ECONOMICS OF
LONG-DISTANCE TRANSMISSION OF WIND POWER

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There is currently much discussion about long-distance transmission of wind power from relatively remote areas where it is plentiful to more populated areas which consume a great deal of electricity. One such discussion focuses on building new transmission lines to transport wind power from the Upper Midwest (North Dakota, South Dakota, Minnesota, and Iowa) where the wind resources are vast to the Midwest and mid-Atlantic states, which consume a great deal of electricity, generated primarily with coal.

The conventional wisdom has been that such projects are technically feasible but not economic, in that the costs (of building these projects) exceed the benefits (the cost savings, primarily in fossil fuel savings). However, recent studies[2] suggest that this may no longer be the case. A problem with these studies is that they rely on computer models that are broad in geographic scope but weak on the real-world intricacies of forecasting what the cost-savings would be.

The purpose of this study is to use a much more rigorous model in assessing the economics of long-distance transmission of wind power from the Upper Midwest to Midwest and East.

After a brief Executive Summary, this paper describes the approach that was employed, the findings, and the policy implications of these findings.[3]

EXECUTIVE SUMMARY

The study finds that long-distance transmission of wind power would be economic (in the sense that the cost-savings from the project would approximate the costs of building the project) if the value of the CO2 emissions reduced by the project were at least $50/ton.

APPROACH

This study used the DAYZER model developed by Cambridge Energy Solutions.[4] This model simulates the operation of electricity market and is widely used by electricity

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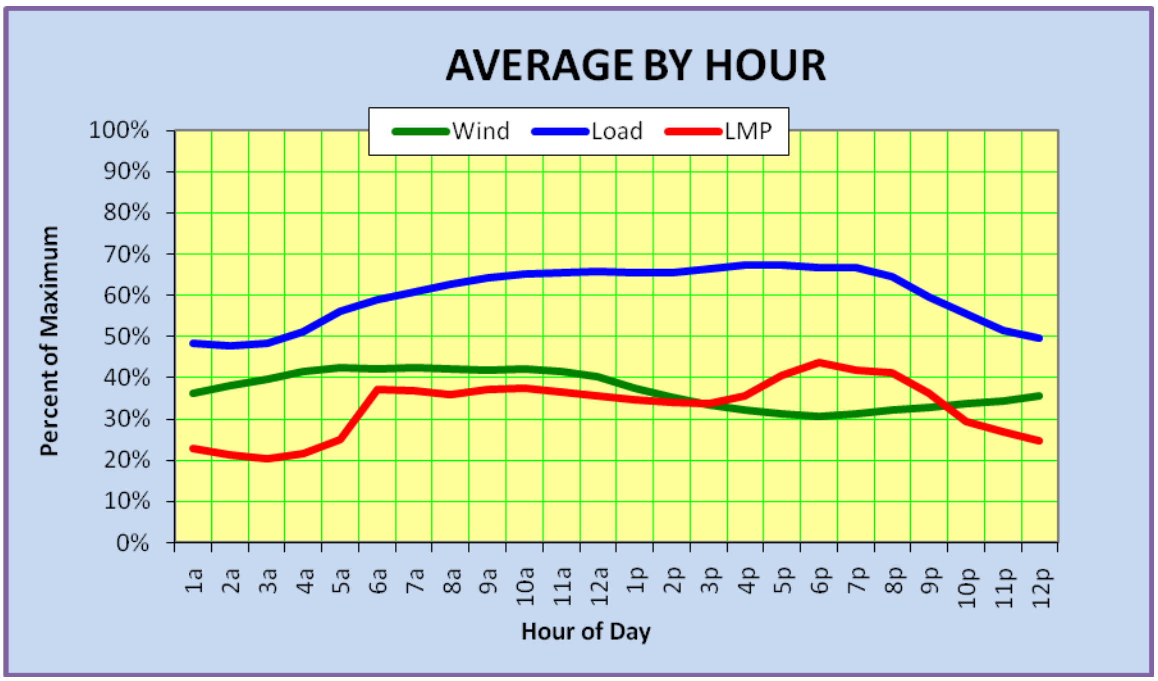
[2] These studies include “20% Wind Energy by 2030,” DOE, July 2008, and “Green Power Express Network, An Analysis of Benefits and Costs,” CRA, February, 2009, performed on behalf of ITC Holdings Corp.

