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September 30, 2013

Burl W. Haar
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101

RE: IN THE MATTER OF THE PETITION OF NORTHERN STATES POWER COMPANY FOR APPROVAL OF TARIFF MODIFICIATIONS IMPLEMENTING NET METERED FACILITY PROVISIONS, STANDBY SERVICE EXEMPTIONS AND METER AGGREGATION PURSUANT TO THE 2013 OMNIBUS ENERGY BILL
DOCKET NO. E002/M-13-642

Dear Dr. Haar,

In addition to our joint comments with Distributed Renewables Advocates, Fresh Energy would like to separately file, as background for the Commission, the recent Market Transformation Pathways for Grid-Connected Rooftop Solar PV in Minnesota, a report summarizing the market and policy analysis and findings of the Minnesota Solar Challenge.

Of particular relevance for this docket, we direct the Commission's attention to the report's 16-page chapter on Net Energy Metering and solar tariff design (beginning on p. 18.)

The Minnesota Solar Challenge program was a collaboration between the Minnesota Department of Commerce, Division of Energy Resources ("Commerce"), the Cities of Minneapolis and Saint Paul, Fresh Energy, and Xcel Energy.

The program, along with the development of this report, was sponsored by the United States Department of Energy (DOE) and the Minnesota Department of Commerce, under DOE's SunShot Initiative – a collaborative national effort to reduce the cost of solar energy to about six cents per kilowatt-hour before the end of the decade, making solar energy much more affordable and accessible. We believe the context provided by this research will provide guidance to the Commission in its decisions regarding this docket.

Sincerely,

Erin Stojan Ruccolo
Director, Electricity Markets

Cc: Service list

Market Transformation Pathways for Grid-Connected Rooftop Solar PV in Minnesota

Produced on behalf of the Minnesota Solar Challenge Program

by Fresh Energy
2013

Powered by SunShot U.S. Department of Energy

Minnesota Solar Challenge

ACKNOWLEDGEMENTS

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Xcel Energy

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The U.S. Department of Energy (DOE) SunShot Initiative is a collaborative national effort to dramatically reduce the cost of solar energy before the end of the decade. To aggressively drive innovation and make subsidy-free solar energy systems cost-competitive with other forms of energy, DOE is supporting efforts by private companies, academia, and national laboratories to reduce the cost of solar electricity to about $0.06 per kilowatt-hour. Part of DOE's larger effort to make solar energy more accessible and affordable, the SunShot Initiative will enable solar-generated power to account for roughly 14 percent of America's electricity generation by 2030.

Disclaimer:

The information in this report is current as of April 2013. Report Addendum added in June 2013.

Photos:

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Cover photo: Edina, MN (4 kW, 2008) Photographer: Karl Schwingel

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Jason Willett	Metropolitan Council Environmental Services
Dan Williams	Powerfully Green

LIST OF ABBREVIATIONS

AEU	annual energy use
CEE	Center for Energy and Environment
CEFIA	Clean Energy Finance and Investment Authority
CIC	Common Interest Community
CIP	Conservation Improvement Program
C-PACE	Commercial Property Assessed Clean Energy
DG	distributed generation
DOE	U.S. Department of Energy
DSIRE	Database of State Incentives for Renewables & Efficiency
EIA	U.S. Energy Information Administration
FERC	Federal Energy Regulatory Commission
FHFA	U.S. Federal Housing Finance Agency
FIT	feed-in tariff
HOA	homeowner association
IREC	Interstate Renewable Energy Council
IOU	investor-owned utility
kW	kilowatt
kWh	kilowatt hour
LBNL	Lawrence Berkeley National Laboratory
LEED	Leadership in Energy and Environmental Design
MADRI	Mid-Atlantic Distributed Resources Initiative
MESA	Managed Energy Services Agreements
MRETS	Midwest Renewable Energy Tracking System
MW	megawatt
MWh	megawatt hour
NARUC	National Association of Regulatory Utility Commissioners
NEG	net excess generation
NEM	net energy metering (aka net metering)
NREL	U.S. DOE National Renewable Energy Laboratory
ORNL	Oak Ridge National Laboratory
PACE	Property Assessed Clean Energy
PBI	production-based incentive
PG&E	Pacific Gas and Electric
PPA	power purchase agreement
PSC	Public Service Commission
PUC	Public Utilities Commission
PURPA	Public Utilities Regulatory Policies Act
PV	photovoltaic
QF	Qualified Facility
RDF	Renewable Development Fund
REC	renewable energy credit
RES	renewable energy standard
RMI	Rocky Mountain Institute
SES	solar energy standard
SREC	solar renewable energy credit
VOST	Value of Solar Tariff

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EXECUTIVE SUMMARY

Minnesota has an abundance of renewable energy resources, including solar energy. Historically, however, the technologies and infrastructure for harvesting Minnesota's solar energy resources were too expensive, too inefficient, or simply did not exist.

Over the last 30 years, the State of Minnesota has enacted policies and programs that have successfully decreased costs, improved efficiencies, spurred new investment, and increased the use of renewable energy resources. These efforts began when Minnesota established the nation's first net metering law in 1981, and continued with legislation mandating investments in wind energy in the 1990s and the renewable energy provisions of the 2007 Next Generation Energy Act.

These and other policy goals and program initiatives encourage the creation of a stable and growing renewable energy market through which Minnesota can realize the economic, environmental, and security benefits of energy development.

Of Minnesota's energy resources, solar energy is the largest. The National Renewable Energy Laboratory (NREL) estimates that the "technical potential" for production of electricity from Minnesota's solar resources is 150 times greater than Minnesota's current annual electric consumption. This is consistent with other national assessments of solar resources. Solar thermal systems are equally viable, but are not addressed in this report.

SOLAR POLICY DEVELOPMENT PROCESSES

The U.S. Department of Energy (DOE) has identified a number of market barriers and market failures that need to be addressed in order for an economically viable solar energy market to develop. For this reason, as part of its SunShot Initiative, DOE created several "market transformation" programs to foster development of local and regional solar energy markets.

In particular, DOE funded the Minnesota Solar Challenge program, for which this report was created. This report provides an assessment of the policy and program options for transforming Minnesota's solar photovoltaic (solar electric) energy market and ultimately creating an economically viable solar industry.

The state has also participated in other DOE-funded solar efforts, including the Minneapolis Saint Paul Solar Cities program. An important element of these DOE-funded programs is an examination of the effectiveness of Minnesota's solar energy market development policies and programs in comparison to national market transformation best practices.

Minnesota has also engaged in a separate initiative to assess policy implications of Minnesota's renewable energy and distributed generation goals. The Department of Commerce, Division of Energy Resources ("Commerce") led a series of Distributed Generation (DG) workshops and stakeholder discussions on how to better capture Minnesota's distributed energy resources, including solar energy. The DG process resulted in the assembly of valuable background information, insight into the concerns and preferences of a variety of stakeholder groups, and a foundation from which new policy and program efforts consistent with the goals of DOE could be launched.

REPORT FINDINGS

This report presents the market and policy findings of the Minnesota Solar Challenge program. The report draws on information collected from state agencies, local government units, solar industry participants, rooftop photovoltaic (PV) adopters (sometimes called customer-generators), state and national experts, the Commerce distributed generation stakeholder process, and the numerous reports and data sets referenced herein.

The number of solar installations in Minnesota lags well behind a number of other states. While the pace of solar development has dramatically increased over the last four years, as of January 2013, Minnesota has just 13 megawatts of installed solar capacity. Colorado, a state with the same population and primary electric utility, has 270 megawatts of installed solar capacity. New Jersey, with a smaller and lower-quality solar resource than Minnesota, has over 1,000 megawatts of solar capacity.

Minnesota also lags behind other states in implementing best practices regarding solar energy market transformation. In spite of strong policy goals supporting the development of renewable energy resources, Minnesota's standards and programs have not evolved with the changing markets and the development of new opportunities.

Specifically:

Solar development in Minnesota still faces market barriers and failures.

While improving, Minnesota's solar development is substantially underperforming relative to other states with similar solar resources. In particular, mid-to-large-scale solar development faces significant barriers to becoming an economically viable market.

Current policy tools inadequately address market barriers and opportunities.

While Minnesota's current net metering policy successfully addresses some market barriers for residential and small commercial installations, it excludes the most economic mid-to-large-scale solar development opportunities in the commercial, industrial, and institutional sectors. Moreover, net metering and rebates do not address all the market barriers to a viable solar energy market, as discussed in the report.

Long-term growth in distributed energy development increases utility business risk.

The rapid growth in customer-installed distributed generation in some states portends the need for transitioning electric utility business models and addressing risks in traditional rate structures. Similarly, over time, Minnesota utilities may face growing challenges related to cost recovery and investment risk.

New best practices are evolving that can mitigate risk and capture opportunity.

Minnesota has new opportunities to address market barriers and failures in the solar development market. A number of policy tools can supplement, or over time replace, net metering and rebates as market transformation tools. Policy tools exist to address market barriers. Experiences in other states, where market penetration rates are higher and solar markets more robust, can help answer questions about utility and ratepayer risks and inform the development of a new business model.

Photo: Minneapolis, MN (30 kW, 2010)

PLAN OF REPORT

This report provides a Minnesota solar market assessment covering the following topics:

1. Minnesota's solar resources and solar development potential

2. Existing Minnesota policy that affects solar market transformation efforts

3. Solar energy markets for small and large-scale installations, including the market barriers and failures that hinder development of a robust and economically viable solar energy market

4. Tools for solar market transformation, including:
    - Solar energy rates and tariffs: net metering, feed-in tariffs, and solar value rates
    - Interconnection standards and processes
    - Solar financing
    - Solar energy standards and portfolio requirements
    - Community-owned solar programs
    - Local regulation of solar development

INTRODUCTION AND BACKGROUND

FUTURE ROLE OF SOLAR ENERGY IN THE NATION'S AND MINNESOTA'S ENERGY PORTFOLIO

In recent years, rooftop and other distributed solar energy generation has become an established global market, and is rapidly becoming a significant contributor to a number of regional energy markets. Solar energy is a favored resource for many states and countries, in part because it is an abundant, domestic resource with no fuel costs and no harmful emissions.

Minnesota's solar markets and industry are not yet robust, but resource and market conditions support the notion that solar power will become an important component of Minnesota's energy portfolio.

According to the National Renewable Energy Laboratory (NREL), solar is Minnesota's single largest energy resource.[1] Market trends are now well established, costs continue to decline, and equipment efficiency continues to improve. These trends have the potential to accelerate the already growing use of solar energy by Minnesota residents and businesses, create a growing retail market in distributed solar generation, and eventually lead to solar energy making a significant contribution to Minnesota's electricity mix.

But the development of a self-sustaining solar energy market elsewhere does not guarantee that Minnesota's solar energy resources will be optimized in the near term. It also does not guarantee that the utility system and business model will efficiently adapt to the evolving nature of distributed solar photovoltaic (PV) generation. Customer-sited (and owned) solar PV generation blurs the traditional distinction between energy generators and energy consumers, creating an energy generation market that may not fit into traditional energy planning and regulation.

Stakeholders in Minnesota's energy future—utilities, business and residential consumers, energy manufacturers and vendors, and state and federal regulators—make daily choices that affect the shape of Minnesota's future energy options. Today's choices regarding generation, transmission, and distribution infrastructure will enable or limit the state's energy options for decades to come.

The growing retail solar energy market may also create new uncertainty and risk for infrastructure and resource investment, such as power and energy contracts, transmission siting, and distribution investment. By clarifying these uncertainties, establishing a clear path to accommodating solar energy investment, and setting appropriate market signals, policy makers can help lower investment risk for utilities, strengthen new distributed generation markets consistent with Minnesota policy goals, and better utilize Minnesota's clean energy resources.

The policy options described in this report are considerations for achieving the overlapping goals of the U.S. Department of Energy (DOE) Rooftop Solar Challenge and Minnesota statutory and regulatory renewable-energy goals. While these goals are framed primarily in terms of reducing solar system costs, policy makers should also keep other solar characteristics (such as quality, durability, safety, and aesthetics) and broader social consideration in mind.

The electricity system that was built in the 20th century relied on what have become known as "baseload" power plants—very large, centralized plants designed to operate nearly all the time. Usually coal, nuclear, or large hydropower plants, these baseload plants were chosen by utilities and regulators as the optimal way to provide electricity service. These power plants were not perfect, as discussed in this report, but they became the anchors of the electricity grid.

MINNESOTA SOLAR CHALLENGE PROGRAM GOALS

In March 2012, DOE awarded Minnesota a one-year grant under the Rooftop Solar Challenge program. The program (which is part of DOE's larger "SunShot Initiative"), seeks to drive dramatic reductions in the cost of solar PV market adoption and deployment.[2]

This program, named the **Minnesota Solar Challenge**, was a collaboration between the Minnesota Department of Commerce, Division of Energy Resources ("Commerce"), the Cities of Minneapolis and Saint Paul, Fresh Energy, and Xcel Energy.

A primary goal of the Minnesota Solar Challenge was to identify ways to reduce market barriers, accelerate the declining costs of solar installations, and reduce the transaction costs associated with utility-connected rooftop and distributed solar energy. The project included market-transformation efforts at the local government level, implementing best practices for integrating solar development into local planning, zoning, and permitting. At the state level, the project was charged with researching and analyzing the solar policy tools used in other states regarding their applicability to Minnesota's efforts to reduce solar costs and market barriers, leading to this report.

MINNESOTA SOLAR RESOURCES AND MARKET GROWTH

The potential for solar energy to contribute to Minnesota's energy future has improved substantially over the last few years for at least two reasons. First, there is a growing recognition that Minnesota has a large and valuable solar resource. Second, the costs of capturing this resource are declining rapidly, making customer-sited solar electricity more accessible and economically feasible from one year to the next.There are three metrics that planners keep in mind when balancing supply and demand. It must be done reliably. It must be done affordably. And increasingly, it must be done in a way that reduces impacts on human health and the environment. In this report, we will mostly focus on reliability and affordability. We will not discuss the effects on human and environmental health of using coal or nuclear power, except to note here that there are many negative effects.

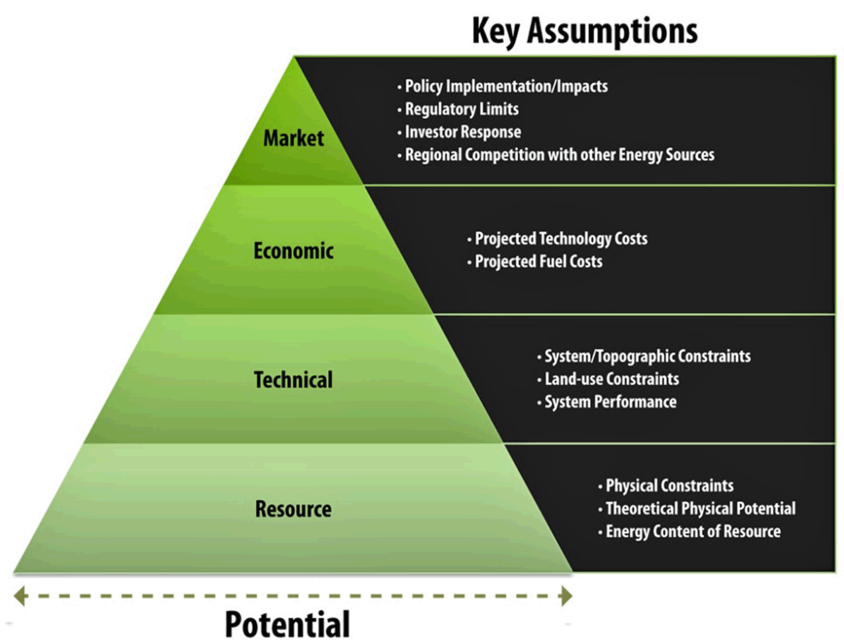
MINNESOTA'S SOLAR ENERGY RESOURCES

Traditional fossil fuel resources (coal, natural gas, and oil) are measured by estimating the size of the underground deposits, or reserves.[3] Industry and government measure the size of various reserves and track how extraction rates, market prices, and new discoveries affect the viability of various resources over time. This information informs long-term infrastructure, investment, and policy decisions, in order to maximize long-term public benefits.

In the same way, solar energy has its own set of resource measurements, which can inform long-term energy policy and energy market development.

NREL's solar PV "technical potential" is an estimate of the potential long-term market size for PV and assumes the existence of economic and policy conditions that support solar development. The NREL estimation methodology accounts for site shading, orientation, and other relevant factors.

Fig 1: Categories of renewable energy potential (NREL)[8]



NREL estimates the technical potential of solar power on Minnesota rooftops at 12,000 megawatts (nameplate capacity).[4] NREL further estimates that this capacity could produce on the order of 14,322 gigawatt-hours of daytime electricity annually.[5] For context, that would be equivalent to roughly 21 percent of total statewide electricity use in 2011.[6]

NREL also estimates a technical potential for ground mounted "utility-scale" solar PV in Minnesota: 6,530,000 megawatts of nameplate capacity, and 10,826,184 gigawatt-hours of daytime electricity per year.[7] That potential is equivalent to 150 times the state's current electricity demand, making solar PV Minnesota's largest single energy resource according to NREL's findings.

