant retired at year end which has not been recorded and/or classified to the various reserve functional classifications, make preliminary closing entries to tentatively functionalize the book cost of the plant retired. In addition, include all costs included in retirement work in progress at year end in the appropriate functional classifications.
4. Show separately interest credits under a sinking fund or similar method of depreciation accounting.

Section A. Balances and Changes During Year

Line No.	Item (a)	Total (c+d+e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased to Others (e)
1	Balance Beginning of Year	3,713,292,517	3,713,287,222	5,295	
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	206,738,004	206,738,004		
4	(413) Exp. of Elec. Plt. Leas. to Others				
5	Transportation Expenses-Clearing	293,720	293,720		
6	Other Clearing Accounts				
7	Other Accounts (Specify):				
8					
9	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 8)	207,031,724	207,031,724		
10	Net Charges for Plant Retired:				
11	Book Cost of Plant Retired	49,775,657	49,775,657		
12	Cost of Removal	108,691,939	108,691,939		
13	Salvage (Credit)	3,439,434	3,439,434		
14	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 11 thru 13)	155,028,162	155,028,162		
15	Other Debit or Cr. Items (Describe):	-46,731,866	-46,731,866		
16					
17	Balance End of Year (Enter Totals of lines 1, 9, 14, 15, and 16)	3,718,564,213	3,718,558,918	5,295	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Consumers Energy Company	(1) [ ] An Original (2) [X] A Resubmission	08/27/2002	End of 2000/Q4

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4. Show separately interest credits under a sinking fund or similar method of depreciation accounting.

Section A. Balances and Changes During Year

Line No.	Item (a)	Total (c+d+e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased to Others (e)
	Section B. Balances at End of Year According to Functional Classification				
18	Steam Production	846,904,180	846,903,938	242	
19	Nuclear Production	1,276,100,521	1,276,100,521		
20	Hydraulic Production-Conventional	7,567,937	7,567,937		
21	Hydraulic Production-Pumped Storage	84,069,252	84,069,252		
22	Other Production	38,110,550	38,110,550		
23	Transmission	231,933,624	231,928,955	4,669	
24	Distribution	1,199,625,660	1,199,625,276	384	
25	General	34,252,489	34,252,489		
26	TOTAL (Enter Total of lines 18 thru 25)	3,718,564,213	3,718,558,918	5,295	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Consumers Energy Company	(1) ☐ An Original (2) ☐ A Resubmission	/ /	End of 2000/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	10,273,878	12,342,299
5	(501) Fuel	302,913,306	309,423,547
6	(502) Steam Expenses	11,482,364	11,463,745
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	7,204,743	7,195,092
10	(506) Miscellaneous Steam Power Expenses	8,304,105	8,346,216
11	(507) Rents		
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	340,178,396	348,770,899
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	4,852,958	5,106,282
16	(511) Maintenance of Structures	4,151,219	5,264,956
17	(512) Maintenance of Boiler Plant	23,846,914	20,173,799
18	(513) Maintenance of Electric Plant	9,613,988	5,294,256
19	(514) Maintenance of Miscellaneous Steam Plant	2,404,761	2,110,670
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	44,869,840	37,949,963
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	385,048,236	386,720,862
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering	7,369,997	8,226,512
25	(518) Fuel	28,624,899	29,611,593
26	(519) Coolants and Water	4,513,331	4,274,803
27	(520) Steam Expenses	10,131,021	12,045,506
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses	2,228,927	2,290,297
31	(524) Miscellaneous Nuclear Power Expenses	26,607,239	27,823,327
32	(525) Rents	102,172	151,111
33	TOTAL Operation (Enter Total of lines 24 thru 32)	79,577,586	84,423,149
34	Maintenance		
35	(528) Maintenance Supervision and Engineering	6,665,179	7,552,266
36	(529) Maintenance of Structures	1,453,038	1,262,196
37	(530) Maintenance of Reactor Plant Equipment	12,682,156	15,807,677
38	(531) Maintenance of Electric Plant	6,382,971	4,033,981
39	(532) Maintenance of Miscellaneous Nuclear Plant	3,423,615	2,380,472
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)	30,606,959	31,036,592
41	TOTAL Power Production Expenses-Nuc. Power (Entr tot lines 33 & 40)	110,184,545	115,459,741
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering	643,675	723,738
45	(536) Water for Power	981,796	881,053
46	(537) Hydraulic Expenses	2,868,381	3,370,987
47	(538) Electric Expenses	1,338,968	1,426,237
48	(539) Miscellaneous Hydraulic Power Generation Expenses	942,684	1,059,431
49	(540) Rents	2,079	574
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	6,777,583	7,462,020

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Consumers Energy Company	(1) [ ] An Original (2) [ ] A Resubmission	/ /	End of 2000/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	363,887	287,399
54	(542) Maintenance of Structures	281,314	341,271
55	(543) Maintenance of Reservoirs, Dams, and Waterways	1,697,146	960,264
56	(544) Maintenance of Electric Plant	1,334,676	829,235
57	(545) Maintenance of Miscellaneous Hydraulic Plant	682,015	860,573
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	4,359,038	3,278,742
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	11,136,621	10,740,762
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	102,376	119,179
63	(547) Fuel	1,744,599	5,047,089
64	(548) Generation Expenses	-4,747	107,429
65	(549) Miscellaneous Other Power Generation Expenses	81,823	98,212
66	(550) Rents		
67	TOTAL Operation (Enter Total of lines 62 thru 66)	1,924,051	5,371,909
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	138,079	123,773
70	(552) Maintenance of Structures	5,254	4,488
71	(553) Maintenance of Generating and Electric Plant	445,700	2,113,078
72	(554) Maintenance of Miscellaneous Other Power Generation Plant		
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	589,033	2,241,339
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	2,513,084	7,613,248
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	925,105,963	850,313,686
77	(556) System Control and Load Dispatching	10,841,585	8,180,348
78	(557) Other Expenses	82,563	109,758
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	936,030,111	858,603,792
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	1,444,912,597	1,379,138,405
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	1,415,727	2,219,945
84	(561) Load Dispatching		
85	(562) Station Expenses	741,923	762,624
86	(563) Overhead Lines Expenses	961,091	956,617
87	(564) Underground Lines Expenses		
88	(565) Transmission of Electricity by Others	11,057,502	6,337,403
89	(566) Miscellaneous Transmission Expenses	2,155,325	1,358,191
90	(567) Rents	34,843	22,375
91	TOTAL Operation (Enter Total of lines 83 thru 90)	16,366,411	11,657,155
92	Maintenance		
93	(568) Maintenance Supervision and Engineering	185,263	155,850
94	(569) Maintenance of Structures	2,762,892	2,471,671
95	(570) Maintenance of Station Equipment	5,152,818	5,081,050
96	(571) Maintenance of Overhead Lines	2,402,819	2,425,759
97	(572) Maintenance of Underground Lines	123,081	57,902
98	(573) Maintenance of Miscellaneous Transmission Plant	90,580	77,956
99	TOTAL Maintenance (Enter Total of lines 93 thru 98)	10,717,453	10,270,188
100	TOTAL Transmission Expenses (Enter Total of lines 91 and 99)	27,083,864	21,927,343
101	3. DISTRIBUTION EXPENSES		
102	Operation		
103	(580) Operation Supervision and Engineering	12,481,322	12,451,045

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Consumers Energy Company	(1) ☐ An Original (2) ☐ A Resubmission	/ /	End of 2000/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
104	3. DISTRIBUTION Expenses (Continued)		
105	(581) Load Dispatching		
106	(582) Station Expenses	3,248,122	3,163,965
107	(583) Overhead Line Expenses	4,499,566	4,917,113
108	(584) Underground Line Expenses	2,639,342	2,047,087
109	(585) Street Lighting and Signal System Expenses	456	-82,636
110	(586) Meter Expenses	2,796,377	3,020,534
111	(587) Customer Installations Expenses	8,210,724	8,133,183
112	(588) Miscellaneous Expenses	8,681,549	8,867,192
113	(589) Rents	2,280,481	3,271,803
114	TOTAL Operation (Enter Total of lines 103 thru 113)	44,837,939	45,789,286
115	Maintenance		
116	(590) Maintenance Supervision and Engineering	3,051,121	3,363,756
117	(591) Maintenance of Structures	323,031	325,656
118	(592) Maintenance of Station Equipment	5,267,304	5,626,281
119	(593) Maintenance of Overhead Lines	34,895,115	38,961,012
120	(594) Maintenance of Underground Lines	2,087,520	1,905,880
121	(595) Maintenance of Line Transformers	465,710	468,336
122	(596) Maintenance of Street Lighting and Signal Systems	1,484,957	1,366,761
123	(597) Maintenance of Meters	986,861	1,074,270
124	(598) Maintenance of Miscellaneous Distribution Plant	83,048	73,580
125	TOTAL Maintenance (Enter Total of lines 116 thru 124)	48,644,667	53,165,532
126	TOTAL Distribution Exp (Enter Total of lines 114 and 125)	93,482,606	98,954,818
127	4. CUSTOMER ACCOUNTS EXPENSES		
128	Operation		
129	(901) Supervision	6,611,844	7,127,420
130	(902) Meter Reading Expenses	7,705,852	8,297,762
131	(903) Customer Records and Collection Expenses	19,343,649	20,726,999
132	(904) Uncollectible Accounts	6,203,538	4,160,031
133	(905) Miscellaneous Customer Accounts Expenses	609,921	655,925
134	TOTAL Customer Accounts Expenses (Total of lines 129 thru 133)	40,474,804	40,968,137
135	5. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
136	Operation		
137	(907) Supervision	74,519	161,707
138	(908) Customer Assistance Expenses	12,637,142	27,246,679
139	(909) Informational and Instructional Expenses	715,445	640,196
140	(910) Miscellaneous Customer Service and Informational Expenses		
141	TOTAL Cust. Service and Information. Exp. (Total lines 137 thru 140)	13,427,106	28,048,582
142	6. SALES EXPENSES		
143	Operation		
144	(911) Supervision	1,326,492	231,008
145	(912) Demonstrating and Selling Expenses	1,013,381	1,033,659
146	(913) Advertising Expenses		
147	(916) Miscellaneous Sales Expenses		
148	TOTAL Sales Expenses (Enter Total of lines 144 thru 147)	2,339,873	1,264,667
149	7. ADMINISTRATIVE AND GENERAL EXPENSES		
150	Operation		
151	(920) Administrative and General Salaries	28,629,746	32,508,728
152	(921) Office Supplies and Expenses	6,232,153	12,720,264
153	(Less) (922) Administrative Expenses Transferred-Credit	3,535,200	3,842,400

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Consumers Energy Company	(1) ☐ An Original (2) ☐ A Resubmission	/ /	End of 2000/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
154	7. ADMINISTRATIVE AND GENERAL EXPENSES (Continued)		
155	(923) Outside Services Employed	4,413,609	5,562,701
156	(924) Property Insurance	-1,952,369	5,812,026
157	(925) Injuries and Damages	6,679,317	3,455,203
158	(926) Employee Pensions and Benefits	67,674,646	70,481,984
159	(927) Franchise Requirements		
160	(928) Regulatory Commission Expenses	782,637	667,989
161	(929) (Less) Duplicate Charges-Cr.		
162	(930.1) General Advertising Expenses	1,241,509	1,137,607
163	(930.2) Miscellaneous General Expenses	3,506,471	4,845,797
164	(931) Rents	1,563,153	1,294,059
165	TOTAL Operation (Enter Total of lines 151 thru 164)	115,235,672	134,643,958
166	Maintenance		
167	(935) Maintenance of General Plant	1,326,156	1,975,748
168	TOTAL Admin & General Expenses (Total of lines 165 thru 167)	116,561,828	136,619,706
169	TOTAL Elec Op and Maint Expn (Tot 80, 100, 126, 134, 141, 148, 168)	1,738,282,678	1,706,921,658

NUMBER OF ELECTRIC DEPARTMENT EMPLOYEES

1. The data on number of employees should be reported for the payroll period ending nearest to October 31, or any payroll period ending 60 days before or after October 31.

2. If the respondent's payroll for the reporting period includes any special construction personnel, include such employes on line 3, and show the number of such special construction employees in a footnote.

3. The number of employees assignable to the electric department from joint functions of combination utilities may be determined by estimate, on the basis of employee equivalents. Show the estimated number of equivalent employees attributed to the electric department from joint functions.

1. Payroll Period Ended (Date)	12/31/2000
2. Total Regular Full-Time Employees	5,777
3. Total Part-Time and Temporary Employees	60
4. Total Employees	5,837

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Consumers Energy Company	(1) [ ] An Original (2) [X] A Resubmission	08/27/2002	End of 2000/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Account 403, 404, 405)
(Except amortization of aquisition adjustments)

1. Report in Section A for the year the amounts for: (a) Depreciation Expense (Account 403); (b) Amortization of Limited-Term Electric Plant (Account 404); and (c) Amortization of Other Electric Plant (Account 405).
2. Report in Section 8 the rates used to compute amortization charges for electric plant (Accounts 404 and 405). State the basis used to compute charges and whether any changes have been made in the basis or rates used from the preceding report year.
3. Report all available information called for in Section C every fifth year beginning with report year 1971, reporting annually only changes to columns (c) through (g) from the complete report of the preceding year.
Unless composite depreciation accounting for total depreciable plant is followed, list numerically in column (a) each plant subaccount, account or functional classification, as appropriate, to which a rate is applied. Identify at the bottom of Section C the type of plant included in any sub-account used.
In column (b) report all depreciable plant balances to which rates are applied showing subtotals by functional Classifications and showing composite total. Indicate at the bottom of section C the manner in which column balances are obtained. If average balances, state the method of averaging used.
For columns (c), (d), and (e) report available information for each plant subaccount, account or functional classification Listed in column (a). If plant mortality studies are prepared to assist in estimating average service Lives, show in column (f) the type mortality curve selected as most appropriate for the account and in column (g), if available, the weighted average remaining life of surviving plant. If composite depreciation accounting is used, report available information called for in columns (b) through (g) on this basis.
4. If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state at the bottom of section C the amounts and nature of the provisions and the plant items to which related.

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Amortization of Limited Term Electric Plant (Acc 404) (c)	Amortization of Other Electric Plant (Acc 405) (d)	Total (e)
1	Intangible Plant		649,595	308,741	958,336
2	Steam Production Plant	42,171,900			42,171,900
3	Nuclear Production Plant	40,129,420		56,440,322	96,569,742
4	Hydraulic Production Plant-Conventional	1,559,600			1,559,600
5	Hydraulic Production Plant-Pumped Storage	5,574,200			5,574,200
6	Other Production Plant	746,800			746,800
7	Transmission Plant	11,930,900			11,930,900
8	Distribution Plant	96,741,300			96,741,300
9	General Plant	7,883,884			7,883,884
10	Common Plant-Electric	10,548,941	1,844,436	5,640,522	18,033,899
11	TOTAL	217,286,945	2,494,031	62,389,585	282,170,561

B. Basis for Amortization Charges

1. Amortization of Limited Term Plant is based on the life of the original building leases.
2. No change in the rates for accounts 404 and 405.
3. Amortization of Intangible Plant is based on the estimated life of the intangible plant.
4. Common Plant Depreciation and Amortization Expenses:

	Account 403	Account 404	Account 405	Total
A. Allocation of Common Depreciation & Amortization Expenses	10,548,941	1,844,436	5,640,522	18,033,899
B. Allocation of Gas Depreciation Expense	0	0	0	0
Total	10,548,941	1,844,436	5,640,522	18,033,899

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Consumers Energy Company	(1) [ ] An Original (2) [X] A Resubmission	08/27/2002	End of 2000/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	Steam						
13	310.2	836	55.00		1.58		
14	311.0	181,981	43.00	-5.70	2.54		
15	312.0	523,118	38.00	-7.00	3.04		
16	314.0	184,337	43.00	-6.20	2.40		
17	315.0	49,734	40.00	-6.10	2.69		
18	316.0 & 316.1	14,356	26.00	-8.30	4.74		
19							
20	Total	954,362					
21							
22	Campbell #3						
23	310.2	19	39.00		2.37		
24	311.0	182,611	39.00	-5.40	2.60		
25	312.0	293,650	37.00	-5.70	2.88		
26	314.0	55,000	38.00	-5.50	2.72		
27	315.0	38,516	39.00	-5.40	2.61		
28	316.0 & 316.1	5,317	33.00	-6.60	3.22		
29							
30	Total	575,113					
31							
32	Hydro						
33	330.3	41	105.00		2.47		
34	331.0 & 331.3	3,540	71.00		2.15		
35	332.0 & 332.1	45,882	76.00	-30.00	2.70		
36	333.0	5,020	85.00		2.16		
37	334.0	2,665	68.00		2.40		
38	335.0	1,692	45.00		2.64		
39	336.0	64	54.00		2.18		
40							
41	Total	58,904					
42	Ludington Pumped Storg						
43	331.0	15,982	55.00	-47.00	3.23		
44	332.0	97,348	55.00	-47.00	3.27		
45	333.0	37,792	55.00	-47.00	3.91		
46	334.0	5,256	55.00	-47.00	3.25		
47	335.0	1,774	55.00	-47.00	3.57		
48	336.0	1,536	55.00	-47.00	3.22		
49							
50	Total	159,688					

Name of Respondent Consumers Energy Company	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 08/27/2002	Year/Period of Report End of 2000/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	Other						
13	341.0	759	32.00	-5.00	3.76		
14	342.0	401	35.00	-5.00	2.75		
15	344.0	34,163	36.00	-5.00	1.79		
16	345.0	1,130	28.00	-5.00	5.32		
17	346.0	400	18.00	5.00	9.42		
18							
19	Total	36,853					
20							
21	Transmission						
22	350.2	15,550	75.00		1.38	R3	
23	352.0	10,568	60.00	-15.00	2.01	R4	
24	353.0	187,435	50.00	-12.00	2.33	R2	
25	354.1	93,984	75.00	-90.00	2.62	R3	
26	354.2	4,712	75.00		1.38	R3	
27	355.1	57,085	60.00	-45.00	2.50	R2.5	
28	355.2	6,393	70.00		1.51	R5	
29	356.0	121,029	60.00	-40.00	2.44	R3	
30	357.0		55.00	-20.00	2.29	S3	
31	358.1		40.00	-10.00	2.81	R2	
32	358.2		50.00		2.10	R2	
33	359.0	971	75.00		1.43	R3	
34							
35	Total	497,727					
36							
37	Distribution - HV						
38	360.4	15,832	75.00		1.38	R3	
39	361.1	8,668	60.00	-15.00	2.01	R4	
40	362.1	179,217	50.00	-12.00	2.33	R2	
41	364.1	1,387	75.00	-90.00	2.62	R3	
42	364.2	89	75.00		1.38	R3	
43	364.3	69,051	60.00	-45.00	2.50	R2.5	
44	364.4	6,891	70.00		1.51	R5	
45	365.2	53,937	60.00	-40.00	2.44	R3	
46	366.1	801	55.00	-20.00	2.29	S3	
47	367.1	2,957	40.00	-10.00	2.81	R2	
48	367.2	5	50.00	1.00	2.10	R2	
49							
50	Total	338,835					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Consumers Energy Company	(1) [ ] An Original (2) [X] A Resubmission	08/27/2002	End of 2000/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	Distribution						
13	360.2	14,391	60.00		1.50	R2	
14	361.0	19,985	50.00	-15.00	2.17	S0.5	
15	362.0	291,236	38.00	-2.00	2.55	S-.5	
16	364.0	523,479	50.00	-132.00	4.39	R2	
17	365.0	480,279	55.00	-30.00	2.26	R1.5	
18	366.0	43,302	50.00	-30.00	2.46	S0.5	
19	367.0	311,728	45.00	-25.00	2.64	L2	
20	368.0	481,695	40.00	-25.00	2.92	S2	
21	369.1	139,580	45.00	-87.00	3.95	R1	
22	369.2	269,218	40.00	-25.00	3.01	R3	
23	370.0	122,351	29.00	-19.00	3.85	R1	
24	371.0	6,232	12.00	-6.00	8.41	L1	
25	373.0	68,036	30.00	-90.00	6.01	R0.5	
26							
27	Total	2,771,512					
28							
29	General						
30	389.2	177	50.00		11.76	S4	
31	390.0 & 390.1	36,455	40.00	-15.00	5.20	R2	
32	391.0 & 391.1	1,395	27.00	10.00	5.93	S-0.5	
33	391.2 & 391.3	8,571	7.00		24.60	R4	
34	393.0 & 393.1	82	35.00	5.00	8.37	S1.5	
35	394.0 & 394.1	4,646	26.00	10.00	5.67	L2	
36	395.0 & 395.1	4,408	25.00		5.55	S2	
37	396.0	593	12.00	20.00	17.50	L1	
38	397.0 & 397.1	35,450	20.00	-10.00	9.21	L2	
39	398.0 & 398.1	1,334	24.00		5.37	L2	
40							
41	Total	93,111					
42							
43							
44	See Footnote for						
45	Reponse to						
46	Instruction 4						
47							
48							
49							
50							

Schedule Page: 336 Line No.: 13 Column: b

(1) Amounts in Column (b) are the average of the beginning and ending balances for 2000.

Schedule Page: 336 Line No.: 13 Column: e

(2) Depreciation Rates in column (e) are per MPSC Order No. U-10754, effective December 5, 1996 and MPSC Order No. U-11724, effective April 1, 2000 (Ludington).

Schedule Page: 336.2 Line No.: 46 Column: a

RESPONSE TO INSTRUCTION 4

Nuclear Decommissioning (External Trust Fund) per MPSC order in case no. U-11662 effective January 1, 1999.

	Palisades	Big Rock
Estimated 1997 Cost (000)	504,234	293,861
Inflation Rate	4.54	4.52
Earnings Rate	7.18	7.18
Plant Retirement Date	2007	2000

The Big Rock plant was retired August 29, 1997, but collection of decommissioning funds continued until December 31, 2000.

In 2000, the operating license for the Palisades Nuclear Plant was extended to the year 2011.

MEC-8

The Detroit Edison Company
One Energy Plaza, Detroit, MI 48226-1279

Detroit Edison
A DTE Energy Company

Jon P. Christinidis
(313) 235-7706
christinidisj@dteenergy.com

March 27, 2009

Ms. Mary Jo Kunkle
Executive Secretary
Michigan Public Service Commission
6545 Mercantile Way
Lansing, Michigan 48909

Re: In the matter, on the Commission's own motion, regarding the regulatory reviews, revisions, determinations, and/or approvals necessary for The Detroit Edison Company to fully comply with Public Acts 286 and 295 of 2008
MPSC Case No. U-15806-K (Paperless e-file)

Dear Ms. Kunkle:

Attached for electronic filing is The Detroit Edison Company's Ex Parte Application for Approval of Renewable Energy Contract, redacted Detroit Edison/Heritage Renewable Energy Contract, Exhibit No. A-8 (JHB-4) from Case No. U-15806-RPS, Affidavit of Irene M. Dimitry, Affidavit of Barbara J. Tuckfield and Affidavit of Kenneth D. Johnston in the above-captioned matter. Also attached is a Proof of Service.