[3] Thanks to Dan Klein, Pablo Paster , and Assef Zobian for their helpful comments. Of course, any inaccuracies are the responsibility of the author.

market traders and analysts. DAYZER is well-structured to assess the economics of long-distance transmission of wind power because it models the transmission system explicitly, the way electricity really flows in proportion to the impedance on each transmission line, rather than assuming incorrectly that electricity flows as if it were in a pipe between geographic regions. DAYZER represents each transmission line and the constraints thereon, plus each generator and load bus. Further, it operates on an hourly basis, enabling it to capture wind generation by hour flowing over transmission lines and constraints by hour given the generation of all generating units by hour. The other models do not capture hourly dynamics.

The rigorous detail in DAYZER matters a lot for this study, since transmission constraints limit the flow of power on an hourly basis. Also, peak wind generation does not correlate well with load and prices. Wind generation tends to be high at night when loads and price are low, and wind generation tends to be low during the day when loads and prices are high. See exhibit 1.

Exhibit 1
WIND GENERATION BY HOUR AVERAGED OVER THE YEAR



Also, wind generation tends to be low during the summer when loads and prices are high. See Exhibit 2.

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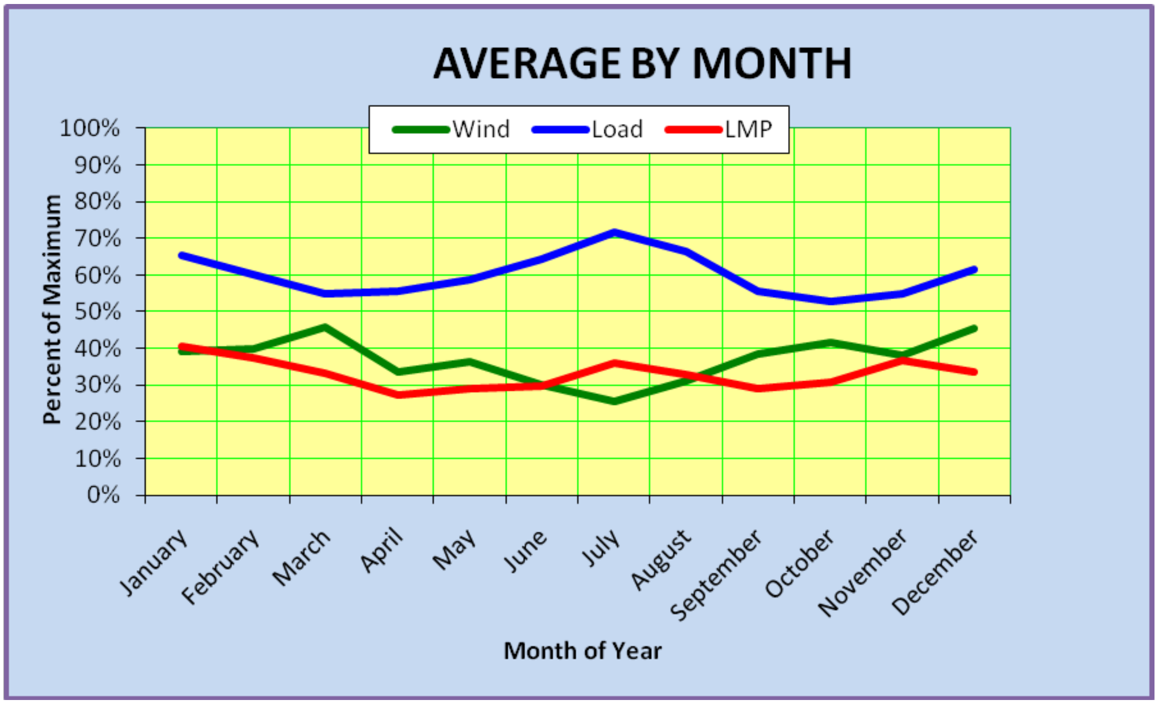
[4] This model is available from Cambridge Energy Solutions, 50 Church Street, Cambridge, MA 02138. www.ces-us.com

