Evaluating utility benefits of customer owned and sited photovoltaics: 
Using regression analysis to examine correlation between photovoltaic electricity production and wholesale electricity pricing in Minneapolis Saint Paul

A Plan B Paper

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Dedication

For my family--Matthew, Miles, and Macy--who offered encouragement and support throughout the duration of this project.
Abstract
There is growing interest in grid-connected, customer owned solar photovoltaic (PV) systems and considerable disagreement about how to determine the value of grid-connected PV. The solar industry asserts that utilities should support customer-sited PV systems because of the high correlation between solar energy production and peaking loads. Some utilities maintain that a utility realizes no net benefit from PV above wholesale value of the electricity because the utility must still maintain adequate infrastructure to meet the PV owner’s peak demand.

This paper evaluates the benefits of solar energy delivered by customer owned and sited PV systems on a monetary basis from the utility’s perspective by examining the capacity of the solar resource to deliver during times of high spot market prices. The analysis is completed for the Minneapolis Saint Paul electricity market using a single PV system’s electricity production data correlated with regional wholesale pricing data to identify whether PV can reduce utility exposure to spot market pricing, thereby creating value to the utility to purchase power from solar producers.
Executive Summary

Grid-connected, customer owned solar photovoltaic (PV) systems are of growing interest in various market sectors including residential and business consumers, government entities, investors, and utilities. Finding ways to determine the value of grid-connected PV is becoming more important, particularly for utilities considering whether or not to offer solar programs. The solar industry asserts that electric utilities should aggressively encourage and incentivize customer owned and sited PV systems because of the correlation between solar energy production and peak loads. Some utilities argue that a utility realizes no net benefit above wholesale value because the utility must still maintain adequate infrastructure to meet the PV owner’s peak demand.

Three regression models are used to evaluate the benefits of solar-generated electric power from the utility’s perspective by examining the capacity of the solar resource to deliver during times of high spot market prices. The analyses are completed for the Minneapolis Saint Paul electricity market using hourly PV production data correlated with regional wholesale pricing data in order to address whether PV can limit a utility’s exposure to spot market pricing thereby creating the potential for market-based transactions between utilities and solar producers.

The analysis was completed for each hour ending 0900-1800 for the period from April 1, 2005 through October 31, 2008. In all three models, Science House solar energy production was the response variable while spot market price (approximated by locational marginal price (LMP) for the Midwest Independent System Operator’s Minnesota Hub) and temperature were the explanatory variables:

\[
SCI_{PV_i} = (LMP_i) + (Temp_i)
\]

Where \(i = 0900 \text{ through } 1800 \text{ hours}\)

**Linear Regression Model**

For the seven hours ending 0900 - 1100 and 1500 - 1800, the relationship between PV production and spot market price, LMP, is both positive and significant. This simple
linear regression model generally supports the solar industry’s claim that solar can help mitigate the need for spot market purchases in the morning and mid through late afternoon. The hypothesis does not hold during the three hours ending 1200-1400.

**Semi-log Model**

For seven of the ten hours analyzed, spot market pricing in the Minnesota Hub is both positively and significantly correlated with PV production. During these hours the model suggests there is more solar production when the LMP is relatively high and less solar production when the LMP is relatively low. The results of this model support the solar industry’s claim that solar can help mitigate the need for spot market purchases late morning through late afternoon.

**Seasonal Linear Regression Model**

Of the three models considered, this model is the most comprehensive considered as part of this project as it accounts for seasonal variability. Based on the findings of the seasonal regression model analysis, there is a positive and significant relationship between the of solar electricity production from photovoltaics and spot market pricing in Minneapolis Saint Paul for six of the ten hours examined. Important exceptions include four midday hours ending 1200-1500. This counter intuitive result may be due to the volatility of the MISO market or other time series variations not accounted for in the model.

With a few notable exceptions, the results of the three models generally align with the solar industry’s position that customer-sited PV adds value to a utility since PV has the potential to offset higher spot market prices. However, a strictly economic evaluation of the value of PV to the utility is insufficient to spur widespread PV deployment in Minnesota at this time. As mechanisms are developed to account for both the larger social and environmental benefits of solar PV and the costs related to conventional energy resources, customer-sited PV will likely become an increasingly important resource for both utilities and their customers.
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List of Acronyms

CREBS  Clean Renewable Energy Bonds
DC     direct current
DOE    U.S. Department of Energy
FERC   Federal Energy Regulatory Commission
GHG    greenhouse gases
HDD    high demand day
kW     kilowatt
kWh    kilowatt-hour
LBNL   Lawrence Berkeley National Laboratory
LMP    Locational Marginal Pricing
Midwest ISO Midwest Independent System Operator
OES    Minnesota Office of Energy Security
PPA    Power Purchase Agreement
PURPA  Public Utility Regulatory Policies Act
PV     photovoltaics
REAP   Rural Energy for America Program
RES    Renewable Electricity Standard
USDA   U.S. Department of Agriculture
Introduction

Given Minnesota’s northern latitude, many question the viability of solar energy technologies in the state. However, watt for watt, a solar photovoltaic (PV) system in Minnesota will annually produce as much electricity as a PV system located in many parts of the southern United States.\(^1\) In fact, according to the Minnesota Office of Energy Security (OES), Minnesota receives more solar energy in one day than the state consumes in a year.\(^2\) Consumers, utilities, and policy makers alike are starting to view solar energy as a viable resource in Minnesota. This paper focuses on the solar photovoltaic market in Minnesota, though solar thermal heating is an emerging technology in the state as well.

Solar PV in Minnesota is characterized by decentralized small-scale, customer owned power generation of less than 100 kilowatts (kW) often sited on rooftops, while in more developed solar markets, megawatt scale systems are being installed on department store roofs, on parking lots, and, in particularly sunny parts of the U.S., as utility scale generation over acres of open land. Solar PV produces direct current (DC) electricity from sunlight using semiconductor technology. The semiconducting layers are typically made with silicon, though the growing thin film PV market uses more options today including cadmium telluride-cadmium sulfide and copper indium gallium selenide as the heterojunctions. The emerging thin film market offers possibilities for significant price reductions from the current retail cost of $3.75 per watt for PV modules to less than $1 per watt.\(^3\)

Many of today’s PV modules are rated between 180 and 225 watts DC. Multiple modules are combined to create panel arrays with the average sized Minnesota PV array being 4.6 kW of capacity—sufficient to produce enough electricity to offset the needs of an efficient Minnesota household.\(^4\) The scalability of solar PV allows it to serve local demand, from an individual house or building, to a cluster of buildings or even whole

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\(^3\) First Solar, Inc. *[First Solar Passes $1 Per Watt Industry Milestone]*.

neighborhoods. PV is one of few options for creating electricity from a renewable resource in urban areas where wind is not feasible. This makes it a popular option for many local governments implementing plans for greenhouse gas reductions. Of course, utilities are the chief electricity market participants so it is important to consider the value of solar generated electricity from their perspective.

Electric utilities worldwide are beginning to recognize how customer owned and sited PV benefits their portfolios through summer peak shaving. Solar PV can offset their need to purchase expensive electric power on the spot market, to avoid brown outs and maintain adequate reserves. The question considered here is whether there is a favorable market mechanism for wider non-utility solar PV deployment based on the benefit to the utility from purchasing solar electricity generated by customer-sited PV. I examine whether solar delivers as promised in terms of its ability to offset the utility’s most expensive spot market purchases during high demand days (HDD). This is a measure of the avoided central power capacity cost benefit of solar PV. If there is indeed sufficient value in supporting customer owned and sited PV to the utility, this could improve the economics of the PV system so that it becomes affordable for many instead of a select few. Until grid parity is achieved, the solar PV industry must compete on those attributes that are recognized by electric utilities.

To start, I offer a general background about policies that have historically affected the development of the solar industry in Minnesota and some benefits of deploying solar on a larger scale. I conclude with the use of three regression models to evaluate the benefit to the utility in terms of the potential for solar PV to offset the need for spot market purchases of energy from independent generators. These models directly test the premise that solar energy is produced when it is most needed—during HDD when we might expect spot market energy prices to be at their highest. The analysis is specific to Xcel Energy service territory in Minnesota.

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5 Jacobson, Ralph. Moving Photovoltaic Power into the Mainstream.
Making the Policy Case for Solar Deployment in Minnesota

From a state policy perspective, the three commonly recognized benefits of employing solar electricity include:

- The creation of local jobs that offer economic benefits to local communities
- Environmental benefits related to greenhouse gas reductions and pollution reduction through avoided use of fossil fuels
- Increased energy security through reduced reliance on imported conventional fuels

Minnesota Governor Pawlenty regularly points to these benefits for renewable energy generally. While the administration’s energy policy emphasis is on wind and biofuels development, it is generally supportive of the idea of solar deployment as well. The Solar America Cities grant from the U.S. Department of Energy (DOE) awarded in March 2008 has spurred discussion among a coalition of cities, state legislators, state agencies, DOE, installers, and Xcel Energy in Minnesota about how best to promote solar in the state. As a result of this partnership, there is now a focused effort by a core group of Minnesota stakeholders to promote the technology. The state legislature responded to the group’s recommendations by appropriating several million dollars for solar development in the Solar Cities of Saint Paul and Minneapolis as well as statewide.

Many policymakers refer to the policy support for wind adopted in 1994 as game-changing for that industry. They believe similar support is necessary to realize market transformation for solar and to attract private investment so that solar can become competitive with conventional resources. As stated by Bill Glahn, director of the Minnesota Office of Energy Security, “The idea is to make a short-term, coordinated investment in solar technologies, so that we can transform the market for solar in Minnesota and allow it to stand on its own in the long-term.”

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6 Hanson, Jeremy Legislative Session Provides Groundbreaking Victory for Solar Energy: Historic Collaboration Sets Stage for Energy Transformation.
Solar Incentives in Minnesota

For all the potential benefits, solar photovoltaics is expensive. Therefore, the existing market conditions for PV in Minnesota have been strongly linked to federal, state, and in some cases, utility incentives, including cash rebates and tax credits. (See Table 1 for state and federal incentives available in Minnesota.) This is the case elsewhere as well—consumers respond most favorably to a combination of local and federal solar incentives. It is in the states that have attractive state or utility incentives that solar markets are developing most rapidly. In Minnesota, the state’s Solar Electric Rebate Program has been the mainstay of the solar PV development that has occurred so far. The program offers a direct payment of $2 per watt to the owner of systems with a capacity of 10 kW or less. (The average system size supported by the program to date is 4.6 kW.) The program’s funding has been exhausted three times in the past two and a half years (November 2006, March 2008, and most recently in October 2008). The stop-start cycle weakens the solar installation community as consumers delay investing in projects until additional funding becomes available.