As with other types of energy, having a large total resource and technical potential does not guarantee the full development of that potential. But the large size of the solar reserve demonstrates that under favorable policy and investment decisions, solar power has the potential to become a substantial component of Minnesota's future energy portfolio.[9]

MINNESOTA'S SOLAR RESOURCE ECONOMICS

At the generation level, annual solar production is based on incident solar radiation ("insolation"), ambient temperature, and site-specific factors.

The figure to the right provides a visual summary of how *one* of these factors, average annual insolation, varies across the United States. In general, Minnesota receives less insolation than the west and southwest, but more than the population centers to the east.

NREL uses these factors to build software tools that estimate the energy production of a standard PV facility located anywhere in the United States.[10]

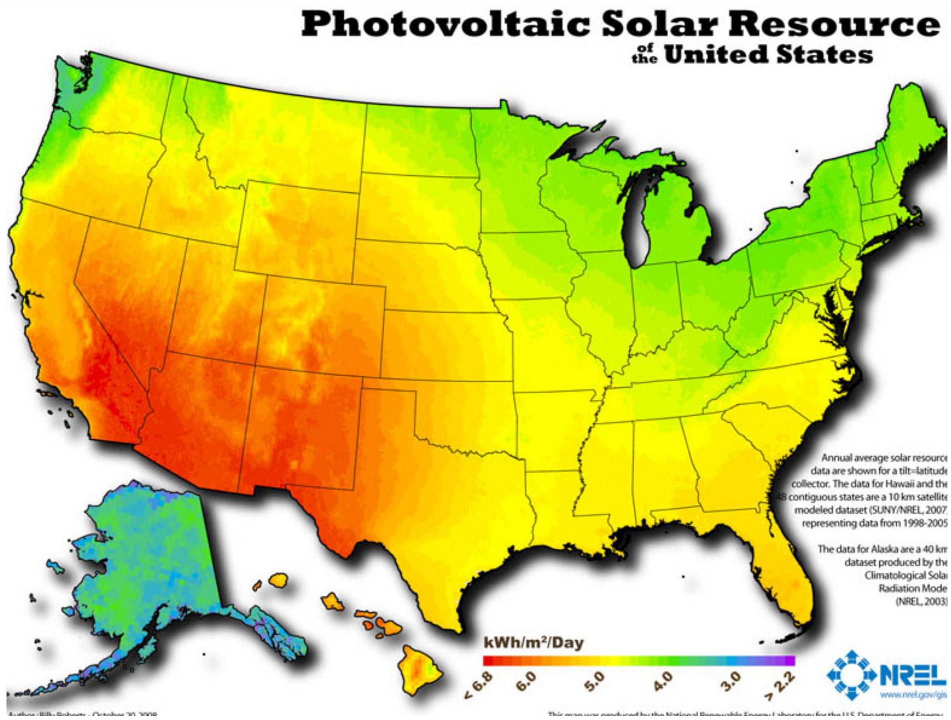
Measured in these terms, expected per-panel solar production in Minnesota is roughly equivalent to that in Florida, Georgia, Illinois, Louisiana, Pennsylvania, South Carolina, Tennessee, and Virginia.

By the same measure, Minnesota's expected panel production is superior to that in Connecticut, Indiana, Massachusetts, Michigan, Ohio, Oregon, Vermont, Washington, and Wisconsin.[11]

Table 1: Solar market size in 18 peer states (by cumulative MW) (2012)[12]

STATE	2012 CUMULATIVE (MW)	2012 ANNUAL (MW)
Massachusetts	207.3	123.2
Pennsylvania	164.3	31.3
Florida	116.9	21.9
Ohio	79.9	48.3
Oregon	56.4	20.6
Tennessee	45.0	23.0
Illinois	42.9	26.7
Connecticut	39.6	7.5
Vermont	28.0	16.3
Georgia	21.4	8.2
Wisconsin	21.1	8.2
Michigan	19.9	11.1
Washington	19.5	7.2
Louisiana	18.2	11.9
Minnesota	11.3	6.5
Virginia	10.5	5.2
South Carolina	4.6	0.5
Indiana	4.4	0.9

Fig 2: Insolation of the United States (NREL)



According to the most recent industry data, however, most of Minnesota's peer states are achieving higher levels of installed solar PV capacity, as measured by capacity of megawatts (MWs) installed (see left).

Indeed, four of these production-based peer states (Oregon, Tennessee, Louisiana, and Washington) are seeing faster growth in grid-tied solar PV capacity despite the fact that they also have lower average electricity rates than Minnesota.[13]

CURRENT MINNESOTA POLICY

EXISTING LEGISLATIVE POLICY GOALS

Minnesota has adopted a number of state policies that support the development of the state's solar energy resource, including the following:

- **Greenhouse gas emissions goals**. The Next Generation Energy Act of 2007 established a statewide goal of cutting greenhouse gas emissions at least 15 percent by 2015, at least 30 percent by 2025 and at least 80 percent by 2050 (compared to 2005 levels).[14]

- **Statewide renewable energy goals**. Renewable energy is recognized as a preferred resource for Minnesota's energy portfolio. Minnesota statute 216C.05 states:

Photo: Pine City, MN (21 kW, 2012) Photographer: Dan Williams

> It is the energy policy of the state of Minnesota that the per capita use of fossil fuel as an energy input be reduced…and [that] 25 percent of the total energy used in the state be derived from renewable energy resources by the year 2025.[15]

- **Fossil fuel reduction goals**. The Next Generation Energy Act of 2007 established a statewide goal of "[reducing] the per capita use of fossil fuel as an energy input …by 15 percent by the year 2015, through increased reliance on energy efficiency and renewable energy alternatives."[16]
- **Energy planning and conservation**. "[T]he state has a vital interest in providing for: increased efficiency in energy consumption [and] the development and use of renewable energy resources wherever possible[.]"[17]
- **Preference for renewable energy generation facilities**. "The commission shall not approve a new or refurbished nonrenewable energy facility in an integrated resource plan or a certificate of need… unless the utility has demonstrated that a renewable energy facility is not in the public interest."[18]
- **Cogeneration and small power production**. Minnesota's current "net metering" policy was established in 1981, with the explicit "intent to give the maximum possible encouragement to cogeneration and small power production consistent with protection of the ratepayers and the public."[19]

In addition, the state has a number of relevant high-level policy goals, including universal service, system reliability, energy efficiency, and ratepayer protection, that could be arguably be supported or undermined by new solar policies.

These policy preferences must be considered in light of additional policy priorities that address energy resource choices and regulation of utility systems, including goals of reasonable energy rates and support for low income households.

EXISTING POLICY AND PROGRAM TOOLS

Minnesota has a number of existing policy and program tools that address specific market transformation goals for solar development, including:

- **Reduced transaction-cost barriers**
  - *Net metering*. All Minnesota utilities are required to net meter electricity generated by customers who install wind or solar energy systems smaller than 40 kilowatts. (See June 2013 Addendum for legislative update.)
  - *Standardized interconnection*. Minnesota has adopted standard guidelines for the way that distributed generation (DG) systems (up to 10 megawatts) are interconnected to the utility
- **Incentives**
  - *Utility incentive programs.* Utilities are permitted to develop solar energy incentives through their Conservation Improvement Program (CIP) plans, which can satisfy a portion of their state-mandated conservation goals.[20]
  - *Sales tax exemption*. All components of solar PV installations are exempt from state sales tax.[21]
  - *Property tax exemption*. Minnesota excludes the value added by solar photovoltaic systems installed after January 1, 1992 from real property taxation.[22]
- **Local development support**
  - *Zoning variance hardship*. The variance provision in Minnesota Statute 463.357 provides a means for addressing zoning barriers at the local level.[23]

The law specifically identifies "inadequate access to direct sunlight for solar energy systems" as a qualifying hardship for obtaining a variance from local government zoning regulations.[24]

- *Solar easements.* Minnesota law specifically enables the purchase and recording of solar easements to protect long-term solar access to direct sunlight, if the local government actively enables the provisions.[25]
- *Local solar planning requirement.* Minnesota statutes require all local governments in the seven-county metropolitan area (over 180 local governments) to address protecting and developing access to direct sunlight for solar energy systems in their comprehensive plans.[26]

MINNEAPOLIS SAINT PAUL SOLAR AMERICA CITIES PROGRAM

The Rooftop Solar Challenge program builds upon the lessons learned through the Solar America Communities program that preceded it. In 2007 and 2008, DOE selected 25 major U.S. cities, including Minneapolis-Saint Paul, as Solar America Cities.

From 2008 to 2012, the Minneapolis Saint Paul Solar America Cities program worked toward **solar market transformation** in the Twin Cities and statewide. The program was a direct collaboration of the cities of Minneapolis and Saint Paul and the Minnesota Department of Commerce, Xcel Energy and a variety of other entities as partners, contributing to and benefitting from program efforts. The overarching goal was to develop a sustainable and replicable framework for solar deployment within the cities' jurisdictions that would lead to market transformation.

Through this effort, the cities worked to accelerate the adoption of currently available solar energy technologies through market transformation activities—identifying local and state market barriers and market failures, devising local initiatives to overcome barriers and repair failures, and implementing market transformation initiatives. These 25 federal-local partnerships enabled DOE to identify barriers to solar energy use in diverse locations and at various stages of market development, and to collaboratively develop solutions to barriers to lay the foundation for a viable solar market.

Examples of DOE's comprehensive approach to spur solar market development under Solar America Cities included advancing workforce training, developing effective outreach and marketing strategies, reviewing codes and standards, streamlining permitting practices, implementing innovative financing mechanisms and mapping tools, and working with local utilities on net metering and interconnection issues. DOE views these local infrastructure and policy issues as critical to enabling solar cost reductions and widespread market transformation.

Building on progress made and lessons learned in the 25 Solar America Cities, DOE announced an expanded effort in 2010 to share the best practices developed with local governments across the nation through a broader program called Solar America Communities. Solar America Communities promotes solar market development within cities, counties, and all other local jurisdictions nationwide.

MINNEAPOLIS SAINT PAUL SOLAR AMERICA CITIES PARTNERS

Minnesota Department of Commerce
Xcel Energy
Minnesota Renewable Energy Society
Green Institute
freEner-g (SolarFlow)
International Brotherhood of Electrical Workers
Neighborhood Energy Connection
Century College
League of Minnesota Cities
Minnesota Solar Energy Industries Association

LOCAL MEASURES

The Solar Cities partners' efforts led to a 600 percent increase in solar PV capacity over the program's four years, including a mix of residential, business, and publicly owned systems. Working with project partner District Energy St. Paul, the Solar Cities program demonstrated the viability of industrial scale solar thermal technology. These projects dramatically raised the visibility of Minnesota's solar resources and set the stage for future solar development.

The cities also examined their own development review processes for market barriers to solar development. The cities demonstrated how to make regulatory processes more efficient, employing streamlined review and permitting processes for solar development, creating safe harbors for solar development in zoning and development codes, and standardizing regulatory fees.

ENERGY INNOVATION CORRIDOR

The Solar Cities effort was instrumental in establishing solar development as a priority within the expressed goals for the Energy Innovation Corridor. The two Solar Cities and Xcel Energy committed to a goal of deploying solar along the Energy Innovation Corridor—the light-rail corridor that connects Minneapolis and Saint Paul's downtowns. These medium-size projects were developed between 2010 and 2012 and resulted in nearly 500 kilowatts of new solar capacity.

Photo: Afton, MN (12 kW, 2011) Photographer: Eric Pasi

In addition to the benefit of new distributed solar capacity, the process developed the cities' capacity to design and specify public solar infrastructure, creating a template for others. The projects also expanded the capacity and ability of local contractors to bid on larger projects. Simultaneously, the competitive and transparent nature of the bidding process encouraged cost efficiencies.

THIRD-PARTY SOLAR LEASING PILOT PROGRAM

Minneapolis and Saint Paul participated in a pilot program to test how third-party ownership can help enable residential and small commercial solar development. The solar lease program was offered by SolarFlow throughout the metropolitan area and co-funded by the Xcel Renewable Development Fund (RDF). The program allowed building owners to lease PV systems from a third-party solar developer rather than financing and owning the systems themselves.[27]

SolarFlow successfully installed 280 kilowatts of leased PV capacity under the program and demonstrated the viability of the third-party model. Current state policy and regulatory barriers have, however, limited the ability to ramp the program up to a larger scale.[28]

STATE POLICY SOLAR WORKGROUP

The Solar Cities team and project partners also collaborated to develop new state policy approaches to transforming Minnesota's solar energy market. The program created a state policy workgroup to find agreement among

STATE POLICY WORKGROUP PRINCIPLES

1. **Develop effective market transformation techniques** to set the stage for deep market penetration of solar.
2. **Take legislative action necessary to leverage incentive funding** and maximize solar deployment to learn what will be needed to broaden solar adoption.
3. **Identify mechanisms** that logically and intrinsically incorporate solar.
4. **Integrate solar** appropriately in anticipation of eventual cost parity rather than simply creating isolated solar projects.
5. **Link solar energy to energy efficiency**—adding solar to efficient buildings.
6. **Stimulate solar development** beyond residential markets into commercial and larger solar opportunities as well.
7. **Position St. Paul, Minneapolis, and the State of Minnesota** to coordinate and immediately utilize any available federal funding.
8. **Anticipate market forces and leverage existing regulatory mechanisms** to deepen solar penetration at cost parity.
9. **Collaborate with all stakeholders** to find solutions that best position our cities and state for solar energy.

stakeholders on solar policy initiatives. The workgroup was comprised of the state's largest electric utility, environmental and energy efficiency organizations, and solar advocacy groups, including stakeholders who might be opposed to legislative action.[29]

The workgroup's goal was to collectively create a state-level policy agenda that would promote the adoption of solar statewide through policies that were acceptable from each stakeholder perspective. The group held strategic planning meetings over several months leading up to the legislative session and established a consensus-based set of principles to guide the process.

This work ultimately resulted in renewed funding for statewide solar energy rebates for small PV systems, and policy changes that enable utilities to offer customer incentives and count solar toward their RES requirements.

DEVELOPING A SOLAR PV VALUATION TOOL

The Minneapolis Saint Paul Solar America Cities team commissioned a study to assess the value of solar energy from both the owner and the utility perspective. Titled "Assessing Minnesota's Solar Resource: Revenue Implications of Solar PV System Orientation and Rate Structure," the June 2011 study examined how solar energy production was valued under six different rate scenarios and alternative solar installation configurations, focusing on the production of a commercial-sized PV array on a small- to mid-sized business.[30]

The analysis also estimated solar production's value on the wholesale power market, based on the Midwest Independent System Operator West region wholesale market prices. The results illustrate a fourfold difference in potential revenue between the lowest and highest revenue generating combinations of orientation and rate structure, demonstrating the need to better optimize value of solar investment for both utility and generator.[31]

NET METERING POLICY DEVELOPMENT REPORT

A 2009 report, titled "Net Metering Policy Development in Minnesota: Overview of Trends in Nationwide Policy Development and Implications of Increasing the Eligible System Size Cap," compares Minnesota's policies to nationally recognized best practices.[32]

The report provides an overview of the current Minnesota policy in the context of these best practices and other jurisdictions' net metering policies, as well as a qualitative assessment of the impacts of raising the system size cap based on the experiences of other states. The report finds that increasing the cap may encourage solar development in the state. The report also finds that states that have increased the size limits have not developed cost/benefit studies before raising the limit.

DISTRIBUTED GENERATION STAKEHOLDER PROCESS

In 2011, Commerce initiated a stakeholder process on how to meet Minnesota's distributed generation goals (DG process).

As part of the DG process, Commerce convened four stakeholder workshops to explore distributed generation resources, opportunities, and issues. The focus of these workshops was on DG systems 10 megawatts and smaller that use renewable energy or high-efficiency combined heat and power generation.

The DG workshops covered a broad swath of complex issues and policies, including

- an overview of distributed generation policies, comparing Minnesota to other states,
- an examination of contractual issues affecting DG, including standby rates, third-party ownership, power purchase agreements, and interconnection standards,
- the role of net metering for customer-sited DG, and
- feedback on maximizing benefits from DG.[33]

While stakeholders expressed a variety of perspectives, they were largely in agreement on two important points:

1. Advances in technology and economics are contributing to increasing interest in DG in Minnesota; consumer requests for DG are growing.
2. Minnesota needs to identify and quantify the impacts (costs and values) of DG as its role in Minnesota's energy portfolio grows. Accurate measurement, however, can be difficult because costs and values of DG vary depending on utility system, type of technology, type of fuel, and length of time being considered.

In support of growing customer interest and in response to stakeholder identified issues and opportunities, Commerce staff conducted an initial distributed generation assessment.