Exhibit 2
WIND GENERATION BY MONTH



This study used detailed wind generation data recently available from National Renewable Energy Lab (NREL).[5] This data was not available when the other studies were undertaken. This data is available for multiple sites within each state and represents potential generation at each site (in ten-minute internals) for every hour of a year.[6]

The key parameters (costs, capacity, and end points in the Midwest) of the Green Power Express, as presented in the CRA study,[7] were employed to represent this potential long-distance transmission, from the Upper Midwest to the PJMRTO.[8] This new network would interface with the PJMRTO on the two western ends of the 765kV transmission lines (at Plano, Illinois and Sullivan, Indiana). The Green Power Express network would carry a maximum of 7000 MWs to the PJMRTO.

The costs of the additional wind generation and long-distance transmission would be at least $3 billion per year. See Exhibit 3.

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5 ftp://fto2.nrel.gov/pub/ewits/MISO/
6 Data are currently available for 2004, 2005, and 2006.
7 See the direct testimony of Ira Shavel of CRA on behalf of the Green Power Express LP. See Exhibits GPE-400 and 401 of Green Power Express submission to FERC.
8 The PJMRTO is a large electricity market serving parts of Illinois, Indiana, Ohio, and Virginia, and West Virginia, Pennsylvania, New Jersey, Maryland, Delaware, and DC.

Exhibit 3

COSTS OF ADDITIONAL
WIND GENERATION AND LONG-DISTANCE TRANSMISSION

Wind			
MWs	13086		
Initial Capital			
$/kW	$1700		
Capital charge rate	8.0%		
$/kW-year	$136		
$millions/year		$1,780	
Fixed Operations and Maintenance Costs			
$/kW-year	$26		
$millions/year		$ 340	
Total for Wind ($ million/year)		**$2,120**	
Transmission			
MWs	7000		
Initial Capital			
$millions	$11,000		
Capital charge rate	8.0%		
$ millions/year			$ 880
Fixed Operations and Maintenance Costs			
$/kW-year	$10		
$millions/year		$ 70	
Capacity Credit			
Allowable credit	13%		
Value of Credit per kW-year	$33		
$millions/year		($ 30)	
Total for Transmission ($million/year)		**$ 920**	
Sum of Wind and Transmission ($million/year)		**$3,040**	

These costs are lower than those ($4.5 to $4.7 billion) presented in the CRA study. One reason is that this study uses a lower capital charge rate (8% versus 12%).[9] The effect is that all annualized capital costs are 50% lower.

DAYZER was used to forecast the operation of the PJMRTO with and without additional wind transmitted from the Upper Midwest. The other studies dealt with a

[9] This study uses a real capital charge rate because all the other costs employed herein are real. 12% is probably a nominal capital charge rate, or it assumes very expensive financing costs. For a discussion of real versus nominal rates, see "Beware Capital Charge Rates," *Electricity Journal*, May, 2006, by Hoff Stauffer.

broader geographic area but less rigorously. The PJMRTO represents a smaller area but is the key geographic market for this project. The PJMRTO would be interconnected directly with the new transmission lines from the Upper Midwest and would transmit this additional wind energy over the vast PJMRTO transmission network to Midwestern states (Illinois, Indiana, Ohio, and West Virginia) and to Mid Atlantic states (Pennsylvania, New Jersey, Maryland, Delaware, DC, and Virginia).

DAYZER was used to make two forecasts of the PJMRTO for 2020, which is about when the new line could be operational:

1. A base case forecast assuming no new transmission from the Upper Midwest and no additional wind generation in the Upper Midwest that would be available to the PJMRTO.
2. A wind case with the same input assumptions except with additional wind generation capacity in the Upper Midwest and with new transmission capacity to transmit that generation into the PJMRTO.

The value of long-distance transmission of wind is the difference between the two cases. The specific inputs for these cases are described in the Appendix.