A comparison of the PV development that is taking place in some areas of the U.S. with Minnesota’s statewide capacity of 1.4 megawatts illustrates how important robust, stable incentives are to the market. Some cities with comparable solar resources to that of Minneapolis Saint Paul are far ahead of the Twin Cities in terms of solar deployment mainly due to local PV incentives. For instance, the City of San Jose, California is home to 11 megawatts of PV, due to attractive incentives of $2.50 per watt AC for PV systems and a streamlined solar permitting process. Similarly, the City of Austin, Texas just entered into an agreement to develop and lease a 30 megawatt solar PV project. These cities’ successes with solar deployment indicate that state and utility policy is as important as the solar resource in influencing solar investment decisions.

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8 Solar San Jose presentation. San Antonio, TX.  
9 California Solar Initiative.  
10 30 MW Solar RFP. Austin Energy.
Table 1: Incentives Available in Minnesota for Solar PV Projects.\textsuperscript{11}

<table>
<thead>
<tr>
<th>Resource</th>
<th>Federal Incentives</th>
<th>State Incentives</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>GENERAL</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>U.S. Department of Agriculture (USDA) Grants &amp; Loans (REAP)</td>
<td>Annual solicitations for energy efficiency and renewable energy grants and loans under the Farm Bill. It is a competitive process that begins each spring/summer and is reserved for ranchers, farmers, and rural small businesses. Some wind development in Minnesota has resulted, but few solar projects to date. <a href="http://www.rurdev.usda.gov/rbs/farmbill">www.rurdev.usda.gov/rbs/farmbill</a></td>
<td></td>
</tr>
<tr>
<td>Clean Renewable Energy Bonds (CREBS)</td>
<td>CREBs are available to the public sector for financing renewable energy projects, including solar. CREBs may be issued by electric cooperatives, government entities, and certain lenders. CREBs are issued, with a 0% interest rate. The borrower pays back only the principal of the bond, and the bondholder receives tax credits in lieu of bond interest.</td>
<td></td>
</tr>
<tr>
<td>Energy Efficient Mortgages</td>
<td>Energy efficient mortgages can be used to pay for solar electric and solar heating technologies. Mortgage types include FHA, VA, and conventional loans.</td>
<td></td>
</tr>
<tr>
<td><strong>SOLAR</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Minnesota Solar Rebate Program</td>
<td>$2 per watt of PV capacity. This program’s funding has been exhausted three times in the past three years. (Nov 2006, Mar 2008, Oct 2008.) In May 2009, the Minnesota Legislature appropriated $3 million in federal energy stimulus funds to revive the program.</td>
<td></td>
</tr>
<tr>
<td>Tax Credit</td>
<td>Investment Tax Credit: Business and residential tax credit of 30% of total costs after other rebates/incentives are applied for solar electric and/or thermal systems completed on or after January 1, 2006 through December 31, 2016. No limit for business or residential.</td>
<td></td>
</tr>
<tr>
<td>Sales Tax Exemption</td>
<td>Sales tax exemption for solar energy systems. (<a href="http://www.mn.gov/law/297A.67">Minnesota Statutes 297A.67, subdivision 29</a>).</td>
<td></td>
</tr>
<tr>
<td>Property Tax</td>
<td>Exemption for photovoltaic systems (<a href="http://www.mn.gov/law/272.02">Minnesota Statutes 272.02</a>).</td>
<td></td>
</tr>
<tr>
<td>Depreciation</td>
<td>Double-declining balance, five-year depreciation schedule tax benefit for businesses.</td>
<td></td>
</tr>
<tr>
<td>Net metering</td>
<td>Solar electric systems &lt; 40kW are eligible for net metering with compensation for excess electricity generated at average retail electricity rate. ([Minnesota Statutes 216B.164 and 7835](<a href="http://www.mn.gov/law/216B.164">http://www.mn.gov/law/216B.164</a> and 7835)).</td>
<td></td>
</tr>
</tbody>
</table>

Note that in addition to the above policies and programs, there are two important state policies that are omitted: The state’s Renewable Electricity Standard (RES) requires 25%

renewable electricity by the year 2025 for all utilities except Xcel Energy which must obtain 30% of its electricity from renewable energy by 2020. However, without a carve-out for a portion of the energy production to come from solar, RES is ineffective for spurring solar development in states. This is because utilities implement the most cost effective renewable technologies such as large scale wind in the absence of policies that specifically incentivize solar.

The second policy omitted is the state’s participation in the Midwest Greenhouse Gas Reduction Accord. Recommendations were released in December 2008\textsuperscript{12} for 15 - 25% greenhouse gas (GHG) reductions by 2020 and 60 - 80% by 2050. Similarly, in the near term this regional effort will not have the effect of expanding the solar market in Minnesota for the same reasons described above.

The 2009 Minnesota legislative session was groundbreaking in terms of solar policies and appropriations. The programs that result from the various solar bills may mark the beginning of widespread solar deployment. Programs and policies that will be implemented during the upcoming biennium include:\textsuperscript{13}

\begin{itemize}
\item $3.4 million for solar PV and solar thermal rebates (more than three times the previous appropriation levels.)
\item A Central Corridor Light Rail Transit Utility Zone between Saint Paul and Minneapolis including requirements for the local electric utility to develop solar energy and energy efficiency within the zone.
\item Xcel Energy may count up to one percent of solar generated electricity toward its RES in addition to wind. (Under current rules, Xcel cannot count any solar generation toward its RES mandate.)
\item Creates a $6.5 million School District and Local Government Renewable Energy Grant Program that allows grants of up to $200,000 for large solar PV projects.
\end{itemize}

\textsuperscript{12}\textit{"Midwest Greenhouse Gas Reduction Accord."} Midwestern Governor's Association.

\textsuperscript{13} Anderson, Ellen. \textit{Appropriations of Federal Stimulus Funds for Energy Programs}. SF 657.
• Creates a $3 million Solar Cities Grant Program for the installation of large and small-scale solar projects, including innovative energy storage technology.

Most of the appropriations described above are funded by the State of Minnesota’s share of the energy funds created by the federal American Recovery and Reinvestment Act signed into law on February 17, 2009. In light of the favorable solar session, many solar stakeholders voice concerns about what will happen to the industry after the stimulus funds have been exhausted in two years. There is an expressed desire to avoid running out of funds which halts solar industry activity.

In addition to state and utility rebates, most states including Minnesota have adopted net metering policies.14 Net metering allows consumers to offset the electricity they would normally buy from their utility at retail rates by generating electricity from qualifying renewable energy resources at their homes or businesses to the utility. The net metered customer's electric meter can run both forward and backward, and the customer is charged only for the net amount of power used. Minnesota law also requires the utility to purchase electricity generated in excess of the customer’s use at the utility’s average retail rate.15

In Minnesota, renewable distributed generation systems, including PV systems, of up to 40 kW DC capacity16 qualify for net metering benefits.17 Net metering rules apply to all of the state’s utilities including investor owned utilities, municipal utilities, and rural electric cooperatives. There is no limit to statewide capacity allowed under net metering. Minnesota was the first state to legislatively adopt net metering in 198118 and is one of just two states along with Wisconsin that requires utilities to purchase excess generation

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16 40 kW of PV capacity can be expected to produce approximately 50,000 kWh or 5 megawatt-hours of energy annually in Minnesota. This is large enough to supply the electricity needs of a midsized business or about five homes.
17 Minnesota Statutes 216B.164.
at the retail electricity rate rather than a wholesale rate. Renewable electricity installations in Minnesota 40 kW or greater do not qualify for net metering benefits, so the owners of these systems must negotiate any compensation for net excess generation through a power purchase agreement (PPA) with a utility.

### Table 2: Xcel Energy average retail utility energy rates by customer class

<table>
<thead>
<tr>
<th>Class</th>
<th>Rate Code</th>
<th>Annual</th>
<th>Winter</th>
<th>Summer</th>
</tr>
</thead>
<tbody>
<tr>
<td>Residential</td>
<td>A01_S</td>
<td>9.24</td>
<td>8.92</td>
<td>9.82</td>
</tr>
<tr>
<td>Small General</td>
<td>A03_S</td>
<td>9.49</td>
<td>9.03</td>
<td>10.4</td>
</tr>
<tr>
<td>Non-Demand Metered</td>
<td>A01NS</td>
<td>9.27</td>
<td>8.93</td>
<td>9.88</td>
</tr>
<tr>
<td>Demand Metered</td>
<td>A14NS</td>
<td>5.31</td>
<td>5.16</td>
<td>5.57</td>
</tr>
</tbody>
</table>

*Shown for Xcel Energy in Minnesota. Units in cents per kilowatt-hour. These are the prices used to set net metering rates for Xcel customers in the state. From Xcel Energy 2009 Annual Filing of Cogeneration and Small Power Production Tariffs.

With a 40 kW net metering cap, PPAs would seem to be the most obvious way to finance mid- to large-scale commercial and government PV projects. At this time however, the PPA negotiation process is difficult for these bigger projects, and as a result, owners of non-net metered systems in Minnesota decide not to enter into PPA arrangements.¹⁹, ²⁰

Some utilities and ratepayer advocates are opposed to net metering rules requiring retail rate purchase of excess generation for renewables. They argue that compensation at retail rate overstates the value of the renewable energy to the utility. From their perspective, any net excess PV generation should be compensated at either wholesale rate or avoided cost. The opposing viewpoint, largely supported by renewable energy advocates, is that Minnesota’s net metering law, while innovative when it was adopted, is now outdated. Renewable energy promoters claim that the 40 kW cap per project is stifling solar growth in Minnesota by keeping systems sizes to less than 40 kW. Right now, of nearly 300 known solar PV installations in the state, only three are larger than 40 kW.²¹ This suggests that net metering benefits are indeed an important part of the economics of most small commercial solar PV projects.

²⁰ Michaud, Carl. Hennepin County. Personal correspondence.
Clearly, with fewer than 300 known solar PV installations in Minnesota, the market for solar is still nascent. At this early stage, incentives in the form of attractive rebates, tax incentives, and net metering rules are important to drive private investment that will in turn bring costs down. Incentives also offer a means of creating an infrastructure around promising technologies like PV, including installer expertise; permitting, inspection, and zoning familiarity; and distributors and equipment manufacturers. Similar evolution has occurred within the wind industry in the last decade, with solar in position to become a player in the next decade as well if appropriate incentives are in place.

**Barriers to solar deployment in Minnesota**

Often, barriers exist because the nation’s power delivery system was designed for large-scale, centralized generation. The Public Utility Regulatory Policies Act (PURPA) passed in 1978 opened the door to distributed renewable energy generation. The law created a market for non-utility power producers by forcing electric utilities to allow interconnection and to purchase net excess power from these producers. PURPA required utilities to purchase renewable energy power at "avoided cost", or the cost to the utility if it were to generate or purchase from a conventional source. States interpreted PURPA in various ways, and many states, including Minnesota, now require far more of utilities than the minimum PURPA requirements.

