Assessing Minnesota's Solar Resource

Revenue implications of solar PV system orientation and rate structure

Solar Cities
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Revenue Implications of Solar PV System Orientation and Rate Structure

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Abstract

This paper examines the revenue implications of various system orientations and rate structures for commercial-scale solar photovoltaic (PV) systems co-located with a building load. Both system orientation and rate structure can have an impact on total revenue generated from a PV system. This study uses several modeling tools developed by the National Renewable Energy Laboratory (NREL) to model PV system revenue for a single system in Minnesota modeled with six different orientations and with each orientation exposed to five different rate structures. The orientations include both fixed horizontal arrays and two-axis tracking systems. The rate structures examined include several rates currently available from the utility territory from which solar radiation data were collected in addition to a hypothetical rate based on wholesale market prices from the Minnesota Hub within the Midwest Independent System Operator (ISO) for the same time period. The study also estimates the capacity contribution of PV resources to load in the Midwest ISO West region and estimates the monetary value of that capacity.

Major Findings:

- The results illustrate a fourfold difference in revenue between the lowest and highest revenue-generating combinations of orientation and rate structure.
- The wholesale market (using 2007 market data) appears to offer substantially greater revenue potential than the rates currently available from the local utility.
- As NREL adds capabilities to its suite of solar modeling tools, analyses like this one will allow system developers to fully evaluate system designs and transaction strategies to maximize the revenue generation of their systems.

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Introduction

Owners of solar PV systems in Minnesota have several rate structures to choose from, including offsetting electricity purchased at retail, using pre-approved rates for customer-owned generation, or signing a purchase power agreement (PPA) with the host utility. In addition, a solar PV generator can sell directly into the ISO wholesale market as a merchant generator. While the transaction costs of such a strategy would preclude most PV generators from selling into the wholesale market, this study estimates the revenue from doing so as a means of estimating the value of PV to the grid. This paper examines the revenue implications of each transactional strategy as well as of various system designs and orientations.

Retail Rates

This study examines the revenue implications for solar PV generation under three retail rates available from the host utility:

(1) A retail demand rate, which uses a fixed energy charge and a peak season and non-peak season demand charge;

(2) A standard tariff available to customer-owned distributed generators, which uses an on-peak and off-peak energy charge while granting capacity payments calculated by the unit's on-peak capacity factor; and

(3) A standard tariff available to cogeneration systems, which uses on-peak and off-peak energy charges while granting seasonally adjusted capacity payments per on-peak kWh so long as the unit maintains a 65 percent capacity factor.

Estimating Wholesale Energy Value

This study examines revenue implications for solar PV generation under two wholesale scenarios that serve as a proxy for estimating the value of solar PV generation at the utility system level. The wholesale scenarios were designed under the following understanding of wholesale valuation and wholesale transactions for other forms of generation.

In recent years a number of regional wholesale electricity markets have been established under the direction of the Federal Energy Regulatory Commission. These markets serve as the mechanism that determines the dispatch of generators throughout the day. The dispatch order for each day is determined based on bids submitted by generators to the ISO the prior afternoon.

The dispatch order is based on:

- The Load Serving Entity (LSE) estimating demand throughout the day
- Each generator's ability to generate throughout the day.

Each generator's bid includes a price as well as operating parameters for each plant. The ISO then determines what dispatch sequence will most cost-effectively match the next day's load profile without violating any plant's operating limitations or any constraints imposed by the transmission system. This process establishes an energy price for each node in the wholesale market. Each node typically represents either a source (generator) or a sink (load center). There are also hubs within the wholesale markets that are aggregates of individual nodes. Prices vary among nodes due to the physical constraints of the transmission system. This means that absent transmission constraints, prices should be uniform across the market footprint. When constraints do arise, prices can vary significantly across the system. The locational prices generated through the wholesale market represent the value of energy delivered at a given location at a specific time. Nodal prices therefore are one method for determining the value of energy delivered by a solar PV generator to the grid.