FINDINGS

Long-distance transmission of additional wind capacity in the Upper Midwest to the PJMRTO would have important positive effects, by adding clean energy equal to about 5% of total generation in the PJMRTO. Emissions would be lower. Consumption of oil and gas would be lower. The price of electricity would be lower. The costs of generating electricity would be lower. See Exhibit 4 below and on the next page.

Exhibit 4

EFFECTS OF LONG DISTANCE TRANSMISSION OF ADDITIONAL WIND GENERATION IN THE UPPER MIDWEST

		Base	**Wind**	**Effect of Wind**	**%**
Emissions	1000 tons/year				
	NOX	771	703	-68	-9%
	SOX	2,598	2,406	-193	-7%
	CO2	438,240	402,154	-36,086	-8%
Fuel Use	10^12 BTUs/year				
	Coal	3,880	3,560	-319	-8%
	Gas	459	426	-33	-7%
	Oil	14	13	0	-4%
	Wind and other	3,366	3,743	377	11%
	Total	7,718	7,743	25	0%

Prices	Average $/MWH				
	East	$45.8	$42.3	($3.4)	-7%
	West	$33.9	$29.3	($4.6)	-14%
	Total	$42.9	$39.2	($3.7)	-9%
Costs	$Billions/year				
	Consumer costs	$30.3	$27.2	($3.2)	-10%
	Generation costs	$24.1	$23.0	($1.1)	-4%
	Real Resource costs	$23.4	$22.4	($1.0)	-4%

Emissions and fossil fuel use would be lower because the additional wind generation would substitute for generation from fossil fuels.

Prices would be lower because the wind generation would substitute for the highest-priced generation in any hour, thereby reducing the market price. The prices would be lower and the price reductions would be greater in the West of the PJMRTO (Illinois, Indiana, Ohio, and West Virginia) than in the East of the PJMRTO (Pennsylvania, New Jersey, Maryland, Delaware, DC, and Virginia) because transmission constraints limit the flow of lower-priced electricity from West to East.

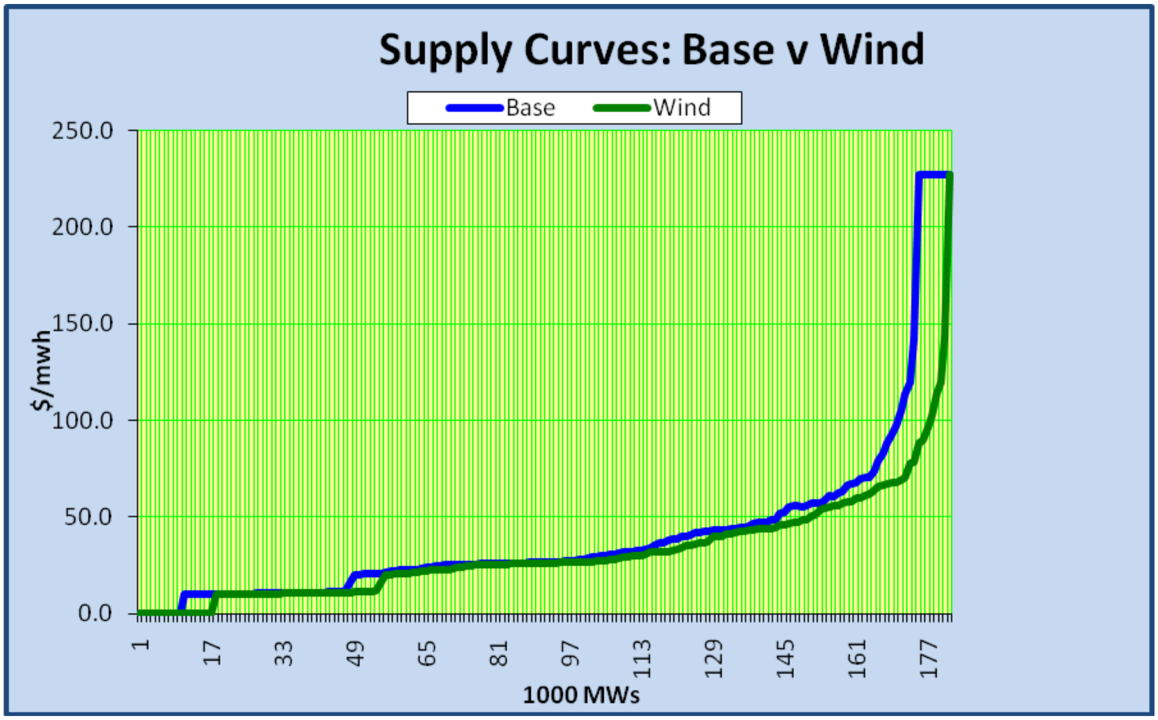
There are three measures of costs. Consumer costs are what consumers would pay for the electricity they would purchase (and what generators would get for the electricity they sell). Changes in consumer costs are driven by changes in the market price of electricity. Generation costs include the fuel, operations and maintenance, and emission allowance costs required to generate the electricity. Changes in generation costs represent changes in the costs of generating electricity. Real resource costs are the cost of producing electricity minus the cost of emission allowances, since these are a transfer from the producer (and consumer) to the government.[10]