Very truly yours,

Jon P. Christinidis

JPC/kbt
Attachment
cc: Service list

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter, on the Commission's own motion, regarding the regulatory reviews, revisions, determinations, and/or approvals necessary for The Detroit Edison Company to fully comply with Public Acts 286 and 295 of 2008.	))))))	Case No. U-15806-K

EX PARTE APPLICATION FOR APPROVAL OF RENEWABLE ENERGY CONTRACT

The Detroit Edison Company ("Detroit Edison", "Company" or "Applicant"), a corporation organized and existing under and by virtue of the laws of the State of Michigan, with its principal office at One Energy Plaza, Detroit, Michigan 48226, hereby files this application pursuant to the Rules of Practice and Procedure Before the Commission R460.17101 et seq., the Michigan Court Rules MCR 2.100 et seq., and the Michigan Administrative Procedures Act (MCL 24.201 et. seq.) seeking the Michigan Public Service Commission's ("Commission") ex parte approval of a Renewable Energy Contract pursuant to 2008 PA 295 (MCL 460.1001 et. seq.), ex parte approval of the associated renewable energy transfer price for recovery under the Company's Power Supply Cost Recovery process under MCL 460.6j, ex parte approval of the capacity charges set forth in Case No. U-15806-RPS Exhibit No. A-8 (JHB-4) 2009 Forecasted Transfer price schedule, column (k) for purposes of MCL 460.6j(13)(b) and ex parte approval of any additional approvals that the Commission may deem necessary under MCL 460.6j. In support of its request, Detroit Edison states as follows:

1. Detroit Edison is a wholly-owned subsidiary of DTE Energy Company, supplying retail electric service to customers located in Southeast Michigan, and is a public utility and electric provider subject to the jurisdiction of the Commission.

2. Applicant is presently serving its jurisdictional metered electric customers under rates and charges approved by the Commission.

3. On October 6, 2008, Governor Jennifer M. Granholm signed 2008 PA 295, the "clean, renewable, and efficient energy act," into law. This Application is being filed in accordance with 2008 PA 295 (MCL 460.1001 et. seq.) and the Commission's October 21, 2008 Order in Case No. U-15806 and December 4, 2008 Order in Case No. U-15800, implementing 2008 PA 295.

4. The "clean, renewable, and efficient energy act" requires Commission approval of certain types of contracts entered into by electric providers, like Detroit Edison, for purposes of 2008 PA 295, specifically including Renewable Energy Contracts. An Electric Provider includes "[a]ny person or entity that is regulated by the commission for the purpose of selling electricity to retail customers in this state." (MCL 460.1005(a)(i)) A Renewable Energy Contract is defined by 2008 PA 295 to mean "a contract to acquire renewable energy and the associated renewable energy credits from 1 or more renewable energy systems." (MCL 460.1011(c)) A Renewable Energy System means "a facility, electricity generation system, or set of electricity generation systems that use 1 or more renewable energy resources to generate electricity." (MCL 460.1011(k)) A Renewable Energy Resource is defined to include "[w]ind energy." (MCL 460.1011(i))

5. Renewable Energy Contracts are required to be approved by the Commission pursuant to MCL 460.1033(3), which relevantly provides:

> "An electric provider shall submit a contract entered into pursuant to subsection (1) [*Subsection 1(b) includes, and provides for approval of, unsolicited Renewable Energy Contracts*] to the commission for review and approval. If the commission approves the contract, it shall be considered to be consistent with the electric provider's renewable energy plan. The commission shall not approve a contract based on an unsolicited proposal unless the commission determines that the unsolicited proposal provides opportunities that may not otherwise be available or commercially practical."

For Renewable Energy Contracts, the Commission must determine whether the contract provides reasonable and prudent terms and conditions pursuant to MCL 460.1037 and complies with the retail rate impact limits under MCL 460.1045.

6. On December 4, 2008, the Commission issued a Temporary Order in Case No. U-15800 pursuant to MCL 460.1191(1), which relevantly provides:

> "Within 60 days after the effective date of this act, the commission shall issue a temporary order implementing this act, including but not limited to, all of the following:
>
> (a) Formats of renewable energy plans for various categories of electric providers.
>
> (b) Guidelines for requests for proposals under this act."

The Commission's December 4, 2008 Order explains that:

> "Under Section 37, all providers whose rates are regulated by the Commission must file renewable energy contracts or contracts to purchase RECs with or without the associated energy with the Commission for review and approval. The Commission intends to review and approve these submitted contracts on an expedited basis with a target of issuing the order within 30 calendar days from the date of filing of each contract." (MPSC Case No. U-15800 Order dated December 4, 2008, p. 16)

7. The attached 20-year contract between Detroit Edison and Heritage Sustainable Energy, LLC. (hereinafter "Heritage") is a Renewable Energy Contract pursuant to 2008 PA 295 involving the provision of 14-16 Megawatts nameplate of wind-powered electric capacity, energy and associated renewable and environmental benefits, including Renewable Energy Credits (hereinafter "RECs") from Heritage to Detroit Edison. (See Attached Redacted Detroit Edison/Heritage Renewable Energy Contract)

8. A limited number of commercially sensitive terms and conditions in the Detroit Edison/Heritage Renewable Energy Contract have been redacted to maintain confidentiality, consistent with past practice at the Commission. For example, the Commission determined in MPSC Case No. U-11130 that executed wholesale power purchase agreements contain confidential information. As a result, the Commission limited disclosure of the confidential portions to the MPSC Staff only in order to "strike a proper balance between the public interest in disclosure and the protection of commercially sensitive information in a competitive environment." MPSC Case No. U-11130, Order dated October 20, 1997 p. 13; Accord, MPSC Case No. U-11631, Order dated April 14, 1998; MPSC Case No. U-11804 Order dated December 21, 1998; MPSC Case No. U-11688 Order dated June 26, 1998; MPSC Case No. U-11661, Order dated June 26, 1998. More recently, in MPSC Case No. U-14626 the Commission approved multiple renewable energy contracts with various contract provisions redacted. (MPSC Case No. U-14626 Order dated October 18, 2005; see also MCL 460.1193(2) "*The Commission and a provider shall handle confidential business information under this act in a manner consistent with state law and general rules of the Commission.*") In order to maintain a reasonably competitive environment for the provision of renewable energy, advanced cleaner energy and related equipment, products and services to Detroit Edison and its customers, it is

important to maintain the confidentiality of commercially sensitive information. Detroit Edison has therefore redacted portions of the Detroit Edison/Heritage Renewable Energy Contract.[1] (See attached Affidavit of Irene M. Dimitry, Detroit Edison's Director of Renewable Energy) The original unredacted Detroit Edison/Heritage Renewable Energy Contract is available for inspection by the MPSC Staff at the Company's premises.

9. This Detroit Edison/Heritage Renewable Energy Contract is an unsolicited proposal that provides opportunities that may not otherwise be available or commercially practical under reasonable and prudent terms and conditions. For example, the Detroit Edison/Heritage Renewable Energy Contract is projected to commence commercial operation by December 31, 2009, or sooner. The rapid commercial operation date of this new renewable energy project, including wind capacity, energy and RECs, is an opportunity that is unlikely to otherwise be available given the current long lead times for studying and approving interconnection requests. In addition, the contract pricing of a flat $116.00 per Megawatt hour net energy delivered less a $1.00 per Megawatt hour administration expense charge is lower than otherwise may be available in the future when demand may increase and credit markets are more stable. Specifically, the contract pricing of a net $115.00 per Megawatt hour net energy delivered is less than the sum of the average proposed wind energy transfer price and the average cost of RECs procured through Renewable Energy Contracts within Detroit Edison's Renewable Energy Plan, in part because Heritage intends to take advantage of "bonus depreciation" opportunities recently extended by the Federal government for a short window of time. This bonus depreciation is only available for projects with a 2009 or 2010 in-service date and for costs incurred in 2008 and 2009, provided a contract was signed after 2007. Finally, in the future,

[1] Detroit Edison reserves the right to redact different or additional terms and conditions in future contracts as circumstances and conditions warrant.

after credit markets stabilize and/or if national renewable energy standards are established, it may be difficult to obtain new wind turbines because they are long lead-time items produced by a limited number of manufacturers at facilities with limited manufacturing capacity. The wind turbines that would supply the Detroit Edison/Heritage Renewable Energy Contract are presently available at pricing levels consistent with this contract. However, with limited construction time remaining in 2009 and the potential volatility of turbine pricing due to unstable credit markets, the Detroit Edison/Heritage Renewable Energy Contract must be approved by the MPSC by no later than April 30, 2009 or Heritage has the right to terminate the agreement. (See attached Affidavit of Irene M. Dimitry, Detroit Edison Director of Renewable Energy; Detroit Edison/Heritage Renewable Energy Contract Provision 17.3)

10. The Detroit Edison/Heritage Renewable Energy Contract is consistent with Detroit Edison's Renewable Energy Plan filed in MPSC Case No. U-15806-RPS and is otherwise reasonable and prudent under MCL 460.1037 and consistent with the retail rate impact limits under MCL 460.1045. (See attached Affidavits of Irene M. Dimitry, Detroit Edison Director of Renewable Energy, Barbara J. Tuckfield, Regulatory Accounting Expert, and Kenneth D. Johnston, Regulatory Consultant)

11. The Company is also requesting that the Commission approve renewable energy transfer prices consistent with the Exhibit No. A-8 (JHB-4) 2009 Forecasted Transfer Price schedule, Column (l), (which was filed within Detroit Edison's Renewable Energy Plan in Case No. U-15806-RPS) for the energy and capacity associated with the Detroit Edison/Heritage Renewable Energy Contract for recovery under the Company's Power Supply Cost Recovery process under MCL 460.6j. (See attached MPSC Case No. U-15806-RPS Exhibit No. A-8 (JHB-4) Column (l); See also MCL 460.1047(2)(b)(iv); MCL 460.1049(3)(c)) The Company is herein

requesting that this Exhibit No. A-8 (JHB-4) schedule of renewable energy transfer prices remain in effect for the 20-year term of the Detroit Edison/Heritage Renewable Energy Contract for purposes of recovery under the Company's Power Supply Cost Recovery process under MCL 460.6j. The Company herein also specifically requests approval of the capacity charges set forth in Exhibit No. A-8 (JHB-4) 2009 Forecasted Transfer Price schedule, Column (k) for purposes of MCL 460.6j(13)(b) and any additional approvals that the Commission may deem necessary under MCL 460.6j. (MCL 460.6j(13)(b) provides, in pertinent part, *"In its order in a power supply cost reconciliation, the commission shall…(b)Disallow any capacity charges associated with power purchased for periods in excess of 6 months unless the utility has obtained the prior approval of the commission."*)

12. The approvals requested in this Application will not result in "*an alteration or amendment in rates or rate schedules*" and "*will not result in an increase in the cost of service to customers*" because the Detroit Edison/Heritage Renewable Energy Contract is consistent with the planned activities, expenses and revenue recovery mechanism surcharges described in Detroit Edison's Renewable Energy Plan in Case No. U-15806-RPS and therefore "*may be authorized and approved without notice or hearing.*" (MCL 460.6a(1)) Neither will there be any increase in Detroit Edison's PSCR factors or other charges for electric service resulting from the requested approvals. (See attached Affidavits of Irene M. Dimitry, Director of Renewable Energy, Barbara Tuckfield, Regulatory Accounting Expert, and Kenneth D. Johnston, Regulatory Consultant.) Thus, approval of this Application without notice or hearing is lawful and appropriate.

WHEREFORE, for the reasons stated above, Detroit Edison respectfully requests that the Commission expeditiously issue an *ex parte* order in this case by no later than April 30, 2009 that:

(i) Consistent with 2008 PA 295, approves the attached Detroit Edison/Heritage Renewable Energy Contract in its entirety and also approves the associated Exhibit No. A-8 (JHB-4) 2009 Forecasted Transfer Price schedule, Column (l), (filed within Detroit Edison's Renewable Energy Plan in Case No. U-15806-RPS) as the schedule of renewable energy transfer prices for the Detroit Edison/Heritage Renewable Energy Contract for recovery under the Company's Power Supply Cost Recovery process under MCL 460.6j for the 20-year term of the Renewable Energy Contract;

(ii) Determines that the Detroit Edison/Heritage Renewable Energy Contract is reasonable and prudent and provides opportunities that may not otherwise be available or commercially practical;

(iii) Provides approval of the capacity charges set forth in Case No. U-15806-RPS Exhibit No. A-8 (JHB-4) 2009 Forecasted Transfer Price schedule, Column (k) for purposes of MCL 460.6j(13)(b), and provides for any additional approvals that the Commission may deem necessary under MCL 460.6j;

(iv) Determines that the Detroit Edison/Heritage Renewable Energy Contract and related approvals will not result in an alteration or amendment in Detroit Edison's rates or rate schedules and will not result in an increase in the cost of service to Detroit Edison's customers and therefore may be authorized and approved without notice or hearing.

(v) Grants such further relief as the Commission may deem necessary or appropriate.

Respectfully submitted,

THE DETROIT EDISON COMPANY

By:______________________________________

Legal Department
Bruce R. Maters (P28080)
Jon P. Christinidis (P47352)
One Energy Plaza, 688 WCB
Detroit, Michigan 48226
(313) 235-7706

Dated: March 27, 2009

LONG-TERM NON-FIRM
RENEWABLE ENERGY CREDIT
AND RENEWABLE
POWER PURCHASE AGREEMENT

BETWEEN

THE DETROIT EDISON COMPANY

AND

HERITAGE STONEY CORNERS WIND FARM I, LLC

MARCH 17, 2009

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EXHIBITS

LONG-TERM NON-FIRM RENEWABLE ENERGY CREDIT AND RENEWABLE POWER PURCHASE AGREEMENT

This Long-Term Non-Firm Renewable Energy Credit and Renewable Power Purchase Agreement is made and entered into as of March 17, 2009 (the "Effective Date") by and between THE DETROIT EDISON COMPANY ("Buyer") and HERITAGE STONEY CORNERS WIND FARM I, LLC, a Michigan limited liability company ("Supplier"). Buyer and Supplier are referred to individually as a "Party" and collectively as the "Parties."

WHEREAS, Buyer is an operating electric public utility, subject to the applicable rules and regulations of the MPSC, as defined herein in Section 1.64, and the FERC, as defined herein in Section 1.42;

WHEREAS, Supplier desires to build the Generating Facility, as defined herein in Section 1.45, which is located in or around Richland Township, Michigan, and which Supplier desires to designate as a Renewable Energy System, as defined herein in Section 1.93, with the MPSC in order to comply with the requirements of this Agreement;

WHEREAS, the Parties intend that the electricity generated by the Generating Facility will comply with the requirements of the Clean, Renewable and Efficient Energy Act and satisfy a portion of Buyer's obligations under the Renewable Energy Credits requirements; and

WHEREAS, Supplier desires to sell to Buyer all the non-firm energy generated by the Generating Facility and all the associated Renewable Energy Credits and Renewable Energy Benefits, and Buyer desires to purchase such energy, Renewable Energy Credits, and Renewable Energy Benefits from Supplier upon the terms and conditions set forth herein.

NOW, THEREFORE, in consideration of the premises and the covenants and conditions contained herein and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, Buyer and Supplier, intending to be legally bound, hereby agree as follows:

DEFINITIONS

As used in this Agreement, the following terms shall have the meanings set forth below:

1.1 "Adjusted Delivered Amount" means, with respect to the calculation of a Shortfall for any Contract Year, the sum of (a) the Delivered Amount for such Contract Year and (b) the aggregate Deemed Delivered Amount for such Contract Year for (i) any Force Majeure, (ii) any Emergency, (iii) any curtailment as a result of the receipt of a curtailment notice from Buyer pursuant to Section 11.7, or (iv) the inability or failure of Buyer to accept Energy for any reason, including as a result of any curtailment by the Transmission Provider or the Control Area Operator, or a default by Buyer hereunder.

1.2 "Affiliate" means, with respect to any Person, each Person that directly or indirectly controls or is controlled by or is under common control with such

Person. For the purposes of this definition, "control" (including, with correlative meanings, the terms "controlled by" and "under common control with") as used with respect to any Person shall mean the possession, directly or indirectly, of the power to direct or cause the direction of the management and policies of such Person, whether through the ownership of voting securities, by contract, or otherwise.

1.3 "After Tax Basis" means a basis such that any payment received or deemed to have been received by a Party (the "Original Payment") under the terms of Section 19.1 of this Agreement shall be supplemented by a further payment to such Party so that the sum of the two (2) payments shall equal the Original Payment, after taking into account (a) all Taxes that would result from the receipt or accrual of such payments, if legally required, and (b) any reduction in Taxes that would result from the deduction of the expense indemnified against, if legally permissible, calculated by reference to the highest federal and Michigan statutory Tax rates applicable to corporations doing business in Michigan and on a net present value basis by reference to the applicable federal rate then in effect under section 1274(d) of the Internal Revenue Code of 1986, as such Law may be amended or superseded.

1.4 "Agreement" means this Long-Term Non-Firm Renewable Energy Credit and Renewable Power Purchase Agreement together with the Exhibits attached hereto, as such may be amended from time to time.

1.5 "Average Monthly Michigan Hub Firm Price" means the weighted average monthly price in dollars per MWh as calculated pursuant to the following procedures. The Average Monthly Michigan Hub Firm Price is calculated as the monthly average, weighted by hours, of the (i) Daily Michigan Hub Firm On-Peak Price and (ii) Daily Michigan Hub Firm Off-Peak Price, for such month. The Daily Michigan Hub Firm On-Peak Price is calculated for a given day as the price set forth in Megawatt Daily's price survey for Day-ahead markets for the MISO / On-peak / Michigan Hub basis location. The Daily Michigan Hub Firm Off-Peak Price is calculated for a given day as the price set forth in Megawatt Daily's price survey for Day-ahead markets for the MISO / Off-peak / Michigan Hub basis location.

1.6 "Base Hours" has the meaning ascribed to that term in Exhibit 19.

1.7 "Billing Period" has the meaning ascribed to that term in Section 9.2.1.

1.8 "Business Day" means any day other than Saturday, Sunday, and any day that is a holiday observed by Buyer.

1.9 "Buyer" has the meaning set forth in the preamble of this Agreement, and includes such Person's permitted successors and assigns.

1.10 "Buyer's REC Account" means the account maintained by the MPSC Administrator for the purpose of tracking the production, sale, transfer, purchase, and retirement of RECs by Buyer.

1.11 "Buyer's Required Regulatory Approvals" means the approvals, consents, authorizations, or permits of, or filing with, or notification to, the Governmental Authorities listed on Exhibit 9.

1.12 "Clean, Renewable and Efficient Energy Act" means an act of the Michigan Legislature relating to energy and requiring certain providers of electric utility service to comply with the standards for renewable energy, and providing for other matters relating thereto, codified as Michigan Revised Statutes, chapter MCL 460.1007 to 460.1195, the regulations promulgated there under inclusive, as such Laws may be amended or superseded.

1.13 "Commercial Operation" means that the Generating Facility has been constructed in accordance with the requirements of the IOA, the EPC Contract, and Good Utility Practice and has delivered Energy to the Delivery Point and all of the requirements set forth in Article 10 and Exhibits 6 and 7 have been satisfied. If Commercial Operation is not achieved on the first day of a month, then Commercial Operation shall be deemed to be achieved on the first day of the following month.

1.14 "Commercial Operation Date" means the date on which Commercial Operation occurs.

1.15 "Confidential Information" has the meaning ascribed to that term in Section 29.1.

1.16 "Contract Representative" of a Party means the individual designated by that Party in Exhibit 4 responsible for ensuring effective communication, coordination, and cooperation between the Parties. A Party may change its Contract Representative by providing notice of such change to the other Party in accordance with the procedures set forth in Section 30.1.

1.17 "Contract Year" means each year beginning on January 1 and ending on December 31 of such year following the Commercial Operation Date; provided, however, that the first Contract Year shall commence on the Commercial Operation Date and end on the following December 31.

1.18 "Control Area" means an electric power system or combination of electric power systems to which a common automatic generation control scheme is applied in order to (a) match, at all times, the power output of the generators within the electric power system(s) and capacity and energy purchased from entities outside the electric power system(s) with the load within the electric power system(s); (b) maintain scheduled interchange with the other Control Areas, within the limits of Good Utility Practice; (c) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice; and (d) provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

1.19 "Control Area Operator" means a Person, its agents, and successors that are responsible for the operation of the Transmission System and for maintaining reliability of the electrical transmission system(s), including the Transmission System, within the Control Area.

1.20 "Cure Period" has the meaning ascribed to that term in Section 25.2.

1.21 "Default Notice" means the notice of an Event of Default to the Defaulting Party.

1.22 "Defaulting Party" has the meaning ascribed to that term in Section 25.1.

1.23 "Deemed Delivered Amount" means the quantity of Energy, expressed in MWh, that would have been produced by the Generating Facility and delivered to the Delivery Point during any period, determined by taking into account (i) the actual 10-minute (or more frequent) wind speeds (interpolated over time intervals, if necessary) measured by wind monitoring equipment located on each Wind Turbine that was available for operation immediately prior to the commencement of the period in question and expected to be available for the duration of the period in question or prorated accordingly or, if such monitoring equipment is unavailable during a relevant interval, then using other available data or interpolated data determined using industry standard practices, as reasonably accepted by Supplier and Buyer; and (ii) the generation determined by the power curve provided by the manufacturer of the Wind Turbines reflecting the Energy that would be produced by a Wind Turbine at all operational speeds, as applied to the wind speeds referred to in clause (i), as adjusted for line losses to the Delivery Point, using historical data compiled by Supplier and reasonably agreed or confirmed by Buyer.

1.24 "Defaulting Party" has the meaning ascribed to that term in Section 25.1.

1.25 "Delivered Amount" means, with respect to any Contract Year, the actual amount of Energy delivered by Supplier and accepted by Buyer at the Delivery Point during such Contract Year.

1.26 "Delivered RECs" means RECs that have been delivered by Supplier to Buyer during a Contract Year pursuant to the terms of this Agreement, in accordance with the Clean, Renewable and Efficient Energy Act and which have been properly recorded to Buyer's REC Account by the MPSC Administrator.

1.27 "Delivery Point" means the delivery point as defined by the IOA or other delivery point on the Transmission System set forth in Exhibit 5, and any other delivery point as may be mutually agreed upon by the Parties.

1.28 "Derating" means a condition of the Generating Facility as a result of which it is unable to produce the forecasted Energy during a Dispatch Hour.

1.29 "Detroit Edison Company, The" means The Detroit Edison Company, a Michigan corporation and operating electric public utility, and any successor entity thereto, subject to the applicable rules of the MPSC and the FERC.

1.30 "Disclosing Party" has the meaning ascribed to that term in Section 29.1.

1.31 "Dispatch Hour" means each hour from the Operation Date through the end of the Term.

1.32 "Dispute" has the meaning ascribed to that term in Section 22.1.

1.33 "Effective Date" has the meaning ascribed to that term in the preamble of this Agreement.

1.34 "Emergency" means any circumstance or combination of circumstances or any condition of the Generating Facility, the Interconnection Facilities, the Transmission System, or the transmission system of other electric utilities which is reasonably likely to (a) endanger life or property and necessitates immediate action to avert injury to persons or serious damage to property; or (b) adversely affect, degrade, or impair Transmission System reliability or transmission system reliability of other electric utilities.

1.35 "Energy" means three phase 60 Hz electrical energy (measured in MWh) that is generated by the Generating Facility from and after the Operation Date. Energy shall also mean the capacity intended to be available and/or delivered to Buyer at the specifications and Delivery Point stated herein.