This initial assessment included determining a baseline (historical and current) for Minnesota DG and net metering capacity, benchmarking Minnesota practices and capacity against other states' and national best practices, reviewing the current Minnesota DG interconnection process and requirements, and identifying DG impacts (costs, benefits, and reliability).[34]

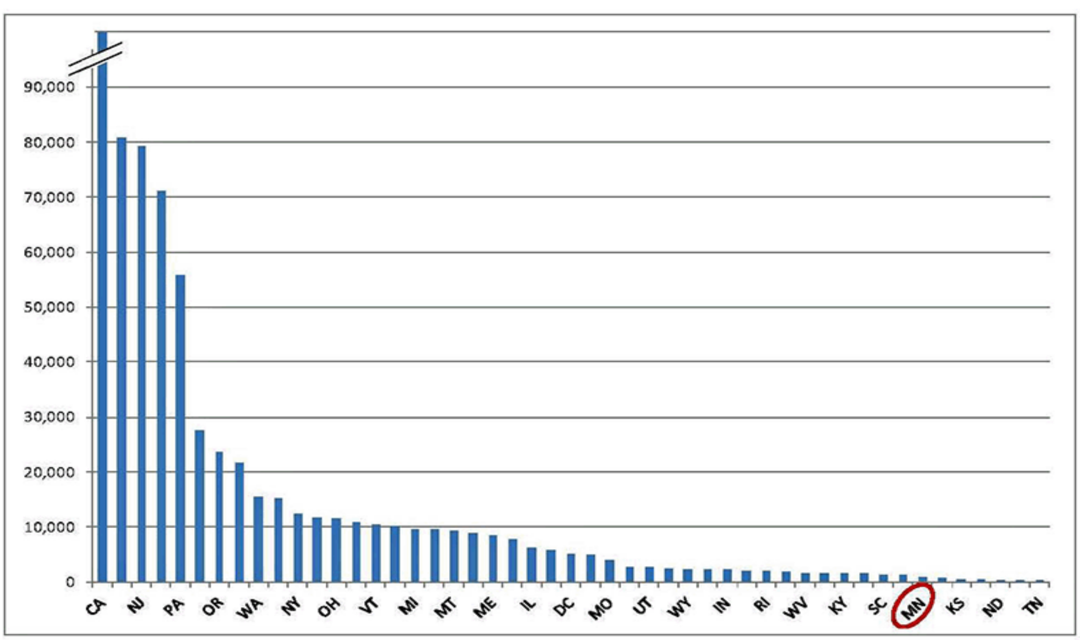
NET METERING ISSUES: 2011 DISTRIBUTED GENERATION WORKSHOPS

1. Changing kilowatt-hour credit rollover policies
2. Modifying net metering capacity limits
3. Clarifying meter aggregation policies
4. Metering requirements and costs
5. Renewable Energy Credit (REC) ownership
   Fees and charges applicable to net metered customers
6. "Grandparenting" rules for existing net metered customers

The DG stakeholder process culminated in a day-long workshop bringing stakeholders together to discuss potential next steps. The DG process will help guide recommendations to the legislature and Commerce's ongoing administrative and programmatic responsibilities.

- Minnesota faces a knowledge gap regarding the values and costs of significantly expanding DG. Studies and models are available from other parts of the country, but Minnesota must be thoughtful when translating and applying these approaches.
- In the near term, Minnesota needs to improve DG accessibility and distribution transparency in order to support customer choice, state policy goals, and to gain experience to inform evaluation of costs and benefits. Near-term options that were discussed include improved net metering, optional "value of solar" or "buy all/sell all" tariff, clarified third-party ownership rules, meter aggregation, and reviewing the impact of standby service and demand tariffs on DG resources.
- In the long term, higher penetrations of DG (much higher than current and anticipated near-term levels), will likely create a need to realign utility business models and regulatory structures to address potential cost shifts, changes in technology, and new risks and opportunities.[35]

Fig. 3: Number of net metering customers by state (2012)[36]



Sources: EIA Form 826, MN QF Reports

MINNESOTA SOLAR MARKET STATUS

The state's solar photovoltaic (PV) market may be roughly divided into four sectors:[37]

- residential
- commercial
- distribution level
- transmission level

This report focuses on the first two markets, in which projects are commonly rooftop sited.

RESIDENTIAL SOLAR MARKET

The Minnesota residential solar energy sector includes owners of single-family homes, single- and multi-family rental housing, condominiums, and low income housing.[38] Properties with solar resources are located in established urban areas with high housing density, old and new suburban areas, communities in transition from rural to urban, and low-density large-lot rural developments. Higher population areas face challenges in capturing solar resources due to density and established urban forests, while other properties within the market are arranged in common interest communities, or CICs, which can impose certain restrictions on homeowners' abilities to install rooftop solar PV.

MINNESOTA'S RESIDENTIAL SOLAR RESOURCE

Minnesota has over 2.3 million housing units. Of these, 1.58 million (67.5 percent) are detached single-family homes. As of 2012, approximately 505,000 units (21.6 percent) are in multi-family residential buildings with a common roof. The remainder are single-family attached homes with a common roof (roughly 169,000 units, or 7.2 percent) and mobile homes (roughly 86,000 units, or 3.7 percent).[39]

Among occupied housing units, roughly three in four are owner-occupied—with the remaining quarter of the market being rental.[40] In Minnesota, an estimated 22 percent of all residential rooftop space is optimal for solar power generation (accounting for tree shading and roof lines).[41] Minnesota's residential sector thus accounts for a significant portion of the state's estimated rooftop solar potential.[42]

RESIDENTIAL MARKET DRIVERS

Market drivers are the factors that transform potential buyers into actual buyers, causing existing markets to expand or new markets to develop. Market drivers in the

residential solar energy market are what drive current consumer demand and what would cause demand to increase. Why do customers become interested in "going solar" in the first place?

- People like solar. According to a January 2013 poll, **87 percent** of Minnesotans support increasing the use of solar to meet the state's future electricity needs.[43]
- Some homeowners may view rooftop solar adoption as a form of **home improvement.**[44] The drivers for home improvement in general (pride of home, perceived marketability) may also be driving interest in residential solar. Solar is also considered an environmentally preferable choice by some homeowners.
- Rooftop solar PV also tends to benefit **local economic activity**, including Minnesota-based participants in the solar supply chain. As of January 2013, over 30 Minnesota companies manufacture components and parts used in solar PV and thermal systems, including 3M, H.B. Fuller Company, Silent Power, Silicon Energy, tenKsolar, and Solar Skies.[45]
- Solar has self-sufficiency and **resiliency** value. In the wake of recent extreme storms, some homeowners may be attracted to the potential for rooftop solar to provide power during an extended blackout (for example, by installing a battery storage system).
- In addition to reducing greenhouse gas emissions, rooftop solar PV also tends to benefit **regional air quality**, especially if paired with an electric vehicle.[46]

Although solar energy sometimes has a tangible economic benefit (reducing utility bills), short "simple-payback" periods are currently unusual in states like Minnesota, where electric rates are relatively low.

Meanwhile, the nationwide solar industry is growing fast, with year-over-year cost reductions in solar equipment and installation costs.[47]

RESIDENTIAL MARKET BARRIERS AND MARKET FAILURES

Market barriers are generally described in economic literature as disincentives to the use or adoption of a good.[48] The large upfront capital cost of solar energy systems, for instance, is frequently cited as a market barrier—many households cannot invest in solar energy even if it makes economic sense because they lack the up-front capital.

Market failures are a distinct group of obstacles to economically efficient actions that are generally defined as a flaw in the way that the market is operating.[49] When market barriers or failures for a particular good or service exists, investment is generally directed away from markets and submarkets which have significant market barriers. Market barriers are typically not intentional, but may arise when technology or private-sector innovation create new opportunities.

Market barriers and failures are acknowledged reasons for intervention into markets, in order to ensure that investments and choices best reflect societal economic efficiency.[50]

In the case of solar PV, market barriers and failures can exist at the customer, installer/developer, or state market level. Examples of Minnesota-specific residential market barriers and failures are noted below.

Customer-level market barriers:

- Potential residential solar adopters face **high initial costs**, limiting the market to homeowners with sufficient cash or other forms of capital. This barrier is partially due to the limited availability of long-term financing and/or solar leasing options.
- Due to ownership issues, residents in multi-family buildings typically do not have the ability to use or invest in onsite solar.
- Homeowners and solar installers sometimes face challenges in navigating local government regulations regarding permitting and development, which vary across the state and are often unclear.
- Homeowners in "common interest communities" face non-standardized **design-review processes** that can add to project risk, uncertainty, and cost.
- Finally, many of today's residential homes are not "**solar ready.**" They were designed and constructed without giving specific consideration to future owners who might want to put solar panels on the roof (leading to shading issues, higher retrofitting costs, or other property-specific constraints).[51]

Installer-level market barriers:

- Relatively high **customer acquisition costs**—at least in part due to high customer learning curves, rebate-driven market seasonality, and overall market friction costs.
- The relatively small scale of Minnesota's solar market may restrict the cost-reducing economies of scale available in larger markets.
- Institutional or regulatory barriers prevent use of some market-driven tools. For example, current policy effectively prevents Minnesota solar leasing businesses from contracting with more than 24 customers.[52]

Industry-level market barriers:

- The value of solar-generated electricity on the utility system is arguably different than either retail rate or other averaged cost measures such as the utility's "avoided cost." Economically efficient levels of solar development would be more likely if the rate paid to solar generators reflected the value of solar generation.
- Interconnection processes and costs, and the value of solar generation, are perceived to be highly uncertain for nonresidential installations.[53] While this may not directly affect the residential market, it has an indirect affect by reducing overall investment and activity. Large-scale solar investment tends to flow into markets where uncertainty is minimized.

COMMONLY USED TOOLS FOR RESIDENTIAL MARKET DEVELOPMENT

Minnesota does have some tools already in place that help overcome barriers to solar investment.

Minnesota's net metering policy serves to reduce barriers in the residential solar market. By providing an easy-to-understand standard contract, net metering creates financial and regulatory predictability and reduces complexity and transaction costs.

Other possible tools for addressing market barriers and failures include:

- ***Third-party residential leasing.*** Addresses the high initial cost barrier, lack of long-term financing options, and the tenure mismatch associated with uncertain ownership duration.

- ***Community-owned solar.*** Increases access to solar resources, reduces complexity for customer-generators, and allows for optimal siting and project-level economies of scale.

- ***Standardized solar tariffs.*** Addresses the differences between the value of solar on the utility system and the retail electric rate, allows for an improved price signal for solar development, and may improve certainty regarding project economics.

- ***Standardized local regulations.*** Provides guidance for common interest communities or local government design review and land use standards.

- ***State and utility solar incentives.*** Addresses the high initial cost barrier and may provide the near-term demand support needed to drive market investment and industry cost-reducing economies of scale. There are multiple types of solar incentives:

  - **Solar rebates** provide customers with project capital at or about the time of system purchase through an upfront payment.

  - **Performance-based incentives** (or PBIs) are paid over time based on actual energy production thus incentivizing optimal siting and production.

  - **Solar renewable energy credits** (SRECs) are sometimes used as an explicit price support for solar generators in states that have adopted a solar energy standard.

CASE STUDY: Xcel Colorado performance-based solar standard

In June 2012 the Public Service Company of Colorado (d/b/a Xcel Energy) launched a new phase of Solar*Rewards, a regulator-approved production-based incentive (PBI). Participating customer-generators see the PBI value on their monthly utility bill, in combination with the cost savings provided through net metering.[60]

The utility has a program goal of supporting 30 megawatts of new solar PV capacity in both 2012 and 2013.[61]

The program is available to residential, commercial, nonprofit and installer/contractor sectors, with the rate of incentive tailored to the scale of the solar facility. Small customer-owned systems (under 10 kilowatts) receive 15 cents/kilowatt-hour for the first ten years of production, while larger systems (10.1 kilowatts and 500 kilowatts) receive 9 cents/kilowatt-hour for the first 20 years of production. The incentive rate for systems larger than 500 kilowatts is established by a competitive bidding process.

To qualify, a project must be sized at less than 120 percent of the associated building's average annual energy use. The PBI is directed to the owner of the solar PV system. For customers who host a third-party owned system (i.e., under a lease or power purchase agreement), the PBI flows to the third-party owner.

As of January 2013, Minnesota has a handful of utility solar rebate programs (see table), but no performance-based incentives.

Table 2: Solar PV incentive programs in Minnesota (2013)[54]

UTILITY	REBATE LEVEL	QUALIFICATIONS
Brainerd Public Utilities	$2.00 per watt	Up to $4,000[55]
Moorhead Public Service Utility	$1.50 per watt	Up to 2013 program budget of $30,000 (essentially 20 kilowatts)[56]
New Ulm Public Utilities	$1.00 per watt	Up to 2 kilowatts for residential, 5 kilowatts for commercial, and 10 kilowatts for industrial sited systems[57]
Triad (Rochester, Owatonna, Austin)	$1.00 per watt	Up to 10 kilowatts system[58] Limited program funding available
Xcel Energy Solar Rewards	$1.50 per watt	Up to 40 kilowatts system[59] $5,000,000 in annual funding available

COMMERCIAL AND INDUSTRIAL SOLAR MARKET

The commercial and industrial solar market includes a variety of customer categories, including small and large businesses, private and public entities, and urban and rural operations. The solar resource for this market exists on a variety of buildings and land areas: commercial flat roof buildings, industrial roof space, agricultural, commercial and industrial land, and property of non-taxable entities such as municipalities, hospitals, schools and higher education.

MINNESOTA'S COMMERCIAL SOLAR RESOURCE

The U.S. National Renewable Energy Laboratory estimates that 65 percent of commercial and industrial roof space is available for solar PV systems in Minnesota (based on solar access and roof orientation).[62]

Overall, commercial properties account for roughly 54.6 percent of Minnesota's rooftop technical solar potential.[63] That works out to over 6,500 megawatts of solar nameplate capacity and over 7,800 gigawatt hours a year.[64]

MARKET DRIVERS

Commercial, institutional, industrial, and agricultural businesses choose to invest in solar for a variety of reasons. While some of these market drivers are similar to those in the residential market, others are significantly different.

- Solar PV helps meet **corporate sustainability** or **green building goals**. Many businesses are adopting sustainability targets, climate action plans, and seeking green building certifications.
- Solar can be a **hedge** against rising utility rates and fuel costs.[65] While natural gas prices have historically been more volatile than coal prices, the cost of coal recently doubled over the course of eight years.[66] Long-term solar power purchase agreements can deliver fixed energy costs.
- Solar has a positive image. Some businesses see market benefits by investing in their solar resources. Solar development contributes to **green marketing efforts** that distinguishes them among potential customers.

Nationally, cash flow (in the form of lower utility bills) also appears to be a substantial driver of commercial solar PV adoption, and the commercial solar market is experiencing ongoing reductions in the installed costs of rooftop solar PV.[67]

In Minnesota, however, cash flow currently appears to be a lower level driver of commercial adoption. This may be due, in part, to the relatively low cost of energy provided by Minnesota utilities, and to uncertainty regarding level of cost savings that can be effectively captured by demand-metered customers (discussed below).[68]

COMMERCIAL MARKET BARRIERS AND MARKET FAILURES

Market barriers and failures have the same effect and economic description for commercial markets as for residential markets (described in detail in the residential market section). The large upfront capital costs of solar PV systems are a market barrier for both the commercial and residential sector. Without capital availability businesses cannot invest in solar PV even if it makes long-term economic sense.

Market failures also affect commercial and industrial businesses' ability or incentive to develop their solar resources. Market failures in the business sector can result from the structure of commercial real estate or business practices, or from regulatory practices that limit optimization of resources and economies of scale.

Examples of commercial and industrial market barriers and failures are noted below.

- ***Capital intensiveness.*** Solar installations are capital intensive, and having access to long-term financing is critical for businesses to develop their solar resource. Some states have large-scale solar developers who will provide access to capital, but for a variety of reasons (regulatory and economic) these financing options are not readily available in Minnesota.
- ***Cost savings uncertainty—demand charges.*** Most commercial and industrial businesses pay separate energy and demand charges on their electric bill. But it is currently difficult to predict what impact, if any, a net-metered solar energy system will have on a customer-generator's demand charges.
- ***Cost savings uncertainty—standby charges.*** Onsite solar generation systems larger than 60 kilowatts are sometimes subject to "standby" charges (discussed below). The effect of such charges on a commercial

customer's utility bill can be highly unpredictable, making it more difficult to develop project pro formas for onsite solar systems larger than 60 kilowatts.

- ***Market unfamiliarity.*** Minnesota currently has relatively few commercial-scale and very few industrial-scale solar installations. Commercial and industrial businesses may perceive a high level of project complexity, given the specialized nature of the technology, project financing, and lack of examples of similar businesses developing their solar resources.

- ***Interconnection uncertainty.*** Utility interconnection requirements, timelines, and purchase rates for net excess generation are relatively more variable and uncertain for PV systems that are not eligible for net metering (i.e., because they are 40 kilowatts or larger). Moreover, some interconnection requirements vary among utilities, creating additional complexity.

- ***Mismatch of planning horizons.*** Solar installations are infrastructural—the functioning lifespan of a rooftop solar system is 30 years or longer.[69] Businesses are typically averse to making such infrastructural investments. Commercial real estate transactions, for instance, are frequently made using limited liability subsidiaries to protect the parent company from long-term risk. Few such tools are currently available in Minnesota for solar development.

- ***Split Incentives.*** Many commercial lease holders pay the electric bills, but do not have ownership of the solar resource and are not allowed to make building improvements such as solar PV. Meanwhile, it may be difficult for a commercial renter to justly installing solar PV if it cannot directly capture the utility bill savings.

Existing regulatory standards may also exacerbate market barriers for solar development by some commercial businesses.

- ***Economies of scale.*** The uncertainties noted for solar installations sized 40 kilowatts or larger limit some commercial customers from capturing project-level economies of scale that could increase project viability.[70] Rules that tend to reduce or limit the size of a rooftop solar array may also tend to exclude the projects that would be most economically attractive from both a customer and developer perspective. (See June 2013 Addendum for legislative update.)