The solar industry is largely dependent on federal, state, and local government to address the policy barriers and manufacturers to reduce module prices. Even as the costs of solar decline, if the policy environment is not solar friendly, PV will not be deployed on a large scale. Utility interconnection policies and the ability to negotiate favorable power purchase agreements are important as well.

There are four major barriers to widespread deployment of solar photovoltaics:

1) The cost of PV generation is still relatively high compared to conventional energy resources, and reliable incentives are still needed for PV deployment;

2) The variable nature of solar energy creates challenges for integrating large-scale solar PV into existing transmission and distribution infrastructure;
3) Minnesota’s net metering rules favor small-scale solar PV projects; and
4) Permitting and interconnecting of solar projects often have disproportionately high transaction costs relative to project size.

**Barrier 1. Cost of PV**

Given the relatively high cost of PV, a key goal of the PV industry and governments supporting solar deployment is to drive cost reductions over time. States and utilities that offer stable and significant incentives help drive the PV market, and in turn reduce prices over time for both PV components and labor. To improve the financial returns on investment, consumers see incentives as key to their purchase in terms of both timing and size of their system. In order to assess the effectiveness of this goal in Minnesota, an analysis of installed cost data from approximately 200 PV systems, totaling almost one megawatt of capacity installed in Minnesota from 2002 through 2008 was completed by the Office of Energy Security. The results showed an increase in price per watt over time—*the opposite of what is occurring elsewhere in the country and the opposite of the policy goal.*

The increasing prices in Minnesota are understandable in the context of competing regional markets. According to a DOE-sponsored report from Lawrence Berkeley National Laboratory (LBNL), the national average cost for a PV system was $7.60 per watt in 2007—the latest year for which data was available.* However, Minnesota's average installed price is about $10 per watt or 32% higher than the national average. Part of the reason for this price discrepancy is that PV costs exhibit significant economies of scale with megawatt-sized systems. The LBNL report found that systems less than 2 kW completed in 2006 and 2007 averaged $9.0/W and systems greater than 750 kW completed in 2002 through 2008.*

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24 Wiser, Ryan, et al. Tracking the Sun: The Installed Cost of Photovoltaics in the U.S.
averaged $6.80 per watt (i.e., about 25% less than the smallest systems). The incentive programs in Minnesota have never applied to systems above 40 kW, and in July 2007, were capped at 10kW.

Another factor that likely contributes to rising PV prices in Minnesota may be that the state is at the end of the solar supply chain. After the large contract obligations in Europe and Japan are met and the east and west coasts of the U.S. are supplied, Minnesota and other secondary markets have access to whatever remains. Solar dealers in the state report that their supply chain is both inconsistent and volatile in terms of module availability and pricing. They are unable to benefit from volume discounts for hundreds of kW purchased. The evidence suggests that large PV markets drive lower average PV costs.

Component pricing data associated with the Minnesota Solar Electric Rebate Program indicates that on average module costs account for approximately 50% of the total project cost. The inverter, a device that converts DC electricity to AC, represents about 10% of total project costs. The rest of the system components and installation comprise the remainder of the cost.

Most industry experts anticipate an over-supply of PV modules in 2009, putting downward pressure on module prices, and presumably on total installed costs as well. In addition, lifting the cap on the federal investment tax credits for residential PV beginning January 1, 2009 and ending Dec 31, 2016, could further reduce net installed costs for residential PV installations, potentially leading to renewed emphasis on the residential market in the years ahead. In Minnesota, the residential PV market accounts for half of all installations in the state.

26 “PV Downturn to Shape More Mature Supply Chain," EE Times Asia.
Barrier 2. Solar PV is not dispatchable
The solar resource is variable and solar PV is not dispatchable which causes energy planners and utilities concern about the widespread integration of solar electricity on the grid. However, there are advances being made in storage technology and investments planned for smart grid integration which would allow the utility to dispatch stored solar energy just as it is able to dispatch conventional resources. If practical energy storage and dispatch solutions are realized, the cost effectiveness and value of solar PV will increase from a utility perspective. Until then, significant solar penetration is unlikely to occur in most areas of the state.

Figure 1: Installed PV capacity in Minnesota. Office of Energy Security.

The DOE issued a solicitation in early 2009 to commission a study that would evaluate the impact of high penetrations of solar PV to the national grid. The objectives of the funding opportunity include developing modeling tools for high penetration scenarios of PV on a distribution system and demonstration of the integration of PV and energy storage into smart grid applications. The solicitation is intended to result in a better understanding of the challenges of integrating large

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amounts of solar into the grid network and outlining a road map to overcome the barriers. Storage will undoubtedly be part of the equation for addressing intermittency problems relating to large-scale integration of solar PV. Without the ability to store and dispatch, the variable nature of PV generation will limit grid penetration even after the technology becomes cost competitive with conventional resources. It has been suggested that utilities may cap net metering and deny interconnections to preserve grid reliability if large amounts of solar are shown to result in voltage instability due to intermittency.\(^2^9\)

**Barrier 3. Minnesota net metering rules favor small PV systems and discourage mid- to large-scale solar PV projects**

Minnesota’s cap of 40 kW exclusively promotes small PV systems. Since economies of scale are not typically realized until system capacities of 750 kW or more are reached, Minnesota PV developers and owners are unable to take advantage of cost reductions being realized in other markets.\(^3^0\) Eighteen states plus Washington, D.C. have adopted net metering laws of one megawatt or greater.\(^3^1\) In these markets, megawatt scale PV systems are becoming more common since the need to negotiate with the utility for a PPA is eliminated. States without favorable net metering rules for renewable resources simply don’t realize large scale PV development.

**Barrier 4. Permitting and interconnection for solar projects often have disproportionately high transaction costs compared to large-scale generation projects**

Permitting and interconnection procedures for energy projects are set by regulators at the state and local levels. Many developers of distributed generation find permitting and interconnection processes costly and cumbersome. The procedures can present intensive paperwork and lengthy time to obtain approvals.

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\(^2^9\) Torres, Juan, et al. *Solar-Grid Integration*

\(^3^0\) Wiser, Ryan, et al. *Tracking the Sun: The Installed Cost of Photovoltaics in the U.S.*

\(^3^1\) See Database of State Incentives for Renewable Energy for details on state interconnection standards and net-metering rules. [http://www.dsireusa.org/documents/SummaryMaps/Net_Metering_map.ppt](http://www.dsireusa.org/documents/SummaryMaps/Net_Metering_map.ppt)
which leads to increased project costs.\textsuperscript{32} This is because the historic model of power plant deployment is to construct large centralized power plants where interconnection requirements are extensive due to the complexity of the projects. While Minnesota’s net metering law prohibits utilities from requiring undue burdens to developing customer owned and sited renewable energy projects,\textsuperscript{33} many utilities require redundant and expensive safety measures of applicants for interconnection and add high monthly fees that offset the monetary benefits of producing energy on-site. Permitting fees and requirements by state and local governments can be similarly lengthy, unpredictable and expensive and discourage solar development. Solar projects are far more likely to be deployed if developers and their clients know that there is a predictable process for permitting and interconnection.

The solar industry to date is largely dependent on federal, state, and local government to address the policy barriers as manufacturers work to reduce module prices. Many of the barriers exist because the nation’s power delivery system was designed around centralized generation. The Public Utility Regulatory Policies Act (PURPA)\textsuperscript{34} passed in 1978 opened the door to distributed renewable energy generation nationally. The law created a market for non-utility power producers by forcing electric utilities and transmission and distribution owners to allow interconnection and compensation for net excess energy from these producers. PURPA required utilities to purchase renewable energy power at "avoided cost", or the cost to the utility if it were to generate or purchase electricity from a conventional source. States interpreted PURPA in various ways, and most states, including Minnesota, now require more of utilities than the minimum PURPA requirements.

Even as the costs of solar PV decline, if the policy environment does not adequately value solar PV benefits, PV will not be deployed on a large scale. Permitting, utility

\textsuperscript{32} Keyes, Jason B. et al. Comparison of the Four Leading Small Generator Interconnection Procedures.
\textsuperscript{33} Minnesota Statutes 216B.164.
\textsuperscript{34} 16 U.S.C. Sections 2601-2645.
interconnection policies, net metering, and the ability to negotiate favorable power purchase agreements are important as well.

**PV Value Drivers**

The solar industry asserts that solar generated electricity has value beyond the kilowatt-hours of energy produced. This is the premise of the feed in tariff policies that are commonplace in Europe today. However, unless utilities, the mainstay of the electricity market, agree that solar electricity provides additional benefits and include that value in their compensation to solar electric providers, it will be difficult for utilities to justify paying a premium for PV generated electricity in the United States. From the utility perspective, paying a premium (above competitive market prices) for PV and then not receiving the value associated with the match between the solar resource and the utility’s peak demand are considerable.

The attributes of PV have been characterized in a study sponsored by the National Renewable Energy Laboratory as shown in Table 3. The study’s cost benefit analysis shows that of the 19 PV value characteristics identified, just six have significant benefits (central power generation cost, central power capacity cost, transmission and distribution costs, reduced GHG emissions, criteria pollutant emissions, and implicit value of PV) and one has significant costs (equipment and installation cost). The study also noted that when aggregated across stakeholders, several values are simply transferred from one stakeholder to another without creating a net benefit or cost (e.g., PV owner savings on electricity bill, federal incentives, and state incentives).  

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Table 3: Commonly cited PV benefits.