1.36 "Energy Replacement Costs" has the meaning ascribed to that term in Section 3.5

1.37 "Environmental Law" shall mean any federal, state, local, or other law (including common law), regulation, rule, ordinance, code, decree, judgment, binding directive, or judicial or administrative order relating to the protection, preservation, or restoration of human health, the environment, or natural resources, including any law relating to the releases or threatened releases of Hazardous Substances into any media (including ambient air, surface water, groundwater, land, and surface and subsurface strata) or otherwise relating to the manufacture, processing, distribution, use, treatment, storage, release, transport, and handling of Hazardous Substances.

1.38 "EPC Contract" has the meaning set forth in Exhibit 6.

1.39 "EPT" means Eastern Standard Time or Eastern Daylight Time, which ever is then prevailing.

1.40 "Event of Default" has the meaning ascribed to that term in Section 25.1.

1.41 "EWG" means an exempt wholesale generator pursuant to Section 32 of the Public Utility Holding Company Act of 2005, as such Law may be amended or superseded.

1.42 "FERC" means the Federal Energy Regulatory Commission and any successor entity thereto.

1.43 "First Full Contract Year" means the first Contract Year that is a full calendar year.

1.44 "Force Majeure" has the meaning set forth in Section 21.2.

1.45 "Generating Facility" means Supplier's renewable generating power plant, including any associated facilities and equipment required to deliver Energy to the Delivery Point, as further described in Exhibits 1 and 5 hereto.

1.46 "Good Faith" means honesty in fact and the observance of reasonable commercial standards of fair dealing in the trade.

1.47 "Good Utility Practice" means (a) the applicable practices, methods, and acts required by or consistent with applicable Laws and reliability criteria, whether or not the Party whose conduct at issue is a member of any relevant organization, and otherwise engaged in or approved by a significant portion of the electric utility industry during the relevant time period; or (b) any of the practices, methods, and acts which, in the exercise of reasonable judgment in light of the facts known or that should have been known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety, and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to acceptable practices, methods, or acts generally accepted in the region and industry. Good Utility Practice shall include compliance with applicable Laws and regulations, applicable reliability criteria, and the criteria, rules, and standards promulgated in the National Electric Safety Code and the National Electrical Code, as they may be amended or superseded from time to time, including the criteria, rules, and standards of any successor organizations.

1.48 "Governmental Authority" means, as to any Person, any federal, state, local, or other governmental, regulatory, or administrative agency, court, commission, department, board, or other governmental subdivision, legislature, rulemaking board, tribunal, or other governmental authority having jurisdiction over such Person or its property or operations.

1.49 "Hazardous Substance" means (a) any petroleum or petroleum products, flammable materials, explosives, radioactive materials, friable asbestos, urea formaldehyde foam insulation, and transformers or other equipment that contain dielectric fluid containing polychlorinated biphenyls (PCBs) in regulated concentrations; (b) any chemicals or other materials or substances which are now or hereafter become defined as, or included in, the definition of "hazardous substances", "hazardous wastes", "hazardous materials", "extremely hazardous wastes", "restricted hazardous wastes", "toxic substances", "toxic pollutants", "contaminants", "pollutants", or words of similar import under any Environmental Law; and (c) any other chemical or other material or substance, exposure to which is now or hereafter prohibited, limited, or regulated as such under any Environmental Law including the Resource Conservation and Recovery Act, 42 U.S.C. Section 6901 et seq., the Comprehensive Environmental Response Compensation and Liability Act, 42 U.S.C. Section 9601 et seq., or any similar state statute, as such Laws may be amended or superseded.

1.50 "IEEE-SA" means the Institute of Electrical and Electronics Engineers Standards Association and any successor entity thereto.

1.51 "Indemnified Party" has the meaning provided in Section 19.1.

1.52 "Indemnifying Party" has the meaning provided in Section 19.1.

1.53 "Interconnection Facilities" means the equipment and facilities, including any modifications, additions, and upgrades made to such facilities, which are necessary to connect the Generating Facility to the Transmission System as described in Exhibit 5.

1.54 "Invoice" means the statements described in Section 9.2 setting forth the Energy delivered to the Delivery Point, if any, and the associated payment due for the Billing Period, and in the case of an invoice delivered for the last month in a Contract Year, the Supply Amount and Shortfall, if any, including the Replacement Costs and REC Replacement Costs.

1.55 "IOA" means the Interconnection and Operating Agreement that has been or will be executed between Supplier and Transmission Provider, or its successors, for the Generating Facility.

1.56 "Law" means any federal, state, local, or other law (including any Environmental Laws), common law, treaty, code, rule, ordinance, binding directive, regulation, order, judgment, decree, ruling, determination, permit, certificate, authorization, or approval of a Governmental Authority, which is binding on a Party or any of its property.

1.57 "Loss" means any and all claims, demands, suits, obligations, payments, liabilities, costs, fines, penalties, sanctions, Taxes, judgments, damages, losses, or expenses imposed by a third-party upon an Indemnified Party or incurred in connection with any claim by a third-party against an Indemnified Party pursuant to Article 19.

1.58 "Material Adverse Effect" means, with respect to a Party, a material adverse effect on the ability of such Party to perform its obligations under this Agreement, individually or in the aggregate, or on the business, operations, or financial condition of such Party.

1.59 "Maximum Annual Amount" has the meaning ascribed to that term in Section 3.3 and Exhibit 13.

1.60 "Mechanical Availability Guaranty" has the meaning ascribed to that term in Exhibit 19.

1.61 "Meter" means any of the physical or electronic metering devices, data processing equipment, and apparatus associated with the meters owned by Buyer or its designee required for (a) an accurate determination of the quantities of Delivered Amounts and Station Usage from the Generating Facility and for recording other related parameters required for the reporting of data to Supplier, and (b) the computation of the payment due to Supplier from Buyer. Meters do not include any check meters Supplier may elect to install as contemplated by Section 9.1.1.

1.62 "MISO" means the Midwest Independent Transmission System Operator, Inc. and any successor entity thereto.

1.63 "Moody's" means Moody's Investor Services, Inc. and any successor entity thereto.

1.64 "MPSC" means the Michigan Public Service Commission and any successor entity thereto.

1.65 "MPSC Administrator" means the Person appointed by the MPSC to administer the RECs established pursuant to the Clean, Renewable and Efficient Energy Act.

1.66 "MPSC Approval Date" means the date on which an order of the MPSC approving this Agreement becomes effective.

1.67 "MW" means a megawatt of electrical capacity.

1.68 "MWh" means a megawatt hour of electrical energy.

1.69 "NERC" means the North American Electric Reliability Corporation and any successor entity thereto.

1.70 "Non-Defaulting Party" means the Party other than the Defaulting Party.

1.71 "OATT" means Transmission Provider's or Control Area Operator's then-effective Open Access Transmission Tariff, which has been accepted for filing by the FERC.

1.72 "Off-Peak" means hours ending 01 through 06 EPT, hours ending 23 through 24 EPT, and all hours on Sunday and NERC designated holidays.

1.73 "On-Peak" means hours ending 07 through 22 EPT Monday through Saturday, other than on NERC designated holidays.

1.74 "Operating Hours" has the meaning ascribed to that term in Exhibit 19.

1.75 "Operating Representative" means any of the individuals designated by a Party, as set forth in Exhibit 4, to transmit and receive routine operating and Emergency communications required under this Agreement. A Party may change any of its Operating Representatives by providing notice of the change to the other Party in accordance with the notice procedures set forth in Section 30.1 herein.

1.76 "Operation Date" means the first date on which the first Wind Turbine that is a component of the Generating Facility is energized and operates in parallel with the Transmission System and delivers Energy to the Delivery Point.

Fifteen (15) calendar days prior to any synchronization to the Transmission System, Supplier shall provide written notice to Buyer's Contract Representative, as set forth in Exhibit 4, that Supplier is preparing to synchronize to the Transmission System and the date on which such synchronization will occur.

1.77 "Party" means each Person set forth in the preamble of this Agreement and its permitted successor or assigns.

1.78 "Person" means any natural person, partnership, limited liability company, joint venture, corporation, trust, unincorporated organization, or Governmental Authority.

1.79 "Planned Operation Date" means the date specified in Exhibit 6 as the date on which the Operation Date is expected to occur.

1.80 "Planned Outages" has the meaning ascribed to that term in Section 12.1.

1.81 "Power Quality Standards" means the Power Quality Standards established by NERC, MISO, Buyer, IEEE-SA, National Electric Safety Code, the National Electric Code, and their respective successor organizations or codes, as they may be amended or superseded from time to time, and consistent with Good Utility Practice.

1.82 "Product" means (a) all Energy produced (i) by the Generating Facility, except Station Usage and (ii) pursuant to Section 3.2.2, if any; (b) all RECs; and (c) all Renewable Energy Benefits.

1.83 "Product Rate" means the rate set forth in Exhibit 2A of this Agreement under "Product Rate."

1.84 "Project Milestone" means each of the milestones listed in Exhibit 6 under the heading "Project Milestone."

1.85 "Project Milestone Schedule" means the schedule of Project Milestones, completion dates, and required documentation specified in Exhibit 6.

1.86 "PTC" means the production tax credit established pursuant to Section 45 of the U.S. Internal Revenue Code of 1986, as such Law may be amended or superseded.

1.87 "QF" means a cogeneration or small power production facility which meets the criteria as defined in Title 18, Code of Federal Regulations, §§ 292.201 through 292.207, as such Law may be amended or superseded.

1.88 "REC Replacement Costs" has the meaning ascribed to that term in Section 3.6.

1.89 "REC Shortfall" means the RECs attributable to a Shortfall.

1.90 "Receiving Party" has the meaning ascribed to that term in Section 29.1.

1.91 “Renewable Energy Benefits” means any and all renewable and environmental attributes, emissions reductions, credits, offsets, allowances, or benefits, however entitled, (a) allocated, assigned, awarded, certified, or otherwise transferred or granted to Supplier or Buyer by the REC Administrator or any Governmental Authority in any jurisdiction in connection with this Agreement; or (b) associated with the production of energy from the Generating Facility, or based in whole or part on the Generating Facility’s use of renewable resources for generation, or because the Generating Facility constitutes a renewable energy system, or because the Generating Facility does not produce greenhouse gases, regulated emissions, or other pollutants, whether any such credits, offsets, allowances, or benefits exist now or in the future, or whether they arise under existing Law or any future Law, or whether such credit, offset, allowance, or benefit or any Law, or the nature of such, is foreseeable or unforeseeable, but in all cases shall not mean RECs or Tax Credits. Renewable Energy Benefits includes such credits, offsets, allowances, or benefits attributable to Energy sold under this Agreement, and Energy consumed by the Generating Facility, such as Station Usage or Standby Service.

1.92 “Renewable Energy Credit” or “REC” means, commencing with the Operation Date and for each Contract Year, a unit of credit which equals one MWh of electricity generated, acquired, or saved by a Renewable Energy System or efficiency measure or as calculated by the MPSC operations staff and certified by the MPSC Administrator pursuant to the Clean, Renewable and Efficient Energy Act.

1.93 “Renewable Energy System” means, with respect to Michigan, a “renewable energy system” as defined in the Clean, Renewable and Efficient Energy Act.

1.94 “Shortfall” means [redacted]

1.95 “S&P” means Standard and Poor’s Ratings Group, a division of McGraw Hill, Inc., and any successor entity thereto.

1.96 “Standby Service” means the electric service supplied by Wolverine Power Cooperative.

1.97 “Station Usage” means all Energy consumed by the Generating Facility.

1.98 "Supplier" has the meaning set forth in the preamble of this Agreement and includes such Person's permitted successors and assigns.

1.99 "Supplier's Lenders" means any Persons other than an Affiliate of Supplier, and their permitted successors and assignees, whose business it is in the ordinary course to provide funding in connection with any development, bridge, construction, permanent debt, or tax equity financing or refinancing (collectively, "Financing") and, in this case, Financing for the Generating Facility.

1.100 "Supplier's Required Regulatory Approvals" means the approvals, consents, authorizations, or permits of, or filings with, or notifications to, the Governmental Authorities listed on Exhibit 10.

1.101 "Supply Amount" means, with respect to any Contract Year, the annual amount of Energy stated in Exhibit 13, in each case unless reduced pursuant to this Agreement. The Supply Amount is firm for Energy, subject to the requirements of this Agreement.

1.102 "Tax" means any federal, state, local, or foreign income, gross receipts, license, payroll, employment, excise, severance, stamp, occupation, premium, windfall profits, environmental, customs duties, capital stock, franchise, profits, withholding, social security (or similar), unemployment, disability, real property (including assessments, fees, or other charges based on the use or ownership of real property), personal property, transactional, sales, use, transfer, registration, value added, alternative or add-on minimum, estimated tax, or other tax of any kind whatsoever, or any liability for unclaimed property or escheatment under common law principles, including any interest, penalty, or addition thereto, whether disputed or not, including any item for which liability arises as a transferee or successor-in-interest.

1.103 "Tax Credits" means any state, local, and/or federal production tax credit, tax deduction, and/or investment tax credit specific to the production of renewable energy and/or investments in renewable energy facilities.

1.104 "Term" has the meaning ascribed to that term in Section 2.2.

1.105 "Transmission Provider" means MISO and any successor operator or owner of the Transmission System.

1.106 "Transmission System" means the facilities used for the transmission of electric energy in interstate commerce, including any modifications or upgrades made to such facilities, owned or operated by the Transmission Provider, except the Interconnection Facilities.

1.107 "Wind Turbines" means the wind turbine generators integrated into the Generating Facility.

1.108 "Wind Turbine Supply Agreement" means Supplier's master wind turbine purchase agreement or other wind turbine purchase agreement under which

Supplier has the right to allocate wind turbines to satisfy the proposed capacity output of the Generating Facility within the timeframe required to achieve the Commercial Operation Date.

1.109 "Yearly REC Amount" means the amount of firm RECs for each Contract Year stated in Exhibit 18, as modified to reflect adjustments in the Supply Amount on a one REC to one MWh basis.

TERM, TERMINATION, AND SURVIVAL OF OBLIGATIONS

2.1 Effective Date. This Agreement shall become effective on the Effective Date.

2.2 Term. Supplier's obligation to deliver Product and Buyer's obligation to accept and pay for Product under this Agreement shall commence on the Operation Date and shall continue for a period of twenty (20) years from January 1 immediately following the Commercial Operation Date, subject to earlier termination of this Agreement pursuant to the terms hereof (the "Term"); provided, however, that unless the approvals described in Article 17 are received as contemplated thereby, Buyer shall not be obligated to accept or pay for any Product.

2.3 Termination.

2.3.1 Mutual Agreement. This Agreement may be terminated by written agreement of the Parties.

2.3.2 For Cause. This Agreement may be terminated at any time by the Non-Defaulting Party upon ten (10) Business Days' prior written notice to the Defaulting Party if an Event of Default has occurred and is continuing after the applicable Cure Period (if any) set forth in Section 25.2 has expired.

2.3.3 Optional Termination. This Agreement may be terminated in accordance with Article 17 in the event the approvals contemplated thereby are not obtained or are granted with conditions that are not reasonably acceptable to either Party. Upon such termination of this Agreement, except as provided in Section 2.4, neither Party shall owe any obligation to the other Party.

2.3.4 Force Majeure. This Agreement may be terminated by a Party if the other Party's obligations hereunder have been excused by the occurrence of an event of Force Majeure for longer than six (6) consecutive months.

2.4 Effect of Termination - Survival of Obligations. Any termination of this Agreement or expiration of the Term shall not release either Party from any applicable provisions of this Agreement with respect to:

2.4.1 The payment of any amounts owed to the other Party arising prior to or resulting from termination of, or on account of breach of, this Agreement;

2.4.2 Indemnity obligations contained in Article 19, which shall survive to the full extent of the statute of limitations period applicable to any third-party claim;

2.4.3 Limitation of liability provisions contained in Article 20;

2.4.4 For a period of one (1) year after the termination date, the right to submit a payment dispute pursuant to Article 22;

2.4.5 The resolution of any dispute submitted pursuant to Article 22 prior to, or resulting from, termination; or

2.4.6 The confidentiality provisions contained in Article 29.

SUPPLY SERVICE OBLIGATIONS

3.1 Energy. Subject to the other provisions of this Agreement, commencing on the Commercial Operation Date, Supplier shall supply and deliver Energy to Buyer at the Delivery Point.

3.2 Dedication. All Product shall be dedicated exclusively to Buyer for the Term of this Agreement.

3.2.1 Supplier shall not, without Buyer's prior written consent (which Buyer may withhold in its sole discretion), (a) sell, divert, grant, transfer, or assign Product to any Person other than Buyer or (b) provide Buyer with electric energy, RECs, or Renewable Energy Benefits from any source other than the Generating Facility.

[redacted]

[redacted].

3.3 Buyer's Obligation and Delivery. Buyer shall take delivery of Energy at the Delivery Point in accordance with the terms of this Agreement. Supplier shall be responsible for all costs associated with delivery of the Energy to the Delivery Point. Buyer shall be responsible for all costs associated with receipt of the Energy at the Delivery Point. Notwithstanding anything in this Agreement to the contrary, Buyer shall (i) be obligated to purchase or accept delivery of Energy from the Generating Facility only if the Generating Facility is at the time qualified as a Renewable Energy System and Buyer receives the RECs associated with such Energy as contemplated by this Agreement and (ii) not be required to purchase or accept more [redacted] ("Maximum Annual Amount").

3.4 Consumption. Supplier shall acquire Standby Service necessary to meet Station Usage.

3.5 Energy Replacement Costs.

3.5.1 Subject to the right of a Shortfall Makeup, commencing [redacted] and for each Contract Year thereafter, in the event of a Shortfall, Supplier shall pay Buyer the replacement costs for energy attributable to the Shortfall, as calculated by Buyer pursuant to Section 3.5.2 ("Energy Replacement Costs").

3.5.2 The Energy Replacement Costs shall be calculated by Buyer and shall equal the [redacted] Average Monthly Michigan Hub Firm Price for the [redacted] creating the Shortfall. Within five (5) Business Days of the end of any Contract Year during which a Shortfall occurred, Supplier shall provide Buyer with written notice of such Shortfall.

3.5.3 The Parties recognize and agree that the payment of Energy Replacement Costs by Supplier pursuant to this Section 3.5 is an appropriate remedy in the event of a Shortfall, and that any such payment does not constitute a forfeiture or penalty of any kind, but rather constitutes expected future costs of a Shortfall to Buyer at the time of the Effective Date. The Parties further acknowledge and agree that the actual costs of a Shortfall to Buyer are difficult or impossible to determine, or otherwise obtaining an adequate remedy is inconvenient, and the damages calculated hereunder constitute a reasonable approximation of the harm or loss to Buyer.

3.5.4 All information used by Buyer to calculate Energy Replacement Costs shall be verifiable by Supplier; and Buyer shall provide a copy of all such information to Supplier supporting such calculations within five (5) Business Days of the request by Supplier for such information, and Supplier agrees to treat such information as Confidential Information pursuant to Article 29.

3.6 REC Replacement Costs.

3.6.1 [redacted] commencing with the [redacted] and for each Contract Year thereafter, in the event of a REC Shortfall, Supplier shall pay Buyer the replacement costs for RECs attributable to the REC Shortfall ("REC Replacement Costs").

3.6.2 The REC Replacement Costs shall be calculated by Buyer and shall be based on the quoted market costs of purchasing replacement RECs to cover the REC Shortfall that are of a non-solar and comparable character and with a comparable expiration date or, if replacement REC market quotes are unavailable, the weighted average cost of non-solar replacement RECs already in Buyer's REC Account delivered for the most recent Contract Year in which a REC Shortfall occurred.

3.6.3 The Parties recognize and agree that the payment of REC Replacement Costs by Supplier pursuant to this Section 3.6 is an appropriate remedy in the event of a REC Shortfall, and that any such payment does not constitute a forfeiture or penalty of any kind, but rather constitutes expected future costs of a REC Shortfall to Buyer at the time of the Effective Date. The Parties further acknowledge and agree that the actual costs of a REC Shortfall to Buyer are difficult or impossible to determine, or otherwise obtaining an adequate remedy is inconvenient, and the damages calculated hereunder constitute a reasonable approximation of the harm or loss to Buyer.

3.6.4 All information used by Buyer to calculate REC Replacement Costs shall be verifiable by Supplier; and Buyer shall provide a copy of all such information to Supplier supporting such calculations within five (5) Business Days of the request by Supplier for such information, and Supplier agrees to treat such information as Confidential Information pursuant to Article 29.

3.7 Adjustment to Supply Amount.

3.7.1 Increase or Decrease Prior to Commercial Operation. No later than the sooner of (a) twelve (12) months after MPSC approval of this Agreement and (b) the Commercial Operation Date, Supplier may, only once as set forth in this Section 3.7.1, adjust the Supply Amount, Yearly REC Amount, and the capacity values in Exhibit 1. Supplier may increase such amounts such that (a) the increased Supply Amount for each Contract Year shall not exceed one hundred and ten percent (110%) of the original Supply Amount for that Contract Year as of the Effective Date and (b) the Yearly REC Amount for each Contract Year shall increase in the same proportion as the increase of the Supply Amount for that Contract Year. Supplier may decrease such amounts such that (a) the decreased Supply Amount for each Contract Year shall not be less than ninety percent (90%) of the original Supply Amount for that Contract Year as of the Effective Date and (b) the Yearly REC Amount for each Contract Year shall decrease in the same proportion as the decrease of the Supply Amount for that Contract Year.

3.7.2 Increase of Supply Amount After Commercial Operation Date. On or before October 1 of each Contract Year, Supplier may increase the Supply Amount and Yearly REC Amount by providing written notice of such increase to Buyer, provided that (a) the increased Supply Amount for each Contract Year shall be no greater than one hundred and ten percent (110%) of the original Supply Amount for that Contract Year as of the Effective Date, as the Supply Amount may be modified pursuant to Section 3.7.1, and (b) the Yearly REC Amount for each Contract Year shall increase in the same proportion as the increase of the Supply Amount for that Contract Year. Each increase to the Supply Amount and Yearly REC Amount under this Section 3.7.2 shall apply no sooner than the third Contract Year subsequent to the Contract Year in which Supplier provides written notice of such an increase, and shall not apply to the first or second Contract Years subsequent to the Contract Year in which Supplier provides written notice of such an increase.

3.7.3 Decrease of Supply Amount After Commercial Operation Date. On or before October 1 of each Contract Year, Supplier may decrease the Supply Amount and Yearly REC Amount by providing written notice of such decrease to Buyer, provided that (a) the decreased Supply Amount for each Contract Year shall be no less than ninety percent (90%) of the original Supply Amount for that Contract Year as of the Effective Date, as the Supply Amount may be modified pursuant to Section 3.7.1, and (b) the Yearly REC Amount for each Contract Year shall decrease in the same proportion as the decrease of the Supply Amount for that Contract Year. A decrease in the Supply Amount and Yearly REC Amount shall in no event be made to assist, accommodate, or otherwise allow for the sale of Product to third parties. Each decrease to the Supply Amount and Yearly REC Amount under this Section 3.7.3 shall apply no sooner than the third Contract Year subsequent to the Contract Year in which Supplier provides written notice of such a decrease, and shall not apply to the first or second Contract Years subsequent to the Contract Year in which Supplier provides written notice of such a decrease.