Estimating "Systemic" Capacity Value

The ability of a PV system to earn capacity payments under a wholesale rate regime is dependent upon market rules. The Midwest ISO imposes a binding resource adequacy (RA) requirement on LSE's but allows LSEs to contract for capacity to meet their RA requirement as each LSE sees fit. The Midwest ISO has implemented a standardized capacity product called Planning Resource Credits (PRC) that are traded in its monthly Voluntary Capacity Auction (VCA) to satisfy RA requirements for the following month. These PRCs can also be used as the basis for longer term bilateral contracts for capacity. The Midwest ISO enforces RA compliance by assessing a Financial Settlement Charge (FSC) on any LSE that fails to meet its capacity obligations. The value of the FSC is determined administratively by the Midwest ISO to reflect the Cost of New Entry (CONE) for a new combustion turbine in the Midwest ISO footprint (Newell, Spees, and Hajos, 2010). Thus, the CONE is an accurate estimate of the value of new capacity in the Midwest ISO market. The Midwest ISO has calculated a CONE of $80 per kilowatt year for 2009 and $90 per kilowatt year for 2010 (MISO, 2009).

This study estimates the value of PV capacity in the Midwest ISO West region, but it is difficult for a PV generator to capture that value. If a PV system is to generate capacity revenue while selling into the Midwest ISO wholesale market, it will need to sell its capacity in a bilateral transaction with an LSE. This poses difficulties for a few reasons. First, if an LSE intends to use contracted capacity to cover its RA obligations, that capacity must conform to the Planning Resource Credits. (This paper does not examine whether a PV system can qualify for PRCs.) Second, there is no industry standard for treating PV as a capacity resource. Third, there are a number of reasons that utilities would be unwilling to purchase capacity from a PV generator. A utility with no foreseeable capacity shortfall is unlikely to procure unnecessary capacity. Even utilities with capacity needs may prefer to acquire capacity from central station generators given the transaction costs associated with many small, intermittent generators.

PV's Capacity Contribution to the "System"

Utility system planners and ISOs have not developed a standard method for determining the capacity value of a PV generator. However, Effective Load Carrying Capacity (ELCC) is recognized as a valid and useful measure for determining the capacity value of intermittent renewable energy sources (Richard Perez et al., 2008; Xcel Energy Services, Inc., 2009; R. Perez et al., 2006). ELCC is a measure of the reliable capacity contribution of a generating unit to the system. Calculating the ELCC of a generation unit requires a probabilistic assessment of capacity value based on hourly Loss of Load Probability (LOLP) values. A shorthand strategy for estimating ELCC is to use system load as a proxy for LOLP values. This strategy has been shown to provide reasonable estimates of ELCC in the absence of LOLP values (Milligan and Parsons, 1997). This strategy can be used to examine the generation of a PV system relative to its rated capacity for the hours of greatest demand during a billing period. For this analysis, the ten hours with the greatest demand during each month were used to evaluate the capacity value of PV. Earlier estimates of the ELCC of solar PV in Minnesota suggest that it can be as high as 46 percent for two axis tracking systems (Table 1). Due to the intermittent nature of PV resources, the ELCC of incremental PV systems diminishes, as the penetration of PV into the system increases.

TABLE 1 **ELCC of PV Systems in Minnesota (R. Perez et al. 2006)**

Grid penetration	2%	5%	10%	15%	20%
Two-axis tracking	46	42	35	29	24
Horizontal	33	30	26	22	19
South 30° tilt	36	32	27	23	20
Southwest 30° tilt	37	34	28	24	20

This analysis assigns a value of $80 per kW year as an estimate of the value of new capacity consistent with the Midwest ISO's use of $80 per kW year as the default Cost of New Entry[1] and the host retail utility's publicly filed avoided cost values (Suzanne Doyle, 2009).

1 The Cost of New Entry reflects the annual revenue necessary to attract investment in new capacity.

The Value of Capacity Under Retail Rates

The local utility uses two different capacity valuation methodologies to determine retail rates:

- The distributed generation (DG) rate uses the generator's capacity factor during on-peak hours to determine capacity payments. A generator's capacity payments are determined by dividing the actual generation during peak hours within the billing period by the potential generation of the system had it generated at rated capacity during peak hours during the billing period.
- The cogeneration rate capacity payments are also based on peak period capacity. However, payments are not made unless a 65 percent capacity factor is maintained (Xcel Energy, 2010). The general service rate is determined by a facility's highest 15 minutes of demand during a billing period. Any demand charge savings arise from the difference between the highest billed demand with and without the PV system.