<table>
<thead>
<tr>
<th>PV Value/Cost</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Central Power Generation Cost</td>
<td>PV systems produce electricity, reducing the amount of electricity that needs to be generated at other plants, which in turn decrease fuel and other O&amp;M costs.</td>
</tr>
<tr>
<td>Central Power Capacity Cost</td>
<td>PV indirectly avoids and/or deters central power plant capacity investments by reducing demand-side consumption. Generation capacity value is the economic value of the avoided and/or deterred incremental resource [typically natural gas turbine] reflecting PV’s peak load reduction NIMBY opposition and higher construction costs are driving capacity costs up. PV also avoids the cost of running more expensive plants during peak loads.</td>
</tr>
<tr>
<td>Transmission and Distribution Cost</td>
<td>PV avoids and/or defers transmission and distribution capacity investments by reducing demand-side consumption. Transmission and distribution capacity value is the economic value of the avoided and/or deferred incremental resource reflecting PV’s peak load reduction. NIMBY opposition and higher construction costs are driving capacity costs up. This value is also applicable to situations involving significant congestion issues.</td>
</tr>
<tr>
<td>System Losses</td>
<td>Avoided electric system losses are an indirect benefit because they increase the value of other benefits including energy production, generation capacity, environmental and T&amp;D capacity.</td>
</tr>
<tr>
<td>Ancillary Services</td>
<td>Utilities can use inverters in PV systems to provide reactive power back to the grid. This increases power quality and could avoid the installation of capacitors.</td>
</tr>
<tr>
<td>System Resiliency</td>
<td>Significant deployment of PV systems coupled with storage could provide disaster recovery benefits.</td>
</tr>
<tr>
<td>Hedge Value</td>
<td>Current electricity generation is heavily dependent on natural gas and coal. Recent environmental constraints suggest that utilities will become more dependent on natural gas. PV lessens the exposure of the utility to volatile fuel prices and provides stable and predictable electricity prices.</td>
</tr>
<tr>
<td>Market Price Impacts/Elasticity</td>
<td>The elasticity of demand for electricity supply increase with more PV. Increase demand for PV may decrease the price of electricity from PV. A decrease in the cost may then increase the demand for this lower cost good.</td>
</tr>
<tr>
<td>Customer Electricity Price Protection</td>
<td>Since there is no fuel expense, the costs of electricity from PG will not increase over the life of the system due to fuel costs and the consumer effectively locks in an electricity price.</td>
</tr>
<tr>
<td>Customer Reliability</td>
<td>PV can provide electricity to the PV owner during outages because it is not dependent on the grid. The electricity during an outage is limited to sunlight availability. Storage systems could help offset the intermittency issue and increase the reliability value to the owner.</td>
</tr>
<tr>
<td>Criteria Pollutant Emissions</td>
<td>PV systems eliminate criteria pollutant emissions (e.g., NOx, SOx) associated with non-renewable generation resources. Health benefits associated with reduced emissions are included in this value.</td>
</tr>
<tr>
<td>Greenhouse Gas Emissions</td>
<td>PV systems eliminate greenhouse gases (CO2) associated with non-renewable generation resources. Renewable Energy Standards and renewable energy certificates are common mechanisms to value emission reductions from renewable sources of energy such as PV.</td>
</tr>
<tr>
<td>Implicit Value of PV</td>
<td>The intrinsic societal value of PV to customers (e.g., environmental friendliness, feeling good, early adopter) and utilities (e.g., public relations, regulator compliance).</td>
</tr>
</tbody>
</table>

Thirteen PV benefits. With carbon regulation on the horizon, the benefits of reduced greenhouse gas emissions from solar production will become more significant. Many would add energy independence as a benefit of solar. From Contreras’ Photovoltaics Value Analysis.\(^{36}\)

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Table 4: Commonly cited PV costs.

<table>
<thead>
<tr>
<th>PV System Installation Cost</th>
<th>The total cost of PV installation.</th>
</tr>
</thead>
<tbody>
<tr>
<td>PV System O&amp;M Cost</td>
<td>Accounts for operations and maintenance expenses for the PV system.</td>
</tr>
<tr>
<td>Benefits Overhead</td>
<td>Costs associated with capturing and monetizing the value streams. Includes program administration and marketing.</td>
</tr>
<tr>
<td>PV Owner Electricity Bill</td>
<td>PV systems result in less revenue to utilities.</td>
</tr>
<tr>
<td>Federal Incentives</td>
<td>Federal incentives to promote PV installation.</td>
</tr>
<tr>
<td>State Incentives</td>
<td>State incentives to promote PV installation.</td>
</tr>
</tbody>
</table>

Six commonly recognized PV costs. Some PV attributes are simply a transfer of value from one entity to another with no net cost or benefit, such as federal tax incentives to solar owners. Reproduced from Contreras’ *Photovoltaics Value Analysis*.

According to Contreras et al, one of the biggest drivers of PV value is the timing of the energy delivered by the PV system. The premise is that PV production correlates highly with energy demand, with loads being greatest during the summer months. This mitigates the central power generation cost and central power capacity cost, the first two values identified in Table 3. Intuitively this makes sense since one would expect that the hottest sunniest days would correlate with the largest commercial and industrial cooling loads. The analysis included in this paper tests the reduced central power generation cost benefit specifically for the Minneapolis Saint Paul metropolitan market.

The DOE Solar America Initiative has adopted a goal of grid parity for solar PV by 2015. Grid parity refers to solar power costing the same as competing conventional power sources before subsidies. Right now the cost of making modules accounts for about half the total cost of PV installations in the United States. The DOE published a schedule shown in Table 4 for meeting this grid parity goal which assumes “business as usual.” It does not rely on new policies that place a price on greenhouse gas emissions. A carbon regulation system would accelerate grid parity as would a national RES. Such policies are being discussed at both the regional and federal levels.

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Until grid parity is achieved, the solar PV industry must compete on those attributes that are recognized by electric utilities. In the next section, I evaluate one specific attribute of solar PV—the ability of customer-sited solar PV systems to reduce an electric utility’s exposure to spot market purchases in Minnesota.


<table>
<thead>
<tr>
<th></th>
<th>Grid 2005 (cents per kWh)</th>
<th>PV 2005 (cents per kWh)</th>
<th>PV 2010 (cents per kWh)</th>
<th>PV 2015 (cents per kWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Residential</td>
<td>6-17</td>
<td>22-30</td>
<td>13-18</td>
<td>8-10</td>
</tr>
<tr>
<td>Commercial</td>
<td>5-15</td>
<td>16-22</td>
<td>9-12</td>
<td>6-8</td>
</tr>
<tr>
<td>Utility</td>
<td>4-8</td>
<td>13-22</td>
<td>10-15</td>
<td>5-7</td>
</tr>
</tbody>
</table>

DOE’s Solar America Initiative established these goals for solar PV pricing before subsidies as part of its market transformation activities. The projections for 2010 seem to be attainable for the residential and utility sectors. Assumes business as usual case.

Photovoltaic electricity is non-dispatchable because the output is based on both technology design parameters such as technology selection, installation characteristics, and site conditions, as well as a solar resource that varies over time (seasonally, daily, hourly, and even second to second). These solar resource variations, however, are not completely random and unpredictable. Indeed, most agree that there is an intuitive positive relationship between PV system output and summer peak electricity demand as Contreras suggests. Despite this alleged relationship, which is difficult to measure and varies from market to market, there is not consensus across electric utilities and the solar industry on a method for calculating PV’s practical use in electricity markets and utility planning.38

Until large-scale dispatchable storage solutions are developed, it is irrelevant to compare the cost of solar PV generated electricity with baseload electricity resources like coal and nuclear. Many solar industry experts argue that since PV generates electricity only during daylight hours and generates more electricity when the sun is shining more intensely during summer peak electricity loads, PV power is produced proportionately more at times when the value of electricity is highest. Therefore, a valuation method that uses the

average wholesale cost of electricity will tend to undervalue PV energy production. A more appropriate comparison is between PV production and electricity spot market prices during times when the solar resource is available—daylight hours only. Austin, Texas Mayor Will Wynn summed it this way: “Diversifying our renewable energy portfolio is a key strategy to hedging against price volatility and meeting the needs of our load profile,” Wynn said. “Our wind generation helps us back down our coal-fired baseload generation at night. Our high capacity-factor biomass plant allows us to offset coal and gas-fired baseload both day and night. And with this [30 megawatt] solar project, we’re essentially shaving the need for new gas-fired peaking power during the day.”

The general correlation between solar resource and electricity demand has been estimated in the range of 35-69% depending on the electricity market. What is less well known, however, is how that translates into dollars and cents on the electricity spot market. For instance, during high demand days we might expect two conditions:

1) strong solar resource
2) high electricity spot market prices

The solar industry suggests that these two conditions generally go hand in hand. The utilities have a fundamental goal of maintaining adequate capacity to meet demand, and if solar technologies can meet that need with the added benefit of hedging spot market exposure then PV will be more favorably evaluated. Before a utility would be willing to offer solar PV generation owners premium prices for electricity generated, however, they need to determine the strength of the correlation for the utility’s particular market.

Frequently, utilities are forced to make spot market purchases of electricity in order to maintain system reliability and meet demand. The average price paid in the Midwest ISO Minnesota Hub market for the three and a half year time period reviewed was $62 per megawatt-hour. During HDD conditions, peaking generators are employed to meet load requirements. These resources include inefficient, high emissions generators that often

40 “Austin, Texas's Mayor Wynn and City Council Approve One of Nation’s Largest Solar Power Plants." ICLEI-Local Governments for Sustainability.
use expensive fuel such as diesel, natural gas, or oil. If the solar industry is correct, PV would compare favorably during HDD because these days tend to intersect with high insolation conditions when the days are long and PV production is at its highest. If the conventional utility perspective is correct, then there will be no clear correlation between high spot market prices and solar energy production.

**Analysis of a Customer Owned Grid-tied PV System in Saint Paul, MN**

Evaluating the benefits of PV with respect to mitigating the need for utility purchases on the spot market is associated with central power capacity cost outlined in Table 3. In completing this analysis I employed the following data:

- Midwest ISO Locational Marginal Pricing (LMP); 1 hour intervals; Minnesota Hub was employed as an approximation of spot market pricing for Xcel Energy in Minnesota; April 2005-Oct 2008.
- PV energy production data; 15 minute interval data converted to hourly data; Science House at the Science Museum of Minnesota; Saint Paul; data collected February 1, 2004 –October 31, 2008.
- Minneapolis Saint Paul Airport temperature; hourly interval data; April 1, 2005-October 31, 2008.\(^2\)

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\(^2\) Hourly Surface Temperature Data for Minneapolis Saint Paul, South Dakota Office of Climatology.
Solar energy production profile for a single day, summer solstice 2008 from the PV system at Science Museum of Minnesota Science House, Saint Paul. Note that for a PV installation oriented due south, maximum production will generally occur at solar noon. The Science House is oriented slightly east of south, so that the system’s peak will occur before noon.

Solar PV production profile for a single day at Science House, winter solstice 2007. Despite efficiency gains in the winter, overall production is reduced relative to summer. On this short winter day, maximum production is about half of the maximum system capacity. (The maximum energy production recorded for a single hour was 7.78 kWh on May 3, 2008.)
The Science House at the Minnesota Science Museum in Saint Paul (45°N, 93°W) was designed as a net zero energy demonstration facility. The Science House design team used energy efficiency strategies with a 10.2 kW solar photovoltaic system and a ground source heat pump to provide daylighting, power, and heat.

The building is equipped for ongoing performance monitoring in order to provide educational data for informing future building design. The solar energy production data was obtained through a data monitoring package maintained and monitored by the Weidt Group. Production data in kilowatt-hours was divided by system size in order to normalize the data since there was a system expansion in April 2007.