- ***Inability to access tax incentives.*** Tax-exempt entities (such as religious congregations, local governments, hospitals, schools, colleges, and universities) face special barriers around accessing tax-based solar incentives—such as the 30 percent federal Investment Tax Credit or the tax benefits of depreciation. One common solution, the use of a third-party owner who can capture and pass along these tax benefits, is limited by current state policy.

- ***Mismatch of energy systems (large systems).*** Campuses, large industrial operations, and businesses with multiple facilities on separate but adjacent lots (including some agricultural operations) may have both a large energy load and a large solar resource. The load and the resource may not, however, be located in the same place. Meter aggregation, a utility practice not currently enabled in Minnesota, allows a single solar PV system to offset multiple loads. (See June 2013 Addendum for legislative update.)

Photo: Maple Grove, MN (72 kW, 2009) Photographer: Ralph Jacobson

COMMONLY USED TOOLS FOR COMMERCIAL MARKET DEVELOPMENT

As with residential market barriers, Minnesota has some tools already in place to reduce barriers to solar development.

State- and utility-funded solar rebate programs and Minnesota's sales tax exemption, for instance, have helped address upfront capital barriers. Minnesota's net energy metering (NEM) policy helps reduce regulatory and transaction costs for small commercial solar installations (up to 40 kilowatts), by creating a simple, predictable, statewide standard for utility interconnection and value of solar generation in excess of instantaneous onsite use. (See June 2013 Addendum for legislative update.)

Other possible tools for addressing market barriers and failures include the following:

- ***Commercial and industrial net metering.*** Addresses market barriers by reducing uncertainty regarding utility interconnection, standby charges, demand charges, and utility purchase price, helping to enable project-level economies of scale and solar cost reductions. (See June 2013 Addendum for legislative update.)
- ***Solar energy tariff.*** Addresses market barriers regarding solar valuation and reduces uncertainty regarding utility purchase price, standby charges, and demand charges. (See June 2013 Addendum for legislative update.)
- ***Standardized interconnection processes.*** Incorporates national best practices can reduce costs and uncertainty, and provide solar developers with more clear and predictable requirements and timelines.[71]
- ***Commercial property assessed clean energy (C-PACE) financing.*** Addresses market barriers such as high initial cost, planning horizon mismatch, and uncertain duration of ownership.
- ***Third-party ownership and financing.*** Addresses high initial costs, limited availability of long-term financing, the inability of non-taxable entities to capture solar-related tax benefits, and the split incentives associated with property ownership and lessees.
- ***State-level solar bonding***. Addresses market barriers associated with high initial costs and other challenges related to the financing and development of public-sector projects.

These tools are discussed in more detail in the following sections.

TOOLS FOR SOLAR DEPLOYMENT

SOLAR ENERGY RATES AND TARIFFS

POLICY PURPOSE

The policy purpose of creating a rate or tariff for solar energy (or any other distributed generation) is to encourage buyers and sellers to make economic choices that are consistent with policy goals.[72] Solar energy rates define the value of customer-owned generation both for the utility and for the owner of the generation.

Photo: St. Paul, MN (20 kW, 2010) Photographer: Ray Colby

A successful solar rate allows customers to make informed economic choices and to predict the costs and benefits of installing self-generation capacity. It also allows utilities to be able to predict and plan for the fiscal and system impacts of customer choices regarding self-generation.[73]

As noted above, financial predictability, regulatory transparency, and prices that reflect long-run costs are important elements to creating a self-sustaining solar energy market. Absent these elements, market failures exist for both residential and commercial/industrial solar investment, contributing to underinvestment in solar development.[74]

Conditions that allow rate or tariff tools to help meet Minnesota's statutory goal of giving "maximum possible encouragement…consistent with protection of ratepayers" to distributed generation include:[75]

1. regulatory structures that allow customers to self-generate,
2. access to energy markets for distributed energy that customer-generators do not use onsite,
3. predictable prices for generated energy and costs of self-generation, to allow self-generation markets to form, and
4. energy prices for self-generation that are reasonably reflective of long-run marginal costs so as to send an appropriate price signal for investment in distributed generation.[76]

As noted in the Minnesota Solar Market Status section (above), some of these conditions currently exist in Minnesota while others do not, or are uncertain. (See June 2013 Addendum for legislative update.) Existing federal and Minnesota rate or tariff policies that help set preconditions for a self-sustaining solar energy market are described below.

EXISTING POLICY

Rate and tariff tools that address barriers to markets in distributed generation were enacted in the late 1970s (federal) and the early 1980s (Minnesota).

At the federal level, Congress enacted the Public Utilities Regulatory Policies Act (PURPA), which created new rules for wholesale power markets. At the state level, Minnesota adopted net-energy metering (or simply "net metering"), which created new rules for retail power markets. These twin policy decisions have succeeded in transforming elements of the market for distributed solar generation, as described below.

At the same time, there have been substantial changes in distributed generation technologies and opportunities, resource planning procedures, and wholesale power markets over the last 30 years. These historic policies may no longer be sufficient to achieve additional market transformation.

Further, questions have been raised about unintended consequences that might be counterproductive to both the economic efficiency of rate structures and Minnesota's renewable energy policy goals.

a) Public Utilities Regulatory Policies Act (PURPA)

PURPA was enacted in 1978 in response to the oil price shocks of the 1970s. (Unlike today, a large fraction of the nation's electricity generation in the 1970s was fueled by oil.)[77] The purpose was to encourage alternative energy development and to diversify the electric power industry.

PURPA removed restrictions on who could build and own generating facilities, creating a new class of electricity producers known as "independent power producers" (or "merchant generators"). PURPA also required electric utilities to buy wholesale power from "qualified facilities" (QFs) that meet PURPA requirements and are willing to sell at the utility's "avoided cost" rate.

A utility's avoided cost is an average estimate of costs the utility avoids by purchasing wholesale power from a QF, rather than generating the same electricity itself.[78] Avoided cost is based on Federal Energy Regulatory Commission (FERC) rules, but FERC allows a wide variety of methods and cost considerations that are to be determined at the state level.

b) Net energy metering

Minnesota first implemented its net metering policy in 1981, making it one of the first states to adopt net energy metering (NEM). As set forth in statute, the intent of Minnesota's net metering policy is:

> "…to give the maximum possible encouragement to cogeneration and small power production consistent with protection of the ratepayers and the public."[79]

NEM is a state-level policy that creates consistent regulatory standards and predictable financial parameters for self-generation at the retail level. NEM permits a utility customer to invest in distributed electricity generation onsite to offset the customer's load and deliver any excess electricity to the utility, in exchange for an equal amount of electricity from the utility at other times (i.e., when onsite generation isn't available).[80]

Under NEM, the customer's utility meter effectively runs forward (when drawing electricity from the distribution grid) and backward (when sending electricity onto the grid). The utility then bills the customer for any net energy used or credits the customer for any net energy generated.[81]

Under Minnesota law, net metering is available to all qualifying facilities with grid-connected distributed generation systems (including rooftop solar PV systems) that have a capacity less than 40 kilowatts.[82] All Minnesota electric utilities and all customer-generators must follow the same set of rules and responsibilities.[83] (See June 2013 Addendum for legislative update.) The net metering contract establishes a predictable ongoing relationship between utilities and customer-generators who install onsite solar PV or other distributed generation (DG) technology.

Since Minnesota enacted its net metering law, over 40 other states have implemented some form of net metering policy. The form of these policies varies from state to state, particularly in regard to the size of qualifying generation systems and the aggregate amount of NEM capacity allowed.[84]

c) Relationship of federal and state policy

PURPA set the stage for distributed generation markets by clearly establishing a right for energy users to self-generate and a right for self-generators to access the energy markets—two of the conditions for creating self-sustaining distributed generation markets described above. FERC administers the provisions of PURPA and enacts the administrative rules under which it is carried out.

However, FERC's responsibility is to regulate interstate electric markets, reliability, and wholesale rates.[85] Intrastate electric markets and retail rates are managed by each state's regulatory authority (the Public Utilities Commission in Minnesota). FERC rules provide a context within which states implement their own policy and priorities in regard to retail rates and power transactions, provided the basic provisions of federal law are not violated.[86] As a result of widespread state initiatives to encourage renewable energy and distributed generation, the relevance of avoided cost and PURPA as tools for DG market transformation have diminished over time.[87]

Thus, while PURPA sets the foundation, the ratemaking tools for Minnesota solar market transformation efforts are rooted in Minnesota's net metering standards and the potential alternatives or modifications to those standards.

d) Successes of existing net metering policy

Minnesota's net metering standard has successfully created a predictable, consistent, and transparent solar rate for many solar installations—overcoming adoption barriers related to project cost and complexity. The standard effectively created a uniform statewide contract for customer-sited installations under a certain size.[89] By setting the "purchase" rate for excess generation, individual customers do not need to negotiate contract terms with their utility. Using the retail rate as the purchase rate, customers are given a rate that is perceived to be fair. For example, if the value of electricity at their home is 10 cents per kilowatt-hour, customers understand the logic of both buying and selling electricity at that rate. Moreover, the use of the retail rate emphasizes the intent of net metering to act as a substitute for onsite storage. Self-generators effectively store excess generation on the grid until they need it onsite.

Photo: Winona, MN (8.5 kW, 2010)

The net metering standard also includes standard rules for interconnection. By creating a single standard for utility interconnection, the net metering standard provides increased predictability for contractors and system owners, while reducing associated transaction costs.

For the residential solar energy market, Minnesota's current net energy metering policy helps reduce some market barriers to solar development. As the market for solar development has expanded, market data shows that residential solar PV accounts for approximately 70 percent of the number of reported NEM solar installations in Minnesota.[90] Although residential installations account for most solar installations, they make up a relatively smaller portion of Minnesota's total installed solar capacity; commercial installations are a larger solar opportunity from a capacity perspective.

CONCERNS WITH EXISTING POLICY

Minnesota's existing solar rate policy, based in the state's net metering standards, has been criticized on the following two fronts:

1. *Failure to fully address market barriers*. The standards fail to address a number of market barriers to meaningful solar development in Minnesota resulting in slow market development, higher costs for solar development, and missed investment opportunities.

2. *Creating potential cross-subsidization*. The standards may include inappropriate incentives, create unintended cross-subsidization issues, or undervalue benefits to the grid, which will increasingly come into play as the solar market (and other distributed generation) grows.

Minnesota's net metering standards, while successfully addressing some of the market barriers for the residential solar market, have not resulted in solar market growth commensurate with solar development seen in other states. Minnesota's solar market growth is substantially lower than in peer states (as discussed in the Introduction and Background section, above).

A significant limitation (relative to market transformation goals) of Minnesota's existing policy is the 40-kilowatt system cap, as the policy ignores larger and more cost-effective solar development opportunities. (See June 2013 Addendum for legislative update.)

During the Department of Commerce's DG process, utilities and other stakeholders raised concerns regarding the potential for hidden cross-subsidies within the structure of net metering and the overall rate structure. These stakeholders asserted that the means by which the DG market benefits from net metering in turn creates inequities in the rest of the utility rate system or incentivizes behavior that runs counter to other Minnesota policy goals. Related concerns include

- the potential for cross-subsidies between net metering participants and nonparticipants,
- net metering impacts and the recovery of fixed costs through rates, and
- customer investment in DG and recognizing the value of the resource generated.

DETAILED DISCUSSION OF NET METERING CONCERNS AND MARKET-TRANSFORMATION ISSUES

a) System capacity limit

The primary solar rate or tariff policy question affecting Minnesota's market transformation efforts is whether and how to address distributed solar installations with a capacity greater than 40 kilowatts. The standard contract elements of NEM policy are statutorily limited to systems less than 40 kilowatts.[91] (See June 2013 Addendum for legislative update.) The market benefits of NEM—providing transactional and financial predictability, transparency, and simplicity—are limited to residential and very small farm and commercial systems.

A 40-kilowatt rooftop solar PV system can be sited on approximately 5,000 square feet of commercial flat-roof space.[92] Commercial and industrial customers with a large roof and large energy use face market barriers to satisfying their energy needs with onsite distributed generation. Financial, interconnection, and operational uncertainty for solar development is substantially greater in the absence of net metering.

A December 2009 technical report by the National Renewable Energy Laboratory concluded that Minnesota's 40-kilowatt net metering threshold was a significant barrier to increasing Minnesota's statewide solar capacity.[93] Similarly, the Solar America Board for Codes and Standards noted that NEM capacity limits generally "hinder the development of renewable energy markets" because a cap on distributed generation (DG) system sizes discourages development of economic systems that are larger than the cap.[94]

From a market transformation perspective, allowing for larger rooftop solar PV systems helps drive down average installed costs (measured in dollars per watt of nameplate capacity) because there are significant economies of scale at the project level.[95]

The 40-kilowatt cap has clearly affected decision-making on solar development projects; most of the nonresidential systems in Minnesota are at or just below 40 kilowatts. For example, when Bloomington-based Quality Bicycle Products added a 100,000-square foot building addition in 2007, it worked to include a 40-kilowatt solar system using Made in Minnesota (MIM) solar panels and equipment.[96] The customer-generator had the roof space and desire to install a much larger system, but settled for a 40-kilowatt system due to the net metering cap.[97]

b) Aggregate capacity limit

A net metering aggregate capacity limit, also known as an "aggregate enrollment cap," is a policy element that limits the amount of NEM that can be connected to a given utility. Minnesota does not have an aggregate capacity limit. (See June 2013 Addendum for legislative update.)

The aggregate capacity-limit policy element has been adopted by at least 12 states (see Table 3 under Alternative Approaches). Most states with aggregate limits tie the limit to a percentage of utility peak load. This net energy metering limit typically applies to each individual utility rather than to the entire state.[98]

The policy purpose of an aggregate capacity limit is to limit unforeseen risks of adding NEM solar PV onto a given utility's distribution system. Solar PV is a relatively new generation source with novel production characteristics—it may take time and experience to determine the amount of distributed solar PV that can be incorporated into legacy utility infrastructure and/or to modify utility infrastructure to accommodate a high level of distributed PV generation.

Minnesota has not adopted a NEM aggregate capacity limit. In practice, the utility interconnection process typically serves to prevent NEM interconnections that would impose significant reliability risk on the utility distribution system.

On the question of whether aggregate capacity limits also limit solar market growth, the signals are mixed. The model net-metering rules published by the Interstate Renewable Energy Council (IREC) criticize NEM aggregate caps as an "arbitrarily and unnecessarily limit" on private investment in renewable energy generation.[99] On the other hand, California has had an NEM capacity cap since 2006, without yet creating an obvious chilling effect on private investment.[100]

c) Credit rollover and other true-up options

Under existing policy in Minnesota, self-generators are paid for any net excess generation on a monthly basis. They may opt to receive these payments in the form of (1) a credit to their account or (2) a monthly payment check.[101]

During the 2011 DG workshops hosted by the Minnesota Department of Commerce, Division of Energy Resources, utilities and other stakeholders expressed concerns regarding the existing rollover/true-up system. Concerns included the administrative burden of issuing monthly payments, unintended incentives for generating more energy than a customer can use onsite annually, and the wisdom of a single set of rules for all utilities.[102]

d) Multiple customer meters

Some customers own multiple buildings that are separately metered by the utility. This is often the case for municipalities, institutions of higher learning, hospitals, and agricultural property owners, among other customer categories.

A practice known as meter aggregation allows customers to combine their electricity load for purposes of net energy metering, and to allocate the benefits of a net-metered solar PV system across the combined meters.[103] In general, a utility can aggregate a customer's multiple meters either physically (by running wire) or virtually through the utility's billing software and database. The latter approach is generally more flexible and less costly, although the utility may incur some costs in adding this functionality to its billing system.

Allowing a customer to aggregate the meters on his/her contiguous property may help simplify the net metering process.[104] For example, meter aggregation enables a customer to put solar PV on his/her optimal or preferred roof site (based on, e.g., rooftop orientation, size, structural strength, and shading), even if that roof does not coincide with the customer's largest meter load.

Minnesota's current net metering policy is silent regarding meter aggregation.[105] (See June 2013 Addendum for legislative update.) There is thus no standard approach across the state's various utilities for netting the production of a solar PV or distributed generation system against multiple customer meters.

As a result, customers with multiple meters who seek to invest in onsite solar PV may experience confusion and lack of clarity regarding billing and logistical issues, leading to increased project complexity and/or suboptimal solar PV siting.

e) Demand charges and capacity credit

Most commercial and industrial electric customers pay for electric utility service through two separate charges: an energy charge and a demand charge.

Photo: Minneapolis, MN (40 kW, 2012) Photographer: Ray Colby

The energy charge is based on the amount of kilowatt-hours used during the billing cycle. The demand charge is a measurement of the highest number of kilowatts used during a given period. Typically, a utility will measure demand in 15-minute intervals and charge for the highest 15-minute interval during the billing cycle.

When a customer-generator's solar PV system is producing electricity, the customer's instantaneous demand will be reduced by the amount of power (kilowatts) generated.[106] But whether the customer-generator receives a credit for that demand reduction on their bill is highly uncertain, because a single 15-minute interval of high demand when solar production is low (e.g., due to transient cloud cover) can establish the demand charge for the entire billing period.