Orientation Issues

Another important variable for assessing the revenue implications of solar PV generation is the design of the solar system and in particular the system orientation. System designers must choose from two classes of orientation options:

- Fixed-horizontal, fixed-vertical, or fixed-tilted arrays.
- One-axis or two-axis tracking arrays.

A fixed horizontal array will typically be the least expensive building-mounted system to install on flat-roofed commercial buildings, but it will offer less generation potential than tilted or tracking system. Tilted and tracking systems have the potential to generate more energy but are progressively more expensive for most commercial building applications. Another cost consideration is the impact, if any, of system orientation on a building's demand charge or on capacity payments.

Two-axis tracking array,
City of Minneapolis Royalston Maintenance Center

Fixed tilted solar array,
City of Minneapolis Currie Maintenance Center

Methodology

Analyzing the revenue generation potential of a solar PV system in the wholesale market requires one of two types of data: (1) historical PV generation data or, (2) modeled data of PV generation based on actual solar insolation and weather data. This study utilized modeled data, because historical data were not available.

Hourly solar insolation, temperature, and relative humidity data were acquired from the Saint Paul Climatological Observatory at the University of Minnesota. Two NREL models were used to estimate PV revenue generation potential:

- The Solar Advisor Model (SAM) (National Renewable Energy Laboratory 2009) was used to model PV system output.
- Energy-10 (National Renewable Energy Laboratory 2006) was used to generate an hourly load profile for a single 19,000 square foot commercial building.[2]

Both the SAM and Energy-10 models use second-version typical meteorological year (TMY2) data sets generated by the Meteonorm 6.1 software package (Jan Remund, Stefan Kunz, and Christoph Schilter 2008) using historical weather data.[3]

The Sandia Array Performance Model embedded in SAM was used to model a single 53 kW PV system in several different orientations. This model was chosen because it uses specific PV module performance parameters based on field testing across a range of environmental conditions. The model uses both direct and diffuse radiation levels as inputs and incorporates the impact of cell temperature, angle-of-incidence, and solar spectral shifts on module performance. Table 2 illustrates the fixed array orientations modeled. One and two-axis tracking systems are also modeled.

TABLE 2 PV System Orientations

TILT	AZIMUTH		
0º	0º	0º	0º
30º	180º	200º	220º
90º	180º		

2 The building was modeled with a DX cooling system, a natural gas furnace and the program's default building characteristics.

3 Solar radiation, temperature, humidity and dew point data were uploaded into Meteonorm. Meteonorm uses that data and existing standard weather data sets to generate a complete TMY-2 file from the measured data.

Wholesale market data from 2007 were downloaded from the Midwest ISO's website and used for modeling. Day-ahead prices for the Minnesota Hub were used to assess the wholesale market value of PV generation. In an efficient market, day-ahead and real-time prices should be equal, because the day ahead forecast will match what happens in real-time. Real-time market prices account for (in part) the difference between the day ahead forecast and real-time conditions and as such can be much more volatile than day-ahead prices. Day-ahead prices were used in the model because they do not account for the operational circumstances – such as units tripping off line – that can cause price volatility in the real time market. Day-ahead prices should therefore be more appropriate for planning purposes than real time prices.

Hourly State Estimator load values for the Midwest ISO West region were used to represent system load. The region is a much larger geographic area than would have been ideal for this analysis, but regional data are the most appropriate publicly-available load data for this location and time period. More appropriate values could include the load values at the Minnesota Hub, the nearest node or for a specific utility.

TABLE 3 **Rate Options**

Rate	kWh Peak Season		kWh Off Peak		Capacity Price	
	Off Peak	On Peak	Off Peak	On Peak	Peak Season	Off Peak Season
General Service*	4.82¢	4.82¢	4.827¢	4.827¢	$10.150/kW/Month	$6.810/kW/Month
Customer Owned Cogeneration	2.75¢	5.75¢	2.99¢	4.87¢	$0.0654/on-peak kWh	$0.0125/kWh/ on-peak kWh
DG Standard Tariff	1.567¢	4.794¢	1.567¢	2.866¢	$5.040/kW/Month	$5.040/kW/Month
Wholesale Rates**	6.52¢	6.52¢			$6.667/kW/Month	

* Includes tariffed rate and fuel adjustment charge

** Wholesale energy rate is the estimated average revenue/kWh based on modeled solar energy output of a fixed (45 degree) tilt system using day ahead prices for the Minnesota hub.