3.8 Title and Risk of Loss. Title to and risk of loss with respect to Energy shall pass from Supplier to Buyer at the Delivery Point. Until title passes, Supplier shall be deemed in exclusive control of the Energy and shall be responsible for any damage or injury caused thereby. After title to the Energy passes to Buyer, Buyer shall be deemed in exclusive control of the Energy and shall be responsible for any damage or injury caused thereby. Supplier shall deliver the Energy to Buyer free and clear of all liens, security interests, claims, and encumbrances or any interest therein or thereto by any Person.

3.9 Guaranteed Mechanical Availability. Supplier shall be obligated to achieve the Mechanical Availability Guaranty as set forth in Exhibit 19. Within thirty (30) calendar days following the end of each Contract Year, Supplier shall provide Buyer with written notice (and reasonable supporting documentation) certified by an officer of Supplier of the (a) Delivered Amount for such Contract Year; (b) Base Hours for each Wind Turbine for such Contract Year; (c) Operating Hours for each Wind Turbine for such Contract Year; (d) total number of hours that each Wind Turbine was not operational as a result of Force Majeure; and (e) total number of hours that each Wind Turbine was not operational as a result of an approved Planned Outage.

PRICE OF PRODUCT

4.1 Product Payments. Supplier shall be paid for the Product based on the Delivered Amount of Energy as determined by data from monthly Meter readings, as follows:

4.1.1 Upon the Operation Date and prior to the Commercial Operation Date, all Product associated with Delivered Amounts of Energy from the Generating Facility shall be paid for by Buyer at the Product Rate.

RENEWABLE ENERGY CREDITS AND RENEWABLE ENERGY BENEFITS

5.1 Delivery of Renewable Energy Credits.

5.1.1 All RECs and any benefits derived there from are exclusively dedicated to and vested in Buyer. Supplier shall deliver to Buyer all RECs derived from the production of Energy from the Generating Facility. Supplier shall timely prepare and execute all documents and shall take all actions necessary under applicable Law to cause the RECs to vest in Buyer, without further compensation, including, but not limited to, all actions necessary to register or certify the RECs or the Generating Facility with the applicable Governmental Authority, and to provide all production data and satisfy the reporting requirements of the applicable Governmental Authority.

5.1.2 Supplier and Buyer agree that all RECs awarded by the MPSC Administrator under this Agreement shall be issued in the name of Buyer.

5.1.3 On or before February 1 of each Contract Year, Supplier, as owner or operator of the Generating Facility, shall deliver to Buyer a written attestation for the prior Contract Year that the Energy represented in MWhs used to certify RECs (a) has not been and will not be sold or otherwise exchanged for compensation or used for credit in Michigan or any other state or jurisdiction and (b) has not been and will not be included within a blended energy product certified to include a fixed percentage of renewable energy in any other state or jurisdiction as prohibited under Michigan law.

5.2 Renewable Energy Benefits. All Renewable Energy Benefits shall be exclusively dedicated to and shall be vested in Buyer, and Supplier hereby transfers to Buyer all Renewable Energy Benefits. Supplier shall take or cause to be taken all commercially reasonable actions and do or cause to be done all things reasonably requested by Buyer to qualify for, and for Supplier or Buyer to receive, all available Renewable Energy Benefits and, if received by Supplier, to transfer such Renewable Energy Benefits to Buyer, without further compensation.

TAX CREDITS

6.1 The Parties agree that the Product payments as provided for in Article 4 account for Tax Credits in effect as of the Effective Date of this Agreement.

6.2 Supplier and Buyer agree that the Product Rate is not subject to adjustment or amendment if Supplier fails to receive any Tax Credits, or if such Tax Credits expire, are repealed, or otherwise cease to apply to Supplier or the Generating Facility in whole or in part, or Supplier or its investors are unable to benefit from such Tax Credits.

RENEWABLE ENERGY STANDARD

7.1 The Parties agree that the RECs will be used by Buyer in meeting its obligations pursuant to the Clean, Renewable and Efficient Energy Act. Supplier shall use commercially reasonable efforts to assist Buyer in Buyer's compliance with applicable requirements set forth in the Clean, Renewable and Efficient Energy Act, and shall provide information reasonably requested by Buyer or otherwise necessary to allow the MPSC to determine Buyer's compliance with such requirements.

RIGHT OF FIRST OFFER

8.1 If Supplier (or any direct or indirect parent of Supplier) intends to sell or transfer the Generating Facility to a non-Affiliate third-party, Supplier must provide written notice to Buyer of such intention. Upon Buyer's receipt of such notice, Buyer shall have the right to negotiate in Good Faith with Supplier for no more than sixty (60) calendar days, unless otherwise agreed to by Supplier, the terms of the sale or transfer of the Generating Facility to Buyer or its designee on an exclusive basis. If Buyer desires to enter into such negotiation, Buyer shall notify Supplier of such decision within fifteen (15) calendar days of receipt of Supplier's notice. Supplier will provide, in a timely manner, information regarding the Generating Facility which is reasonable or customary to allow Buyer to perform due diligence and to negotiate in Good Faith for the purchase of the Generating Facility.

8.2 In the event that Buyer does not exercise its right to negotiate pursuant to Section 8.1, Supplier must comply with Article 24 in any assignment or delegation of Supplier's rights, interests, or obligations herein to a purchaser of the Generating Facility.

8.3 In the event that Supplier does not execute an agreement, subject to receipt of appropriate regulatory approvals, to sell or transfer the Generating Facility to any non-Affiliate third-party in accordance with this Article 8 within three hundred sixty-five (365) calendar days of the date that Supplier provided Buyer with written notice pursuant to Section 8.1, Supplier (or any direct or indirect parent of Supplier) must again follow the procedures of this Article 8 if it intends to sell or transfer the Generating Facility to a non-Affiliate third-party.

METERING, INVOICING, AND PAYMENTS

9.1 Metering.

9.1.1 Meters. Buyer shall, at Buyer's expense, provide, install, own, operate and maintain all Meters in good operating condition. The Meters shall be used for quantity measurements under this Agreement. Such equipment shall be bi-directional and shall be capable of measuring and reading instantaneous, hourly real and reactive energy and capacity. The Meters shall also be used for, among other things, metering Station Usage of the Generating Facility. Supplier, at its expense, may install additional check meters. Supplier shall not install any check-metering equipment on Buyer-owned facilities.

9.1.2 Location. Meters shall be installed at the location specified in Exhibit 5, or as otherwise reasonably determined by Buyer to effectuate this Agreement.

9.1.3 Non-Interference. Supplier shall not undertake any action that may interfere with the operation of the Meters. Supplier shall be liable for all costs, expenses, and liabilities associated with any such interference with the Meters.

9.1.4 Meter Testing. Meters shall be tested at least once every calendar year by Buyer, at Buyer's expense. Either Party may request a special test of Meters or check meters, but the testing Party shall bear the cost of such testing unless there is an inaccuracy outside the limits established in American National Standard Institute Code for Electricity Metering (ANSI C12.1, latest version), in which case the Party whose meters were found to be inaccurate shall be responsible for the costs of the special testing. Meters installed pursuant to this Agreement shall be sealed and the seal broken only when the meters are to be adjusted, inspected, or tested. Authorized representatives of both Parties shall have the right to be present at all routine or special tests and to inspect any readings, testing, adjustment, or calibration of the Meters or check meters. Buyer's Operating Representative shall provide fifteen (15) calendar days prior notice of routine Meter testing to Supplier's Operating Representative. If Supplier has installed check meters in accordance with Section 9.1.1, Supplier shall test and calibrate each such meter at least once every calendar year. Supplier's Operating Representative shall provide fifteen (15) calendar days prior written notice of routine check meter testing to Buyer's Operating Representative. In the event of special Meter testing, the Parties' Operating Representatives shall notify each other in writing with as much advance notice as practicable.

9.1.5 Metering Accuracy. If the Meters are registering but their accuracy is outside the limits established in ANSI C12.1, Buyer shall repair and recalibrate or replace the Meters and Buyer shall adjust payments to Supplier for the Delivered Amount for the lesser of the period in which the inaccuracy existed and ninety (90) calendar days. If the period in which the inaccuracy existed cannot be determined, adjusted payments shall be made for a period equal to one-half of the elapsed time since the latest prior test and calibration of the Meters; provided, however, the adjustment period shall not exceed ninety (90) calendar days. If adjusted payments are required, Supplier shall render a statement describing the adjustments to Buyer within thirty (30) calendar days of the date on which the inaccuracy was rectified. Any payment adjustments due Supplier pursuant to this Section 9.1.5 shall accompany Supplier's statement.

9.1.6 Failed Meters. If the Meters fail to register, Buyer shall make payments to Supplier based upon Supplier's check metering; provided, however, that if the accuracy of the check meters is subsequently determined to be outside the limits established in ANSI C12.1, Buyer shall adjust the payments to Supplier for the Delivered Amount calculated using the check meters for the lesser of the period in which the inaccuracy existed and ninety (90) calendar days. If the period in which the inaccuracy existed cannot be determined, adjusted payments shall be made for a period equal to one-half of the elapsed time since the latest prior test and calibration of the check meters; provided, however, the adjustment period shall not exceed ninety (90) calendar days. If no such metering is available, payments shall be based upon the Parties' best estimate of the Delivered Amount. In such event, the Parties' estimated payments shall be in full satisfaction of payments due hereunder. If the Parties cannot agree on a best estimate of the Delivered Amount, the dispute shall be resolved in accordance with Article 22.

9.2 Invoices.

9.2.1 Invoicing and Payment. On or before the 10th day of each month, Supplier shall send to Buyer an Invoice for the prior month (a "Billing Period"). The Invoice shall be calculated based upon Meter data available to Supplier and as set forth in Exhibit 2B.

9.2.2 Monthly Energy Invoice Calculation. Supplier shall calculate each monthly Invoice as set forth in Exhibit 2B.

9.2.3 Energy Replacement Costs and REC Replacement Costs Invoice Calculation. In addition to the requirements for monthly Invoices set forth in this Section 9.2, in the event of a (a) Shortfall, Buyer shall, within fifteen (15) Business Days after the end of the applicable Contract Year, send to Supplier an Invoice for Energy Replacement Costs, which shall include the calculations set forth in Exhibit 2D; and (b) REC Shortfall, Buyer shall, within fifteen (15) Business Days after the end of the applicable Contract Year, send to Supplier an Invoice for REC Replacement Costs, which shall include the calculations set forth in Exhibit 2C. For the purpose of this Section 9.2.3, the applicable Contract Year means (i) two Contract Years following a Shortfall and (ii) Supplier failed to achieve a Shortfall Makeup for such Shortfall.

9.3 Payments.

9.3.1 Payment to Buyer. The Invoice referred to in Section 9.2.1 above shall net any amounts owing to Buyer from amounts due to Supplier and shall indicate the net payment due Supplier or Buyer, as applicable. Supplier shall provide supporting data in reasonable detail to support its calculations of any amounts owing to Buyer. Any payment due to Buyer shall be credited to following Billing Periods and if no such Billing Periods remain, payment shall be made within thirty (30) calendar days of the date of the Invoice.

9.3.2 Method of Payment. Buyer and Supplier, as applicable, shall remit the payment of any undisputed amounts by wire transfer pursuant to the instructions stated on the Invoice, and if no instructions are stated on such Invoice, then in accordance with Exhibit 4. Payment will be made on or before the later of (a) twenty (20) calendar days following the end of each month and (b) ten (10) calendar days from receipt of Invoice by the applicable Party.

9.3.3 Examination and Correction of Invoices. As soon as practicable, either Party shall notify the other Party in writing of any alleged error in Supplier's Invoice.

9.3.3.1 If a Party notifies the other Party of an alleged error in Supplier's Invoice, the Parties agree to make Good Faith efforts to reconcile the billing and mutually agree on the appropriate remedy, if any.

9.3.3.2 If a correction is determined to be required, Supplier shall provide an adjusted Invoice to Buyer. If such correction results in an additional payment to Supplier, Buyer shall pay Supplier the amount of the adjusted Invoice within thirty (30) calendar days of the date of the receipt of adjusted Invoice. If such correction resulted in a refund owed to Buyer, Supplier shall pay Buyer the amount of the adjusted Invoice within thirty (30) calendar days of the date of the statement or, at Buyer's option, Buyer may net such amount against the subsequent monthly payment to Supplier.

9.3.3.3 If Supplier fails to provide Buyer with notice of any alleged error in Supplier's Invoice within twelve (12) months of Buyer's receipt of such Invoice, then Supplier shall be deemed to have waived all rights to object to such Invoice.

9.3.4 Overdue Amounts and Refunds. Overdue amounts and refunds of overpayments shall bear interest from and including, the due date or the date of overpayment, as the case may be, to the date of payment of such overdue amounts or refund at a rate calculated pursuant to 18 C.F.R. § 35.19a, as such Law may be amended or superseded.

9.3.5 Access to Books and Records. Supplier agrees to make available for inspection upon five (5) Business Days written notice from Buyer its books and records for the purpose of allowing Buyer to verify the information contained within the Invoices presented pursuant to this Article 9.

9.3.6 Parties Right to Net. Either Party shall have the right to net any undisputed amounts owed to the other Party under this Agreement.

9.3.7 Taxes. Buyer is responsible for any Taxes imposed on or associated with the Energy or its receipt at the Delivery Point. Supplier is responsible for any Taxes imposed on or associated with the Energy or its delivery to the Delivery Point. Either Party, upon written request of the other Party, shall provide a certificate of exemption or other reasonably satisfactory evidence of exemption if either Party is exempt from Taxes, and shall use reasonable efforts to obtain and cooperate with the other Party in obtaining any exemption from or reduction of any Tax. Each Party shall hold harmless the other Party from and against Taxes imposed on the other Party as a result of a Party's actions or inactions and that otherwise would not have occurred in the absence of this Agreement in accordance with Article 19.

FACILITY CONSTRUCTION, OPERATIONS, AND MODIFICATIONS

10.1 Construction of Generating Facility. Supplier shall construct the Generating Facility in accordance with Good Utility Practice, in accordance with the Project Milestones, and to ensure that (a) Supplier is capable of meeting its supply obligations over the Term and (b) the Generating Facility is at all times in compliance with all requirements imposed on a Renewable Energy System as set forth in the Clean, Renewable and Efficient Energy Act. Supplier shall provide to Buyer in a form satisfactory to Buyer within thirty (30) calendar days after execution of the IOA, an update to Exhibit 5 which shall include a single line diagram of the Generating Facility, Interconnection Facilities, the Delivery Point, and the location of Meters, which location shall be reasonably acceptable to Buyer. At Buyer's request, Supplier shall provide Buyer with copies of the EPC Contract for the proposed Generating Facility and any documentation and drawings reasonably requested by Buyer, redacted of any pricing information.

10.2 Performance of Project Milestones. Supplier shall complete each Project Milestone set forth in Exhibit 6 on or before 1600 hours EPT on the date specified for each Project Milestone.

10.2.1 Completion of Project Milestones. Upon Supplier's completion of each Project Milestone, Supplier shall provide to Buyer in writing pursuant to Section 30.1 documentation as specified in Exhibit 6 and reasonably satisfactory to Buyer demonstrating such Project Milestone completion within thirty (30) calendar days following such completion but no later than the date specified for each Project Milestone listed in Exhibit 6. Buyer shall acknowledge receipt of the documentation provided under this Section 10.2.1 and shall provide Supplier with written acceptance or denial of each Project Milestone within fifteen (15) calendar days of receipt of the documentation.

10.2.2 Progress Towards Completion. Supplier shall notify Buyer promptly (and in any event within ten (10) Business Days) following its becoming aware of information that leads to a reasonable conclusion that a Project Milestone will not be met, and shall convene a meeting with Buyer to discuss the situation not later than fifteen (15) calendar days after becoming aware of this information.

10.3 Commercial Operation. Supplier shall notify Buyer at least ten (10) Business Days prior to the commencement of any performance tests required by the EPC Contract and the IOA. Buyer shall have the right to be present at and witness each such test. Supplier shall notify Buyer at least ten (10) Business Days prior to the commencement of the performance tests required by Exhibit 7. Buyer shall be deemed to waive its right to be present at the performance tests if Buyer fails to appear at the scheduled time for the performance tests. Within five (5) Business Days of the successful completion of the performance tests pursuant to Exhibit 7, Supplier shall provide Buyer with a written certification that all of the requirements for Commercial Operation hereunder have been satisfied together with completed test summary data sheets and other relevant data derived from such tests demonstrating to Buyer's satisfaction that such tests have been successfully completed.

10.4 Delay Damages.

10.4.1 In the event the Supplier fails to achieve Commercial Operation by the date specified in Exhibit 6, for each calendar day that the Supplier fails to achieve Commercial Operation thereafter, Supplier shall pay [redacted] Buyer shall invoice Supplier on a monthly basis for any such amounts under this Section 10.4 and Supplier shall pay such amounts invoiced within twenty (20) calendar days of receipt of the invoice.

10.4.2 The provisions of this Section 10.4 are in addition to, and not in lieu of, Buyer's right to terminate this Agreement under Article 25 [redacted]

10.4.3 The Parties recognize and agree that the payment of amounts by Supplier pursuant to this Section 10.4 is an appropriate remedy and that any such payment does not constitute a forfeiture or penalty of any kind, but rather constitutes anticipated costs to Buyer under the terms of this Agreement.

10.5 Modification. Without the prior written consent of Buyer, which shall not be unreasonably withheld, Supplier shall not make any modification to the Generating Facility that might (a) expose Buyer to any additional liability or increase its obligations under this Agreement or (b) adversely affect Supplier's or Buyer's ability to perform its obligations under this Agreement or any Law or to any third-party. Any such modifications shall be conducted in accordance with Good Utility Practice and all applicable Laws and reliability criteria, as such may be amended from time to time. To the extent additions and modifications extend beyond the limits for a Planned Outage as set forth in Article 12 and interfere with the ability of the Generating Facility to cause or contribute to a Shortfall, Supplier shall pay Energy Replacement Costs and REC Replacement Costs to Buyer pursuant to Sections 3.5 and 3.6, respectively.

10.6 Operation and Maintenance. Supplier at all times shall install, operate, maintain, and repair the Generating Facility in accordance with Good Utility Practice to ensure (a) Supplier is capable of meeting its supply obligations over the Term, (b) the Generating Facility is at all times a Renewable Energy System, and (c) Supplier is at all times in compliance with all requirements of a renewable energy generator set forth in the Clean, Renewable and Efficient Energy Act. Supplier agrees to (x) maintain records of all operations of the Generating Facility in accordance with Good Utility Practice, and (y) follow such regulations, directions, and procedures of Buyer, the Control Area Operator, the Transmission Provider, MISO, NERC, and any applicable Governmental Authority to protect and prevent the Transmission System from experiencing any negative impacts resulting from the operation of the Generating Facility. In the event of an inconsistency, Buyer shall choose whose procedures shall govern. Each Party shall use all reasonable efforts to avoid any interference with the other's operations. Supplier shall cause the Energy of the Generating Facility to meet the Power Quality Standards at all times, and shall operate the Generating Facility consistent with MISO, NERC, Buyer, Control Area Operator, and Transmission Provider requirements.

10.7 Operation And Maintenance Agreement. No later than ninety (90) calendar days prior to the Commercial Operation Date, if Supplier is not the operator, Supplier shall provide a copy of the agreement between Supplier and the operator which requires the operator to operate the Generating Facility in accordance with the terms hereof, which shall be attached to this Agreement as Exhibit 15. Supplier shall also provide a certified copy of a certificate warranting that the operator is a corporation, limited liability company, or partnership in good standing with the State of Michigan, which shall be attached to this Agreement as part of Exhibit 15.

10.8 Ground Lease; Rights-of-way. If the land on which the Generating Facility is located is not owned by Supplier, no later than sixty (60) calendar days prior to commencement of Generating Facility construction, Supplier shall provide a copy of the agreement with the owner of the land, attached as Exhibit 16, which establishes (a) the exclusive right of Supplier to construct and operate the Generating Facility on the land for a period not ending before the expiration of the Term and (b) the existence of required rights-of-way and easements.

10.9 Fossil Fuel. If the Generating Facility uses any fossil fuel as an energy source to produce Energy, Supplier shall not permit, without the express prior written consent of Buyer, fossil fuel to constitute more than one percent (1%) of the total input, as measured in British thermal units, used by the Generating Facility to produce Energy.

10.10 Right to Review. Buyer and Supplier each shall have the right to review during normal business hours copies of the relevant books and records of the other Party to confirm the accuracy of such as they pertain only to transactions under this Agreement. The review shall be consistent with standard business practices and shall follow reasonable notice to the other Party. Reasonable notice for a review of the previous month's records shall be a minimum of seven (7) Business Days. If a review is requested of other than the previous month's records, then notice of that request shall be provided with a minimum of fourteen (14) Business Days notice by the requesting Party. The notice shall specify the period to be covered by the review. The Party providing records can exercise its right under Article 29 to protect the confidentiality of the records.

EMERGENCY AND CURTAILMENT

11.1 In the event of an Emergency, Buyer and Supplier shall promptly comply with any applicable requirements of any Governmental Authority, NERC, MISO, Control Area Operator, Transmission Provider, and any successor of any of them regarding the reduced or increased generation of the Generating Facility.

11.2 Each Party shall provide prompt oral and written notification to the other Party of any Emergency. If requested by the other Party, the Party declaring the Emergency shall provide a description in reasonable detail of the Emergency and any steps employed to cure it.

11.3 In the event of an Emergency, either Party may take reasonable and necessary action to prevent, avoid, or mitigate injury, danger, damage, or loss to its own equipment and facilities, or to expedite restoration of service; provided, however, that the Party taking such action shall give the other Party prior notice, if practicable, before taking any action. This Section 11.3 shall not be construed to supersede Sections 11.1 and 11.2.

11.4 In the event of an Emergency, if and when Buyer requests Supplier not to institute a Planned Outage of the Generating Facility, Supplier agrees to take all commercially reasonable steps to avoid instituting the Planned Outage until such time as the condition of the Emergency has passed.

11.5 In the event of an Emergency declared by Supplier, such that Supplier cannot deliver some or all of the Supply Amount to the Delivery Point, Supplier will pay Buyer's Energy Replacement Costs pursuant to Section 3.5 and REC Replacement Costs pursuant to Section 3.6, unless such Supplier declared Emergency qualifies as an event of Force Majeure in accordance with Article 21.

11.6 In the event of an Emergency, as a result of which Buyer is unable to receive some or all of the Energy at the Delivery Point or is unable to deliver some or all of the Energy to its customers, then Buyer shall have no payment liability in respect of such Energy that Buyer is unable to receive. The Supply Amount and Yearly REC Amount will be reduced accordingly in part or total, as applicable, during the period of any such Emergency.

11.7 Supplier shall curtail deliveries of Energy at any time, in whole or in part, in a quantity and for any duration specified by Buyer upon at least thirty (30) minutes prior notice (which may be given by e-mail or telephone) to Supplier. The quantity of Energy curtailed and any associated RECs shall equal a Deemed Delivered Amount for such period of curtailment. Supplier shall promptly provide Buyer with such information and data as Buyer may request to confirm to its satisfaction such Deemed Delivered Amount. Supplier shall be paid for such Deemed Delivered Amount at the Product Rate plus an amount equal to the value of the PTCs, if any, associated with such Deemed Delivered Amount that Supplier or any of its Affiliates were unable to utilize as a result of Buyer's curtailment notice, as if the Deemed Delivered Amount were delivered to Buyer. During any such period of curtailment, Supplier shall not produce Energy (to the extent curtailed by Buyer) or sell Product to any third-party. All Energy and any associated RECs curtailed in accordance with this Section 11.7 shall be considered Product delivered to Buyer for all purposes under this Agreement.