**Table 6: Science House PV system characteristics.**

<table>
<thead>
<tr>
<th>PV system size and manufacturer</th>
<th>10.2 kW; UNI-SOLAR® flexible thin-film photovoltaic laminates</th>
</tr>
</thead>
<tbody>
<tr>
<td>Installation dates</td>
<td>8.8 kW on June 2003; An additional 1.4 kW added April 2007</td>
</tr>
<tr>
<td>Installation method</td>
<td>The PV thin-film laminate adheres to the troughs of the standing seam metal roofs of the building and the adjacent shed</td>
</tr>
<tr>
<td>Azimuth angle</td>
<td>18° east of south for the main building (8.8 kW); the smaller array on the tower at about 10° west of south (1.4 kW)</td>
</tr>
<tr>
<td>Tilt angle</td>
<td>22.5 degrees from horizontal to optimize for summer</td>
</tr>
</tbody>
</table>

The 1,690 square foot Science House runs on solar electricity, producing more electricity than it uses from mid-March through early November. It consumes more than it generates from early November to mid-March. (See the Science House net PV production profile in Figure 4.) The resulting net surplus of energy means that the Science House produces more
electricity than it uses on an annual basis. Instead of having an energy storage system or being net metered, the Science House feeds excess electricity to the neighboring Science Museum when it is producing a surplus and draws current from the museum’s service when consumption is greater than production.\textsuperscript{43}

**Figure 4 Science House PV Production – Consumption.**

Net energy production at Science House during the period from Jan 1, 2006- Oct 31, 2008 was +9,303 kilowatt-hours. The building’s solar PV system is meeting the goal of being a net zero energy building. That is, the amount of energy provided by on-site solar energy resources is greater than the amount of energy used by the building.

Figure 5: Science House Solar Energy Production versus Time.

Solar Production versus Time (0900)

Solar Production versus Time (1200)
“Science House Solar Energy production in kilowatt-hours versus Time” for hours ending at 0900, 1200, 1500, and 1800. (Apr 05 - Nov 08) The production patterns for each hour show a strong seasonal and time of day correlation with peak production occurring during summer afternoons and the lowest production values during winter off-noon hours.
Figure 6: Spot Market Price versus Time. Hours ending 0900, 1200, 1500, and 1800.
“Spot Market Price versus Time” for hours ending at 0900, 1200, 1500, and 1800. (Apr 2005 – Oct 2008). Generally, pricing follows a seasonal pattern with the highest prices occurring during the summer months. Note that prices can peak during the winter as well. This is because energy pricing reflects more than just local electricity demand. Power outages and weather conditions elsewhere in the region can contribute to higher winter prices.
The following analysis considers the economics of grid-connected customer owned and sited solar PV from the Science House from a utility perspective. I analyze the strength of the correlation between the PV system’s energy production and spot market prices. (See the spot market pricing profile in Figure 6.) The results will help address the potential of solar to offset the utility’s need to purchase energy on the spot market during volatile HDDs thereby offering value as a price hedging and risk reduction tool.

**Midwest ISO**

The Midwest Independent System Operator (Midwest ISO) is responsible for continuously balancing energy supply and demand at least cost and optimizing the efficiency of managing grid conditions. Midwest ISO was established in 2002 and administers two settlement markets, one for day ahead and another for real time energy markets. This is known as the Day 2 market and dates back to April 1, 2005, the date that real-time market operations commenced and Midwest ISO began centrally dispatching wholesale electricity and transmission service throughout most of the Midwest.

Midwest ISO tracks and reports Locational Marginal Prices by location. LMPs represent the price of one megawatt-hour of energy at a particular substation. The LMPs are provided at five-minute intervals for numerous locations throughout the Midwest ISO market footprint to provide market participants with price indices. Each LMP represents the price at a commercial pricing node. The individual LMPs are aggregated into regional hub prices. The five Midwest ISO hubs are Cinergy, First Energy, Illinois, Michigan, and Minnesota. LMP and hub prices give the market participants, both buyers and generators, current market information.

The statistical averages in Tables 7 and 8 cover the period between April 1, 2005- Oct. 31, 2008 for the Minnesota Hub LMP, the chosen proxy for spot market pricing.

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### Table 7: Statistical values for Minnesota Hub pricing by hour.

<table>
<thead>
<tr>
<th></th>
<th>Average</th>
<th>Median</th>
<th>Minimum</th>
<th>Maximum</th>
<th>Standard Deviation</th>
</tr>
</thead>
<tbody>
<tr>
<td>LMP01</td>
<td>$21.11</td>
<td>$19.76</td>
<td>-$311.24</td>
<td>$265.71</td>
<td>$30.73</td>
</tr>
<tr>
<td>LMP02</td>
<td>$19.87</td>
<td>$17.96</td>
<td>-$120.71</td>
<td>$245.40</td>
<td>$25.39</td>
</tr>
<tr>
<td>LMP03</td>
<td>$16.60</td>
<td>$16.40</td>
<td>-$238.35</td>
<td>$240.36</td>
<td>$23.82</td>
</tr>
<tr>
<td>LMP04</td>
<td>$16.04</td>
<td>$16.60</td>
<td>-$180.28</td>
<td>$235.89</td>
<td>$22.20</td>
</tr>
<tr>
<td>LMP05</td>
<td>$17.94</td>
<td>$18.05</td>
<td>-$150.46</td>
<td>$231.87</td>
<td>$20.72</td>
</tr>
<tr>
<td>LMP06</td>
<td>$23.48</td>
<td>$21.38</td>
<td>-$214.37</td>
<td>$148.25</td>
<td>$24.77</td>
</tr>
<tr>
<td>LMP07</td>
<td>$34.36</td>
<td>$27.30</td>
<td>-$245.82</td>
<td>$343.67</td>
<td>$33.07</td>
</tr>
<tr>
<td>LMP08</td>
<td>$49.68</td>
<td>$38.66</td>
<td>-$241.83</td>
<td>$402.06</td>
<td>$43.57</td>
</tr>
<tr>
<td>LMP09</td>
<td>$55.63</td>
<td>$43.91</td>
<td>-$97.07</td>
<td>$552.83</td>
<td>$49.19</td>
</tr>
<tr>
<td>LMP10</td>
<td>$60.01</td>
<td>$51.04</td>
<td>-$148.53</td>
<td>$403.33</td>
<td>$42.95</td>
</tr>
<tr>
<td>LMP11</td>
<td>$63.64</td>
<td>$54.42</td>
<td>-$106.74</td>
<td>$420.81</td>
<td>$45.13</td>
</tr>
<tr>
<td>LMP12</td>
<td>$64.91</td>
<td>$54.68</td>
<td>-$90.46</td>
<td>$457.78</td>
<td>$47.32</td>
</tr>
<tr>
<td>LMP13</td>
<td>$63.51</td>
<td>$54.17</td>
<td>-$95.95</td>
<td>$305.94</td>
<td>$41.22</td>
</tr>
<tr>
<td>LMP14</td>
<td>$62.49</td>
<td>$52.03</td>
<td>-$49.46</td>
<td>$419.66</td>
<td>$43.79</td>
</tr>
<tr>
<td>LMP15</td>
<td>$58.68</td>
<td>$44.73</td>
<td>-$62.91</td>
<td>$402.19</td>
<td>$44.71</td>
</tr>
<tr>
<td>LMP16</td>
<td>$59.85</td>
<td>$42.80</td>
<td>-$74.22</td>
<td>$373.58</td>
<td>$50.67</td>
</tr>
<tr>
<td>LMP17</td>
<td>$58.72</td>
<td>$44.69</td>
<td>-$93.28</td>
<td>$529.69</td>
<td>$47.54</td>
</tr>
<tr>
<td>LMP18</td>
<td>$59.61</td>
<td>$49.59</td>
<td>-$136.79</td>
<td>$323.61</td>
<td>$41.46</td>
</tr>
<tr>
<td>LMP19</td>
<td>$67.20</td>
<td>$55.11</td>
<td>-$75.95</td>
<td>$388.42</td>
<td>$47.49</td>
</tr>
<tr>
<td>LMP20</td>
<td>$66.44</td>
<td>$57.30</td>
<td>-$158.52</td>
<td>$466.76</td>
<td>$45.45</td>
</tr>
<tr>
<td>LMP21</td>
<td>$63.34</td>
<td>$55.53</td>
<td>-$108.19</td>
<td>$343.41</td>
<td>$40.53</td>
</tr>
<tr>
<td>LMP22</td>
<td>$48.80</td>
<td>$38.48</td>
<td>-$204.04</td>
<td>$272.07</td>
<td>$35.53</td>
</tr>
<tr>
<td>LMP23</td>
<td>$34.22</td>
<td>$28.02</td>
<td>-$307.55</td>
<td>$287.86</td>
<td>$32.17</td>
</tr>
<tr>
<td>LMP24</td>
<td>$25.35</td>
<td>$22.06</td>
<td>-$260.64</td>
<td>$329.04</td>
<td>$32.61</td>
</tr>
<tr>
<td>Overall</td>
<td>$46.31</td>
<td>$43.36</td>
<td>-$311.24</td>
<td>$552.83</td>
<td>-</td>
</tr>
</tbody>
</table>

Statistical values for Minnesota Hub LMP pricing by hour in $ per megawatt-hour. Apr 2005-Oct 2008. The highest spot market prices during this period occurred between the hours ending 0900 and 1700. The lowest prices occurred during the hours ending 0100 and 0800.

### Table 8: Statistical values for Minnesota Hub pricing, all hours.

<table>
<thead>
<tr>
<th></th>
<th>LMP ($ per MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Mean=</td>
<td>46.31</td>
</tr>
<tr>
<td>Median=</td>
<td>34.23</td>
</tr>
<tr>
<td>Maximum=</td>
<td>552.83</td>
</tr>
<tr>
<td>Minimum=</td>
<td>-311.24</td>
</tr>
</tbody>
</table>
Actual historic LMPs (both day ahead and real time) are available by node and hub from the Midwest ISO website.\textsuperscript{47} LMPs are calculated according to the following formula:

\[ \text{LMP} = \text{Energy} + \text{Congestion} + \text{Losses} \]

Where:

- LMP = Locational Marginal Price
- Energy = Marginal cost of energy
- Congestion = Cost due to congestion
- Loss = Cost of energy losses

The LMP reflects the marginal cost of bringing the next unit of an energy commodity (the one that balances supply and demand) to market. It is useful as a proxy for spot market pricing. The spot market price is what a utility pays a third party electricity generator on the open market when it requires additional resources beyond utility owned generation and resources under contract in order to meet customer electricity demand. The Minnesota Hub data is a composite of about 170 nodal prices in Minnesota and is used to set Minnesota trading prices.\textsuperscript{48}

The Midwest ISO calculates a weighted hub price for the set of buses that comprise each hub in its territory. The hub prices are the weighted average of the LMPs at the buses within the hub. The weights are pre-determined by the Midwest ISO. The price for a Hub \( j \) within Midwest ISO territory is:

\[ \text{Hub Price} \, j = \sum_{i=1}^{NH} \left( WH_i \times \text{LMP Hub}_i \right) \]

Where:

- \( NH \) is the number of buses in Hub \( j \).
- \( WH_i \) is the weighting factor for bus \( i \) in Hub \( j \).\textsuperscript{49}

The sum of the weighting factors adds up to 1.