Results

Each PV generation file was run against five different rate structures (three existing retail rates and two wholesale rate scenarios) using the NREL PV Rate Analysis Tool. The rate structures are outlined in Table 3.

Rate Choice

Revenues from the two wholesale rate scenarios – the energy-only wholesale rate and the wholesale energy plus capacity payment rate – were greater than from any of the host utility's published retail rates (customer-owned generation or offsetting retail purchases for a demand-billed customer).

TABLE 4 System Revenue

a. System Energy Revenue

Rate	180, 0	180, 90	180, 30	200, 30	220, 30	Tracking, Tracking
Cogen Rate	$2,573	$2,015	$3,096	$3,050	$2,924	$4,102
Customer Owned DG	$1,740	$1,387	$2,056	$2,032	$1,957	$2,702
Demand	$2,765	$2,335	$3,326	$3,254	$3,107	$4,510
Wholesale	$3,873	$3,285	$4,689	$4,623	$4,434	$6,140
Wholesale w/Capacity	$3,873	$3,285	$4,689	$4,623	$4,434	$6,140

b. System Capacity Revenue

Rate	180, 0	180, 90	180, 30	200, 30	220, 30	Tracking, Tracking
Cogen Rate	$ -	$ -	$ -	$ -	$ -	$ -
Customer Owned DG	$684	$600	$840	$835	$803	$1,067
Demand	$87	$61	$83	$83	$83	$76
Wholesale	$ -	$ -	$ -	$ -	$ -	$ -
Wholesale w/Capacity	$1,483	$718	$1,498	$1,632	$1,727	$1,898

c. Total System Revenue

Rate	180, 0	180, 90	180, 30	200, 30	220, 30	Tracking, Tracking
Cogen Rate	$2,573	$2,015	$3,096	$3,050	$2,924	$4,102
Customer Owned DG	$2,424	$1,988	$2,896	$2,867	$2,760	$3,769
Demand	$2,852	$2,396	$3,410	$3,338	$3,191	$4,586
Wholesale	$3,873	$3,285	$4,689	$4,623	$4,434	$6,140
Wholesale w/Capacity	$5,356	$4,003	$6,188	$6,255	$6,160	$8,038

highest revenue

lowest revenue

Total revenue from solar PV generation is the sum of energy revenue and capacity revenue. Tables 4a to 4c illustrate the energy, capacity and total revenue for each of the six modeled system orientations under each of the five rates. Table 4a shows that revenue from wholesale energy sales is substantially greater than revenue under any of the retail rates. The greater energy revenue from the wholesale market is largely due to wholesale energy prices being higher during 2007 while the sun was shining than the energy rates available from the retail utility. As is discussed below, 2007 was a year of high wholesale electricity prices. In the years since, wholesale prices have fallen significantly.

Table 4b shows capacity revenue under all the rate and orientation scenarios. Revenue from the wholesale capacity rate scenario is again significantly greater than capacity revenue (or demand savings) under the retail rates. The reasons for the capacity revenue findings are somewhat more complex than for the energy revenue findings.

Capacity Revenue

Under retail rate scenarios, the PV system generated virtually no demand charge savings. Figures 5 and 6 provide insight into this by illustrating the maximum building load and net building load for each hour in the months of January and June. In the winter months, the sun's energy is less intense during the early and late hours of building operation, so it is nearly impossible to generate significant demand savings. During the summer months, the sun is up for enough hours to provide significant savings, but a single fifteen minute interval of cloudy skies when the building demand is high will prevent what might otherwise be a significant demand reduction.