Modeled energy use at commercial facilities leads some observers to conclude that the capacity value provided by distributed solar generation is not reflected in savings in customer-generators' energy bills.[107]

For commercial and industrial solar customer-generators, savings attributable to solar development may not include value for the capacity reductions provided by solar generation. This is in spite of strong evidence that solar does provide important capacity value to the utility system.[108] This has led some stakeholders to advocate for reconsideration of rate design elements such as demand charges that seem to undervalue the avoided cost elements of net metered distributed generation.[109] The rate elements of Minnesota's net metering standards do not address this market failure, and thus could benefit from a new tool or mechanism to provide appropriate value of solar capacity for distributed solar generation for commercial scale projects.

f) Subsidization concerns

Utility rates for most Minnesota utility customers are "cost-based," meaning that the rate charged to customers approximates the actual costs of serving each rate class (e.g., Residential rate class or General Commercial rate class). The justification for using retail rates to value self-generated electricity (net metering) is based on the assumption that if it costs the utility 10 cents to deliver a kilowatt-hour of daytime electricity to a residential customer, then the value (to the utility) of electricity produced at the customer's premises is worth 10 cents.

However, the retail rate is an average of the costs to serve the customers within a rate class, meaning that some customers within the rate class are paying less than the cost to serve them, while others are paying more than the cost to serve them.

In addition, the retail rate is an average of costs over time. Costs incurred by the utility to provide electric service include both long-term and short-term expenses. Some of these costs are associated with long-lived assets (multiple decades) and change very little over the life of the asset, while other costs vary hourly. The actual cost to serve a customer can vary substantially depending on the time of the day.

Photo: Marshall, MN (30 kW, 2007)

Using the retail rate as a proxy for the value of distributed generation has been characterized by some as "rough justice."[110] Net metering has come under scrutiny by both utilities and by solar energy advocates as to whether rough justice is appropriate for non-net metering ratepayers or for owners of distributed solar generation.

Ratepayer cross-subsidization

In recent years, utilities and other stakeholders have criticized NEM programs as being a subsidy paid to NEM customers by "non-participating" customers of the same utility.[111] NEM programs have also been criticized by investor-owned utilities (IOUs) with concerns regarding loss of revenue and inability to recover costs incurred to provide electric service.[112]

These arguments are interrelated. If the actual value of solar distributed generation is less than the retail rate, then the utility is not getting full cost recovery when a customer self-generates.[113] But customers' electric bills do not go up until the utility increases its rates, at which time the utility is once again fully recovering its costs.

Minnesota utility concerns regarding NEM cost-shifting

Minnesota's electric utilities argue that the more solar power a residential customer generates, the less electricity the customer needs from the utility. The customer is therefore not paying for the fixed costs that are included in residential electric rates, resulting in a hidden subsidy.[114]

A municipal utility representative explained:

> "[T]hese fixed costs must be recovered every month by the utility. Because the customer-owner is reducing his purchases from the utility, the utility must recover these fixed costs from the kilowatt-hours sold to other customers. The smaller the municipality, the fewer kilowatts available to spread these fixed costs among. This results in greater cost impacts on the other customers."[115]

Further, some electric utilities assert that customers with on-site solar make a greater use of the utility grid than non-solar customers, and should pay an additional network fee.

Minnesota solar industry concerns regarding undervaluation

In contrast, solar energy advocates and other stakeholders have argued that solar customer-generators may actually be under-compensated by the retail rate. The cost-based retail rate is an average over time (over the day, over the year) of the utility's fixed and variable costs of providing electric service. Solar generation generally coincides with the time of day and year when many of the utility's costs are highest.[116]

Advocates also argue that the distributed energy generator is providing a source of energy not only at the time of highest costs, but geographically near the point of load (taking load off the transmission and distribution system). The utility may have received value over and above retail price from the customer-generator's provision of daytime electricity at or near customer loads.[117]

Moreover, demand-metered customer-generators continue to pay fixed costs via the demand charge. Solar self-generation generally does not result in reductions in the demand portion of their electric bill, due to the nature of how demand charges are calculated. These customer-generators provide capacity value for which they see no benefit of commensurate reduced costs.

Finally, stakeholders have argued that valuable services and benefits provided by distributed solar generation are not accounted for in the retail rate price. These benefits include points of value to the utility such as mitigating price-volatility risk associated with fossil fuels and centralized facilities, and reducing carbon, mercury, air toxics, and other environmental benefits. The non-priced benefits also include points of value to non-utility entities, such as the economic benefits of local solar deployment.

Implications for Minnesota

In other states, utility-specific studies on NEM cost-benefit and/or solar value have been performed by or for a number of utilities.[118] In general, it seems that residential NEM customer-generators may or may not impose a net cost on other ratepayers, depending on utility-specific costs, benefits, and estimation methodologies.[119]

On the other hand, it appears that demand-metered customers with NEM facilities will often provide a net benefit to nonparticipating customers.[120]

The outcomes of NEM cost-benefit analysis seems to depend on a number of factors, including the individual utility, its cost structure and retail rate design, and the NEM policy and level of solar PV adoption being analyzed.[121]

Minnesota's NEM standard has not been evaluated for net costs or benefits for nonparticipating ratepayers. Anecdotal and circumstantial evidence indicates that NEM presents a possibility for either cross-subsidization by nonparticipants or under-compensation for owners of distributed solar—in which case NEM participants could be said to be subsidizing nonparticipants.

One detailed 2009 NREL analysis of Minnesota's NEM standards did address the issue of potential rate impacts to nonparticipants, although it did not conduct a cost-benefit assessment.[122] Examining the cross-subsidization issue for states that had net metering participation rates well in excess of Minnesota's participation rates, the study concluded (emphasis in original):

> Careful design of a net metering policy to accurately reflect the value of the net metered systems to the public good, the system owner, ratepayers, and the utility is required to minimize the potential unfair impacts to any one party. However, capturing all of these impacts in a single study is difficult. Nonetheless, **a higher net metering system size cap seems to coincide with accelerated market transformation and a greater installed capacity without significant negative rate payer impacts**.[123]

Policy implications of the net metering cross-subsidization issues include:

1. **Level of risk for nonparticipants**. Today's relatively low level of net metering suggests that NEM is not currently contributing to cost-recovery difficulties or significant risk to non-NEM participants.[124] It is generally accepted that that net metering customers generate well less than one percent of Minnesota's total electric utility sales.

   Many states that have considered the risks associated with NEM have set caps or thresholds for evaluation on the total capacity of NEM customers allowed on the system. These caps are typically three to five percent of aggregate load (approximately 50 times greater than Minnesota's current penetration rate).

Pacific Gas & Electric and the Rocky Mountain Institute recently convened a roundtable discussion about cross-subsidization risks associated with increasing numbers of net metering customers.[125] As noted in the final report, the impetus for the discussion was the strong growth of the distributed solar market that "is nearing penetration levels that will cause noticeable impacts to grid operations and utility business models." PG&E is now approaching California's applicable five percent aggregate NEM capacity limit.

2. **Consideration of existing cross-subsidization**. If NEM does result in cross subsidization within rate classes, that fact alone may not necessarily demand corrective action. Intra-class cross-subsidization is an inevitability of a cost-based system of setting rates. Cross-subsidization between rate classes and within rate classes has long been recognized as a tradeoff for achieving other economic and practical efficiencies in the rate making process.[126]

   Thus, if a NEM cross-subsidy were to be demonstrated (either to or from net metering customers), the question may become whether the subsidy is within an acceptable range, comparable to other forms of cross-subsidization that are inadvertently or purposely built into the state's current system of setting utility rates.

   Moreover, subsidies are sometimes accepted as an inevitable part of the ratemaking process for the purpose of meeting statutory or non-cost service goals such as universal service, economic development, protection of low income customers, rate simplicity, or environmental protection.

3. **Long-term conflicts within regulatory structure and utility business model.** While cost-recovery (and cross-subsidization) risks are currently low, Minnesota policy goals are to make distributed solar a significant part of Minnesota's energy supply portfolio. Existing rate making and cost-recovery standards were not designed for a system with large numbers of self-generators. The historic utility business model and rate making processes are likely to expose utilities and ratepayers to higher levels of risk as distributed generation becomes a significant part of the energy portfolio. Minnesota may accelerate the DG deployment by developing new rate-making concepts and utility business models.

NET METERING DESIGN ALTERNATIVES

While Minnesota was an early adopter of net energy metering, other states have since adopted and expanded on NEM policies, developing alternative policy designs for addressing market barriers and market-transformation concerns. NEM policies vary primarily in regard to four design elements:

- NEM system capacity limits
- compensation for net excess generation
- single-customer meter aggregation
- standby charges

a) NEM system capacity limits

Arguably the most prominent failure of Minnesota's existing policy to remove market barriers is the 40-kilowatt net metering cap. Commercial, industrial, and institutional electric customers face significant financial and regulatory uncertainty in regard to solar development on their facilities. Those customers that choose to install solar energy systems frequently limit the size to 40 kilowatts to coincide with the current NEM cap.

In contrast, under the commercial net metering rules in place in Colorado, Illinois, Ohio, Oregon, New Jersey and other states, many commercial customers are allowed to use rooftop solar to offset 100 percent or more of their buildings' average annual energy use (AEU).

As shown in the table at the right, Colorado has set its NEM cap at 120 percent of the customer-generator's annual energy use (AEU). New Jersey and Ohio have set their NEM caps at 100 percent of the building's AEU.

Illinois adopted a 2,000-kilowatt system cap in 2011.[127] Oregon has had a 2,000-kilowatt NEM system cap since at least 2007.

The caps in Illinois and Colorado are also differentiated, meaning those states have different system caps for different customer types, utilities, or utility types.

Of the nine states that revised their net metering policies since 2009, four of them (Delaware, Illinois, Maryland, and Pennsylvania) have system capacity limits of 2,000 kilowatts or higher.[129]

Table 3: Net metering system caps (by highest NEM capacity limit)[128]

STATE	DATE NEM POLICY REVISED OR ADOPTED	HIGHEST NEM CAPACITY LIMIT (%AEU OR kW)	AGGREGATE CAPACITY LIMIT (% PEAK LOAD)
Arizona	2008	125%	none
Colorado*	2010, 2009, 2008, 2005	120%	none
New Jersey	2012, 2004, 1999	100%	none
Ohio	2009, 2000, 1999	100%	none
New Mexico	2008	80,000	none
Massachusetts*	2012, 1997	10,000	3%
California	2011, 2008, 1996	5,000	5%
Rhode Island	2011	5,000	3%
Pennsylvania*	2012, 2006, 2004	3,000	none
Connecticut	2011, 1998	2,000	none
Delaware*	2011, 2010, 1999	2,000	5%
Florida	2008	2,000	none
Illinois	2012, 2011, 2008, 2007	2,000	5%
Maryland	2012, 1997	2,000	~8%
New York*	2012, '11, '10, '09, 1997	2,000	1%
Oregon*	2007, 2005, 1999	2,000	none for IOUs
Utah*	2009, 2002	2,000	20%
Washington, D.C.	2010, 2005, 2000	1,000	
Indiana	2011, 2004	1,000	
N. Carolina	2008, 2007, 2005, 1998*	1,000	none
Nevada	2011, 2004, 1997	1,000	2%
New Hampshire	2001, 1998, 1983	1,000	
Iowa	1984	500	none
Vermont	2012, 2001, 1998	500	
Virginia	2011, 2010, 2000	500	
Louisiana	2011, 2005, 2003	300	
Michigan	2008, 2005	150	0.75%
Georgia	2001	100	0.2%
Hawaii	2011, 2001	100	15% of distribution circuit capacity
Missouri	2008, 2007	100	
N. Dakota	1991	100	
S. Carolina*	2008	100	
Washington	1998	100	
Wisconsin*	2011, 1992, 1983	100	none
Minnesota	2000, 1983, 1981	40	none
Kentucky	2009, 2004	30	
Nebraska	2009, 2008, 2004	25	

*Designates states that have differentiated NEM system or aggregate caps.

Two other states (Colorado and Ohio) adopted or retained a system capacity limit based on a percentage of the customer-generator's annual energy use.

Kentucky and Nebraska adopted or implemented net-meeting policies for distributed generation systems with rated capacities below 30 kilowatts and 25 kilowatts, respectively.

Finally, Wisconsin's PSC issued a 2011 ruling that did not affect system capacity limits.

The Interstate Renewable Energy Council (IREC) tracks best practices in net metering and other state policy for solar market transformation. IREC's Model Net Metering Rules do not put an explicit kilowatt cap on eligible solar PV systems, "provided…that the rated capacity of the Renewable Energy Generation does not exceed the Customer-generator's service entrance capacity."[130]

Sizing the NEM cap to annual energy use (or another measure of customer load) introduces a certain amount of complexity and some informational challenges. In the most basic case, this policy approach requires the solar customer (or solar developer) to know what the customer's energy usage was during the relevant measuring period.

b) Compensation for net excess generation

Annual net excess generation (NEG) is the amount of energy "credit" that a self-generator has in its account at the end of an annual cycle. Most net metering customers have a balance of zero, as they generate less energy over the year than they use.

Minnesota's policy requires utilities to compensate NEM customer-generators' NEG at the average retail energy rate for customer's rate class.

Most other states compensate NEG based on some measure of the utility's avoided energy cost, as defined by PURPA. Crediting at avoided cost, which is a wholesale rate, discourages customer-generators from installing a system that is larger than necessary to satisfy their expected annual electricity needs. Another consequence may be to encourage increased onsite energy consumption by the customer-generator.[131]

A minority of states allow utilities to zero out customers' NEM rollover account at the end of the annual period, without providing any compensation for the customer-generator's NEG. Some Minnesota utilities have voiced support for this approach.[132]

States also vary in the timing of NEG compensation. Most states with net metering allow utilities to reset customers' rollover accounts on an annual basis. This approach helps smooth out the variation in a system's solar production over the course of a year, which is generally highest in summer and lowest during the winter months.

Approximately 12 states have indefinite rollover, under which a customer's rollover credits continue to accumulate until the customer exits the utility's billing system, or moves to another meter inside the utility's service territory. Through the state led DG Process, some utilities in Minnesota have raised concerns about this approach, citing billing and financial concerns with having to maintain NEM credits in their billing system with no timeframe for their utilization.[133]

c) Single-customer meter aggregation

Presently, at least 14 states (not including Minnesota) allow for some form of customer meter aggregation in the net metering context. States with this policy design feature include California, Connecticut, Colorado, Illinois, Oregon, Pennsylvania, Massachusetts, Maryland, New Jersey, New York, Rhode Island, Utah, Vermont, and Washington.[134] Some states, such as California, allow for meter aggregation only in certain situations (e.g., for multi-family housing).[135]

The IREC Model Net Metering Rules recommend that meter aggregation be allowed at the customer's option, but only when all the meters are located on contiguous properties and used to measure electricity used for the customer-generator's requirements.[136]

IREC recommends that a customer-generator's meters should not have to be on the same rate schedule in order to qualify for aggregation, but that net metering credits should apply only to utility charges that use kilowatt-hours as the billing determinant.[137]

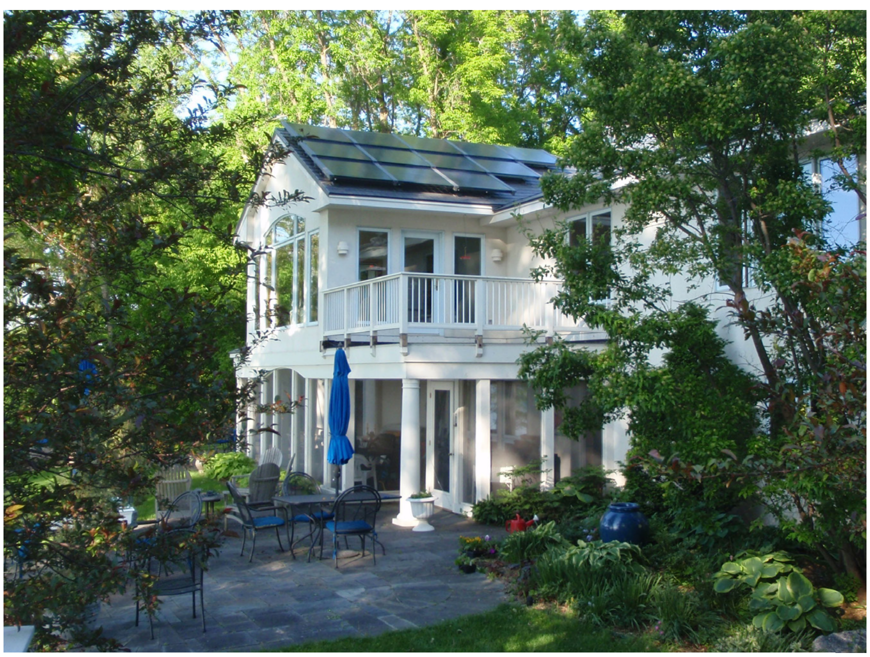


Photo: Eden Prairie, MN (8 kW, 2012) Photographer: Rebecca Lundberg

d) Standby charges

Some Minnesota utilities currently charge “standby” service fees to ratepayers with onsite distributed generation systems sized 60 kilowatts and above.[138] Net metered systems are not currently charged standby charges because the NEM capacity limit is below the 60-kilowatt standby threshold. (See June 2013 Addendum for legislative update.)