\textsuperscript{47} See Midwest ISO LMP Contour Map. 
<http://www.midwestmarket.org/page/LMP+Contour+Map+(EOR)>

\textsuperscript{48} Schuerger, Matt. Energy Systems Consulting Services, LLC. Personal Correspondence.

I compare Minnesota Hub LMP data available from the Midwest ISO website to actual hourly solar electric production data from a stationary PV system in Saint Paul, Minnesota and examine the relationship between the two using regression analysis. The regression models selected were 1) linear, 2) semi-log, and 3) a linear seasonally-defined analysis (winter, spring, summer and fall.) The analysis was restricted to daylight hours and covers the period between April 1, 2005 and October 31, 2008, the limits of the LMP data available.

The response variable in this analysis is the hourly Science House solar energy production, SCI_PV. The explanatory variables for the regression analysis are LMP and Temperature. The explanatory variables may be incomplete as there are multiple factors that affect PV production such as humidity, snow cover, clouds, and the accumulation of dust on the panels. For simplicity, these factors are not included in the following models.

LMP is included because this is the quantity we wish to directly compare to PV production. Temperature is included as an explanatory variable because it is readily available and a good proxy for insolation. PV production is explained in part by temperatures with solar production increasing as temperatures increase. This is the case even though solar panels become less efficient at converting light to electricity with an increase in temperature—the increased insolation associated with summer more than overcomes the decrease in efficiency lost to higher ambient temperatures.

**Linear Regression Model**

A linear regression model was completed hour by hour during the three and one half year period as:

\[
SCI_{PV_i} = \beta_0 + \beta_1 (LMP_i) + \beta_2 (Temp_i)
\]

Where

- \(\beta_0\) = Intercept
- \(\beta_1\) = LMP slope
- \(\beta_2\) = Temperature slope

\(i = 0900\) through \(1800\) hours
The technical and economic assumptions are presented in Table 9.

### Table 9: Variables and assumptions used in analysis.

<table>
<thead>
<tr>
<th>Variable</th>
<th>Data Set</th>
<th>Assumption</th>
</tr>
</thead>
<tbody>
<tr>
<td>SCI_PV (response variable)</td>
<td>Science House solar energy production recorded hourly</td>
<td>The PV installation at Science House has been in good, continuous working order and is representative of other solar photovoltaic installations in Minnesota.</td>
</tr>
<tr>
<td>LMP, Locational Market Price</td>
<td>Midwest Independent System Operator’s Minnesota Hub pricing in $ per MWh</td>
<td>Midwest ISO’s historical Minnesota Hub Locational Marginal Pricing data is a good proxy for spot market pricing in Minnesota.</td>
</tr>
<tr>
<td>Temp, Temperature in degrees F</td>
<td>Temperature recorded hourly at MSP airport</td>
<td>Temperature at MSP is a close approximation of temperatures at the PV site being analyzed. PV production is explained in part by temperatures with higher temperatures correlating with higher insolation and therefore, higher PV production.</td>
</tr>
</tbody>
</table>

**Summary of results**

The results of the linear regression model are shown in Table 10. The LMP and Temperature T-scores indicate the significance of these explanatory variables for predicting Science House solar energy production. In this analysis, temperature is the strongest predictor of PV production based on the consistently high T-score values. This may suggest multicollinearity, but including temperature along with the variable LMP improves the model’s ability to accurately describe seasonal variation in the amount of solar available as compared to using LMP alone.
Table 10: Science House linear regression model results for hour by hour analysis.

<table>
<thead>
<tr>
<th>Hour End</th>
<th>$B_0$</th>
<th>T-Score</th>
<th>$B_1$ (LMP) T-Score</th>
<th>$B_2$ (Temp) T-Score</th>
<th>F Value</th>
<th>Adj R²</th>
</tr>
</thead>
<tbody>
<tr>
<td>0900</td>
<td>0.06</td>
<td>4.24 ***</td>
<td>0.00253 2.44 **</td>
<td>0.004593 20.78 ***</td>
<td>232</td>
<td>.261</td>
</tr>
<tr>
<td>1000</td>
<td>0.11</td>
<td>6.38 ***</td>
<td>0.00279 2.02 **</td>
<td>0.005047 19.87 ***</td>
<td>201</td>
<td>.234</td>
</tr>
<tr>
<td>1100</td>
<td>0.13</td>
<td>7.35 ***</td>
<td>0.00343 2.51 ***</td>
<td>0.005143 19.56 ***</td>
<td>191</td>
<td>.225</td>
</tr>
<tr>
<td>1200</td>
<td>0.14</td>
<td>8.27 ***</td>
<td>0.00150 1.20</td>
<td>0.005040 19.93 ***</td>
<td>199</td>
<td>.232</td>
</tr>
<tr>
<td>1300</td>
<td>0.17</td>
<td>8.07 ***</td>
<td>0.00030 0.22</td>
<td>0.004641 19.63 ***</td>
<td>197</td>
<td>.230</td>
</tr>
<tr>
<td>1400</td>
<td>0.072</td>
<td>5.85 ***</td>
<td>-0.00011 -0.11</td>
<td>0.004347 21.52 ***</td>
<td>251</td>
<td>.276</td>
</tr>
<tr>
<td>1500</td>
<td>-0.03</td>
<td>-0.337</td>
<td>0.00144 1.81 *</td>
<td>0.003740 24.90 ***</td>
<td>373</td>
<td>.363</td>
</tr>
<tr>
<td>1600</td>
<td>-0.04</td>
<td>-8.97 ***</td>
<td>0.00160 3.86 ***</td>
<td>0.002635 29.68 ***</td>
<td>613</td>
<td>.483</td>
</tr>
<tr>
<td>1700</td>
<td>-0.03</td>
<td>-14.94 ***</td>
<td>0.00056 2.94 **</td>
<td>0.001263 33.23 ***</td>
<td>698</td>
<td>.516</td>
</tr>
<tr>
<td>1800</td>
<td>-0.04</td>
<td>-15.11 ***</td>
<td>0.00030 3.66 ***</td>
<td>0.000449 30.91 ***</td>
<td>513</td>
<td>.439</td>
</tr>
</tbody>
</table>

***significant to 1%; **significant to 5%; * significant to 10%

For the seven hours ending 0900 through 1100 and 1500 - 1800, the relationship between PV production and LMP is both positive and significant. During these hours the model suggests there is more solar production when the LMP price is relatively high and less production when the LMP price is relatively low supporting the solar industry’s claim that solar can help mitigate the need for spot market purchases. However, during midday hours ending 1200 -1400 the relationship is insignificant.

The T-scores associated with LMP indicate that for seven of the ten hours, spot market pricing is both positively and significantly correlated with PV production during most hours. The insignificance of solar production relative to LMP price during midday three midday hours is a noteworthy outcome under this model. It means that peak solar production is not highly correlated with peak LMP prices during those hours in the Minnesota market. This is contrary to what the solar industry maintains.

The linear regression model suggests a correlation between PV energy production and spot market pricing for at least some of the hours. The F-statistic was consistently significant, which indicates that the regression model is valid and that the explanatory variables taken together are significant.
From these results, it seems likely that the use of solar PV could mitigate extreme price spikes in wholesale energy markets. However, this model assumes that the relationship between Science House PV production and the explanatory variables, LMP and Temp, are linear. In the next section I consider a non-linear relationship using the same variables.

**Semi-log Model**

The semi-log regression equation was modeled hour by hour between 0900 and 1800 during the three and one half year period as:

\[
SCI_{PV_{0900}} = \beta_0 + \beta_{1i} \ln(LMP_i) + \beta_{2i} \ln(Temp_i)
\]

Where:
- \(\beta_0\) = Intercept
- \(\beta_{1i}\) = ln (LMP) slope
- \(\beta_{2i}\) = ln (Temperature) slope
- \(i = 0900\) through 1800 hours

The response variable in this analysis is again the hourly Science House solar energy production. The explanatory variables for the regression analysis include: ln (LMP) and ln (Temp). The technical and economic assumptions remain the same as for the linear regression model.

A semi-log model was employed in recognition that an exponential trend may exist in the data set. While there are several exponential functions that could have been modeled, I chose to use a semi-log model because it allows us to examine whether as the values of LMP and temperature increase, there is exponential PV production growth potential. By taking the logarithm of the explanatory variables we can identify any exponential trend. The results are shown in Table 11.
Table 11: Science House semi-log regression model results for hour by hour analysis.

<table>
<thead>
<tr>
<th>Hour ending</th>
<th>$B_0$</th>
<th>T-Score $\ln(LMP)$</th>
<th>$B_1$</th>
<th>T-Score $\ln(LMP)$</th>
<th>$B_2$</th>
<th>T-Score $\ln(Temp)$</th>
<th>F Value</th>
<th>Adj $R^2$</th>
</tr>
</thead>
<tbody>
<tr>
<td>0900</td>
<td>-1.83</td>
<td>-3.72 ***</td>
<td>0.006</td>
<td>0.69</td>
<td>0.124</td>
<td>15.87 ***</td>
<td>1.37</td>
<td>0.178</td>
</tr>
<tr>
<td>1000</td>
<td>-2.10</td>
<td>-3.53 ***</td>
<td>0.010</td>
<td>0.99</td>
<td>0.147</td>
<td>15.67 ***</td>
<td>1.25</td>
<td>0.164</td>
</tr>
<tr>
<td>1100</td>
<td>-2.32</td>
<td>-3.82 ***</td>
<td>0.033</td>
<td>2.84 ***</td>
<td>0.140</td>
<td>14.85 ***</td>
<td>1.11</td>
<td>0.232</td>
</tr>
<tr>
<td>1200</td>
<td>-2.03</td>
<td>-3.55 ***</td>
<td>0.015</td>
<td>1.50</td>
<td>0.147</td>
<td>15.57 ***</td>
<td>1.21</td>
<td>0.226</td>
</tr>
<tr>
<td>1300</td>
<td>-2.32</td>
<td>-4.56 ***</td>
<td>0.017</td>
<td>1.87 *</td>
<td>0.142</td>
<td>15.56 ***</td>
<td>1.23</td>
<td>0.159</td>
</tr>
<tr>
<td>1400</td>
<td>-3.22</td>
<td>-7.96 ***</td>
<td>0.020</td>
<td>2.73 ***</td>
<td>0.143</td>
<td>17.52 ***</td>
<td>1.67</td>
<td>0.174</td>
</tr>
<tr>
<td>1500</td>
<td>-3.81</td>
<td>-13.16 ***</td>
<td>0.033</td>
<td>5.88 ***</td>
<td>0.120</td>
<td>19.53 ***</td>
<td>2.45</td>
<td>0.274</td>
</tr>
<tr>
<td>1600</td>
<td>-3.32</td>
<td>-20.82 ***</td>
<td>0.030</td>
<td>9.50 ***</td>
<td>0.085</td>
<td>22.68 ***</td>
<td>4.10</td>
<td>0.390</td>
</tr>
<tr>
<td>1700</td>
<td>-1.67</td>
<td>-23.12 ***</td>
<td>0.013</td>
<td>9.41 ***</td>
<td>0.041</td>
<td>25.04 ***</td>
<td>4.49</td>
<td>0.410</td>
</tr>
<tr>
<td>1800</td>
<td>-0.55</td>
<td>-16.60 ***</td>
<td>0.004</td>
<td>6.43 ***</td>
<td>0.014</td>
<td>22.50 ***</td>
<td>2.76</td>
<td>0.299</td>
</tr>
</tbody>
</table>

***Significant to 1%; **Significant to 5%; * Significant to 10%

For the hours ending 1100 - 1800, the relationship between PV production and LMP is both positive and significant. During these hours the model suggests there is more solar production when the LMP price is relatively high supporting the solar industry’s claim that solar can help mitigate the need for spot market purchases.