FIGURE 5
January maximum demand by hour of day

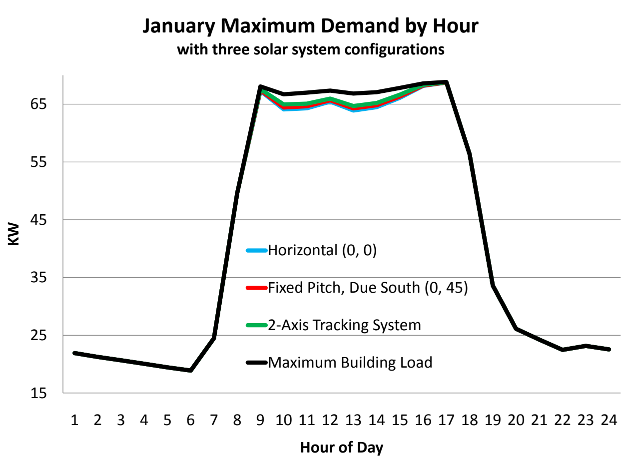
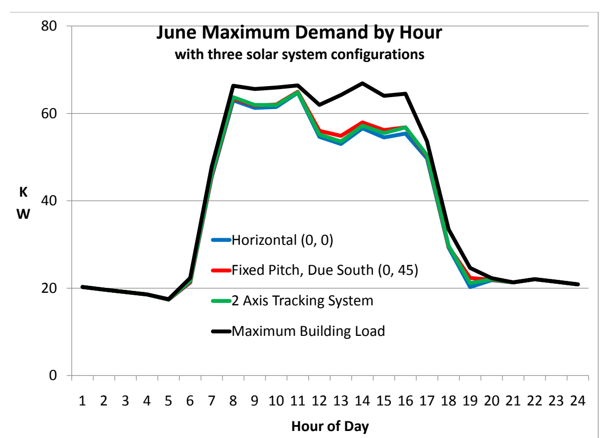


FIGURE 6
June maximum demand by hour of day



The customer-owned DG rate and the wholesale-capacity rate yield similar levels of capacity-based revenue. This revenue, however, is distributed unequally throughout the year:

- The DG rate is based on system capacity factor during on-peak hours, so the capacity payment has no relation to PV generation during periods of high system demand. This leads to a significant stream of capacity revenue for each month of the year.

- The wholesale capacity valuation model is based on system performance during peak system hours. Very little revenue is generated during winter months because the peak system hours during those months tend to occur during the late evening, after the sun has gone down. Nearly all of the capacity revenue under this rate is generated from April through September.

Figures 7a to 7c illustrate the capacity revenue for each system under each of the demand-based rates.

TABLE 7. Monthly Capacity Revenue

a. Demand Charge Savings

	180, 0	180, 90	180, 30	200, 30	220, 30	2 Axis
January	$0.75	$0.39	$0.70	$0.70	$0.70	$0.40
February	$9.94	$5.61	$9.35	$9.35	$9.35	$6.61
March	$3.01	$1.64	$2.82	$2.82	$2.82	$2.06
April	$9.02	$5.15	$8.49	$8.49	$8.49	$7.81
May	$2.83	$1.54	$2.66	$2.66	$2.66	$2.40
June	$21.54	$14.28	$20.55	$20.55	$20.55	$20.55
July	$8.16	$7.81	$8.11	$8.11	$8.11	$8.05
August	$7.37	$4.08	$6.92	$6.92	$6.92	$6.74
September	$5.87	$3.23	$5.51	$5.51	$5.51	$4.84
October	$17.36	$16.30	$17.21	$17.21	$17.21	$16.47
November	$0.97	$0.51	$0.91	$0.91	$0.91	$0.53
December	$0.11	$0.04	$0.10	$0.10	$0.10	$0.05

b. Capacity Factor Revenue

	180, 0	180, 90	180, 30	200, 30	220, 30	2 Axis
January	$28.13	$61.80	$54.34	$52.19	$46.97	$74.05
February	$43.11	$72.75	$71.35	$69.47	$63.96	$93.77
March	$55.40	$61.07	$74.28	$73.05	$68.91	$93.12
April	$77.90	$54.95	$88.83	$89.15	$86.95	$111.00
May	$80.85	$40.23	$82.82	$84.56	$84.93	$105.50
June	$93.47	$38.64	$92.67	$93.69	$93.41	$116.70
July	$93.61	$41.38	$94.40	$95.01	$94.19	$120.42
August	$65.72	$38.94	$70.10	$70.48	$69.42	$85.62
September	$65.16	$56.72	$79.89	$80.10	$77.51	$99.68
October	$36.49	$49.15	$53.35	$52.37	$48.95	$66.52
November	$25.64	$44.11	$42.41	$40.98	$37.42	$53.53
December	$18.47	$40.54	$35.44	$33.92	$30.40	$47.54