Some other states, recognizing the value of clarity and transparency, have adopted a NEM “safe harbor” provision that prohibits utility fees and charges not specifically defined and approved by policy makers.

The issue of charging NEM customers for standby service is related to the issue of whether, and to what extent, NEM customers pay for their utility’s fixed capacity costs through demand charges. Distributed solar generators that are subject to a utility demand charge generally do not see a reduction in that charge due to their net-metered solar installation. (See Demand Charges and Capacity Credit, above.) This is perceived by some as unfair, as solar installations frequently provide capacity value to the utility.[139]

ALTERNATIVE OPTIONS TO NET METERING

a) Feed-in tariffs and reverse auctions

Alternative solar rate policies used in other countries and in a few places in the United States are the feed-in tariff (FIT) and a related policy known as the reverse auction. FITs and reverse auctions are tools that focus first on enabling resource acquisition of a specific type of resource, and then set an incentive buy rate that will create development activity for that resource. Utilities must purchase the energy generated at the standard prices, terms, and conditions.

The term “feed-in tariff” recognizes the tariff nature of the FIT (a fixed price, like the utility’s tariffs) but rather than selling at that price, the utility is buying (or feeding in, rather than feeding out) at the tariff price. Like net metering, this policy is typically more than simply a purchase rate for solar electricity, including elements of interconnection, policies relative to other rates and charges, and an explicit link to DG market transformation goals.

As discussed below, FIT policies typically use one of two types of pricing models: an administratively or legislatively determined incentive rate or a “reverse auction” rate.

Feed-in tariff pricing models

In the first FIT pricing model, decision makers determine how much distributed solar they want to encourage, then set a solar incentive rate high enough to result in that level of investment. The initial rate may be ratcheted down over time.

In the second FIT pricing model, the rate is set through a reverse auction mechanism. For example, the utility may establish a bidding process for a given amount of solar capacity and award contracts to the lowest bidders. (This is called a “reverse” auction because the lowest—rather than the highest—bidders win.)

In both cases, the price paid by the utility is generally not directly linked to the utility’s costs or the cost of other types of resources that could provide the same electricity. FIT prices are often legislated rather than set through a regulatory process, with the initial FIT price being substantially above retail rates to encourage a rapid ramp up of solar development.

With a reverse auction, the prices are market driven, but are assumed to include a subsidy because the auction is limited to solar resources (to the exclusion of non-solar generation sources that might be less expensive). Auctions are also intended to open up solar development investment and eventually push prices lower.

Using these policy tools, the subsidy may decline as solar development accelerates, with the goal of reaching a point where the subsidy disappears and the solar market is economically self-sustaining and competitive with other energy resources.

The FIT price is a long-term price, where early entrants to the market are rewarded with long-term, 10- or 20-year contracts at the incentive rate. The long-term contract limits long-term uncertainty and grants the solar developer the ability to acquire financing.

FIT and other utility rates

Unlike either net metering or value of solar tariffs, FIT is not connected to the cost of providing electricity to ratepayers. FIT is first and foremost a market transformation tool, where the market transformation benefits are assumed to be sufficient justification for the higher cost electricity.

Some FIT programs are constructed to limit cost impacts to nonparticipating utility customers, usually by capping the amount of capacity to be acquired via a FIT to a small portion of the utility's load. Utilities are allowed cost recovery by rolling the FIT power acquisitions through the fuel adjustment charge or a similar rider. However, utilities and some consumers (typically large commercial or industrial customers) actively oppose FIT because of the disconnection from utility costs and the higher rate that may result as the subsidized rate is passed through to consumers.

FIT and market transformation goals

FIT policies have some market transformation advantages over net metering. Most notably, because FIT is not tied to onsite consumption, the participant can size the solar development to the size of the solar resource and capture economies of scale (further advancing market transformation goals).[140]

FIT and other market transformation policy tools

As noted above, the FIT rate is linked to market transformation outcomes rather than displaced or avoided costs. The FIT rate will decline based on successful ramping up of solar development.

The FIT policy goal is similar to some other policy tools, including utility rebate programs, solar energy standards, and some community solar programs. All of these policy tools are designed to achieve solar market transformation or solar resource acquisition goals. A FIT rate can be integrated into these other policies, provided that the policy objectives and program structures are consistent with each other. FITs have been characterized, for instance, as being a mirror opposite of a solar renewable energy standard, one being focused on the market response to a specific price, the other focused on a specific amount of resource to acquire.[141]

CASE STUDY: Germany feed-in tariff

The most prominent and successful example from a market transformation perspective is the solar FIT that was instituted in Germany, initially approved in 2001. The FIT was open-ended, meaning there was no cap on the amount of capacity to be acquired, leading to substantial amounts of solar capacity being installed, in spite of a solar resource that is significantly less attractive than the solar resource in most of the United States. The original FIT price (0.45 to 0.57 Euros/kilowatt-hour) has ratcheted down considerably since the start of the program (now at 0.11 to 0.16 Euros/kilowatt-hour).

Germany's program has increased retail rates for most consumers, with the exception of industrial consumers (who are exempted from the program). The magnitude of the rate impact on residential and commercial customers is somewhat uncertain, as the market transformation efforts have reduced the overall wholesale price for power.[142] This price-reducing impact, which benefits all power consumers, has arguably resulted in a cross-subsidy from residential consumers to industrial consumers.[143] The German government estimates that by 2020, solar PV will account for approximately 7 percent of the national energy portfolio.[144]

It is important to note that Germany's FIT program operates in an economic context that is significantly different from Minnesota. For example, Germany's residential utility rates are generally more than double Minnesota's residential rates. Several utilities in the United States have instituted FIT policies, although most of them have capacity caps to limit impacts to nonparticipants.

b) Value-of-solar tariff

Both NEM and FITs use a proxy for identifying the value of distributed solar generation. Net metering assumes the retail rate is a reasonable measure of value on the utility system, while FIT assumes that value is measured by the market transformation and environmental benefits.

Rather than use a proxy, one could conduct a rigorous cost-benefit analysis taking into account all measurable and relevant value and cost components of distributed solar generation and set a purchase rate or tariff based on this analysis.

A solar production rate, referred to here as a value-of-solar tariff (VOST), is one tool that could address some of the rate and revenue concerns associated with net metering and FIT.

A VOST operates somewhat like a FIT, but the basis for the rate is considerably different. The purchase rate for distributed solar generation includes the utility's long-run costs of providing service during the time that solar generation is occurring. Rather than creating an incentive, the VOST is based on utility costs and benefits, in the same way that the utility's own rates are based on the utility's costs of providing service. The VOST does not include a subsidy and is not necessarily premised on meeting DG goals, but does recognize the value of distributed solar generation on the utility's system.

Under the VOST, the solar customer is charged for all energy consumption, just as if the customer did not have a solar PV system. The solar customer is separately metered and credited for their solar generation at the annually adjusted VOST rate. Replacing net metering with a VOST moves the netting from the meter (kilowatt-hours) to the customer utility bill (dollars).[145]

It is important to note that under VOST, the utility explicitly buys all the solar energy generated by utility customers who have on-site solar PV and participate in the value-of-solar tariff.[146] From an accounting perspective, this moves the participating customer-generator's solar production onto the utility's cost line (increasing costs), and off of the revenue line (where it has a negative value).

A VOST can work in conjunction with incentives that serve other market-transformation goals, similar to the conceptual basis for net metering. Also, similar to net metering, a VOST includes elements of a standard contract that makes investments and financial assessment predictable and transparent. Unlike net metering, a VOST explicitly identifies the value of a particular form of distributed generation, solar PV, on a particular utility system.

VOST and the retail rate

As noted in the net metering discussion, net metering operates under the assumption that the value of onsite generation (the price paid for electricity generated in excess of onsite use) is equivalent to the retail rate. Because retail rates are based in the documented cost of providing utility service, this assumption is not entirely unreasonable, but is at best rough justice.

While retail rates are cost-based, the retail rate is an average of costs that the utility faces over the day, over the year, and over the lifetime of utility equipment. Moreover, the retail rate is an average of costs for providing service to different customers within a single rate class. Like other averages, the cost faced by the utility for providing power to customers at different points in time and for different customers is sometimes higher than retail rates and sometimes lower.

The "value-of-solar" rate concept addresses the following questions:

1. When solar energy is being generated, is the cost of providing power at, below, or above the retail rate?
2. Depending on who generates solar energy or where it's generated, is the cost of providing power for that type of customer or location at, below, or above the retail rate?

While the penetration rate of customer-generated electricity on the utility system is low, the differences between using the average cost (retail rate) and the actual cost (at the time and location of the customer's generation and consumption) is of small consequence (as noted in the discussion about Minnesota's net metering policy).

When the penetration rate of customer-generation becomes larger, the risks of using average cost increases. Setting an accurate value rate for self-generation is important for three significant reasons:

1. Maximizing the value of distributed solar generation to the utility, and consequently to the rest of the ratepayers.
2. Sending the appropriate price signal to the customer-generator, to ensure an appropriate level of investment.
3. Recognizing the utility costs associated with integrating customer-sited solar generation into the utility system.

Cost vs. value

Within the context of setting rates, the terms "cost" and "value" are not used interchangeably. Both economists and Minnesota statutes distinguish between the concepts of "cost" and "value" as they relate to utility rates:

- cost: the actual price (in currency or other measure) paid for something
- value: the measure of benefit received from something

Minnesota statutes state that utility rates are to be based on the cost of furnishing service, and rejects the use of market value for assets in rate base.

The term "value" in "value-of-solar tariff" is, however, not a reference to the market value of distributed solar generation, but rather the value to the utility, relative to the utility's costs.

VOST methods and components

There have been over 30 studies of the costs and values of distributed resources, including rooftop solar PV.[147] These studies were not all designed to ascertain the value of solar on the utility system, and a wide variety of methodologies were thus used. Nevertheless, the work is informative about what kinds of costs and benefits of DG can be considered. A subset of these studies was aimed at determining the value of solar installations on the utility system.

The most prominent example of assessing the value of distributed solar generation on the utility system is the work completed by the Austin Energy (Texas) municipal utility. Beginning in 2006, Austin Energy performed a detailed cost-benefit analysis of the value of solar PV on its system. The analysis was conducted to evaluate the cost to the utility from its market-bid purchased power agreements for solar generation. The analysis revealed that the power purchase agreements (PPAs) were providing power at a competitive cost to other forms of serving electric load. Later, Austin Energy conducted a more detailed analysis to assess the value of distributed solar at the residential level. The utility discovered that the net metering retail rate was under-compensating rooftop solar PV owners for the value provided by their daytime power generation.[148] Austin Energy used the study results to design a replacement for its residential net metering program, which they call a value-of-solar tariff.

Austin Energy's VOST, which was the first implemented in the United States, rolled out to the utility's residential customers in mid-2012. Under the tariff, the utility buys all customer-generated solar power for 12.8 cents per kilowatt-hour (2012 rate), higher than the 10-cents-per-kilowatt-hour retail rate that applied under Austin Energy's net metering program.[149]

The concept used for setting Austin's VOST has been used in other utility service territories.[150] Different utilities considered somewhat different cost elements in identifying a VOST, but a largely consistent set of cost elements defines the alternatives for assessing the value of distributed solar generation on any utility system or within any community.

A set of common cost elements is noted below; some of the cost elements are overlapping and/or controversial, but all have been used in various approaches to assess distributed solar value to the utility system.[151]

- fuel cost savings
- line loss savings
- operation and maintenance savings
- generation capacity value
- ancillary services
- avoided reserve capacity
- transmission capacity value
- distribution capacity value
- fuel price hedge value
- environmental value
- customer reliability
- implicit value of solar
- economic development value
- solar penetration cost (a negative value)

As with a Power Purchase Agreement (PPA) or a long-term contract rate, the VOST rate is calculated by taking the present value of the future revenue streams of all the relevant value components. The VOST rate is expressed in a present value per kilowatt-hour.

Some of the above cost components are generally accepted to be quantifiable utility costs that are routinely used in ratemaking, while other components are quantifiable but not always relevant to ratemaking. And some (such as economic development and implicit value of solar), are cost or value components that are more difficult to quantify or are typically outside the realm of utility ratemaking.

Application of VOST

A value-of-solar tariff is an alternative to Minnesota's existing solar rate policy, i.e. net metering. Regardless of the process for setting the actual purchase rate, there are some important distinctions between net metering and VOST that would require policy choices and which have different ramifications for state policy and utility planning. Those differences are noted below:

1. ***Relationship to onsite energy use.*** Net metering establishes a utility compensation rate, but only for the solar energy a customer-generator produces in excess of its onsite electricity use.

   In contrast, VOST sets a value without consideration of the onsite characteristics of any single customer. A customer-generator could thus generate solar electricity well in excess of its onsite use, sizing the solar installation to maximize value from its solar resource, rather than sizing to match its load. But that scenario is only possible if a customer's onsite solar resource exceeds their onsite energy demand.

2. ***Cost recovery and nonparticipant risk.*** As discussed above, a major point of debate regarding net metering is whether and to what extent it reduces utility cost recovery, or shifts cost recovery from participating to nonparticipating ratepayers.

   VOST significantly mitigates these potential risks. First, because the utility will recover costs associated with VOST purchases via the fuel adjustment rider, the utility's cost-recovery risk is largely eliminated. Second, because the VOST rate is based on the costs that ratepayers would otherwise incur (i.e., the costs offset by utility procurement of solar), the risk of rate increase rates due to VOST is low. The risk is not, however, eliminated. Ratepayers may see increased rates under the following circumstances:

(1) The VOST rate was inaccurately calculated and does not reflect values correctly.

(2) The cost savings from the purchase of distributed solar generation is separated in time from the payment for the solar generation. (For instance, if the costs are paid this year, but the cost savings are realized next year.)

Thus, while the risk of rate impacts is low, ratepayers bear all the risk. Under net metering, the risk is faced by the utility—until the utility's next rate case, at which point any net costs are passed to ratepayers.

Photo: Plymouth, MN (5 kW, 2010) Photographer: Jamie Borell

3. ***Incorporation of Renewable Energy Credits (RECs).*** Under Minnesota net metering standards, the disposition of the RECs is not addressed. The Public Utilities Commission (PUC) has issued some context-specific rulings regarding REC ownership.[152] But the applicability of this PUC ruling is not clear for net-metered solar generation. Thus, a cost-based VOST rate may need to explicitly include the value of the REC (and grant ownership to the utility) if environmental value is included in the VOST rate calculation, or otherwise exclude the value of the REC (and leave ownership with the customer-generator).

4. ***True-ups and adjustments.*** Under NEM, the solar rate automatically changes when other rates change. In contrast, a VOST rate may be adjusted at specified time intervals (e.g., on an annual basis), and the adjustment may not necessarily track other rate changes.

   For instance, due to marginal economics, the value of distributed solar generation on the utility system is expected to change (perhaps decline) as the solar penetration rate increases.

   Austin Energy's VOST rate is recalculated each year in order to maximize value and set appropriate price signals. From the perspective of a solar PV host or developer, annual rate changes may create difficulties for assembling financial pro formas and acquiring project financing.

5. ***Integration with non-rate policy tools.*** VOST is not an incentive, but can work with incentive programs, including solar energy standards and traditional solar rebate programs.

SOLAR INTERCONNECTION

POLICY PURPOSE

Interconnection is the set of regulatory rules and utility procedures that governs how a distributed generator, such as a homeowner's solar photovoltaic system, interconnects with the utility grid. Most solar PV generation is connected to the utility grid and thus must comply with interconnection standards and procedures.

Interconnection procedures are intended to standardize and reduce the risks associated with connecting a new generator to the utility system. As with all regulation, however, interconnection standards should address reasonable risks without adding more cost or complexity than necessary.

Unnecessary requirements may delay or prevent the development of a robust solar market. On the other hand, interconnection practices that are clear, transparent, and consistent can support market development by reducing project-level interconnection uncertainty and complexity costs.

CURRENT MINNESOTA POLICY

Minnesota's interconnection policy was established through legislation adopted in 2001.[153] The policy was implemented by the Public Utility Commission in 2004 through the Commission's Distributed Generation Interconnection Order.[154] (The Interstate Renewable Energy Council, discussed below, first developed its model interconnection procedures in 2005 and published a revised model in 2009.[155])

Minnesota's interconnection process is designed, in part, to minimize potential reliability, safety, and stability impacts, as well as risks to utility infrastructure.

Successes of Minnesota's DG interconnection policy

Interconnection has proven successful in terms of protecting worker safety and utility infrastructure. There are no significant problems to date with distributed generation for either line worker safety or damage to utility infrastructure in Minnesota.

Issues identified with Minnesota's interconnection order

Minnesota's interconnection policy helped establish a streamlined interconnection process for net-metered generation systems.

For some systems larger than 40 kilowatts, however, utility interconnection rules can be relatively complex. For example, Minnesota's interconnection process generally requires that those systems must go through the same approval process as required for a very large 10-megawatt system. Moreover, the state's DG interconnection order allows each utility to develop its own interconnection process, leading to variation and complexity.[156]

Some Minnesota customers and solar developers have raised the following categories of concerns in focus groups and interview conversations:

- Solar interconnection processes vary from utility to utility, increasing administrative costs and complexity for both applicants and utilities.
- There exists a lack of clarity and consistency around interconnection timelines. While the DG interconnection order imposes timelines for some interconnection steps, utility compliance is not uniform.[157] This lack of specificity may be due in part to the use of a single process for a broad range of generator sizes, with a range of size-based technical and procedural requirements.
- Lack of a clear and transparent process for interconnection to a utility "area network."[158] Area networks, which exist in downtown Duluth, Minneapolis, and Saint Paul, contain fault-tolerant utility distribution infrastructure intended to increase reliability for critical loads.