PLANNED OUTAGES

12.1 Except in the event of an Emergency, Supplier shall schedule any (a) planned outage of the Generating Facility and (b) reduction of the capability of the Generating Facility to deliver the Supply Amount (any and all of (a) and (b) are referred to as "Planned Outages") in accordance with Sections 12.1.1, 12.1.2 and 12.1.3.

12.1.1 Within ninety (90) calendar days prior to the Commercial Operation Date and on or before October 1 of each Contract Year, Supplier shall provide Buyer with a schedule of proposed peak Planned Outages for the months of January, February, June, July, August, and December of the upcoming Contract Year and non-peak Planned Outages for the months of March, April, May, September, October, and November of the upcoming Contract Year. The proposed schedules for peak Planned Outages and non-peak Planned Outages will designate the days and amount (in MWs) in which the Generating Facility output will be reduced in whole or in part. Each proposed schedule shall include all applicable information, including the following: month, day, and time of a Planned Outage, facilities impacted, duration of outage, purpose of outage, and other relevant information.

12.1.2 Buyer shall promptly review Supplier's proposed peak Planned Outage schedule and shall either require modifications or approve the proposed schedule within thirty (30) calendar days of Buyer's receipt of such schedule. No approval shall be required for non-peak Planned Outages. Supplier shall use commercially reasonable efforts to accomplish all Planned Outages in accordance with the approved schedule.

12.1.3 Regardless of any prior approval of a peak Planned Outage, Supplier shall not start any Planned Outage on the Generating Facility without notifying Buyer's Operating Representative five (5) Business Days prior to the start of such Planned Outage.

REPORTS AND OPERATIONS LOG

13.1 Copies of Communications. Supplier shall promptly provide Buyer with copies of any orders, decrees, letters, or other written communications to or from any Governmental Authority asserting or indicating that Supplier or its Generating Facility is in violation of Laws that relate to Supplier or the operation or maintenance of the Generating Facility and could have an adverse effect on Buyer. Supplier shall keep Buyer apprised of the status of any such matters.

13.2 Notification of Generating Facility Status. Supplier shall notify Buyer of the status of the Generating Facility as an EWG, QF, or such other status no later than ninety (90) calendar days prior to the Operation Date. Supplier shall notify Buyer, as soon as practicable, of any changes in that status after the Operation Date of this Agreement.

13.3 Notices of Change in Generating Facility. In addition to any consent required pursuant to Section 10.4, Supplier shall provide notice to Buyer as soon as practicable prior to any temporary or permanent change to the performance, operating characteristics, or Wind Turbines of the Generating Facility. Such notice shall describe any changes, expected or otherwise, to the total capacity of the Generating Facility, the rate of production and delivery of Energy, interconnection and transmission issues, and such additional information as may be required by Buyer.

13.4 Project Reports and Project Review Meetings.

13.4.1 Prior to the Commercial Operation Date. Supplier shall provide to Buyer in a monthly project report the status in achieving Project Milestones, progress in obtaining any approvals or certificates in connection with achieving the Commercial Operation Date, and a discussion of any foreseeable disruptions or delays. The monthly project reports should be provided at the latest on the 15th day of every month for the previous month. The Parties shall conduct meetings every six (6) months or more frequently if requested by Buyer to review this data and any information related to Supplier's status in achieving the Project Milestone activities listed in Exhibit 6.

13.4.2 Scheduled Operation Date and Commercial Operation Date. In addition to any other requirements for Commercial Operation under this Agreement, Supplier shall provide notice to Buyer of its scheduled Operation Date and Commercial Operation Date on the MPSC Approval Date, if any, and Supplier shall provide to Buyer in writing any adjustments to such scheduled dates as soon as possible, and shall coordinate with Buyer regarding the commencement of operation of the Generating Facility.

13.4.3 After Commercial Operation Date. After the Commercial Operation Date, Supplier shall provide to Buyer on January 1 and July 1 of each calendar year throughout the Term of this Agreement, in both electronic and hard copy format, a report which shall include all pertinent information in connection with Supplier's Generating Facility, which includes all reporting information maintained in the operational log. Each February during the Term, the Parties shall meet to conduct an annual review of the Generating Facility. Additional data and meetings may be required as necessitated by Generating Facility performance.

13.4.4 Operations Log. Supplier shall maintain an operations log, which shall include the Delivered Amount, unplanned maintenance outages and Planned Outages, circuit breaker trip operations, partial deratings of equipment, and any other significant event or information related to the operation of the Generating Facility. The operations log shall be available for inspection by Buyer upon reasonable advance request, and Supplier shall make the data that supports the log available on a real-time basis by remote access to Buyer, if Buyer acquires the necessary equipment and software license to process the data by remote access

13.4.5 Financial Information. Upon Buyer's written request, Supplier shall, within thirty (30) calendar days of such request, provide Buyer with (a) copies of Supplier's most recent financial statements required by Supplier's Lenders and (b) in the initial request by Buyer, the relevant provisions of Supplier's lending agreements setting forth the financial reporting obligations and, for any subsequent requests, any amendments thereto. In the event Supplier is funding one hundred percent (100%) of the engineering, procurement, construction, and operation of the Generating Facility with its own equity, then Supplier shall, within thirty (30) calendar days of a request for its most recent financial statements, provide Buyer with copies of such financial statements prepared in accordance with generally accepted accounting principles in the United State as in effect from time to time.

COMMUNICATIONS

14.1 On Call. Supplier's Operating Representative shall be available to address and make decisions on all operational matters under this Agreement on a twenty-four (24) hour, seven (7) day per week basis. Supplier shall, at its expense, maintain and install a twenty-four (24) hour, seven (7) day per week communication link with Buyer's Operating Representative at Buyer's operations center and with Buyer's scheduling personnel, as listed on Exhibit 4, to maintain communications between personnel on site at the Generating Facility and Buyer's Operating Representative at Buyer's operations center, Buyer's schedulers, and the Control Area Operator at all times. Supplier shall provide at its expense:

14.1.1 For the purposes of telemetering, a telecommunications circuit from the Generating Facility to Buyer's operations center;

14.1.2 Two (2) dedicated ringdown voice telephone lines for purposes of accessing Buyer's dial-up metering equipment and for communications with Buyer's operations center; and

14.1.3 Equipment to transmit to and receive voice data, facsimiles, and email from Buyer and the Control Area Operator, including cellular telephones.

SCHEDULING SERVICES

15.1 Scheduling Services. Buyer shall be responsible for offering the Generating Facility into the MISO energy market and will act as the generation owner of the Generating Facility in the MISO energy market. Buyer shall receive all revenue from MISO related to the operation of the Generating Facility and be responsible for all payments to MISO related to the operation of the Generating Facility.

15.2 Scheduling Services Fee. For providing the foregoing scheduling services, Supplier will pay Buyer $1.00/MWh.

COMPLIANCE

16.1 Compliance with Laws. Each Party shall comply with all relevant Laws and shall, at its sole expense, maintain in full force and effect all relevant permits, authorizations, licenses, and other authorizations material to the maintenance of its facilities and the performance of obligations under this Agreement. Each Party and its representatives shall comply with all relevant requirements of the Control Area Operator, Transmission Provider, and each Governmental Authority to ensure the safety of its employees and the public.

16.2 Good Utility Practice. Buyer and Supplier shall perform, or cause to be performed, their obligations under this Agreement in all material respects in accordance with Good Utility Practice.

APPROVALS

17.1 Condition Precedent. Each Party's performance of its respective obligations under Articles 3, 4, 5, 7, 8, 9, 10, 11, 12, 14, 15 and 28 of this Agreement is subject to the Parties obtaining their respective approvals described in Section 17.2 and Section 17.4 in form and substance reasonably satisfactory to Buyer and Supplier.

17.2 MPSC Approval. Within fourteen (14) calendar days following the Effective Date, Buyer shall submit this Agreement to the MPSC for approval consistent with the Clean, Renewable and Efficient Energy Act and any other applicable statutory requirements.

17.3 Failure to Obtain Approval; Conditions of Approval. If the MPSC fails to grant approval or acceptance of this Agreement Pursuant to Section 17.2, then Buyer shall have the right to terminate this Agreement upon written notice to Supplier within fourteen (14) calendar days of such MPSC disapproval. If the MPSC grants the approval or acceptance of this Agreement and the conditions of such approval or acceptance are not reasonably acceptable to Buyer, then Buyer shall have the right to terminate this Agreement upon written notice to Supplier within fourteen (14) calendar days of such MPSC approval or acceptance. If the MPSC grants the approval or acceptance of this Agreement and the conditions of such approval or acceptance are not reasonably acceptable to Supplier, then Supplier shall have the right to terminate this Agreement upon written notice to Buyer within fourteen (14) calendar days of such MPSC approval or acceptance. If the MPSC fails to grant approval or acceptance of this Agreement by April 30, 2009, Supplier shall have the right to terminate this Agreement upon written notice to Buyer on or before May 15, 2009.

17.4 Cooperation. Each Party agrees to notify the other Party of any significant developments in obtaining any approval in connection with achieving Commercial Operation, including MPSC approval. Each Party shall use reasonable efforts to obtain such required approvals and shall exercise due diligence and shall act in Good Faith to cooperate with and assist each other in acquiring each approval necessary to effectuate this Agreement.

17.5 Intervention. Supplier shall (a) timely file a petition to intervene in the MPSC proceeding related to the approval of this Agreement, (b) retain counsel to represent Supplier in such proceeding, and (c) actively support the regulatory approval process.

CREDITWORTHINESS AND SECURITY

18.1 Credit Appraisal. Acceptance of this Agreement is contingent upon (i) Buyer's completion of a credit appraisal of Supplier and (ii) Buyer's determination, in its sole discretion, that Supplier is able to perform its obligations. To enable Buyer to conduct such credit appraisal, Supplier shall submit the information below to the extent such information is applicable to Supplier.

18.1.2 Supplier shall provide the latest audited fiscal and latest interim financial statements, prepared in accordance with generally accepted accounting principles;

18.1.3 Supplier shall confirm in writing that it is not operating under any chapter of the bankruptcy laws and is not subject to liquidation or debt reduction procedures under state laws, such as an assignment for the benefit of creditors, or any informal creditors' committee agreement;

18.1.4 Supplier shall confirm in writing that no significant collection lawsuits or judgments are outstanding which would seriously reflect upon the business entity's ability to remain solvent;

18.1.5 Supplier shall provide a statement of prospective Supplier's legal composition and ownership;

18.1.6 Supplier shall provide such other information be may be requested by Buyer; and

18.1.7 in the event Supplier cannot provide the information above, it shall, if applicable, provide that information for Supplier's parent company or guarantor.

18.2 Waiver of Buyer Security. Supplier hereby waives any and all rights it may have, including rights at Law and otherwise, to require Buyer to provide financial assurances or security (including, but not limited to, cash, letters of credit, bonds, or other collateral) in respect of its obligations under this Agreement.

18.3 [redacted]

INDEMNIFICATION

19.1 Indemnification for Losses. A Party to this Agreement (the "Indemnifying Party") shall indemnify, defend and hold harmless, on an After Tax Basis, the other Party, its parent and Affiliates, and each of their officers, directors, employees, attorneys, agents, and successors and assigns (each an "Indemnified Party") from and against any and all Losses arising out of, relating to, or resulting from any third-party claims as a result of the Indemnifying Party's breach of, or the performance or non-performance of, its obligations under this Agreement (including Taxes, failure to maintain insurance at levels required by this Agreement, and penalties, fines, reasonable attorneys' fees, and costs incurred in connection with the Clean, Renewable and Efficient Energy Act) or any other act or failure to act; provided, however, that no Party shall be indemnified hereunder for any Loss to the extent resulting from its own negligence, fraud, or willful misconduct.

19.1.1 In furtherance of the foregoing indemnification and not by way of limitation thereof, the Indemnifying Party hereby waives any defense it otherwise might have against the Indemnified Party under applicable workers' compensation laws.

19.1.2 In claims against any Indemnified Party by an agent of the Indemnifying Party, or anyone directly or indirectly employed by them or anyone for whose acts the Indemnifying Party may be liable, the indemnification obligation under this Article 19 shall not be limited by a limitation on amount or type of damages, compensation, or benefits payable by or for the Indemnifying Party or a subcontractor under workers' or workmen's compensation acts, disability benefit acts, or other employee benefit acts.

19.2 No Negation of Existing Indemnities; Survival. Each Party's indemnity obligations under this Agreement shall not be construed to negate, abridge, or reduce other rights or obligations, which would otherwise exist at Law or in equity. The obligations contained herein shall survive any termination, cancellation, expiration, or suspension of this Agreement to the extent that any third-party claims are commenced during the applicable statute of limitations period.

19.3 Indemnification Procedures.

19.3.1 Any Indemnified Party seeking indemnification under this Agreement for any Loss shall give the Indemnifying Party notice of such Loss promptly, but in any event on or before thirty (30) calendar days after the Indemnified Party's actual knowledge of such claim or action. Such notice shall describe the Loss in reasonable detail, and shall indicate the amount (estimated if necessary) of the Loss that has been, or may be sustained by, the Indemnified Party. To the extent that the Indemnifying Party will have been actually and materially prejudiced as a result of the failure to provide such notice, the Indemnified Party shall bear all responsibility for any additional costs or expenses incurred by the Indemnifying Party as a result of such failure to provide notice.

19.3.2 In any action or proceeding brought against an Indemnified Party by reason of any claim indemnifiable hereunder, the Indemnifying Party may, at its sole option, elect to assume the defense at the Indemnifying Party's expense, and shall have the right to control the defense thereof and to determine the settlement or compromise of any such action or proceeding. Notwithstanding the foregoing, an Indemnified Party shall in all cases be entitled to control its own defense in any action if it:

19.3.2.1 May result in injunctions or other equitable remedies with respect to the Indemnified Party which would have a Material Adverse Effect on its business or operations;

19.3.2.2 May result in material liabilities which may not be fully indemnified hereunder; or

19.3.2.3 May have a Material Adverse Effect on the business or the financial condition of the Indemnified Party (including a Material Adverse Effect on the tax liabilities, earnings, ongoing business relationships, or regulation of the Indemnified Party) even if the Indemnifying Party pays all indemnification amounts in full.

19.3.3 Subject to Section 19.3.2, neither Party may settle or compromise any claim for which indemnification is sought under this Agreement without the prior written consent of the other Party; provided, however, said consent shall not be unreasonably withheld or delayed.

LIMITATION OF LIABILITY

20.1 Responsibility for Damages. Notwithstanding anything under Section 19.1 to the contrary, and except where caused by Buyer's negligence or willful misconduct, Supplier shall be responsible for all physical damage to or destruction of the property, equipment, and/or facilities owned by it, and Supplier hereby releases Buyer from any reimbursement for such damage or destruction.

20.2 Limitation on Damages. To the fullest extent permitted by Law, and notwithstanding other provisions of this Agreement, in no event shall a Party be liable to the other Party, whether in contract, warranty, tort, negligence, strict liability, or otherwise, for special, indirect, incidental, multiple, consequential (including lost profits or revenues, business interruption damages, and lost business opportunities), exemplary, or punitive damages related to, arising out of, or resulting from performance or nonperformance of this Agreement. For purposes of clarification, Energy Replacement Costs, REC Replacement Costs, or payment made by either Party to satisfy payments owing under Sections 3.5, 3.6, 9.6, 10.4, or 28.6 shall not be considered special, indirect, incidental, multiple, consequential (including lost profits or revenues, business interruption damages and lost business opportunities), exemplary, or punitive damages under this Section 20.2. In addition, this limitation on damages shall not apply with respect to claims brought by third parties for which a Party is entitled to indemnification under this Agreement.

20.3 Survival. The provisions of this Article 20 shall survive any termination, cancellation, expiration, or suspension of this Agreement.

FORCE MAJEURE

21.1 Excuse. Subject to Section 21.4, neither Party shall be considered in default under this Agreement for any delay or failure in the performance of its obligations, and shall be excused in the performance of its obligations under this Agreement (including any obligation to deliver or accept Product), if such delay or failure is due to an event of Force Majeure.

21.2 "Force Majeure" means, subject to Section 21.3, any of the following enumerated events that occur subsequent to the Effective Date and before the termination or expiration of the Term of this Agreement, and that delays or prevents a Party's performance of its obligations under this Agreement, but only to the extent that (a) such event of Force Majeure is not attributable to fault or negligence on the part of that Party; (b) such event of Force Majeure is caused by factors beyond that Party's reasonable control; (c) despite taking all reasonable technical and commercial precautions and measures to prevent, avoid, mitigate, or overcome such event and the consequences thereof, the Party affected has been unable to prevent, avoid, mitigate, or overcome such event or consequences; and (d) such Party has satisfied the requirements of Section 21.4:

21.2.1 Acts of God such as storms, hurricanes, floods, lightning, and earthquakes;

21.2.2 Sabotage or destruction by a third-party of facilities and equipment relating to the performance by the affected Party of its obligations under this Agreement;

21.2.3 War, riot, acts of a public enemy, or other civil disturbance;

21.2.4 Strike, walkout, lockout or other significant labor dispute;

21.2.5 Action or inaction of a Governmental Authority (excluding any change in Law, including Renewable Energy Law); or

21.2.6 Action or inaction of Transmission Provider, but excluding any FERC approved amendments to Transmission Provider's FERC approved tariff.

21.3 Exclusions. None of the following shall constitute an event of Force Majeure:

21.3.1 Economic hardship of either Party;

21.3.2 The non-availability of wind to generate electricity from the Generating Facility;

21.3.3 A Party's failure to obtain any permit, license, consent, agreement, or other approval from a Governmental Authority attributable to the fault or negligence of that Party, except to the extent it is caused by an event listed in Sections 21.2.3 or 21.2.4; and

21.3.4 A Party's failure to meet a Project Milestone, except to the extent it is caused by an event listed in Section 21.2.

21.4 Conditions. A Party may rely on a claim of Force Majeure to excuse its performance only to the extent that such Party:

21.4.1 Provides prompt notice of such Force Majeure event to the other Party, giving an estimate of its expected duration and the probable impact on the performance of its obligations under this Agreement;

21.4.2 Exercises all reasonable efforts to continue to perform its obligations under this Agreement;

21.4.3 Expeditiously takes action to correct or cure the event or condition excusing performance so that the suspension of performance is no greater in scope and no longer in duration than is dictated by the event or condition being corrected or cured using commercially reasonable efforts; provided, however, that settlement of strikes or other labor disputes will be completely within the sole discretion of the Party affected by such strike or labor dispute;

21.4.4 Exercises all commercially reasonable efforts to mitigate or limit damages to the other Party; and

21.4.5 Provides prompt notice to the other Party of the cessation of the event or condition giving rise to its excuse from performance.

DISPUTES

22.1 Dispute or Claim. Any cause of action, claim, or dispute which either Party may have against the other arising out of or relating to this Agreement, including the interpretation of the terms hereof or any Laws that affect this Agreement, or the transactions contemplated hereunder, or the breach, termination, or validity thereof ("Dispute") shall be submitted in writing to the other Party. The written submission of any Dispute shall include a concise statement of the question or issue in dispute together with a statement listing the relevant facts and appropriate supporting documentation.

22.2 Good Faith Resolution. The Parties agree to cooperate in Good Faith to expedite the resolution of any Dispute. Pending resolution of a Dispute, the Parties shall proceed diligently with the performance of their obligations under this Agreement.

22.3 Informal Negotiation. The Parties shall first attempt in Good Faith to resolve any Dispute through informal negotiations by the Operating Representatives or Contract Representatives and senior management of each Party.

22.4 Litigation. In the event the Parties are unable to resolve any Dispute pursuant to the foregoing, either may seek redress in a court of law or equity subject to the exclusive jurisdiction in the federal or state courts located in Detroit, Michigan.

22.5 Recovery Costs. In the event any action is brought at law or in equity in court to enforce any provision of this Agreement, or for damages by reason of any alleged breach of this Agreement, then the prevailing Party will be entitled to recover from the other Party all costs of the suit, including court costs, the prevailing Party's reasonable attorneys' fees, and related costs and expenses of litigation.

NATURE OF OBLIGATIONS

23.1 Relationship of the Parties. The provisions of this Agreement shall not be construed to create an association, trust, partnership, or joint venture; or impose a trust or partnership duty, obligation, or liability or agency relationship between the Parties.

23.2 No Public Dedication. By this Agreement, neither Party dedicates any part of its facilities nor the service provided under this Agreement to the public.

ASSIGNMENT

24.1 Buyer Assignment. Buyer's obligations hereunder shall not be assigned by Buyer without the prior written consent of Supplier, which consent shall not be unreasonably withheld.

24.2 Supplier Assignment. Supplier's obligations hereunder shall not be assigned by Supplier without the prior written consent of Buyer, which consent shall not be unreasonably withheld.

24.3 Liability After Assignment. A Party's assignment or transfer of rights or obligations pursuant to this Article 24 of this Agreement shall relieve said Party from any liability and financial responsibility for the performance thereof arising after any such transfer or assignment, provided such transferee enters into an assignment and assumption agreement in form and substance satisfactory to the other Party, pursuant to which such transferee assumes all of the assigning or transferring Party's obligations hereunder and otherwise agrees to be bound by the terms of this Agreement.

24.4 Transfers of Ownership. Subject to Article 8, during the Term, Supplier shall not sell, transfer, assign, or otherwise dispose of its ownership interest in the Generating Facility to any third-party absent (a) a transfer of this Agreement to such third-party and (b) Supplier entering into an assignment and assumption agreement, in form and substance satisfactory to Buyer, with such third-party pursuant to which such third-party assumes all of Supplier's obligations hereunder and otherwise agrees to be bound by the terms of this Agreement.

24.5 Assignee Obligations. Supplier shall procure and deliver to Buyer an undertaking, enforceable by Buyer, from each party possessing a security interest in the Generating Facility to the effect that, if such party forecloses on its security interest, (a) it will assume Supplier's obligations under and otherwise be bound by the terms of this Agreement, and (b) it will not sell, transfer, or otherwise dispose of its interest in the Generating Facility to any third-party absent an agreement from such third-party to assume Supplier's obligations under and otherwise be bound by the terms of this Agreement.

24.6 Successors and Assigns. This Agreement and all of the provisions hereof are binding upon, and inure to the benefit of, the Parties and their respective successors and permitted assigns.