c. Revenue Based on Effective Load Carrying Capability

	180, 0	180, 90	180, 30	200, 30	220, 30	2 Axis
January	$1.91	$11.22	$7.22	$4.10	$1.43	$18.00
February	$20.28	$56.68	$46.62	$33.40	$19.01	$85.56
March	$26.79	$20.64	$29.11	$27.63	$25.72	$29.03
April	$143.69	$122.54	$176.65	$155.32	$130.63	$226.74
May	$121.29	$66.94	$125.64	$129.61	$131.22	$135.10
June	$131.10	$48.11	$123.54	$138.47	$150.14	$176.43
July	$132.86	$66.69	$134.80	$144.21	$150.60	$161.51
August	$122.32	$54.18	$124.10	$144.07	$159.37	$184.52
September	$100.66	$74.17	$118.89	$137.75	$150.60	$179.96
October	$35.17	$39.72	$47.51	$54.11	$57.94	$68.47
November	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
December	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00

highest revenue

lowest revenue

System Orientation

PV system orientation significantly affects system revenue. Table 4c (previous page) shows a widely varying revenue stream that leads to several conclusions on maximizing value based on system orientation:

- System orientation choices have less impact on system revenue than rate choice. While there was up to a twofold difference in revenue for identical systems under different rates, the maximum impact of system orientation under a single rate is on the order of 50 percent.

- System orientation does significantly affect output and therefore revenue. The vertical and horizontal systems generate the least revenue, and tracking systems generate the most.

- System tilt and orientation for fixed systems is only of modest importance. The revenue differences between the various fixed-tilted systems are modest.

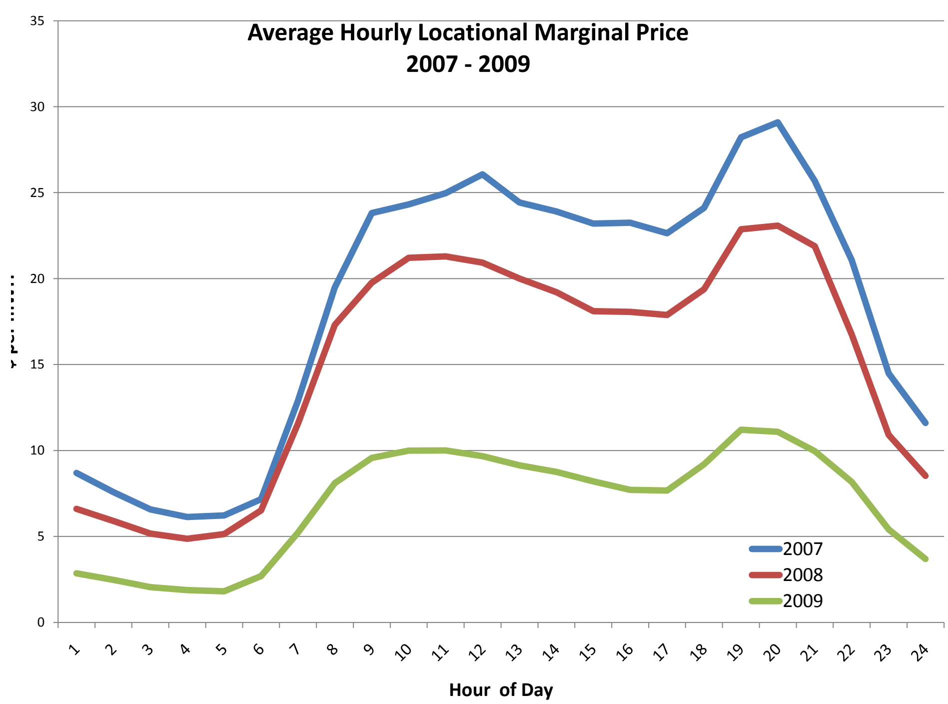
Discussion

This analysis provides insight into the revenue implications of system orientation and rate choice. However, revenue implications alone will not determine the choice of system orientation and rate.