Summary of results

The T-scores for the variables $\ln(LMP)$ and $\ln(Temp)$ indicate the significance of these parameters as explanatory variables for defining the relationship between them and Science House solar energy production. In this analysis, temperature is again the strongest predictor of PV production based on the consistently high T-score values, but as the day progresses, $\ln(LMP)$ generally increases in significance.

The T-scores associated with $\ln(LMP)$ indicate that for six of the eight hours analyzed, spot market pricing in the Minnesota Hub is both positively and significantly correlated with PV production during most daylight hours. The positive coefficients imply that as LMP and Temp increase, PV production will increase exponentially. The significance of $\ln(LMP)$ is not randomly occurring, but a transition from positive and insignificant in the morning hours to being positive and significant by the hour ending at 1000 with T-scores
increasing hour by hour. This result seems intuitive: during the beginning of the day, there may initially be more electricity demand at a time when there is less solar power available to meet the ramped up energy needs. However, as the day progresses, the solar production better correlates with LMP and temperature, which suggests an improving correlation with the utility’s load profile. From these results, it seems plausible that the use of solar PV could mitigate extreme price spikes in wholesale energy markets. A weakness of this form of semi-log model regression is that there are missing values given that the explanatory variables, Temp and LMP, have some negative values. It also suggests unlimited PV production growth potential as temperatures and LMP prices increase, which is not physically possible.

Seasonal Linear Regression Analysis Using Intercept Dummies

Given the seasonal variability inherent in each of the variables in the analysis, it is reasonable to consider a model that will capture the seasonal relationships between the response and explanatory variables. The following analysis employs intercept dummies to account for important seasonal variation. In this model, four distinct y-intercepts are permitted, one for each season, while the slopes are fixed for the relationship between PV production and LMP and temperature. The seasonal regression model was estimated for each hour for the three and one half year period as:

\[
SCI_{PV_i} = \beta_0 + \beta_1 \text{Temp}_i + \beta_2 \text{LMP}_i + \beta_3 \text{spring}_i + \beta_4 \text{summer}_i + \beta_5 \text{fall}_i 
\]

Where:
- \(\beta_0\) = Winter intercept
- \(\beta_1\) = Temperature slope
- \(\beta_2\) = LMP slope
- \(\beta_3\) = Spring intercept
- \(\beta_4\) = Summer intercept
- \(\beta_5\) = Fall intercept

\(i = 0900 \text{ through } 1800 \text{ hours}\)
The third linear regression model, employing seasonal intercept dummies, allows for four distinct y-intercepts. Above, the upper curve fit represents a winter relationship between PV production and temperature while the lower is for summer. (The lines are for illustrative purposes and not drawn to scale.)

Figure 7 illustrates how this model differs from a simple linear regression model. The model is intended to capture nuances between seasons that the other models were unable to detect. The seasons are defined as:

- Winter: Jan 1 - Mar 31
- Spring: Apr 1 - Jun 30
- Summer: Jul 1 – Sep 30
- Fall: Oct 1 – Dec 31

The results are shown in Table 12.
Table 12: Science House regression model results for hour by hour analysis using seasonal parameters.

***significant to 1%; **significant to 5%; *significant to 10%

<table>
<thead>
<tr>
<th>Hour</th>
<th>$\beta_0$ winter intercept</th>
<th>T-Score</th>
<th>$\beta_1$ Temp</th>
<th>T-Score Temp</th>
<th>$\beta_2$ LMP (Slope)</th>
<th>T-Score</th>
<th>$\beta_3$ Spr intercept</th>
<th>T-Score Spring</th>
<th>$\beta_4$ Sum intercept</th>
<th>T-Score Sum</th>
<th>$\beta_5$ Fall intercept</th>
<th>T-Score Fall</th>
<th>F -Value</th>
<th>Adj R2</th>
</tr>
</thead>
<tbody>
<tr>
<td>0900</td>
<td>.105</td>
<td>6.65 ***</td>
<td>000243</td>
<td>9.01 ***</td>
<td>003290</td>
<td>2.39 **</td>
<td>.067</td>
<td>3.530 ***</td>
<td>.005</td>
<td>2.51 ***</td>
<td>-.053</td>
<td>-3.57 ***</td>
<td>110</td>
<td>.295</td>
</tr>
<tr>
<td>1000</td>
<td>.160</td>
<td>8.24 ***</td>
<td>000269</td>
<td>10.73 ***</td>
<td>004615</td>
<td>1.98 **</td>
<td>.004</td>
<td>0.160</td>
<td>-.012</td>
<td>-0.45</td>
<td>-.092</td>
<td>-5.08 ***</td>
<td>91</td>
<td>.257</td>
</tr>
<tr>
<td>1100</td>
<td>.187</td>
<td>9.24 ***</td>
<td>000306</td>
<td>11.77 ***</td>
<td>005240</td>
<td>2.28 **</td>
<td>-.0420</td>
<td>-1.729 *</td>
<td>-.053</td>
<td>-1.90 *</td>
<td>-.122</td>
<td>-6.32 ***</td>
<td>88</td>
<td>.251</td>
</tr>
<tr>
<td>1200</td>
<td>.202</td>
<td>10.62 ***</td>
<td>000069</td>
<td>12.57 ***</td>
<td>005306</td>
<td>0.56</td>
<td>-.0560</td>
<td>-2.409 **</td>
<td>-.072</td>
<td>-2.71 ***</td>
<td>-.143</td>
<td>-7.72 ***</td>
<td>97</td>
<td>.268</td>
</tr>
<tr>
<td>1300</td>
<td>.189</td>
<td>10.77 ***</td>
<td>000057</td>
<td>12.74 ***</td>
<td>004924</td>
<td>-0.44</td>
<td>-.048</td>
<td>-2.216 **</td>
<td>-.081</td>
<td>-3.31 ***</td>
<td>-.153</td>
<td>-8.92 ***</td>
<td>103</td>
<td>.281</td>
</tr>
<tr>
<td>1400</td>
<td>.139</td>
<td>10.11 ***</td>
<td>000090</td>
<td>13.36 ***</td>
<td>004220</td>
<td>-0.85</td>
<td>-.030</td>
<td>-1.708 *</td>
<td>-.045</td>
<td>-2.26 **</td>
<td>-.143</td>
<td>-10.25 ***</td>
<td>138</td>
<td>.344</td>
</tr>
<tr>
<td>1500</td>
<td>.056</td>
<td>5.90 ***</td>
<td>003224</td>
<td>14.45 ***</td>
<td>00094</td>
<td>1.26</td>
<td>.011</td>
<td>0.893</td>
<td>-.014</td>
<td>-0.99</td>
<td>-.113</td>
<td>-11.50 ***</td>
<td>220</td>
<td>.456</td>
</tr>
<tr>
<td>1600</td>
<td>-.002</td>
<td>-0.41</td>
<td>001889</td>
<td>15.57 ***</td>
<td>000135</td>
<td>3.68 ***</td>
<td>.041</td>
<td>6.151 ***</td>
<td>.018</td>
<td>2.41 **</td>
<td>-.063</td>
<td>-11.89 ***</td>
<td>405</td>
<td>.607</td>
</tr>
<tr>
<td>1700</td>
<td>-.016</td>
<td>-7.32 ***</td>
<td>000806</td>
<td>15.26 ***</td>
<td>000070</td>
<td>4.25 ***</td>
<td>.031</td>
<td>10.846 ***</td>
<td>.015</td>
<td>4.64 ***</td>
<td>-.019</td>
<td>-8.52 ***</td>
<td>473</td>
<td>.643</td>
</tr>
<tr>
<td>1800</td>
<td>-.011</td>
<td>-11.64 ***</td>
<td>000058</td>
<td>14.38 ***</td>
<td>000324</td>
<td>7.51 ***</td>
<td>.011</td>
<td>8.564 ***</td>
<td>.002</td>
<td>1.52</td>
<td>-.006</td>
<td>-5.93 ***</td>
<td>307</td>
<td>.539</td>
</tr>
</tbody>
</table>
Summary of Results

Based on the results of the seasonal regression model, it is appropriate to treat the seasons separately in order to capture the time series nature of the relationship between solar energy production and spot market pricing (LMP) in Minnesota. For each of the seasons, the correlation is positive as indicated by the positive slope coefficient, $B_2$. The relationship is significant in the morning, 0900-1200 and late afternoon, 1600-1800. The results of this model generally support the solar industry’s claim that utilities may realize a benefit from the use of customer-sited solar PV to offset the cost of spot market electricity purchases in the Minnesota Hub market because throughout most of the daylight hours there is a positive and significant relationship between PV production and LMP. However, a notable exception occurs during the four hours ending 1200-1500 when the relationship between PV energy production and LMP is insignificant. During these hours, the solar industry’s hypothesis does not hold.

As a next step, a seasonal linear regression model using both seasonal intercept dummies and slope dummies was completed. However, this approach did not produce different results from the seasonal linear regression model that used intercept dummies only. Only two of the new variables had slopes that were significantly different from the winter slope: the fall slope dummy for the hours ending at 1100 and at 1700. Spring and summer slopes did not differ significantly from the winter slope during any hour. Overall, hour by hour variations in the relationship between PV energy production and LMP are not further explained with the use of seasonal slope dummies so the results are not included here.