24.7 Collateral Assignment by Supplier. In the event that Supplier transfers, pledges, encumbers, or collaterally assigns this Agreement to Supplier's Lenders, Supplier shall provide written notice to Buyer of such transfer, pledge, encumbrance, or assignment, including the address of Supplier's Lenders. In connection with any financing or refinancing of the Generating Facility, Buyer shall negotiate in Good Faith with Supplier and Supplier's Lenders to agree upon a consent to collateral assignment of this Agreement, which consent to collateral assignment shall be in form and substance agreed to by Buyer, Supplier, and Supplier's Lenders, and shall include the following provisions:

24.7.1 The Parties shall not amend or modify this Agreement in any material respect without the prior written consent of the Supplier's Lenders;

24.7.2 Prior to exercising its right to terminate this Agreement as a result of an Event of Default by Supplier, Buyer shall give notice of such Event of Default by Supplier to the administrative agent of Supplier's Lenders, which Buyer has been provided written notice of;

24.7.3 Supplier's Lenders shall have the right, but not the obligation, to cure an Event of Default on behalf of Supplier in accordance with the provisions of this Agreement, provided that Supplier's Lenders shall be provided an additional forty-five (45) calendar days, from the end of the Cure Period provided pursuant to Section 25.2, to effect a cure of such Event of Default;

24.7.4 An agreement, enforceable by Buyer, from each of Supplier's Lenders that:

24.7.4.1 Supplier's Lenders shall receive prior notice of and the right to approve material amendments to the Agreement, which approval shall not be unreasonably withheld, delayed, or conditioned;

24.7.4.2 If Supplier's Lenders, directly or indirectly, take possession of, or title to, the Generating Facility (including possession by a receiver or title by foreclosure or deed in lieu of foreclosure), then Supplier's Lenders shall assume all of Supplier's obligations under this Agreement, provided that Supplier's Lenders shall have no personal liability for any monetary obligations of Supplier under this Agreement which are due and owing to Buyer as of the assumption date; provided, however, that prior to such assumption, if Buyer advises Supplier's Lenders that Buyer will require that Supplier's Lenders cure (or cause to be cured) any Supplier Event of Default hereunder existing as of the possession date (irrespective of when such Event of Default occurred) in order to avoid the exercise by Buyer (in its sole discretion) of Buyer's right to terminate the Agreement in respect of such Event of Default, then Supplier's Lenders, at their option and in their sole discretion, may elect to either: (i) cause such Event of Default to be cured or (ii) not assume this Agreement; and

24.7.4.3 If Supplier's Lenders elect to sell or transfer the Generating Facility (after directly or indirectly taking possession of, or title to, the Generating Facility), or if the sale of the Generating Facility occurs through the actions of Supplier's Lenders (including a foreclosure sale where a third-party is the buyer, or otherwise), then, as a condition of such sale or transfer, (a) Supplier's Lenders shall cause the buyer or transferee of the Generating Facility to assume all of Supplier's obligations arising under this Agreement and (b) the buyer or transferee of the Generating Facility shall (i) have creditworthiness that is equal to or superior to the creditworthiness of Supplier as of the Effective Date, as determined by Buyer in its reasonable discretion, and (ii) have experience in operating renewable energy generating facilities that is equivalent or superior to that of Supplier, or the operator of the Generating Facility if Supplier is not the operator, as determined by Buyer in its reasonable discretion.

DEFAULT AND REMEDIES

25.1 Events of Default. Except to the extent excused due to an event of Force Majeure in accordance with Article 21, an event of default ("Event of Default") shall be deemed to have occurred with respect to a Party (the "Defaulting Party") upon the occurrence of one or more of the following events:

25.1.1 failure to comply with any material obligations imposed upon it by this Agreement;

25.1.2 failure to make timely payments due under this Agreement;

25.1.3 failure to comply with the material requirements of the Control Area Operator, Transmission Provider, Buyer, MISO, MPSC, FERC, and any successor thereto where following such directions is required hereunder;

25.1.4 in the case of Supplier, its failure at any time to qualify the Generating Facility as a Renewable Energy System or itself as a renewable energy producer or similar status under the Renewable Energy Law;

25.1.5 in the case of Supplier, its failure to install, operate, maintain, or repair the Generating Facility in accordance with Good Utility Practice;

25.1.6 in the case of Supplier, its failure to meet any of the Project Milestones under the terms of Section 10.2.1 within twelve (12) months of the date set forth in Exhibit 6 and according to the terms and conditions set forth in Exhibit 6;

25.1.7 in the case of Supplier, its failure to comply with the provisions of Article 18;

25.1.8 in the case of Supplier, its failure to comply with the provisions of Article 24;

25.1.9 in the case of Supplier, its failure to maintain the guaranteed Mechanical Availability Guaranty in accordance with Exhibit 19;

25.1.10 in the case of Supplier, its failure to comply with the provisions of Article 28; and

25.1.11 in the case of Supplier, if Supplier (a) becomes insolvent and files for or is forced into bankruptcy, (b) makes an assignment for the benefit of creditors, (c) is unable to pay its debts as they become due, or (d) is subject to a similar action or proceeding.

25.2 Cure Period. Upon the occurrence of an Event of Default, other than pursuant to Section 25.1.11, the Defaulting Party shall be entitled to a period of ten (10) calendar days from such occurrence (the "Cure Period") to cure such Event of Default during which time the duties and obligations of the Non-Defaulting Party under this Agreement are suspended; provided, however, that in the case of an Event of Default under Section 25.1.6, with written notice from Supplier to Buyer, such Cure Period may be extended for an additional sixty (60) calendar days if (a) Supplier can demonstrate to Buyer that such Event of Default was not capable of being cured within such ten (10) calendar day period and such Event of Default is capable of being cured within an additional sixty (60) calendar day period; (b) Supplier is diligently and continuously proceeding to cure such Event of Default; and (c) Supplier posts additional security in a form consistent with the provisions of Section 18.3, and in an amount acceptable to Buyer in its sole discretion, but in no event in excess of fifteen percent (15%) of the original amount of security posted, if any.

25.3 Remedies. If an Event of Default is not cured by the Defaulting Party during the Cure Period, the Non-Defaulting Party shall be entitled to all legal and equitable remedies that are not expressly prohibited by the terms of this Agreement, including termination of this Agreement as provided in Section 2.3 [redacted]

[redacted]

REPRESENTATIONS AND WARRANTIES OF SUPPLIER

Supplier represents and warrants the following to Buyer as of the date of achievement for each Project Milestone and the beginning of each Contract Year, as applicable:

26.1 Organization; Qualification. Supplier is a limited liability company duly organized, validly existing, and in good standing under the laws of the State of Michigan and has all requisite power and authority to own, lease, and/or operate its properties and to carry on its business as is now being conducted. Supplier is duly qualified or licensed to do business as a limited liability company and is in good standing in each jurisdiction in which the property owned, leased, or operated by it or the nature of the business conducted by it makes such qualification necessary, except where the failure to be so duly qualified or licensed and in good standing would not have a Material Adverse Effect.

26.2 Authority Relative to this Agreement. Supplier has full authority to execute, deliver, and perform this Agreement to which it is a Party and to consummate the transactions contemplated herein. Other than obtaining the Supplier's Required Regulatory Approvals as set out in Exhibit 10, no other proceedings or approvals on the part of Supplier are necessary to authorize this Agreement. This Agreement constitutes a legal, valid, and binding obligation of Supplier enforceable in accordance with its terms, except as the enforcement thereof may be limited by applicable bankruptcy, insolvency, or similar laws affecting the enforcement of rights generally.

26.3 Consents and Approvals; No Violation. Other than obtaining the Supplier's Required Regulatory Approvals as set out in Exhibit 10, the execution, delivery, and performance of this Agreement by Supplier shall not (a) conflict with or result in any breach of any provision of the articles of organization (or other similar governing documents) of Supplier; (b) require any consent, approval, authorization or permit of, or filing with or notification to, any Governmental Authority, except where the failure to obtain such consent, approval, authorization or permit, or to make such filing or notification, could not reasonably be expected to have a Material Adverse Effect; or (c) result in a default (or give rise to any right of termination, cancellation, or acceleration) under any of the terms, conditions, or provisions of any note, bond, mortgage, indenture, agreement, lease, or other instrument or obligation to which Supplier or any of its subsidiaries is a party or by which any of their respective assets may be bound, except for such defaults (or rights of termination, cancellation, or acceleration) as to which requisite waivers or consents have been obtained.

26.4 Regulation as a Utility. Except as set forth in Exhibit 10, Supplier is not subject to regulation as a public utility or public service company (or similar designation) by any Governmental Authority.

26.5 Availability of Funds. Supplier has, or will have, and shall maintain, sufficient funds available to it to perform all obligations under this Agreement and to consummate the obligations contemplated pursuant thereto.

26.6 Interconnection Process. Supplier has initiated with the Transmission Provider the process of obtaining the rights to interconnect the Generating Facility to the Transmission System in order to provide for the delivery of Energy to and at the Delivery Point.

26.7 Interconnection Cost Due Diligence. Supplier has conducted due diligence regarding the costs of all facilities necessary to interconnect the Generating Facility to the Delivery Point and all such costs are covered by the Product Rate.

26.8 Permits, Authorizations, Licenses, and Grants. Supplier has applied or will apply for or has received the permits, authorizations, licenses, and grants listed in Exhibits 10 and 11, and that no other permits, authorizations, licenses, or grants are required by Supplier to construct and operate the Generating Facility and fulfill Supplier's obligations under this Agreement.

26.9 Related Agreements. Supplier has entered into or will enter into all necessary and material agreements as listed in Exhibit 12 related to Supplier's obligations under this Agreement.

26.10 Certification. The Generating Facility qualifies as a Renewable Energy System and Supplier has been and is in compliance with all requirements set forth in the Clean, Renewable and Efficient Energy Act.

26.11 Title. Upon achieving the Operation Date, Supplier owns all Product attributable to the Generating Facility and has the right to sell such Product to Buyer. Supplier will convey good title to the Product to Buyer free and clear of any liens or other encumbrances or title defects, including any which would affect Buyer's ownership of any portion of such Product or prevent the subsequent transfer of any portion of such Product by Buyer to a third-party.

26.12 Generating Facility Site. Supplier either (a) owns the real property on which the Generating Facility is located, (b) has obtained the option to exclusively use and/or purchase the real property on which the Generating Facility will be located, or (c) has obtained the necessary rights to construct and operate the Generating Facility on such real property, throughout the Term.

REPRESENTATIONS AND WARRANTIES OF BUYER

Buyer represents and warrants the following to Supplier as of the date of achievement for each Project Milestone and the beginning of each Contract Year, as applicable:

27.1 Organization; Qualification. Buyer is a corporation duly organized, validly existing and in good standing under the laws of the State of Michigan and has all requisite corporate power and authority to own, lease, and operate its properties and to carry on its business as is now being conducted. Buyer is duly qualified or licensed to do business as a corporation and is in good standing in each jurisdiction in which the property owned, leased, or operated by it or the nature of the business conducted by it makes such qualification necessary, except where the failure to be so duly qualified or licensed and in good standing would not have a Material Adverse Effect.

27.2 Authority Relative to this Agreement. Buyer has full corporate authority to execute, deliver, and perform this Agreement to which it is a Party and to consummate the transactions contemplated herein. Other than obtaining the Buyer's Required Regulatory Approvals as set out in Exhibit 9, no other proceedings or approvals on the part of Buyer are necessary to authorize this Agreement. This Agreement constitutes a legal, valid, and binding obligation of Buyer enforceable in accordance with its terms, except as the enforcement thereof may be limited by applicable bankruptcy, insolvency, or similar laws affecting the enforcement of rights generally.

27.3 Consents and Approvals; No Violation. Other than obtaining the Buyer's Required Regulatory Approvals as set out in Exhibit 9, the execution, delivery, and performance of this Agreement by Buyer shall not (a) conflict with or result in any breach of any provision of the articles of organization (or other similar governing documents) of Buyer; (b) require any consent, approval, authorization, or permit of, or filing with or notification to, any Governmental Authority, except (i) where the failure to obtain such consent, approval, authorization, or permit, or to make such filing or notification, could not reasonably be expected to have a Material Adverse Effect or (ii) for those consents, authorizations, approvals, permits, filings, and notices which become applicable to Buyer as a result of specific regulatory status of Buyer (or any of its Affiliates) or as a result of any other facts that specifically relate to the business or activities in which Buyer (or any of its Affiliates) is or proposes to be engaged, which consents, approvals, authorizations, permits, filings, and notices have been obtained or made by Buyer; or (c) result in a default (or give rise to any right of termination, cancellation, or acceleration) under any of the terms, conditions, or provisions of any note, bond, mortgage, indenture, agreement, lease, or other instrument or obligation to which Buyer or any of its subsidiaries is a party or by which any of their respective assets may be bound, except for such defaults (or rights of termination, cancellation, or acceleration) as to which requisite waivers or consents have been obtained.

27.4 Related Agreements. Buyer warrants that it has entered into or will enter into all necessary and material agreements related to Buyer's obligations under this Agreement.

INSURANCE

28.1 General Requirements. Supplier shall maintain at all times, at its own expense, general/commercial liability, worker's compensation, and other forms of insurance relating to its property, operations, and facilities in the manner and amounts set forth herein from the Effective Date of this

Agreement. Supplier shall maintain coverage on all policies written on a "claims made" or "occurrence" basis. If converted to an occurrence form policy, the new policy shall be endorsed to provide coverage back to a retroactive date acceptable to Buyer.

28.2 Qualified Insurers. Every contract of insurance providing the coverage required herein shall be with an insurer or eligible surplus lines insurer qualified to do business in the State of Michigan and with the equivalent, on a continuous basis, of a "Best Rating" of "A" or better and shall include provisions or endorsements:

28.2.1 Stating that such insurance is primary insurance with respect to the interest of Buyer and that any insurance maintained by Buyer is excess and not contributory insurance required hereunder;

28.2.2 Stating that no reduction, cancellation, or expiration of the policy shall be effective until ninety (90) calendar days from the date notice thereof is actually received by Buyer, provided that upon Supplier's receipt of any notice of reduction, cancellation, or expiration, Supplier shall immediately provide notice thereof to Buyer; and

28.2.3 Naming Buyer as an additional insured on the general liability insurance policies of Supplier as its interests may appear with respect to this Agreement.

28.3 Certificates of Insurance. Within thirty (30) calendar days of the Effective Date, Supplier shall provide to Buyer, and shall continue to provide to Buyer within thirty (30) calendar days of each anniversary of the Effective Date until the expiration of this Agreement, upon any change in coverage, or at the request of Buyer not to exceed once each year, properly executed and current certificates of insurance with respect to all insurance policies required to be maintained by Supplier under this Agreement. Certificates of insurance shall provide the following information:

28.3.1 The name of insurance company, policy number, and expiration date;

28.3.2 The coverage required and the limits on each, including the amount of deductibles or self-insured retentions, which shall be for the account of Supplier maintaining such policy; and

28.3.3 A statement indicating that Buyer shall receive at least ninety (90) calendar days prior notice of cancellation or expiration of a policy or of a reduction of liability limits with respect to a policy.

28.4 Certified Copies of Insurance Policies. At Buyer's request, in addition to the foregoing certifications, Supplier shall deliver to Buyer a copy of each insurance policy, certified as a true copy by an authorized representative of the issuing insurance company.

28.5 Inspection of Insurance Policies. Buyer shall have the right to inspect the original policies of insurance applicable to this Agreement at Supplier's place of business during regular business hours.

28.6 Supplier's Minimum Insurance Requirements.

28.6.1 Worker's Compensation. Worker's compensation insurance in accordance with statutory requirements including employer's liability insurance with limits of not less than [redacted] per occurrence and endorsement providing insurance for obligations under the U.S. Longshoremen's and Harbor Worker's Compensation Act and the Jones Act where applicable.

28.6.2 General Liability. General liability insurance including bodily injury, property damage, products/completed operations, contractual and personal injury liability with a combined single limit of at [redacted] per occurrence and at [redacted] annual aggregate.

28.6.3 Automobile Liability. Automobile liability insurance including owned, non-owned, and hired automobiles with combined bodily injury and property damage limits of at [redacted] per occurrence and at [redacted] aggregate.

28.7 Failure to Comply. If Supplier fails to comply with the provisions of this Article 28, Supplier shall save harmless and indemnify Buyer from any direct and indirect loss and liability, including attorneys' fees and other costs of litigation, resulting from the injury or death of any person or damage to any property if Buyer would have been protected had Supplier complied with the requirements of this Article 28, in accordance with the indemnification provisions of Article 19.

CONFIDENTIALITY

29.1 Confidential Information. "Confidential Information" means information provided by one Party (the "Disclosing Party") to the other (the "Receiving Party") in connection with the negotiation or performance of this Agreement that is clearly labeled or designated by the Disclosing Party as "confidential" or "proprietary" or with words of like meaning or, if disclosed orally, clearly identified as confidential with that status confirmed promptly thereafter in writing, excluding, however, information described in Section 29.3.

29.2 Treatment of Confidential Information. The Receiving Party shall treat any Confidential Information with at least the same degree of care regarding its secrecy and confidentiality as the Receiving Party's similar information is treated within the Receiving Party's organization. The Receiving Party shall keep confidential and not disclose the Confidential Information of the Disclosing Party to third parties (except as stated hereinafter) nor use it for any purpose other than the performance under this Agreement, without the express prior written consent of the Disclosing Party. The Receiving Party further agrees that it shall restrict disclosure of Confidential Information as follows:

29.2.1 Disclosure shall be restricted solely to (a) its agents as may be necessary to enforce the terms of this Agreement; (b) its Affiliates, shareholders, directors, officers, employees, advisors, lenders, and representatives as necessary; (c) any Governmental Authority in connection with seeking any required regulatory approval; (d) to the extent required by applicable Law, in the case of Buyer only, potential transferees of Energy or RECs obtained by Buyer; and (e) potential assignees of this Agreement (together with their agents, advisors, and representatives) as may be necessary in connection with any such assignment (which assignment or transfer shall be in compliance with Article 24), in each case after advising those agents of their obligations under this Article 29.

29.2.2 In the event that the Receiving Party is required by applicable Law to disclose any Confidential Information, the Receiving Party shall provide the Disclosing Party with prompt notice of such request or requirement to enable Disclosing Party to seek an appropriate protective order or other remedy and to consult with Disclosing Party with respect to Disclosing Party taking steps to resist or narrow the scope of such request or legal process. The Receiving Party agrees not to oppose any action by the Disclosing Party to obtain a protective order or other appropriate remedy. In the absence of such protective order, and provided that the Receiving Party is advised by its counsel that it is compelled to disclose the Confidential Information, the Receiving Party shall:

29.2.2.1 Furnish only that portion of the Confidential Information which the Receiving Party is advised by counsel is legally required; and

29.2.2.2 Use its commercially reasonable efforts, at the expense of the Disclosing Party, to ensure that all Confidential Information so disclosed will be accorded confidential treatment.

29.2.3 Section 29.2.2 shall only apply to information disclosed as contemplated by 29.2.1.

29.3 Excluded Information. Confidential Information shall be deemed not to include the following:

29.3.1 Information which is or becomes generally available to the public other than as a result of a disclosure by the Receiving Party in breach of this Article 29;

29.3.2 Information which was available to the Receiving Party on a non-confidential basis prior to its disclosure by the Disclosing Party; and

29.3.3 Information which becomes available to the Receiving Party on a non-confidential basis from a Person other than the Disclosing Party or its representative who is not otherwise bound by a confidentiality agreement with Disclosing Party or its agent or is otherwise not under any obligation to Disclosing Party or its agent not to disclose such information to the Receiving Party and the Receiving Party, exercising reasonable due diligence, should have known of such obligation.

29.4 Injunctive Relief Due to Breach. The Parties agree that remedies at Law may be inadequate to protect each other in the event of a breach of this Article 29, and the Receiving Party hereby in advance agrees that the Disclosing Party shall be entitled to seek, without proof of actual damages, temporary, preliminary, and permanent injunctive relief from any Governmental Authority restraining the Receiving Party from committing or continuing any breach of this Article 29.

29.5 Public Statements. The Parties shall consult with each other prior to issuing any public announcement, statement or other disclosure with respect to this Agreement or the transactions contemplated hereby and Supplier shall not issue any such public announcement, statement or other disclosure without having first received the written consent of Buyer, except as may be required by Law. Notwithstanding the foregoing, Supplier acknowledges and agrees that Buyer may advertise, issue brochures or make other announcements, publications or releases regarding this Agreement and the Generating Facility for educational, promotional or informational purposes. Supplier shall reasonably cooperate with Buyer regarding such activities, including providing Buyer with reasonable access to the Generating Facility and authorizing the use of pictures of the Generating Facility for such activities. It shall not be deemed a violation of this Section 29.5 to file this Agreement with the MPSC or FERC for approval as required by applicable Law.

MISCELLANEOUS

30.1 Notices.

30.1.1 All notices hereunder shall, unless expressly specified otherwise, be in writing and shall be addressed, except as otherwise stated herein, to the Parties' Contract Representatives as set forth in Exhibit 4 or as modified from time to time by the receiving Party by notice to the other Party. Any changes to Exhibit 4 shall not constitute an amendment to this Agreement.

30.1.2 All notices or submittals required by this Agreement shall be sent either by hand-delivery, regular first class U.S. mail, registered or certified U.S. mail postage paid return receipt requested, overnight courier delivery, electronic mail, or facsimile transmission. Such notices or submittals will be effective upon receipt by the addressee, except that notices or submittals transmitted by electronic mail or facsimile transmission shall be deemed to have been validly and effectively given on the day (if a Business Day and, if not, on the next following Business Day) on which it is transmitted if transmitted before 1600 EPT, and if transmitted after that time, on the following Business Day; provided, however, that if any notice or submittal is tendered to an addressee and the delivery thereof is refused by such addressee, such notice shall be effective upon such tender.

30.1.3 All oral notifications required under this Agreement shall be made to the receiving Party's Operating Representative and shall promptly be followed by notice as provided in the other provisions of this Section 30.1.

30.2 Integration. This Agreement contains the entire agreement and understanding between the Parties with respect to all of the subject matter contained herein, thereby merging and superseding all prior agreements and representations, whether written or oral, by the Parties with respect to such subject matter.

30.3 Counterparts. This Agreement may be executed in two (2) counterparts, both of which shall be deemed an original and when taken together shall constitute one and the same instrument.

30.4 Interpretation. In the event an ambiguity or question of intent or interpretation arises, this Agreement shall be construed as if drafted jointly by the Parties and no presumption or burden of proof shall arise favoring or disfavoring any Party by virtue of authorship of any of the provisions of this Agreement. Any reference to any federal, state, local, or foreign statute or law shall be deemed also to refer to all rules and regulations promulgated thereunder, unless the context requires otherwise. The words "include", "includes", and "including" in this Agreement shall not be limiting and shall be deemed in all instances to be followed by the phrase "without limitation". References to Articles and Sections herein are cross-references to Articles and Sections, respectively, in this Agreement. Unless otherwise stated and where the context requires, words, including capitalized terms, importing the singular will include the plural and vice versa.

30.5 Headings. The headings or section titles contained in this Agreement are inserted solely for convenience and do not constitute a part of this Agreement between the Parties, nor should they be used to aid in any manner in the construction of this Agreement.

30.6 Discontinued or Modified Index. If the Average Monthly Michigan Hub Firm Price discontinues publishing or substantially modifies any index utilized herein, then the index used herein will be modified to the most appropriate available index, with appropriate basis changes to take into account any changes in the location of measurement.

30.7 Severability. If any term, provision, or condition of this Agreement is held to be invalid, void, or unenforceable by a Governmental Authority and such holding is subject to no further appeal or judicial review, then such invalid, void, or unenforceable term, provision, or condition shall be deemed severed from this Agreement and all remaining terms, provisions, and conditions of this Agreement shall continue in full force and effect. The Parties shall endeavor in Good Faith to replace such invalid, void, or unenforceable provisions with valid and enforceable provisions which achieve the purpose intended by the Parties to the greatest extent permitted by law.