The consumer cost reductions exceed the generator cost reductions. Consumer cost reductions reflect market price decreases times all electricity consumed (and produced), whereas generator cost reductions reflect only the cost of the generation displaced by wind. The effect of additional wind power on prices is greatest when it replaces higher-priced oil/gas generation that was on the margin setting the market price with lower-priced coal-fired generation that becomes the marginal generator setting the

[10] The generation cost savings ($1.1 billion) and the consumer cost savings ($3.2 billion) are much less than the $5+ billion reported in the CRA study. But CRA did not report cost savings absent a price on CO2. Hence, the CRA cost savings are properly compared to a case where there is a price on CO2. Such a case is reported in a companion paper: "Adverse Consequences of Pricing Carbon," Hoff Stauffer, Wingaersheek Research Group, May, 2009; see http://www.wingrg.com/Papers.html When CO2 is priced at $50/ton, the estimated generation cost savings increase to about $3 billion.

market price. Price decreases are greatest at the levels of load where the difference in the supply curves (with and without wind) is greatest. See Exhibit 5.

Exhibit 5
PJMRTO SUPPLY CURVE
WITH AND WITHOUT WIND



The costs of the new wind capacity and the transmission capacity (about $3 billion per year) would be about the same as the consumer cost savings and exceed both the generation cost savings and the real resource cost savings by a material amount. See Exhibit 6.

Exhibit 6
NET COSTS OF LONG DISTANCE TRANSMISSION OF
ADDITIONAL WIND GENERATION IN THE UPPER MIDWEST

	Costs	Savings	Net Costs	**Cost per ton of CO2 Removed**
Consumer costs	$3.0	($3.2)	($0.1)	($4)
Generation costs	$3.0	($1.1)	$2.0	$54
Real Resource costs	$3.0	($1.0)	$2.0	$56

The estimated cost per ton removed for generation cost is roughly $50/ton of CO2. This estimate is sensitive to the cost estimates for new wind and transmission capacity. If the costs were $4.5 billion per year (as reported in the CRA study) rather than the $3.0 billion employed herein, the net generation cost per ton removed would be

$95/ton. If a continuation of the production tax credit for wind generation were factored into the cost estimates, the generation cost per ton removed would be $30/ton.

The estimated cost per ton removed could also be sensitive to such key inputs as the price of natural gas. Accordingly, a sensitivity analysis was conducted, making forecasts with the price of natural gas 50% higher. The estimated cost per ton removed remained at about $50/ton.

But the apparent net generation costs ignore the value of the 36 million tons of CO2 reduced, as well as the value of the other pollutants reduced and the value of the reduced oil and gas imports (in terms of national security and the like). If these other values were worth the equivalent of about $50 per ton on CO2 reduced, then the net generation costs would be about zero.

POLICY IMPLICATIONS

One policy option would be to use an imputed value for the CO2 reductions (and other positive outcomes) to justify (or not) the investments in wind and long-distance transmission and to charge the costs of these investments to the consumers who would benefit. This would be a traditional regulatory approach that would be consistent with the economics and with equitable treatment of consumers.