This analysis has not examined all of the variables that will impact system design and rate choices. For instance, this analysis has not examined differences in transaction costs associated with the available rate choices, the cost implications of various system designs, or the price risk of selling power into the wholesale market.

To illustrate the price risk associated with selling into the wholesale market, Figure 8 shows the average hourly locational marginal price (LMP) for 2007 to 2009. As the 2008 recession grew, demand for electric power dropped, with wholesale power prices dropping in response. Power prices have fallen considerably since 2007 (the year analyzed in this study), so while the wholesale market was the most attractive rate option in 2007, it may not have been in 2009, particularly if there is no opportunity to earn capacity revenue.

FIGURE 8 Average Hourly Locational Marginal Price ($ per MWH)



Rate Choice

This analysis suggests that large-scale systems in Minnesota could generate substantially more revenue through the wholesale energy market (in normal economic conditions) as merchant generators than under the retail rates offered by the host utility. The wholesale energy market alone provides greater compensation for PV generation than the host utility's retail rates, suggesting that the host utility's rate designs for customer-owned generation do not fully reflect the value of solar PV systems.

However, the sharp decline in wholesale rates that occurred with the 2008 economic downtown begs the question about whether the future system value of solar generation is typified by the pre-recession market or some other less robust market. The system value of solar generation clearly exceeds the revenue benefit that system owners receive when wholesale markets are robust.

Capacity Valuation

This analysis suggests that PV's capacity contribution – as measured by its effective load carrying capability in the Midwest ISO West region during the summer months – is as high as 50 percent of rated capacity. PV provides virtually no capacity value, however, during the winter months. PV's capacity value to the utility system is not reflected in either the host utility's cogeneration rate, which would grant zero capacity credit to a PV system, or the DG rate, which would grant significant capacity-based revenues even during winter months when no effective capacity is provided.

This paper demonstrates that some utility rate structures do not provide a capacity value for solar that is equal to its capacity value when using the ELCC method for calculating capacity. When peak system demand coincides with the sun shining, a PV system should be eligible for capacity credits equal to somewhere between its rated capacity and zero. What that capacity rating should be is an empirical question that this paper has attempted to answer for one specific location in one specific wholesale market. The capacity contribution to system peak of a PV system will undoubtedly vary across regions or even from year to year at the same location. Differences in system load shape and variations in weather across the country and across time will likely lead to different capacity contributions. Utility planners and ISOs have, however, devised reliable methods of assigning capacity values to intermittent loads such as wind and solar (Midwest ISO, 2011). As utilities and the solar industry gain more experience with PV technology, a standardized capacity valuation model may emerge that can establish a fixed capacity payment over the life of a system. For the immediate future, however, a performance-based model for PV capacity may be the most equitable solution for both utilities and system owners. Utilities could be assured that they will only pay for capacity that is provided, and owners will be able to capture the value that they provide to the system. Such a model would more accurately price PV capacity value by moving away from the on-peak capacity factor used in the host utility's rates and instead evaluating PV system performance in relation to actual system load.

PV systems provide significant capacity relative to system load, yet they provide little demand savings when paired with a retail customer's load. This finding suggests that for the purposes of determining a capacity value, PV generation should be treated as a resource, not as a modifier of retail load. Hence, a PV generator co-located with a retail customer could be metered independently of the retail load, and the PV system could be designed to have no impact on the host retail customer's charges. In combination with a wholesale rate structure, this arrangement would ensure that the PV generator is fully compensated for the services it provides, and the retail customer pays for the services that it uses.

System Orientation

The impacts of PV system orientation on energy production are well documented. The contribution of PV system orientation to demand charge mitigation or capacity valuation, on the other hand, have not been well characterized. These findings suggest that system orientation will have a minimal impact on mitigating demand charges for a commercial building with normal operating hours, because PV generation is not well matched to such a building's load. With respect to system capacity, the impacts on capacity revenue are similar to the impacts seen for energy revenue. Tracking systems provide the greatest capacity revenue, fixed-horizontal and fixed-vertical systems the least, and fixed-tilted systems somewhere in between. As with energy revenues, if a system is going to be fixed and tilted, the precise orientation will have only a small impact on system revenue.

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