30.8 Waivers; Remedies Cumulative. No failure or delay on the part of a Party in exercising any of its rights under this Agreement or in insisting upon strict performance of provisions of this Agreement, no partial exercise by either Party of any of its rights under this Agreement, and no course of dealing or course of performance between the Parties shall constitute a waiver of the rights of either Party under this Agreement. Any waiver shall be effective only by a written instrument signed by the Party granting such waiver, and such shall not operate as a waiver of, or estoppel with respect to, any subsequent failure to comply therewith. The remedies provided in this Agreement are cumulative and not exclusive of any remedies provided by law.

30.9 Amendments. The Parties agree that if the Laws that govern this Agreement are amended or superseded such that a change in Law causes a Material Adverse Effect on either Party, the affected Party is entitled to provide written notice to the other requesting that the Parties convene and negotiate in Good Faith ways to amend this Agreement to mitigate the Material Adverse Effect. Otherwise, amendments to this Agreement shall be mutually agreed upon by the Parties, produced in writing, and shall be executed by an authorized representative of each Party. The Buyer may submit an amendment to the MPSC and FERC, as applicable, for filing, acceptance, or approval.

30.10 Time is of the Essence. Time is of the essence to this Agreement and in the performance of all of the covenants, obligations, and conditions hereof.

30.11 Choice of Law. This Agreement and the rights and obligations of the Parties shall be construed and governed by the Laws of the State of Michigan.

30.12 Further Assurances. The Parties hereto agree to execute and deliver promptly, at the expense of the Party requesting such action, any and all other and further instruments, documents, and information which a Party may request and which are reasonably necessary or appropriate to give full force and effect to the terms and intent of this Agreement.

30.13 Forward Contract. The Parties acknowledge and agree that this Agreement is a contract (other than a Commodity Contract) for the purchase, sale, or transfer of a commodity or any similar good, article, service, right, or interest which is presently or in the future becomes the subject of dealing in the forward contract trade, or product or byproduct thereof, with a maturity date more than two calendar days after the date the contract is entered into. "Commodity Contract" means (a) with respect to a futures commission merchant, contract for the purchase or sale of a commodity for future delivery on, or subject to the rules of, a contract market or board of trade; (b) with respect to a foreign futures commission merchant, foreign future; (c) with respect to a leverage transaction merchant, leverage transaction; (d) with respect to a clearing organization, contract for the purchase or sale of a commodity for future delivery on, or subject to the rules of, a contract market or board of trade that is cleared by such clearing organization, or commodity option traded on, or subject to the rules of, a contract market or board of trade that is cleared by such clearing organization; or (e) with respect to a commodity options dealer, commodity option.

30.14 No Third-Party Beneficiaries. Except with respect to the rights of the Indemnified Party in Section 19.1 and Supplier's Lenders in Section 24.8, (a) nothing in this Agreement nor any action taken hereunder shall be construed to create any duty, liability, or standard of care to any third-party; (b) no third-party shall have any rights or interest, direct or indirect, in this Agreement or the services to be provided hereunder; and (c) this Agreement is intended solely for the benefit of the Parties, and the Parties expressly disclaim any intent to create any rights in any third-party as a third-party beneficiary to this Agreement or the services to be provided hereunder.

[SIGNATURES APPEAR ON THE FOLLOWING PAGE]

IN WITNESS WHEREOF, the Parties hereto have caused this Agreement to be executed by their duly authorized representative on the date first stated above.

BUYER:	SUPPLIER:
THE DETROIT EDISON COMPANY	HERITAGE STONEY CORNERS WIND FARM I, LLC
By: ________________________________	By: ________________________________
Name:	Name: Martin G. Lagina
Title:	Title: Manager

EXHIBIT 1

DESCRIPTION OF GENERATING FACILITY

1. Name of Facility: Heritage Stoney Corners Wind Farm I
   - (a) Location: In or around Richland Township, Michigan
2. Owner: Heritage Stoney Corners Wind Farm I, LLC
3. Operator: TBD
4. Equipment: Wind Turbines
   - (a) Type of Facility: Wind Generation
   - (b) Capacity

     Total nominal nameplate capacity: 14 MW

     Total nominal net capacity: 14 MW

EXHIBIT 2A

PRODUCT RATE

The Product Rate for the Term shall be: $116 per MWh.

EXHIBIT 2B

MONTHLY ENERGY INVOICE DETAIL

Supplier Letterhead

Generating Facility:

Generating Facility ID:

Date:
Invoice:
Number:
Billing:
Period:

CURRENT MONTHLY BILLING DATA INPUT

	Total Adjusted Supply Amount	MWh	Pricing	$/MWh
+	Monthly Supply Off-Peak Amount		Product Rate	
+ -	Monthly Planned On-Peak Outages			
-	Planned Outages		Average Monthly [________] Non-Firm Price	
-	Force Majeure		Daily Off-Peak [________] Non-Firm Index	
-	Buyer Declared Emergencies		Avg Monthly Buyer Inc Cost of Generation	
	Total Adjusted Supply Amount	-		
	Shortfall Trigger		Shortfall	
			Shortfall Amount	-

Delivered Amount
Max Off-Peak
Max On-Peak
Product
Total Delivered -

CURRENT MONTHLY BILLING CALCULATIONS

Product

Shortfall Triggered Replacement Cost

CURRENT MONTHLY INVOICE CALCULATION

Product Payments	Rates/MWh	Amounts
+ Product Rate		
+		
+ Shortfall Replacement Cost		
- Total Product Payment		
Total Product Payment		

TOTAL AMOUNT DUE:

PAYMENT DUE NO LATER THAN:

EXHIBIT 2C

REC REPLACEMENT INVOICE

Buyer Letterhead

Generating Facility:	Date:
Generating Facility ID:	Invoice Number:
	Contract Year:
	Payment Due Date:

GROSS METERED DATA

	Hours	Yearly REC Amount (MWh)
Contract Year Data		
Gross Generation Metered Data		
Yearly REC Amount		
Less Excused Adjustments:		
Force Majeure		
Buyer Declared Emergencies		
Yearly Adjusted REC Shortfall		

REC REPLACEMENT CALCULATION

REC Replacement Cost
Yearly Adjusted REC Shortfall
TOTAL REPLACEMENT COSTS

EXHIBIT 2D

ENERGY REPLACEMENT INVOICE

Letterhead

Generating Facility:	Date:
	Invoice Number:
Generating Facility ID:	Contract Year:
	Payment Due Date:

SHORTFALL CALCULATION	
Contract Year Data	MWh
Delivered Energy	
Adjusted Delivered Energy	
Supply Amount	
Excused Adjustments:	
Planned Outages	
Force Majeure	
Buyer Declared Emergencies	
Total Adjusted Supply Amount	
Shortfall Triggered	
Total Replacement Shortfall Amount	
PRICING CALCULATION	$/MWh
Product Rate	
Average Monthly [________] Non-Firm Price	
Replacement Cost	
ENERGY REPLACEMENT COST CALCULATION	
Energy Replacement Cost	
Energy Shortfall	
TOTAL REPLACEMENT COSTS	

*The Energy Replacement Invoice is the first component of Exhibit 2D. Please see the following page for the second component.

EXHIBIT 2D

ENERGY REPLACEMENT INVOICE DETAIL

Supplier Letterhead

Date	Hour	MWh	Supply Amount	Base Delivered Amount	Product Rate	Shortfall	Shortfall Excused (Yes/No)	Reasons for Shortfall & Comments	Replacement Energy Rate	Replacement Energy Cost

*The Monthly Energy Invoice Detail is the second component of Exhibit 2D and is to be attached to the Monthly Energy Invoice. It is to detail the supply of Energy for each hour using the fields shown above.

EXHIBIT 3

STANDBY SERVICE TARIFF

Standby Service to be provided by Wolverine Power Cooperative.

EXHIBIT 4

NOTICES, BILLING AND PAYMENT INSTRUCTIONS

Supplier:

[Supplier Name]

Contact	Mailing Address	Phone	E-mail
Contract Representative:			
Name and/or Title	[Mailing & Physical Address if different]		
Operating Representative:			
Name and/or Title	[Mailing & Physical Address if different]		
Operating Notifications:			
Prescheduling			
Real-Time			
Monthly Checkout			
Invoices:			
Name and/or Title	[Mailing & Physical Address if different]		
PAYMENT INSTRUCTIONS			
Payment Check:			
Name and/or Title/Department			
Address [inc. Mail/Suite #s]			
City, ST & Zip			
OR			
Payment Wire Transfer:			
Bank Name			
Bank Address			
Bank City, ST & Zip			

Account Name	[usually Supplier Name/reference]
ABA	
Account Number	

Buyer:

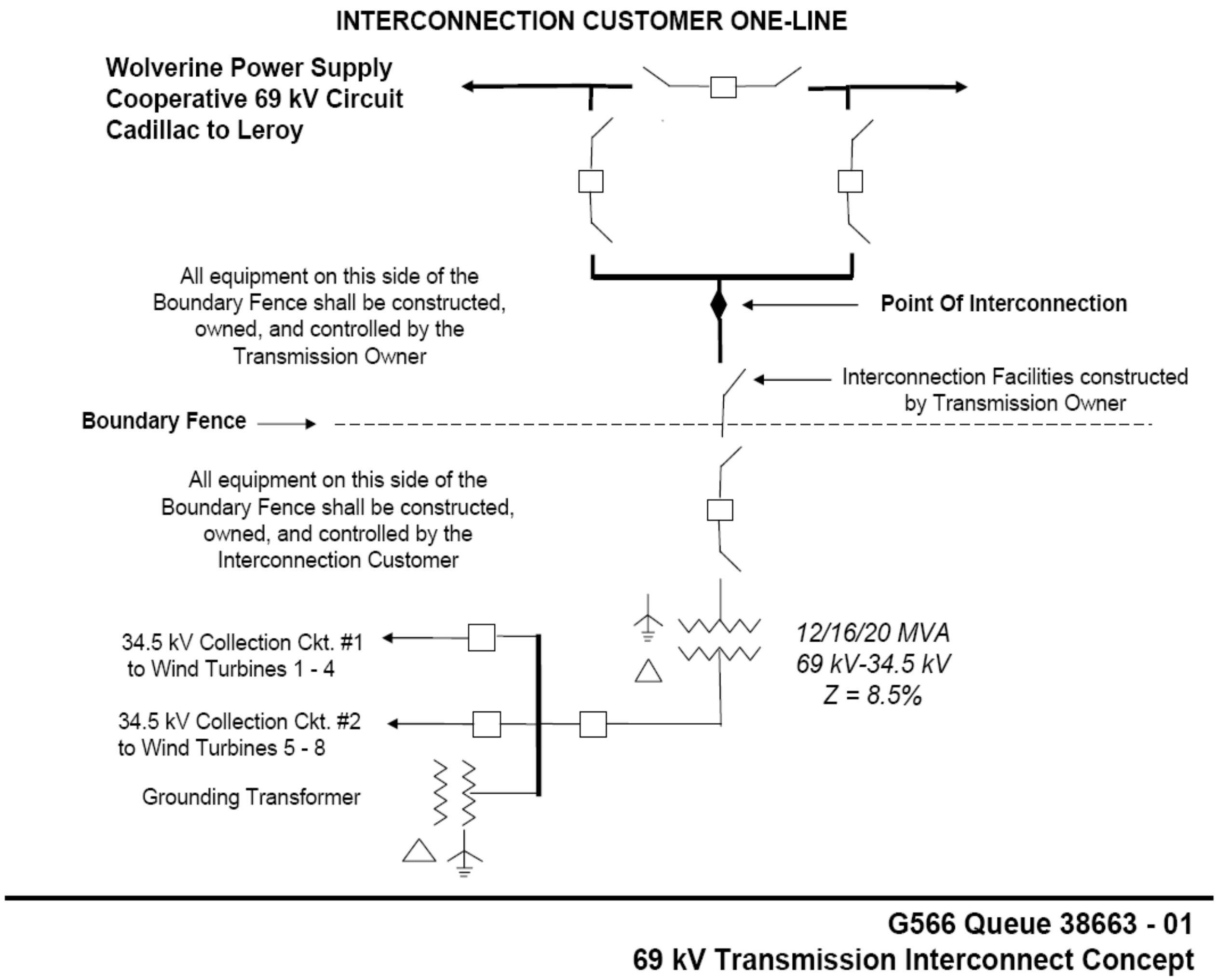
The Detroit Edison Company

Contact	Mailing Address	Address:
Contract Representative		
Manager, Contract Administration		Mailing
	Physical Delivery Address:	Physical
		Phone: E-mail:
Operating Representatives		
Scheduling		
Short-term Analysis		
Generation Dispatch	Address:	
Emergencies (including Force Majeure)		
Grid Reliability		
Transmission		
Short-term Analysis		
Metering		Phone: E-mail:
Invoices		Fax:
Renewables Contracts Accountant		
		Fax:
CC all invoices to	Phone: E-mail	

EXHIBIT 5

ONE-LINE DIAGRAM OF GENERATING FACILITY AND INTERCONNECTION FACILITIES

See attached one-line diagram of the Generating Facility, which indicates the Interconnection Facilities, the Delivery Point, ownership and the location of Meters, which location shall be reasonably satisfactory to Buyer. In accordance with Section 10.1, within thirty (30) calendar days after it executes or amends the IOA, Supplier shall provide an update to Exhibit 5.


INTERCONNECTION CUSTOMER ONE-LINE
Wolverine Power Supply
Cooperative 69 kV Circuit
Cadillac to Leroy
All equipment on this side of the Boundary Fence shall be constructed, owned, and controlled by the Transmission Owner
Point Of Interconnection
Interconnection Facilities constructed by Transmission Owner
Boundary Fence
All equipment on this side of the Boundary Fence shall be constructed, owned, and controlled by the Interconnection Customer
34.5 kV Collection Ckt. #1 to Wind Turbines 1 - 4
34.5 kV Collection Ckt. #2 to Wind Turbines 5 - 8
Grounding Transformer
12/16/20 MVA
69 kV-34.5 kV
Z = 8.5%
G566 Queue 38663 - 01
69 kV Transmission Interconnect Concept

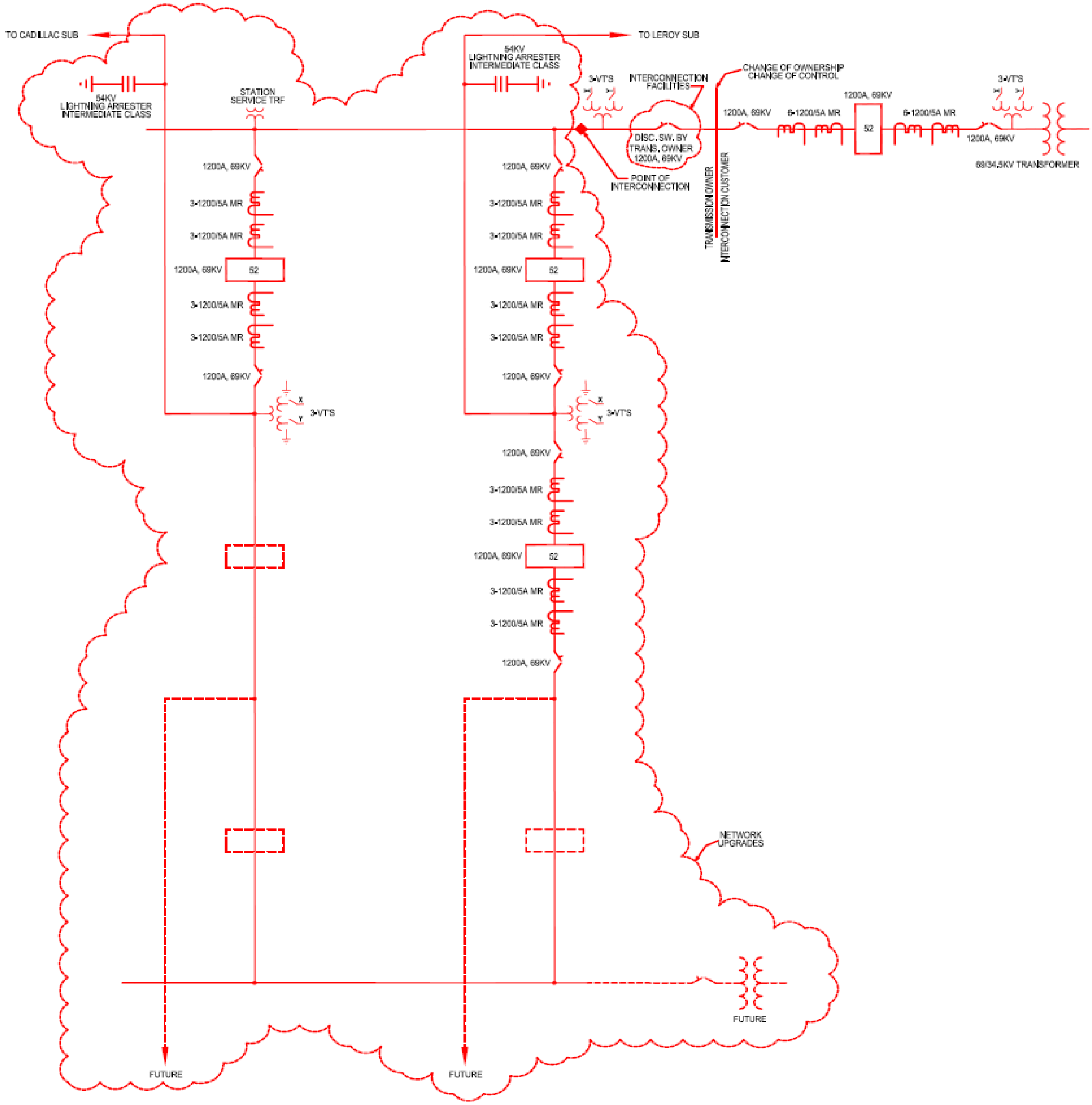

TO CADILLAC SUB
TO LEROY SUB
54KV
LIGHTNING ARRESTER
INTERMEDIATE CLASS
STATION
SERVICE TRF
3-VT'S
INTERCONNECTION
FACILITIES
CHANGE OF OWNERSHIP
CHANGE OF CONTROL
DISC. SW. BY
TRANS. OWNER
1200A, 69KV
POINT OF
INTERCONNECTION
TRANSMISSION OWNER
INTERCONNECTION CUSTOMER
6-1200/5A MR
52
3-1200/5A MR
69/34.5KV TRANSFORMER
NETWORK
UPGRADES
FUTURE

EXHIBIT 6

PROJECT MILESTONE SCHEDULE

All time periods are in months after the MPSC Approval Date. As stated below for convenience of drafting after MPSC approval will be shown as "AD". Any other timing is as otherwise described in specific items below. Buyer will update this Exhibit with actual dates after MPSC approval is received.

All milestones may be completed earlier than stated times, at the sole option of Supplier.

A) Project Milestone: Supplier shall have executed the IOA.

Completion Date: completed as of Effective Date

Documentation: Supplier shall provide Buyer with a fully executed copy of the IOA.

B) Project Milestone: Supplier shall have provided a copy of the Wind Turbine Supply Agreement.

Completion Date: one month AD

Documentation: Supplier shall provide Buyer with a fully executed redacted copy of the Wind Turbine Supply Agreement.

C) Project Milestone: Supplier shall obtain all permits, licenses, easements and approvals to construct and operate the Generating Facility.

Completion Date: two months AD.

Documentation: Supplier shall provide Buyer with written documentation and decisions from the appropriate agencies indicating hearings during which approvals were granted and final written decisions from those agencies where the approval was made.

D) Project Milestone: Supplier shall demonstrate to Buyer that it has closed on financing for the engineering, procurement and construction of the Generating Facility.

Completion Date: one month AD.

Documentation: Supplier shall provide Buyer with written documentation demonstrating that Supplier has closed on financing for the engineering, procurement and construction of the Generating Facility.

E) Project Milestone: Notice to proceed has been issued to the construction contractor under the turnkey engineering, procurement and construction contract (the "EPC Contract") for the Generating Facility and construction of the Generating Facility has commenced.

Completion Date: one month AD

Documentation: Supplier shall provide Buyer a copy of the executed Notice to Proceed acknowledged by the construction contractor and documentation from qualified professionals which indicates that physical work has begun on-site regarding the construction of the Generating Facility.

F) Project Milestone: Supplier's major equipment shall be delivered to Generating Facility's construction site.

Completion Date: five months after Notice to Proceed has been issued to the construction contractor under the EPC Contract.

Documentation: Supplier shall provide Buyer with documentation, including a bill(s) of lading that the major equipment has been delivered to the Generating Facility's construction site.

G) Project Milestone: Supplier shall qualify as a QF or such similar status under applicable Law.

Completion Date: No later than thirty (30) calendar days prior to the Planned Operation Date.

Documentation: Supplier shall provide Buyer with documentation that it has filed for and obtained EWG, QF or such similar status under applicable Law and shall remain a QF or such similar status for the entire Term of this Agreement.

H) Project Milestone: The Generating Facility achieves the Operation Date.

Completion Date: eight months AD

Documentation: Buyer's Meters shall record Energy being delivered from the Generating Facility to Buyer and the Generating Facility provides written notice to Buyer that the Generating Facility satisfies the definition of Operation Date in the Agreement

I) Project Milestone: Supplier shall have installed seven Wind Turbines with a total installed capacity nameplate rating stated in Exhibit 1.

Completion Date: seven months AD

Documentation: Supplier provides written notice to Buyer that the Generating Facility is comprised of a total of seven or more Wind Turbines, all of which are fully installed and operational at the Generating Facility site, and further satisfies the definition of the Generating Facility in the Agreement.

J) Project Milestone: The Generating Facility achieves the Commercial Operation Date.

Completion Date: eight months AD

Documentation: Supplier provides written notice to Buyer that the Generating Facility satisfies the definition of the Commercial Operation Date in the Agreement.

EXHIBIT 7

PERFORMANCE TESTS

EXHIBIT 8

[RESERVED]

EXHIBIT 9

BUYER'S REQUIRED REGULATORY APPROVALS

1. MPSC approval of this Agreement

EXHIBIT 10

SUPPLIER'S REQUIRED REGULATORY APPROVALS

1. Renewable Energy System certification.
2. MPSC approval of this Agreement.
3. MISO interconnect.

EXHIBIT 11

SUPPLIER'S REQUIRED PERMITS FOR CONSTRUCTION AND OPERATION

Permit	Agency
Tall Tower Permits	Federal Aviation Administration and Michigan Department of Transportation
Building Permits	Missaukee County

EXHIBIT 12

SUPPLIER'S REQUIRED AGREEMENTS

1. This Agreement
1. The IOA
2. Private Lease Agreement
3. EPC Contract
4. Operations and Maintenance Agreement
5. Wind Turbine Supply Agreement

EXHIBIT 13

SUPPLY AMOUNT

The Supply Amount shall be the Energy amounts as specified in the attached table below.

The Maximum Annual Amount shall be the maximum Energy amounts that Buyer must take per Contract Year.

Annual Supply Amount	MWh	Maximum Annual Amount
Contract Year 1 (pro rata if not January 1 COD)	[redacted]	[redacted]
Remaining Contract Years	[redacted]	[redacted]

EXHIBIT 14

[RESERVED]

EXHIBIT 15

OPERATION AND MAINTENANCE AGREEMENT; OPERATOR GOOD STANDING CERTIFICATE

In accordance with Section 10.7, Supplier shall provide Exhibit 15 no later than ninety (90) calendar days prior to the Commercial Operation Date.