Conclusion—Does PV production correlate with spot market pricing in Minneapolis Saint Paul

The value of PV generated electricity will vary, depending on location of the system and time considerations, both seasonal and time of day. The results of this analysis are specific to the greater Twin Cities metropolitan region.
Based on the findings of all three regression models, there is generally a positive and significant relationship between the solar electricity production from PV and spot market pricing in Minneapolis Saint Paul which tends to support the solar industry’s perspective. However, important notable exceptions occur during the morning hours in the case of the semi-log model and during midday hours in the two linear regression models. During three to four hour periods out of the ten examined, the solar industry’s hypothesis fails to hold. Some possible reasons include:

- **The Minnesota Hub area’s load profile does not closely match wholesale pricing during midday hours.** The value of reducing the utility’s spot market exposure in the Minnesota Hub market by producing electricity from solar PV in Minneapolis Saint Paul may be less beneficial than expected by the solar community due to anomalies outlined in a recent briefing by the Federal Energy Regulatory Commission (FERC). The presentation by FERC highlighted the phenomena that since the Midwest ISO market opened, persistent transmission constraints in Wisconsin, the Upper Peninsula of Michigan, and Minnesota caused prices in these regions to deviate from other areas of Midwest ISO’s territory. Minnesota Hub prices are often volatile and at times move significantly above or below other Midwest ISO hub prices. Possible contributing factors cited by FERC include generator outages or derates due to maintenance, a large concentration of baseload units, higher than expected summer temperatures, and decreased imports into the Minnesota region.\(^50\) These larger transmission system anomalies may help explain why the Minnesota Hub’s LMP price does not show a consistent correlation throughout all hours of the day.\(^51\)

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\(^{50}\) Midwest Electric Market: Overview and Focal Points. Federal Energy Regulatory Commission.

\(^{51}\) Campbell, Nancy. MISO Briefing. Ed. S. Miller.
• **Load profiles and spot market pricing may vary not just with time of day and time of year, but also with time of week.** Many utilities offer time of use rates that reflect the fact that certain hours of day (10 a.m. – 9 p.m.), days of week (M-F), and seasons of year (summer) are generally more expensive to provide energy than others. For instance, it is generally well known that utilities are more vulnerable to capacity challenges and high spot market pricing during a hot summer weekday afternoon than on a weekend afternoon in the middle of winter. The models examined as part of this paper accounted for variations in the value of electricity with time of day and with seasons, but not for time of week. A more comprehensive model would treat weekends and holidays separately from weekdays. Weekend and holiday electricity loads and the associated LMPs are less responsive to high temperatures because of the reduced commercial and industrial loads during non-business hours. Taken together, weekends and holidays account for more than 100 days annually—a significant portion of the year. It is plausible that PV energy production is not well correlated with the wholesale electricity market (LMP) during weekends and holidays. If this is the case, it may be that during midday hours (1200-1500 in the seasonal linear regression model) the solar industry’s hypothesis only holds true on business days, Monday through Friday. This could be tested by treating weekdays and weekends/holidays separately with use of additional dummy variables.
A graph of PV energy production vs. LMP, the variable chosen to represent spot market price. Note that most of the time, the Minnesota Hub LMP is less than $100 per megawatt-hour, which corresponds to less than $.10 per kilowatt-hour. The vertical line at $53 per megawatt-hour represents Xcel’s net metering rate for demand metered customers in Minnesota. The line at $92 per megawatt-hour represents Xcel’s net metering rate for residential customers. The area in the circle represents the highest value PV production.

Beyond examining correlation between solar energy production and spot market pricing, it is useful to consider the relationship more generally. Figure 8 shows that of the 31,442 hours of data recorded during the 3.5 years reviewed, it is rare that Minnesota Hub LMP pricing reached $200 or greater per megawatt-hour, in fact, less than two percent of the time.\(^{52}\) A compensation price of $200 per megawatt-hour is an approximate break even point for PV investments from a customer perspective since this is the approximate cost of electricity from unsubsidized PV installations. However, since we are considering the benefits of customer owned PV systems rather than utility owned systems, one can’t assume that net metered PV systems are not beneficial for the utility since the utility has no capital investment in the PV installation. As shown in Table 2, the average net

metering price for the residential market is $.092 per kilowatt-hour. This means that generally when the Minnesota LMP price goes above $.092 per kilowatt-hour (or $92.40 per megawatt-hour), grid-tied, customer-sited PV systems in Minnesota are a good deal for the local electric utility. According to Table 6, the average Minnesota Hub LMP price is $46.31 over all hours and higher during daylight hours. In fact, under the current net metering rules, customer investment in solar PV is generally a good deal for the utility. However, it does not appear economical for the utility to pay a premium of $0.20-$0.50 per kilowatt-hour for energy from a PV system at present.

Limitations of the regression models

A weakness of this analysis is that the spot market prices as characterized by LMP reflect only fuel and operating costs. In other words, the third party generator makes offers based on fuel and maintenance costs without adding infrastructure investment into the selling price. For solar PV there is no fuel cost and very little maintenance cost. Thus, the method used here for comparing solar PV electricity production to the average cost of electricity purchased on the spot market ignores the potential savings in terms of capital investment in infrastructure, thereby undervaluing solar energy production.

Also, the regression models fail to account for social and environmental benefits of solar PV generation. Similarly, the models employed do not consider the social and environmental costs associated with conventional fuels such as coal, gas and oil—the resources that set spot market pricing.

Still, the regression models are useful in evaluating the current economics of customer owned and sited solar PV systems from a utility perspective, which was the goal of the paper. The results affirm that free market drivers alone are not adequate to encourage
widespread solar deployment. It is necessary to identify a mechanism to value the larger social and environmental benefits of solar PV and costs related to conventional energy resources in order to justify large-scale investment.

**Recommendations for utility solar policy development**

Despite the economics, many utilities have made the decision that solar PV does have a place in their portfolios. The Solar Electric Power Association’s 2008 Top Ten Utility Solar Integration Rankings report states that “a doubling or more of solar megawatts in a utility’s portfolio was not unusual [nationwide] in 2008.” More growth is expected in 2009.\(^\text{53}\) In Minnesota, Xcel Energy announced that the company will purchase solar renewable energy credits from Minnesota customers beginning in January 2010. The proposed purchase price is $2.25 per watt installed. If approved by the Office of Energy Security, Xcel will join Minnesota Power, Austin Utilities, and Great River Energy in offering incentives for customer-sited PV.

The regression models employed in this paper were intended to examine just one of the 16 commonly recognized benefits of solar. As shown in Table 3, there are various recognized benefits of solar PV and it follows that there are other valid methods for estimating the value of PV generation. Given the general agreement that there is a societal benefit to investing in solar PV, other studies are in order to better quantify some of the attributes. Given the variability in energy markets, utility specific studies should be considered for solar related policy decisions. Below are recommendations to determine the impact of expected trends and advances that could affect the value of solar PV to utilities. The recommendations expand on the purpose of this paper by investigating methods to identify the economic benefits a utility receives by purchasing electricity from grid connected, customer-sited PV. A favorable solar policy framework is key to expanding future solar markets, followed closely by favorable utility policies for the purchase of electricity from solar PV systems.

1) **Additional study is needed to measure the cost/benefit impacts of dispatchable solar energy to electric utilities.**

If distributed generation solar electricity is to be deployed widely, utilities will be challenged not only in terms of reduced revenue potential, but also by the complexity of serving a grid network with a high penetration of variable resources. Dispatchability of solar electricity would allow the utility to optimize use of solar generated electricity when it is most needed, thereby increasing its value to the utility. Given existing battery technology, in most cases energy storage is seen as too expensive to incorporate into photovoltaic systems. Therefore, most solar PV systems installed today are grid-connected and have no battery back up storage. The standard order of operation for solar electricity production is:

a. Serve the PV host’s electricity load
b. If the host site’s load is less than the solar production, the energy is directed to the distribution network.

Many PV system owners consider the grid a virtual storage medium since they are credited for any excess generation and the grid supports their energy needs even when the sun isn’t available. From a utility perspective, if a combination of storage and dispatchability of solar electricity were available to and controllable by the utility grid, it would allow improved transmission and distribution efficiency and reduce the utility’s standby generation requirements. This is one aspect of the much anticipated smart grid technology. Smart grid would allow the current antiquated power system to interface with a state of the art information system that would give real time feedback on grid conditions.\(^{54}\) The information communicated to the utility would improve reliability and efficiency issues and the consumer would receive real-time feedback on energy pricing. Storage options that are coupled with smart grid technology would allow the utility to use the PV production to:

a. Serve the PV host’s electricity load;

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\(^{54}\) Grid 2030: A National Vision for Electricity’s Second 100 Years, United States Department of Energy
b. Direct the PV energy to the distribution network; or
c. Store the PV energy for later use

thereby increasing benefits of customer owned and sited PV to the utility.

2) Cost impacts of proposed carbon cap and trade or similar program on spot market pricing.

The new administration has expressed support for implementing a carbon cap and trade system for internalizing the cost of global warming pollution. Since much of the available peaking generation relies on fossil fuels, a carbon regulation framework would have the effect of increasing spot market prices. A question that remains is to what extent would such a policy alter the economics of photovoltaic generation in Minnesota from a utility perspective? If the cost of carbon dioxide emissions is great enough, it could affect the utility’s perspective on the role of solar PV as they face increasing demand and significant capacity deficits in the near future. An underlying question is: At what cost per ton of carbon dioxide emissions will customer-sited solar PV net a positive return for the utility as a preferred resource relative to spot market purchases of electricity?\(^\text{55}\)

From Table 5, an estimation of the average cost of generating small-scale solar electricity from PV today is $150-$200 per megawatt-hour. Table 8 shows that the average price of electricity available on the spot market is $46 per megawatt-hour. In order to close the cost gap, carbon dioxide emissions would need to be assessed at between $104 and $154 per ton for the Minnesota Hub. While nowhere in the United States are carbon emissions being assessed at that rate, as the cost of solar PV declines, the gap will close. It is likely that supporting customer-sited PV will make sense for many utilities, but the timing will depend on the price of carbon dioxide emissions, climate, wholesale market conditions, and other factors unique to the utility’s service territory.

3) Additional analysis is needed to identify how solar photovoltaics can assist with utility capacity challenges that will result from increased per capita consumption of electricity that will force more reliance on spot market purchases and pricing vulnerability.

Despite federal, state and utility policies to decrease energy consumption, according to the Energy Information Administration, electricity consumption per capita continues to increase in Minnesota. The trend is likely to continue with several vehicle manufacturers announcing plans to release new plug-in hybrid electric vehicle models in the coming years. This fits in with federal and state policy goals of reducing reliance on foreign sources of fuel. Electrification of the U.S. vehicle fleet will add additional stresses to the nation’s current dated transmission and distribution infrastructure. However, transportation is one of the markets where solar PV can compete with traditional fuels. This could change the economic considerations surrounding customer-sited PV for utilities as utilities look for new ways to provide reliable power and meet increasing demand.

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