Another way would be to adopt a "market approach" – in the form of a carbon tax or a cap and trade system – that puts a market price on CO2 emissions. This is the subject of a companion paper entitled: "Adverse Consequences of Pricing Carbon."[11]

[11] Hoff Stauffer, Wingaersheek Research Institute, May, 2009 http://www.wingrg.com/Papers.html

APPENDIX

INPUTS

Transmission from Upper Midwest to PJMRTO

The key parameters (costs, capacity, and end points in the Midwest) of the Green Power Express[12] were employed to represent the potential long-distance transmission from the Upper Midwest to the PJMRTO.

This new transmission network would interface with the PJMRTO on the two western ends of the existing 765 kV transmission lines (at Plano, Illinois and Sullivan, Indiana). It would carry a maximum of 7000 MWs. This study assumed that 3500 MWs would be delivered at Plano and 3500 MWs would be delivered at Sullivan.

It would cost $10 to $12 billion to build.

This study assumed that the fixed operations and maintenance costs would be $10/KW-year.

Wind data

The wind data came from NREL at ftp://fto2.nrel.gov/pub/ewits/MISO/. This data is recently available.

For this study, the data for 2004 were used. Average potential generation per hour was calculated from the ten-minute data for each site. The total potential generation per state by hour was calculated by adding up the sites in each state. The total potential generation for the Upper Midwest was calculated by adding up the states in the Upper Midwest. Then, this total potential was scaled down to represent the hourly flows that could be carried by a new transmission line.

A total of 13,086 MWs of new wind capacity was assumed to be built. This is 60% of the total available. The potential generation from this wind capacity would have a capacity factor of about 37%. But this potential generation was scaled to the 7000 MW capacity of the new transmission network. This means that not all of the potential generation could be used all of the time due to the limit of 7000MWs on the new transmission lines. The effect of the scaling was that the 7000 MWs of new transmission line would operate at a 64% capacity factor and the new wind generation capacity would generate at a 34% capacity factor.

The CRA study supporting the Green Power Express assumed that about 13,800 MWs of new wind capacity would be needed to keep this line relatively full, since wind generators seldom generates at maximum capacity (see Exhibits 1 and 2 above).

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12 As reported in the CRA study.

Assuming more wind capacity means that the utilization of the new long-distance transmission lines would be greater, improving the economics of the network, but it also means that the costs of wind generation would be greater. A sensitivity analysis was conducted where more wind generation was added. The incremental cost savings from the additional wind generation were far less than the additional costs of the additional wind generation.

Transmission Within the PJMRTO

The transmission data available for DAYZER from CES were used to represent transmission within the PJMRTO. This does not include some of the major transmission enhancements planned to be operational by 2020, which would relieve transmission constraints between the western part of the PJMRTO and the eastern part. Hence, some of the new generation capacity (required to meet load growth) was added in the eastern part where it was most needed, absent these enhancements. This new generation capacity has an effect similar to the planned transmission enhancements.

Capacity Additions

No uncontrolled new coal plants were added.

A few controlled coal plants were added, assuming 90% reduction in CO2 emissions.

Some new nuclear capacity was added, at sites which a currently under active consideration.

Wind and biomass capacity, within the PJMRTO, was expanded a lot, by about a factor of four for wind and by an order of magnitude for biomass.

In addition, some gas-fired capacity was added to relieve transmission constraints, such as in New Jersey.

Load Forecast

Load was forecast to grow 0.9%, reflecting the recent slowdown in load growth and current efforts underway to increase end-use efficiency.

Fuel and Allowance Price Forecasts

Current fuel and allowance prices were assumed to increase at 2% real per year.

All The Rest

All the rest of the input data, such as Generating Unit Characteristics, came from the DAYZER input files prepared by CES.

POSSIBLE NEXT STEPS

- Enlarge scope of DAYZER to include MISO
- Explicitly model new transmission from west
- Explicitly model planned transmission enhancements by 2020 in PJMRTO
- Test wind data for other years
- Review/revise seasonal fuel price variations.