EXHIBIT 16

GROUND LEASE; RIGHTS-OF-WAY

In accordance with Section 10.8, Supplier shall provide Exhibit 16 no later than sixty (60) calendar days prior to commencement of on-site development activities for the Generating Facility.

EXHIBIT 17

[RESERVED]

EXHIBIT 18

YEARLY REC AMOUNT

CONTRACT YEARS

Years	REC Amount
Contract Year 1 (pro rata if not January 1 COD)	[redacted]
Remaining Contract Years	[redacted]

EXHIBIT 19

GUARANTEED MECHANICAL AVAILABILITY

Supplier guarantees that (a) the Generating Facility shall achieve a mechanical availability guaranty (as defined below and hereinafter referred to as the "Mechanical Availability Guaranty") of [redacted] the prior two (2) year period for [redacted] after the Generating Facility achieves Commercial Operation and (b) the Generating Facility shall achieve a Mechanical Availability Guaranty of [redacted] the prior two (2) year period for each Contract Year following [redacted] the Generating Facility achieves Commercial Operation throughout the remainder of the Term. In the event that for any Contract Year the Mechanical Availability Guaranty is less than the guaranteed level as set forth above, Supplier shall have the next Contract Year to cure the deficiency. In the event that for such next Contract Year the Mechanical Availability Guaranty remains below the guaranteed level, Supplier shall have six months from the end of such Contract Year to cure the deficiency. After the end of the foregoing six months, the Generating Facility shall enter a six-month test period during which Buyer may take reasonable steps to confirm that the Generating Facility meets the Mechanical Availability Guaranty. If after the six-month test period Buyer reasonably determines that the Generating Facility fails to meet the Mechanical Availability Guaranty, such occurrence shall be an Event of Default under this Agreement.

The term "Mechanical Availability Guaranty" shall be calculated, for any rolling two year period and for all Wind Turbines, as a percentage, in accordance with the following formula:

$$\text{Mechanical Availability Percentage} = 100 \times \frac{\text{total Operating Hours during the average of the two year period for all Wind Turbines}}{\text{total Base Hours during the average of the two year period for all Wind Turbines}}$$

where:

"Base Hours" means, for each Wind Turbine, the total number of hours in the period less any hours during such period that such Wind Turbine is not operational as a result of a Planned Outage approved by Buyer or an event of Force Majeure; and

"Operating Hours" means, for each Wind Turbine, the total number of hours in the period that such Wind Turbine is physically capable of producing Energy.

As an example, assume that:

(a) the Generating Facility consists of one hundred (100) Wind Turbines,

(b) the total Operating Hours during the first and second Contract Years for all one hundred (100) Wind Turbines was 1,620,000,

(c) there were 36,000 hours during the first and second Contract Years that the Wind Turbines were not operational as a result of a Planned Outage approved by Buyer,

(d) there were not any hours during the first and second Contract Years that the Wind Turbines were not operational as a result of an event of Force Majeure, and

(e) the total number of hours during the first and second Contract Years was 17,520, then the Mechanical Availability Guaranty for the third Contract Year would be as follows:

$$\text{Mechanical Availability Percentage} = 100 \times \frac{1{,}620{,}000}{(17{,}520*100-36{,}000)}$$

$$\text{Mechanical Availability Percentage} = 100 \times \frac{1{,}620{,}000}{1{,}716{,}100}$$

$$\text{Mechanical Availability Percentage} = 100 \times .9440$$

$$\text{Mechanical Availability Percentage} = 94\%$$

Michigan Public Service Commission
The Detroit Edison Company
2009 Forecasted Transfer Price For Use in
PA 295 Activities for the Period 2009 - 2029

Case No.: U-15806 RPS
Exhibit No.: A-8 (JHB-4)
Page: 1 of 1
Witness: J. Byron

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
					Landfill		Anaerobic/Cellulosic Digester		Solar		Wind		
line no.	Year	Annual Average Locational Marginal Cost ($/MWh)	Final Capacity Cost ($/MW-Yr)	Final Capacity Cost @ 100% Capacity Factor ($/MWh)	Adjusted Capacity Payment ($/MWh)	Total Transfer Price ($/MWh)	Adjusted Capacity Payment ($/MWh)	Total Transfer Price ($/MWh)	Adjusted Capacity Payment ($/MWh)	Total Transfer Price ($/MWh)	Adjusted Capacity Payment ($/MWh)	Total Transfer Price ($/MWh)	Blended Transfer Price ($/MWh)
1													
2	2006[(1)]	43.71	3.,350										
3	2007[(1)]	48.77	11,678										
4	2008[(1)]	52.25	15,400										
5	2009	48.52	24,700	$ 2.82	$ 3.13	$ 51.66	$ 3.52	$ 52.05	$ 21.69	$ 70.21	$ 1.14	$ 49.66	$ 51.34
6	2010	54.39	30,000	$ 3.42	$ 3.81	$ 58.20	$ 4.28	$ 58.67	$ 26.34	$ 80.73	$ 1.38	$ 55.77	$ 57.84
7	2011	56.32	40,000	$ 4.57	$ 5.07	$ 61.40	$ 5.71	$ 62.03	$ 35.12	$ 91.45	$ 1.84	$ 58.16	$ 60.62
8	2012	71.73	60,000	$ 6.83	$ 7.59	$ 79.32	$ 8.54	$ 80.27	$ 52.54	$ 124.27	$ 2.75	$ 74.49	$ 77.49
9	2013	72.32	90,000	$ 10.27	$ 11.42	$ 83.74	$ 12.84	$ 85.17	$ 79.03	$ 151.35	$ 4.14	$ 76.47	$ 80.12
10	2014	73.05	125,000	$ 14.27	$ 15.85	$ 88.90	$ 17.84	$ 90.88	$ 109.76	$ 182.81	$ 5.75	$ 78.80	$ 82.97
11	2015	76.01	156,154	$ 17.83	$ 19.81	$ 95.82	$ 22.28	$ 98.29	$ 137.12	$ 213.13	$ 7.19	$ 83.20	$ 88.05
12	2016	78.06	162,831	$ 18.54	$ 20.60	$ 98.65	$ 23.17	$ 101.23	$ 142.59	$ 220.65	$ 7.47	$ 85.53	$ 90.61
13	2017	79.12	169,393	$ 19.34	$ 21.49	$ 100.60	$ 24.17	$ 103.29	$ 148.75	$ 227.87	$ 7.80	$ 86.92	$ 92.18
14	2018	81.20	176,047	$ 20.10	$ 22.33	$ 103.53	$ 25.12	$ 106.32	$ 154.59	$ 235.79	$ 8.10	$ 89.30	$ 93.86
15	2019	84.75	182,846	$ 20.87	$ 23.19	$ 107.95	$ 26.09	$ 110.85	$ 160.56	$ 245.31	$ 8.42	$ 93.17	$ 97.57
16	2020	88.04	189,960	$ 21.63	$ 24.03	$ 112.07	$ 27.03	$ 115.07	$ 166.35	$ 254.39	$ 8.72	$ 96.76	$ 100.97
17	2021	92.34	197,423	$ 22.54	$ 25.04	$ 117.38	$ 28.17	$ 120.51	$ 173.36	$ 265.70	$ 9.09	$ 101.43	$ 105.78
18	2022	96.36	205,164	$ 23.42	$ 26.02	$ 122.38	$ 29.28	$ 125.63	$ 180.16	$ 276.51	$ 9.44	$ 105.80	$ 110.33
19	2023	101.25	213,210	$ 24.34	$ 27.04	$ 128.29	$ 30.42	$ 131.67	$ 187.22	$ 288.47	$ 9.81	$ 111.06	$ 115.76
20	2024	106.78	221,470	$ 25.21	$ 28.01	$ 134.80	$ 31.52	$ 138.30	$ 193.95	$ 300.73	$ 10.17	$ 116.95	$ 121.69
21	2025	107.68	230,268	$ 26.29	$ 29.21	$ 136.89	$ 32.86	$ 140.54	$ 202.20	$ 309.88	$ 10.60	$ 118.28	$ 123.05
22	2026	111.74	239,304	$ 27.32	$ 30.35	$ 142.09	$ 34.15	$ 145.89	$ 210.14	$ 321.88	$ 11.02	$ 122.76	$ 127.66
23	2027	116.34	248,730	$ 28.39	$ 31.55	$ 147.89	$ 35.49	$ 151.83	$ 218.41	$ 334.75	$ 11.45	$ 127.79	$ 132.88
24	2028	124.68	258,620	$ 29.44	$ 32.71	$ 157.39	$ 36.80	$ 161.48	$ 226.48	$ 351.16	$ 11.87	$ 136.55	$ 141.88
25	2029	129.94	268,341	$ 30.63	$ 34.04	$ 163.98	$ 38.29	$ 168.23	$ 235.64	$ 365.58	$ 12.35	$ 142.29	$ 147.79
26													

		Capacity Factor %	On-Peak Capacity Credit %
27	Techonolgy		
28	Landfill	90%	100.0%
29	Anaerobic/Cellulosic Digester	80%	100.0%
30	Solar	13%	100.0%
31	Wind	31%	12.5%

32

33 (1) 2006-2008 Actual LMPs & Capacity Prices

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter, on the Commission's own	)	
motion, regarding the regulatory reviews,	)	
revisions, determinations, and/or approvals	)	Case No. U-15806-K
necessary for The Detroit Edison Company	)	
to fully comply with Public Acts 286 and	)	
295 of 2008.	)	

AFFIDAVIT OF IRENE M. DIMITRY

STATE OF MICHIGAN)
)ss.
COUNTY OF WAYNE)

Irene M. Dimitry, being first duly sworn, deposes and says:

1. I am the Director of Renewable Energy for The Detroit Edison Company ("Detroit Edison" or "Company"), a position I have held for 10 months. I have earned a Bachelor of Arts in Business Administration from Wayne State University and a Masters of Business Administration from the University of Michigan. I have worked for Detroit Edison for over fourteen years in a number of positions with increasing leadership responsibilities, including: Business Planning, Service Center Operations, the President's Staff organization, Customer Marketing, Customer Billing, and Enterprise Performance Management. Prior to my current position, I served as the Director of Strategy and Planning for Detroit Edison. In this role, I was responsible for Integrated Resource Planning, Customer Research, general rate case support and strategic initiatives related to the Company's business plans. I have sponsored testimony in Michigan Public Service Commission ("MPSC") Case No. U-15806-RPS.

2. As Director of Renewable Energy, I am responsible for planning and executing Detroit Edison's renewable energy activities consistent with 2008 PA 295.

3. The Detroit Edison/Heritage Renewable Energy Contract is consistent with Detroit Edison's Renewable Energy Plan filed in MPSC Case No. U-15806-RPS and is otherwise reasonable and prudent based upon, among other things, the following Detroit Edison/Heritage Renewable Energy Contract pricing information. The Detroit Edison/Heritage Renewable Energy Contract pricing of a net $115.00 per Megawatt hour net energy delivered is less than the sum of the average proposed wind generation transfer price within Detroit Edison's Renewable Energy Plan of $95.77 (average of column l of Exhibit No. A-8 (JHB-4) in Case No. U-15806-RPS) and the projected average cost of Renewable Energy Credits ("RECs") procured through Renewable Energy Contracts of $31 (average price of line 5 in work paper WP JHB-7 in Case No. U-15806-RPS), which totals $126.62 per megawatt hour. An additional comparison confirms that the Detroit Edison/Heritage Renewable Energy Contract is reasonable and prudent. For this additional comparison, I calculated the implied per MWh cost for Renewable Energy Contracts within Consumers Energy's Renewable Energy Plan to be $166 per MWh, using data from column B of Exhibit A-20 (JSR-20) in Case No. U-15805 to represent the MWh volume of Renewable Energy Contracts and line 4 of Exhibit A-33 (TWS-1) in Case No. U-15805 to represent associated Renewable Energy Contract costs. From a volume and timing perspective, the Detroit Edison/Heritage Renewable Energy Contract is also consistent with Detroit Edison's Renewable Energy Plan, which projects the delivery of energy, capacity, and RECs through Renewable Energy Contracts beginning in 2010. See Exhibit No. A-10 (JHB-6), in Case No. U-15806-RPS.

4. This Detroit Edison/Heritage Renewable Energy Contract is an unsolicited proposal that provides opportunities that may not otherwise be available or commercially practical. Based on my immersion in Michigan-based renewable energy matters over the past two years, as well as the experience and insight of my staff, I believe that a wind farm that can be developed and commercially operational in Michigan by the end of 2009 is unique and provides opportunities that may not otherwise be available or commercially practical. In addition to the Heritage project's rapid deployment and reasonable cost, Heritage has also agreed to allow Detroit Edison personnel to observe activities at the wind farm, creating a valuable, low-risk, and timely learning experience related to the design, mobilization, construction, commissioning, and overall project management for a wind farm. Heritage has previously developed and currently operates a 5 MW wind farm near Cadillac, Michigan from which the Company already obtains renewable energy and RECs to support its GreenCurrents program. I believe that this unique, early learning experience will help Detroit Edison become more effective in managing its planned portfolio of Company-owned and contracted wind farms.

5. This Detroit Edison/Heritage agreement is a Renewable Energy Contract, as defined under MCL 460.1011(c), and will be counted toward the "[a]t least 50%" of Renewable Energy Contracts that do not require transfer of ownership of the applicable renewable energy system to the electric provider and from contracts for the purchase of RECs without the associated renewable energy under MCL 460.1033(1)(b). Heritage Stoney Corners Wind Farm I, LLC is not affiliated with Detroit Edison or DTE Energy.

6. The Company will routinely compete for renewable energy and advanced cleaner energy equipment, facility sites and related products and services. Maintaining the confidentiality of the specific terms and conditions involved in acquiring such equipment,

facilities sites and related products and services will help ensure that the suppliers offer their best prices to Detroit Edison and thereby help Detroit Edison achieve the lowest reasonable cost for these items.

7. Accordingly, maintaining the confidentiality of the various redacted provisions of the Detroit Edison/Heritage Renewable Energy Contract will help the Company provide Detroit Edison customers the lowest cost renewable energy and advanced cleaner energy project alternatives consistent with 2008 PA 295.

8. Public disclosure of the redacted details in the Detroit Edison/Heritage Renewable Energy Contract will hamper the Company's ability to provide the lowest reasonable renewable energy power supply cost to its retail electric customers. Therefore, I believe it is in The Detroit Edison Company's, as well as its customers', best interest for such competitively sensitive information to remain confidential and undisclosed.

9. Based on my experience, I believe it is in The Detroit Edison Company's, as well as its customers' best interest for the Commission to grant the Company's request to approve the Detroit Edison/Heritage Renewable Energy Contract.

Further, Affiant sayeth not.

Irene Dimitry

IRENE M. DIMITRY

Subscribed and sworn to before me this 27th day of March, 2009.

Karyn B. Teal

Notary Public

KARYN BETH TEAL
NOTARY PUBLIC, STATE OF MI
COUNTY OF MACOMB
MY COMMISSION EXPIRES Jul 21, 2011
ACTING IN COUNTY OF Wayne

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter, on the Commission's own motion, regarding the regulatory reviews, revisions, determinations, and/or approvals necessary for The Detroit Edison Company to fully comply with Public Acts 286 and 295 of 2008.	)	Case No. U-15806-K

AFFIDAVIT OF BARBARA J. TUCKFIELD

STATE OF MICHIGAN)
)ss.
COUNTY OF WAYNE)

Barbara J. Tuckfield, being first duly sworn, deposes and says:

1. I am a Regulatory Accounting Expert in the Regulatory Accounting & Strategy Section of the Controllers Organization for The Detroit Edison Company ("Detroit Edison" or "Company"). I received a Bachelor of Arts Degree in Economics from the University of Michigan, a Bachelor of Science Degree in Accounting from Lawrence Technological University and a Master of Business Administration from Lawrence Technological University. I sponsored testimony in the following Detroit Edison cases: U-15159 - Reconciliation and True-up of the Regulatory Asset Recovery Surcharge ("RARS"), U-15002-R - Reconciliation of the Pension Equalization Mechanism, U-14838 - Reconciliation of the Choice Incentive Mechanism and U-15806-RPS - Renewable Energy Plan.

2. As a Regulatory Accounting Expert I provide forecasting and regulatory accounting support at Detroit Edison. I am responsible for the development and implementation of regulatory accounting policies and practices, as well as supporting regulatory filings. I analyze the accounting implications of new legislation and MPSC orders, and provide expert testimony

on accounting issues in various proceedings before the MPSC. I research and assist in establishing accounting policies and implementation. I also provide support for the Company's expert witnesses in various proceedings before the MPSC by preparing historical and projected financial statements as well as other financial analysis.

3. I am proposing that the Detroit Edison/Heritage Renewable Energy Contract be recorded as power production and purchased power expense. The accounting practice proposed meets generally accepted accounting principles. Each Power Purchase Agreement "PPA" must be evaluated to determine if it contains an embedded lease. EITF 01-8, "Determining Whether an Arrangement Contains a Lease," provides the accounting guidance for embedded leases. An embedded lease is defined as an agreement that conveys the right to use property, plant or equipment usually for a stated period of time. This Detroit Edison/Heritage Renewable Energy Contract PPA does not contain an embedded lease, and therefore would be recorded as power production and purchased power expense.

4. Based on my experience and the above determinations I believe that the subject contract is consistent with the unaffiliated 3rd party PPAs discussed and included in Detroit Edison's Renewable Energy Plan by Witness Gallagher and Witness Dimitry.

Further, Affiant sayeth not.

BARBARA J. TUCKFIELD

Subscribed and sworn to before
me this 27th day of March, 2009.

Notary Public

KARYN BETH TEAL
NOTARY PUBLIC, STATE OF MI
COUNTY OF MACOMB
MY COMMISSION EXPIRES Jul 21, 2011
ACTING IN COUNTY OF Wayne

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter, on the Commission's own motion, regarding the regulatory reviews, revisions, determinations, and/or approvals necessary for The Detroit Edison Company to fully comply with Public Acts 286 and 295 of 2008.	))))))	Case No. U-15806-K

AFFIDAVIT OF KENNETH D. JOHNSTON

STATE OF MICHIGAN)
)ss.
COUNTY OF WAYNE)

Kenneth D. Johnston, being first duly sworn, deposes and says:

1. I am a Regulatory Consultant in Regulatory Affairs for The Detroit Edison Company ("Detroit Edison" or "Company"). I have earned a Bachelor of Science Degree in Engineering from Lawrence Technological University and a Masters of Business Administration in Finance from the University of Michigan. In addition, I have completed advanced level mathematics and mechanical engineering courses at Lawrence Technological University. I have worked for Detroit Edison for over 25 years in various engineering-related, power/plant-related, customer-related, and regulatory-related areas.

2. As a Regulatory Consultant in Regulatory Affairs, I am responsible for coordinating, managing and providing expert testimony on various rate matters before the Michigan Public Service Commission (MPSC) and the Federal Energy Regulatory Commission (FERC). Subject matter includes Electric Choice (implementation cost recovery, rates, tariff administration, transition charges, code of conduct, market priced power, and program participation), transmission & ancillary services (rates, billing, energy scheduling, energy

imbalance service), power supply cost recovery, energy efficiency, rates for industrial send-out steam, and wholesale-for-resale rates.

3. The recovery of the total power production and purchased power expense cost and the projected imputed debt cost of the Detroit Edison/Heritage Renewable Energy Contract is currently reflected in the PSCR transfer prices set forth in Exhibit No. A-8 (JHB-4) column (l) and the revenue recovery mechanism surcharges set forth in Exhibit No. A-24 (KDJ-5) in the Company's March 4, 2009 Renewable Energy Plan filing in Case No. U-15806-RPS. As indicated in the accompanying affidavit of Ms. Tuckfield, the Detroit Edison/Heritage Renewable Energy Contract is not an embedded lease and, therefore, this Renewable Energy Contract PPA is consistent with the type of PPA for which Witness Gallagher developed net equity costs associated with imputed debt in the Company's March 4, 2009 Renewable Energy Plan filing in Case No. U-15806-RPS. The total power production and purchased power cost of the Detroit Edison/Heritage Renewable Energy Contract, as discussed in the accompanying affidavit of Ms. Dimitry, is also consistent with the PPA costs projected by the Company in the Company's March 4, 2009 Renewable Energy Plan filing in Case No. U-15806-RPS. As, such, approval of this contract will not result in "*an alteration or amendment in rates or rate schedules*" and "*will not result in an increase in the cost of service to customers.*"

5. Based on my experience, the above determinations, and the conclusions of Ms. Dimitry and Ms. Tuckfield, I believe that there will be no alteration or amendment in Detroit Edison rates or rate schedules nor will Commission approval of the Detroit Edison/Heritage Renewable Energy Contract increase the cost of service to Detroit Edison customers.

Further, Affiant sayeth not.

Kenneth D. Johnston

KENNETH D. JOHNSTON

Subscribed and sworn to before
me this 27th day of March, 2009.

Karyn Beth Teal

Notary Public

KARYN BETH TEAL
NOTARY PUBLIC, STATE OF MI
COUNTY OF MACOMB
MY COMMISSION EXPIRES Jul 21, 2011
ACTING IN COUNTY OF Wayne

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter, on the Commission's own motion, regarding the regulatory reviews, revisions, determinations, and/or approvals necessary for The Detroit Edison Company to fully comply with Public Acts 286 and 295 of 2008.	)))))))	Case No. U-15806-K (Paperless e-file)

PROOF OF SERVICE

STATE OF MICHIGAN)
) ss.
COUNTY OF WAYNE)

Estella R. Branson, being duly sworn, deposes and says that on the 27th day of March, 2009, a copy of The Detroit Edison Company's Ex Parte Application for Approval of Renewable Energy Contract, redacted Detroit Edison/Heritage Renewable Energy Contract, Exhibit No. A-8 (JHB-4) from Case No. U-15806-RPS, Affidavit of Irene M. Dimitry, Affidavit of Barbara J. Tuckfield and Affidavit of Kenneth D. Johnston in the above captioned matter was served upon the persons on the attached service list via e-mail.

____
Estella R. Branson

Subscribed and sworn to before
me this 27th day of March, 2009.

____
Notary Public

MPSC Case No. U-15806
March 13, 2009
SERVICE LIST

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STATE OF MICHIGAN

MICHIGAN PUBLIC SERVICE COMMISSION

In the matter, on the Commission's own motion, regarding the regulatory reviews, revisions, determinations, and/or approvals necessary for CONSUMERS ENERGY COMPANY to fully comply with Public Acts 286 and 295 of 2008.	Case N$^{o.}$ U-15805; U-15889 (Consolidated)

ELECTRONIC SERVICE LIST

On the date below, an electronic copy of the attached corrected pages from the Testimony of George E. Sansoucy and David A. Wright, corrected pages from the Surrebuttal Testimony of George E. Sansoucy and MEC Exhibits 1-8 was served upon the following:

Name/Party	E-mail Address
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The statements above are true to the best of my knowledge, information and belief.

Date: April 17, 2009

By: Digitally signed by Bradley D. Klein DN: cn=Bradley D. Klein, o=Environmental Law & Policy Center, ou, email=bklein@elpc.org, c=US Date: 2009.04.17 16:30:53 -05'00'

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