ALTERNATIVE INTERCONNECTION POLICY APPROACHES

Photo: Lake Elmo, MN (5 kW, 2010) Photographer: Jamie Borell

Since the 2001 adoption of Minnesota's interconnection statute, a set of relatively well-recognized best practices has been developed.

The Interstate Renewable Energy Council (IREC), an industry standards group that receives project sponsorship from the U.S. Department of Energy (DOE), collects and publishes technical best practices in the IREC Model Interconnection Procedures.[159] IREC's model procedures are designed to address safety, stability, and reliability concerns without creating unnecessary complexity or cost for applicants.[160]

At the heart of the IREC approach is the establishment of four separate levels of review to accommodate systems based on system capacity, complexity and level of certification.[161] The tiers are described in detail below.

Tier 1: Qualifying inverter-based solar facilities under 25 kilowatts[162]

Under the IREC approach, Tier 1 recognizes the general reliability and safety of small distributed solar facilities that use certified equipment. IREC also recognizes that a given utility may one day receive hundreds or more of these routine, small-scale interconnection applications every year.

As such, IREC recommends that interconnection applications that satisfy the Tier 1 technical screen receive relatively quick utility approval or denial, be exempt from interconnection-study and liability insurance requirements, and be subject to limited or no application fees.

Tier 2: Qualifying solar facilities under 2 megawatts[163]

IREC's second tier expands on the first to recognize (1) the greater impact systems of this size can have on the local distribution grid and (2) the greater potential variability between interconnection applications.

IREC recommends an efficient timeline for application review, but also allows utilities the flexibility and tools necessary to conduct a more thorough application review (including an interconnection study if necessary). IREC suggests that Tier 2 interconnection fees should be allowed to increase with application complexity, facility size, and required level of review.

Tier 3: Qualifying non-exporting solar facilities under 10 megawatts[164]

IREC's third tier is intended for relatively large solar facilities that are nonetheless intended primarily to generate electricity for onsite usage (*e.g.*, for an industrial energy user). To qualify for this tier, a facility must generally be designed to limit the amount of excess electricity it provides to its utility.

IREC recommends a somewhat streamlined review process for such facilities (compared to the review process for similarly sized facilities that are intended to supply electricity to the utility distribution system) because non-exporting generation facilities generally raise fewer concerns regarding reliability, infrastructure costs, and energy distribution management.

Tier 4: All other solar facilities[165]

IREC's fourth tier is a "catch all" category that applies to all systems that do not satisfy one of the above technical screens. This includes all solar facilities sized at 10 megawatts or above, along with smaller systems that are intended to export electricity to the utility-distribution grid or that use non-certified equipment.

IREC recommends that such interconnection applications receive the most thorough level of review, and allow for utilities to require that applicants pay the cost for any interconnection studies and equipment needed to ensure the safety and reliability of the interconnection and overall distribution system.

IREC also recommends the following set of interconnection best practices:

1. All utilities (including municipal utilities and electric cooperatives) should be subject to the state policy.
2. All customer classes should be eligible.
3. There should be no individual system capacity limit. The state standard should apply to all state-jurisdictional interconnections.
4. Application costs should be kept to a minimum, especially for smaller systems.
5. Reasonable, punctual procedural timelines should be adopted and enforced.
6. A standard form agreement that is easy to understand and free of burdensome terms should be used.
7. Clear, transparent technical screens should be established.
8. Utilities should not require an external disconnect switch for smaller, inverter-based systems.
9. Utilities should not require customers to purchase liability insurance (in addition to the coverage provided by a typical insurance policy), and utilities should not be permitted to require customers to add the utility as an additional insured.

10. Interconnection to area networks should generally be permitted, with reasonable limitations where appropriate.

11. There should be a dispute resolution process.[166]

Minnesota's interconnection grade from Freeing the Grid

Each year, Freeing the Grid (a national organization affiliated with IREC) attempts to grade each state's interconnection (and net energy metering) policies against current IREC best practices. For the last two years, the organization graded Minnesota's solar interconnection policy as an "F."[167]

Minnesota's low interconnection grade is related to:

- A lack of distinction between the interconnection requirements for small generation systems, which pose little risk, and large complicated generation systems that require special engineering.

- The fact that utilities are allowed to require inverter-based systems to have an external disconnect switch, which IREC suggests is redundant and adds unnecessary cost.[168]

- Liability insurance requirements in excess of the IREC recommended best practice.[169]

PATHWAYS FOR REVISIONS TO INTERCONNECTION PROCESS

A number of Minnesota's distributed-generation stakeholders have suggested that the state's technical interconnection rules should be updated to incorporate improved technical standards and better align with recognized best practices. Such action could be undertaken directly by the Public Utilities Commission (PUC), but there is reason to question whether existing statutory authority would allow them to implement IREC best practices.[170] Legislative action may thus be necessary to initiate the process of revising the state's utility interconnection policy.

CASE STUDY: Delaware interconnection policy

The State of Delaware revised its utility interconnection policy in 2010. Delaware Senate bill 267, which addressed a number of policy issues related to solar power, required the Delaware Public Service Commission (PSC) to develop interconnection rules using IREC's best practices and model interconnection rules as a guide.[171]

The Commission's subsequent order required, among other things, that the state's largest utility, Delmarva Power, file revised interconnection standards, revised tariffs, and such other forms necessary to comply with the order within 30 days of the July 10, 2011 publication of final rules.[172]

As of August 2011, Delmarva established a four-tiered approach to determine the level of review required before a system may be connected to the grid.[173] Different levels of review are subject to specific technical screens, review procedures, and timelines. Generally speaking, the utility interconnection process is more extensive with increasing system size.[174]

Briefly described, Delmarva adopted the following four tiers (modeled on the IREC model tiers):

Tier 1: Lab certified, inverter-based systems up to 10 kilowatts.

Tier 2: Lab certified or field inverter-based systems 2 megawatts or smaller on a radial distribution circuit or spot network serving one customer.

Tier 3: Systems that will not export power to the grid and which do not require new facility construction by the utility. There are extra requirements for systems being located on an area network as well as those on radial networks.

Tier 4: Systems 10 megawatts or smaller that do not otherwise meet the criteria for any other tier.[175]

Delaware's interconnection regulations also require utility reporting, record retention, and a specified dispute-resolution process.[176]

The State of Delaware's approach did not directly achieve interconnection uniformity across the state's electricity utilities. Of the state's five electricity utilities, only Delmarva Power was directly subject to the Commission's interconnection order.[177] The other utilities were required to revise their interconnection procedures (based on the IREC model) without direct Commission review. Delaware's approach also deviates from IREC best practices in that it allows utilities to require an external disconnect switch and only waives liability insurance requirements for distributed generators that are less than one megawatt in size.[178]

SOLAR FINANCING

POLICY PURPOSE

The economic life of a typical solar PV system can be as long as 30 years or more.[179] That longevity, together with other factors, means that some rooftop solar PV systems will more than pay for themselves through lower utility bills over time. But without access to attractive long-term financing, many customers cannot install rooftop solar PV onsite due to the high initial cost barrier.

Photo: Blaine, MN (9 kW, 2009 & 2012) Photographer: Sam Villella

Limited access to long-term financing, current options

Residential

Residential solar financing can be difficult to obtain. Currently, the primary option for long-term financing (i.e., with a 20-year term or longer) in the residential market is **mortgage refinancing**. Mortgage rates are currently near a historic low. But in the wake of the 2008 collapse in housing prices, many homeowners do not have enough equity to qualify for refinancing. Further, mortgage refinancing is a relatively costly option for homeowners that simply want to invest in rooftop solar.

The mortgagee who refinances incurs transaction costs on the entire value of their home. The smaller the rooftop system, the higher those costs are relative to the actual loan required.

Other existing home-related options, such as a **home equity loan** or **line of credit**, generally provide shorter terms, and are only available to homeowners with sufficient equity.

Many Minnesota homeowners have access to loans that tailored toward energy-efficiency home improvements. But while solar equipment may qualify for loans under these programs, restrictions within the programs limit the feasibility for financing residential solar. For example, the Center for Energy and Environment (CEE) and the Neighborhood Energy Connection, two of the state's leading providers of energy efficiency financing, consider solar an eligible technology for residential loans, but carry upper limits for total loan amounts and household income levels that may limit accessibility.

In part for these reasons, many Minnesota homeowners lack a practical way to access the capital necessary to adopt rooftop solar PV.

From the perspective of a typical residential customer, the ideal solar-financing offer might provide

- reasonable income and requirements,
- few geographic restrictions,
- loan sizes large enough to cover the cost of a solar project', which may be considerable (especially if the project involves roof replacement),[180]
- short, medium and long-term repayment options,
- compatibility with federal, state, and utility solar incentives,
- compatibility with contractors, and
- affordable interest rates.[181]

Commercial and industrial

Conventional commercial financing is not always a good fit for rooftop solar PV. Typically, such loans are secured by the underlying real estate or by a personal guarantee from the business owner. Both approaches can restrict a business's future borrowing capacity.

In Minnesota, solar equipment is eligible for financing under CEE's Commercial Energy Efficiency Loan Program.[182] But the loan term is limited to 10 years, and the program excludes solar systems that do not pay for themselves within that time.[183] As of January 2013, CEE has financed only a handful of commercial rooftop solar PV projects through its commercial loan program, largely due to program cost.[184]

From the perspective of a typical commercial/industrial customer, the ideal solar-financing offer might provide

- lender security without reducing the property owner's ability to borrow money in the future,[185]
- easy pass-through to property tenants,
- a long-term repayment option,
- features that address the ownership-tenure mismatch concern, and
- compatibility with solar incentives and contractor requirements.

Matthew H. Brown, a clean energy financing expert with Harcourt Brown & Carey, presented on the topic of commercial solar financing at a November 13, 2012 workshop sponsored by the Minnesota Department of Commerce (titled "Increasing Energy Projects in the Private Sector"). In his presentation, Mr. Brown identified four pilot-stage commercial financing models that could satisfy some or most of the above requirements:

- Commercial Property Assessed Clean Energy (C-PACE) financing.
- On Bill Financing (OBF), in which the utility includes billing, collection, and financing as part of their utility bill (as piloted in California). Failure to pay may, if allowed by tariff, subject the defaulting customer to disconnection.
- On Bill Repayment (OBR), in which the utility includes billing and collection as part of their utility bill, and processes payment of the loan to a third-party.
- Energy Services and Managed Energy Services Agreements (ESA/MESA), for projects $500,000 and up.
- Equipment Lease Programs, for projects under $100,000.

While each approach has advantages and disadvantages, Mr. Brown identified special merit in building on Minnesota's existing C-PACE authorizing statute. His analysis found that, "the overall structure [of Minnesota's statute] reflects best practices around the country."[186]

COMMERCIAL PROPERTY-ASSESSED CLEAN ENERGY (C-PACE) FINANCING

Property-assessed financing is a tool that has been used for a variety of eligible property improvements since the 1950s.[187] In recent years, some states have extended the financing tool to cover energy efficiency and clean energy property investments, including rooftop solar PV systems.

a) Policy purpose

Commercial Property Assessed Clean Energy (C-PACE) financing is a tool that enables commercial, industrial, and multi-family residential property owners access to low-cost financing that is repaid through a voluntary property-tax assessment that runs with the property.[188] The approach is attractive to lenders because it provides a clear process to recovering the loan amount even in the event of default.

Apart from satisfying lender requirements, which is a prerequisite for any successful financing tool, C-PACE financing also helps overcome other barriers to deploying rooftop solar. The ability to finance 100 percent of a project's cost addresses the high initial-cost barrier. C-PACE's special assessment term (up to 20 years in some cases) aligns relatively well with the productive life of the asset.[189]

An assessment mechanism may allow the property owner to avoid carrying the debt on their balance sheet, where it might otherwise reduce their ability to borrow money for other uses (e.g., business expansion). But proposed changes to accounting rules would require disclosure of "lease financed" investments made by businesses, similar to C-PACE.

C-PACE financing may also help overcome the tenure mismatch barrier because the property assessment runs with the property (i.e., the energy improvements it allows), regardless of who owns the property. At the same time, a C-PACE assessment may shift the risk of a default onto future property owners, or otherwise complicate future property transactions.

C-PACE financing may also incorporate safeguards to ensure that the energy improvements pay for themselves over their useful life.[190]

b) Current Minnesota policy

In 2010, Minnesota adopted legislation to allow cities, counties, and other entities to develop and implement

C-PACE financing programs, under the title of "Energy Improvements Program for Local Governments."[191]

Local C-PACE programs, if implemented, would enable qualifying commercial, industrial, and multi-family residential property access to financing for energy efficiency improvements, electric vehicle charging equipment, and renewable energy generation systems—including rooftop solar PV.[192]

State law also speaks to residential properties, but the development of Residential PACE financing programs has been slowed due to concerns raised by the U.S. Federal Housing Finance Agency.[193] For this reason, PACE programs nationwide tend to focus on commercial and industrial properties.

Minnesota's C-PACE statute limits the financing term to the useful life of the energy improvements installed, or 20 years (whichever is less).[194] But a separate statute effectively limits property assessments to a maximum 10-year term.[195] (See June 2013 Addendum for legislative update.)

Minnesota's C-PACE policy includes safeguards to ensure that potential energy savings are accurately estimated before financing is secured. This informational requirement helps educate property owners regarding the magnitude of potential operational cost savings so they can make informed decisions.

c) Current Minnesota C-PACE financing programs

In November 2011, the Edina City Council voted unanimously to adopt the Edina Emerald Energy Program (EEEP), creating the state's first (and only) C-PACE program.[196]

The total cost of developing and implementing the Edina program was $11,400.[197] (This does not include ongoing administrative costs, some of which are borne by program applicants.) Program development costs included the city staff time and legal and bonding counsel required to develop program documentation, including administrative guidelines, loan application, bond purchase agreement, bond resolution, eligible improvements list, and financing flowchart and summary.

Edina C-PACE financing is available to qualifying commercial, industrial, and multi-family residential property owners. Eligible improvements include energy efficiency measures and solar equipment (including both solar PV and solar hot water).[198]

The applicant is required to find a private investor to back a municipal revenue bond from the City, the sale of which funds the loan payment. Repayment is processed through a lien on the owner's property over a term not to exceed 10 years.[199]

Because private investment is covering the cost of the loan, no public money is used. The city is reimbursed for administrative expenses.[200]

So far, two projects have used the Edina C-PACE program. The first project secured Edina C-PACE financing for a 27-kilowatt rooftop solar PV system. A California-based investor purchased the associated 10-year municipal revenue bond.

In the second project, Edina-based Parasole Restaurant Holdings secured Edina C-PACE financing for $39,000 in energy efficiency upgrades to its Salut Bar Americain property.[201] Minnesota-based Bremer Bank purchased the associated five-year bond (becoming the first community bank in the nation to serve as a C-PACE investor).[202]

The efficiency upgrades for Salut are expected to save $5,500 a year in net operating costs during the five-year repayment period, after which net annual savings will increase to over $15,000 a year for the life of the equipment.[203] "It is a meaningful savings," says Parasole's chief development officer, Alan Ackerberg.[204]

Private developers claim to have additional C-PACE financed commercial solar projects in development.[205]

d) Barriers to implementation and use

Assessment term

Minnesota's C-PACE statute explicitly contemplates an assessment term of up to twenty years, as allowed in many other states. But a pre-existing limitation in special assessment statute serves to limit C-PACE assessments to a 10-year term.[206] (See June 2013 Addendum for legislative update.)

A technical change to this statute would allow local C-PACE programs to provide longer-term repayment, which could help reduce annual assessment costs and allow C-PACE financed commercial and industrial solar projects to become "cash-flow positive" at an earlier point in the project life. Allowing for earlier positive cash flow would tend to increase the attractiveness of energy improvement projects.

It is important to note that while the Minnesota C-PACE statue is silent on mortgage lender consent, securing mortgage-lender consent to subordinate status when required may be easier for projects with a more positive cash flow. C-PACE energy improvements may also improve property valuation and the mortgage borrower's overall net operating income.

Nonetheless, there may be concerns regarding extending the allowable assessment term. First, subordinate creditors that support allowing a 10-year assessment ahead of them in lien priority might have concerns with a 20-year assessment. Second, there is no guarantee that the bond market will buy 20-year bonds tied to taxable private real estate, even with the first lien position. Third, the longer the repayment term, the more risk that the equipment will fail or become obsolete before the assessment is paid in full. A longer repayment term is also generally associated with higher overall interest payments.

Administrative considerations

C-PACE programs are administratively costly and complex to develop with no certainty of interest within the community.

As described above, there are costs to developing a C-PACE program. Further, the complexity associated with developing and administering a local C-PACE program may limit the number of local governments that choose to employ C-PACE. Further, given the newness of the program, some city officials lack confidence that a C-PACE program would generate sufficient project activity to justify the commitment of limited staff resources.

A potential solution could be to develop a regional- or statewide authority that is available to administer and handle various components of local C-PACE programs on a local government opt-in basis. For example, the authority might handle technical loan review, loan origination, credit underwriting, and bond issuance, with the local government retaining responsibility for property assessment and collection.[207]

At least one state, Connecticut, has developed state-level authority to provide technical and administrative assistance to participating local governments (see case study, below). Other states are evaluating regional (i.e., sub-state) approaches.

CASE STUDY: State of Connecticut C-PACE assistance program

Connecticut has developed a statewide approach intended to address the above-described barriers regarding the cost and complexity of developing local C-PACE financing programs. In June 2012, Connecticut passed legislation enabling municipalities to opt-in to the state's C-PACE program.

To encourage and expedite participation, the program is managed and administered by the Clean Energy Finance and Investment Authority (CEFIA), a quasi-public organization designed to develop and support financing programs that promote clean energy investment and stimulate demand for clean energy and deployment in the state.[208] CEFIA is authorized to provide technical assistance to, and handle administrative tasks for, local C-PACE financing programs on an opt-in basis.

CEFIA essentially acts as a facilitator between property owners, banks and C-PACE investors, cities, and energy efficiency/solar contractors to make the complexity inherent in C-PACE easier to navigate for all parties.

Under the program, qualifying commercial (including multi-family properties with five or more units) and industrial real property owners can apply for financing for energy efficiency upgrades and solar installations. Connecticut's program has similar features to many other C-PACE programs throughout the country, and utilizes the following steps to see a project from start to finish:[209]

1. Property owner works with an energy auditor or contractor to identify eligible projects.
2. Owner applies on CEFIA's C-PACE website for financing and CEFIA works with the owner to secure low-cost private financing. No direct government financing is used.
3. When the project is approved, CEFIA requests that a lien be placed on the property in the given municipality and transfers funding when the project is completed.
4. Payments are made through CEFIA via a line item on the owner's property tax bill over a term of up to 20 years. If the property is sold, the assessment stays with the building.

As of February 7, 2013, 11 Connecticut municipalities have enacted agreements to develop local C-PACE programs,[210] and 8 capital providers have been approved by CEFIA as C-PACE lenders, including Wells Fargo Securities, Citigroup Global Markets, and Clean Fund.[211]

THIRD-PARTY OWNERSHIP

a) Policy purpose

Though many people may prefer to buy solar-generated electricity, not all want or are able to own a PV system. Property owners may want to take advantage of their onsite solar resource without having to take responsibility for the system's ongoing operation, maintenance, performance monitoring, and insurance.[212]

The third-party model is also attractive to some **tax-exempt institutions**, such as state agencies and/or institutions, schools, colleges and universities, hospitals, churches, and local governments. Because of their tax-exempt status, these institutions cannot capture the 30-percent federal Investment Tax Credit (which is set to revert to a 10-percent credit on January 1, 2017) and accelerated depreciation benefits that are available to businesses.[213] A third-party developer can capture these benefits and share them with the host, resulting in lower net project costs.[214]

Property owners could elect to be a system host, rather than an owner, for a number of other reasons. Using a third-party model may allow the customer to obtain greater cost certainty, for example by shifting any casualty loss and **production risk** to the third-party owner (who may be better positioned to manage such risk).[215]

The use of a third party can also add value at the residential and homeowner level, where the third party essentially serves as a general contractor that oversees project construction and long-term operations and maintenance.[216]

Maintaining ownership of the solar generation asset also allows the third party to pre-arrange financing for its customers ("third-party financing"), in part because the third party can use the assets as equity or loan security. This pre-arranged financing (which can take various forms) may help residential homeowners and businesses overcome the high initial-cost barrier associated with going solar.

There are potential downsides to the third-party ownership model. The inclusion of a third party and/or financing may add additional cost components, potentially increasing the overall (lifetime) cost of a given solar installation, depending on tax credits and other economic factors.[217] Second, a number of utilities have voiced concerns that the third-party ownership model may be problematic in the context of traditionally regulated utility systems.

Third-party ownership business models fall into two main categories: solar power purchase agreements and residential system leasing.

(1) Solar power purchase agreements (PPAs)

Under this approach, a third party owns the customer-sited solar PV facility and sells the energy produced to the customer under a private contract. The first company to provide solar as a service (rather than a product) was SunEdison, which began offering PPAs to commercial customers in 2003.[218]

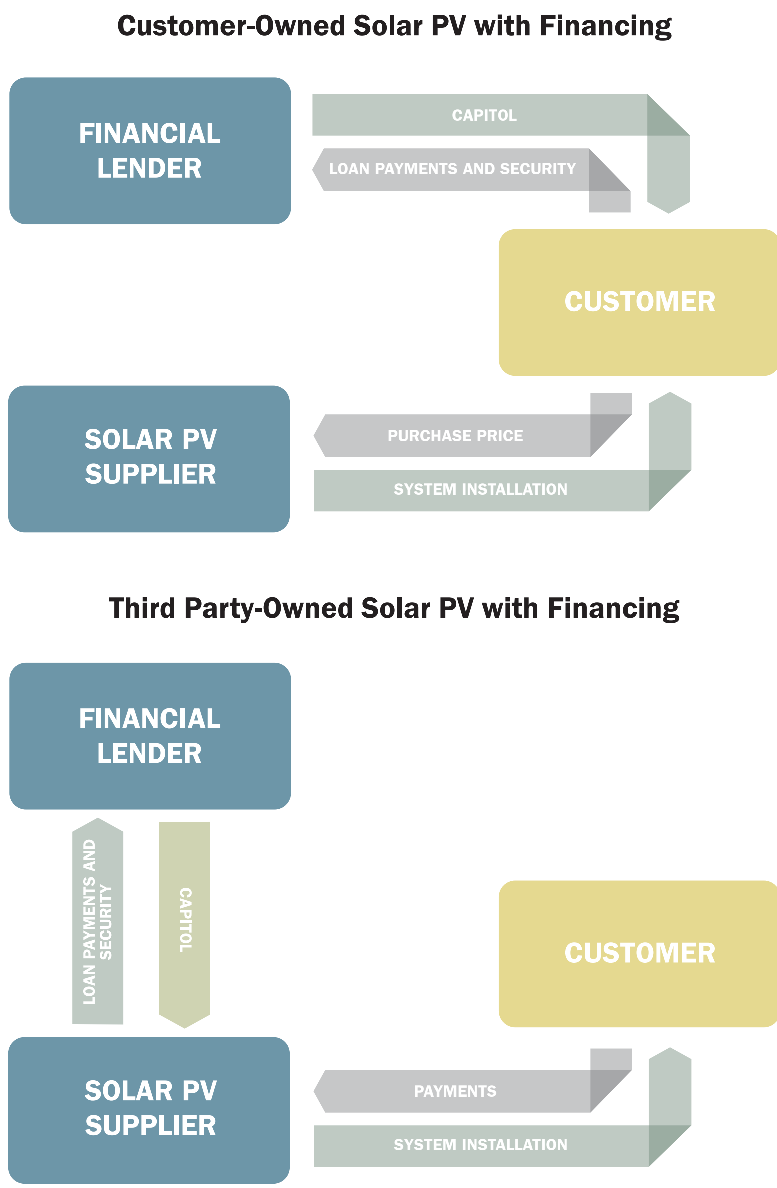
The model quickly proved popular, in part because it allowed publicly traded companies to pay for solar power over the course of the systems' useful life rather than buying the system up front and carrying the associated debt on their balance sheet.

Third-party ownership also provides important benefits to potential financial lenders. The model allows capital to be lent to a single entity (the third-party owner), who can then provide a form of pass-through financing to multiple business owners. The third-party owner can also often provide superior security to the lender (insulating the lender from risk of customer non-payment, simplifying the collections process, and obviating the administrative costs of obtaining security from each end customer).

In the traditional ownership model, financing (if any) is usually identified and obtained by the customer. Under a third-party model, customer financing often comes standard, with the owner having already secured financing for qualifying

Photo: Minneapolis, MN (40 kW, 2010) Photographer: Ray Colby

Fig. 4: Customer financing vs. third-party financing[219]



customers. (This is roughly analogous to the way that auto makers and dealers provide financing or lease options at the point of sale.)

Lenders, such as banks and tax equity investors, are attracted to third-party financing because it allows them to aggregate financing and reduces their risk (relative to making individual consumer loans). In this way, third-party leasing companies are able to tap deep pools of capital at lower financing rates. For example, third-party residential solar providers attracted over $600 million in new capital investments in 2012.[220] (According to Shayle Kann, Vice President of Research at GTM Research, this influx of capital "signifies the growing acceptance of solar leases and power purchase agreements as a secure investment for project investors.")

For customers, one potential downside of buying solar as a service is that the value of the system's production may (it is unclear) thereby become subject to Minnesota sales tax. Minnesota has a sales tax exemption for the direct purchase of a solar energy system, but no clear exemption for taxes on power purchased from an onsite solar PV system.[221]

At least two states have recently created a sales-tax exemption for energy purchased from onsite solar PV systems under third-party PPAs:

- Maryland: As of July 2011, sales of electricity from solar energy receive a sales and use tax exemption. To qualify, sale must be for residential use on a property owned by a net metering eligible customer-generator.[222]
- Wisconsin: As of July 2011, receipts from the sale of electricity produced by a qualifying renewable energy system are exempted from the state's sales tax.

(2) Solar equipment leasing

A second variety of third-party ownership is solar leasing. In this model, the customer leases the solar PV system (e.g., for a fixed monthly lease payment) and is allowed the use of all solar energy produced by the system during the course of the lease. As the owner of these rooftop systems, the leasing company will typically provide (or contract for the provision of) system installation, operation, performance monitoring, and maintenance.

In states that authorize it, solar equipment leasing has become especially popular in the residential market, in part because the business model effectively satisfies or obviates the need for long-term customer financing. Of the 22 states (not including Minnesota) that authorize broad third-party ownership, 14 have attracted businesses that offer solar PV to homeowners for no money down or with monthly net cost savings.[225]

CASE STUDY: Cherokee United Church rooftop solar PV

In August 2012, Saint Paul-based Cherokee Park United Church (CPUC) commissioned a 21-kilowatt rooftop solar PV system to provide roughly 125 percent of the church's annual electricity needs.[224] Because of its nonprofit and tax-exempt status, however, CPUC could not directly access the 30 percent federal tax credit.

Church members and community leaders approached Minneapolis-based solar developer Sundial Solar about serving as a third-party owner for the project. Under the project agreement, Sundial Solar maintains ownership of the solar PV array for the five or six years necessary to capture the federal tax credit and depreciation benefits. After the tax benefits are realized, CPUC will buy the rooftop solar PV system for fair market value and take ownership of the system.

A 2012 report by the U.S. National Renewable Energy Lab (NREL) found that third-party residential leasing expands access to rooftop solar PV. For homeowner-owned systems, NREL found a positive purchase correlation in neighborhoods with average household incomes of $150,000 or more. With third-party residential leasing, a positive correlation existed in neighborhoods with average household incomes of $100,000 or more.[226]

b) Current policy

Minnesota provides limited authorization for third-party owners

Third-party ownership models face regulatory challenges in some states. Several of these challenges "pertain to whether third-party owners are deemed to act as monopoly utilities, competitive service suppliers…or both depending on the degree of retail electricity market deregulation."[227]

Third-party owners (if authorized) are not subject to the same state-level regulations as utilities, but licensing requirements and other regulations may apply.[228]

Minnesota's utility definition statute, Minn. Stat. 216B.02, appears broad enough to encompass third-party solar owners and the various business models that they might employ (including both solar PPA and solar leasing). Minnesota adopted this definition well before the advent of modern solar PV technology, so it is unlikely that the definition was crafted with customer-sited solar specifically in mind. Under the statute, there are two broad sub-definitions of "public utility."

The **first sub-definition** covers any entity that operates, maintains, or controls electric "equipment or facilities for furnishing at retail…electric service to or for the public…."[229] Under this definition, an entity that merely operates or maintains a customer-sited solar PV system could be considered a public utility. An argument can be made that each third-party owned solar facility provide power only to a single customer (the host), rather than "to or for the public." But the language of the statute does not provide clear guidance, so there is a risk to third-party owners that they could be deemed a public utility (with all the costs and benefits entailed).[230]

Under the **second sub-definition** any entity "engaged in the production and retail sale" of electricity is a public utility.[231] While this language is broad, it is again difficult (in the absence of any close precedent in case law) to predict with certainty how a court might apply the language to third-party solar owners.[232]

The statute does include an **exemption** that appears to allow for third-party ownership at a limited scale: "No person shall be deemed to be a public utility if it produces or furnishes service to less than 25 persons."[233] The exemption was adopted into statute prior to 1978, indicating that the exemption was not originally directed towards third-party solar PV owners.

Policy makers should be aware that proposed modifications to Minnesota's current utility-definition statute would be subject to utility scrutiny regarding potential long-term impacts and/or unintended consequences.

Eligibility for net metering, solar tariffs, and solar incentives

Minnesota's current net metering policy does not appear to limit or restrict third-party ownership models.[234] No Minnesota utility has offered a value-of-solar tariff to date. One policy question that would be raised by such a tariff is whether systems of third-party solar owners would be eligible.

Currently, seven utilities offer solar PV rebate programs in Minnesota.[235] The two largest rebate programs specifically exclude homeowners who lease (rather than buy) their solar energy system.

To qualify for Xcel Energy's Solar*Rewards program, you must "own the PV system and the property/building on which the system will be installed."[236] To qualify for Xcel Energy's Minnesota Bonus PV rebate program, you must have also applied for and be eligible for an Xcel Energy Solar*Rewards agreement. So neither a third-party owner nor a residential customer who hosts a third-party-owned system qualifies for the Made in Minnesota rebate.

Similarly, to qualify for Minnesota Power's solar rebate, you must "own the PV system and the property/building where the system will be installed."[237]

The remaining utility rebate programs do not appear to exclude third-party owned systems from eligibility.

c) Third-party-ownership authorization in other states

At least 22 states (plus Washington, D.C.) explicitly authorize or allow third-party solar PV ownership.[238] According to the Database of State Incentives for Renewables & Efficiency ("DSIRE"), six states explicitly disallow or restrict third-party solar ownership, while the status of third-party ownership in the remaining states (including Minnesota) is "unclear or unknown."[239]

In roughly half of these states, the authorization is statutory, while the rest authorized third-party ownership though a regulatory decision.

Fig. 5: State authorization of third-party PV ownership models (2012)[240]

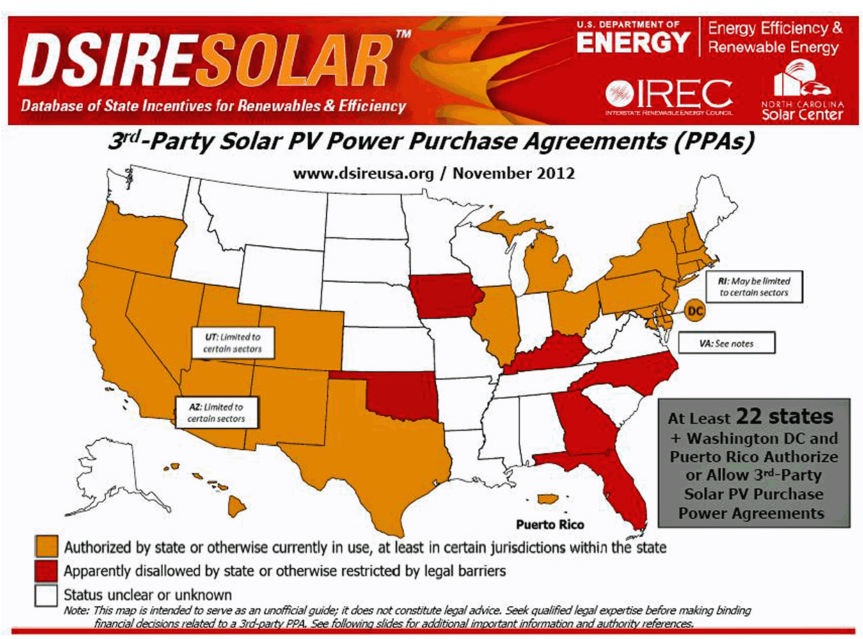


Table 5: State authorization of third party ownership models (by year)[241]

STATE	YEAR AUTHORIZED	FORM OF AUTHORIZATION
New York	2004	PUC Docket
Pennsylvania	2005	PUC Docket
Ohio	2008	PUC Docket
California	2008	Legislation
Illinois	2008	Legislation
Michigan	2008	Legislation (and PUC Docket)
Oregon	2008	PUC Docket
Colorado*	2009	Legislation (and PUC Docket)
Maryland	2009	Legislation
Massachusetts	2009	PUC Docket
Nevada	2009	Legislation (and PUC Docket)
New Jersey	2009	PUC Docket
Arizona	2010	PUC Docket
Delaware	2010	Legislation
New Mexico	2010	Legislation
Utah*	2010	Legislation
Connecticut	2011	Legislation
Hawaii	2011	Legislation
Rhode Island	2011	unknown
Texas	2011	Legislation
New Hampshire	2012	PUC Docket
Vermont*	unknown	unknown

*Indicates states that are traditionally regulated according to the U.S Energy Information Administration.[242]

Six states explicitly disallow some form third-party ownership: Florida, Georgia, Iowa, Kentucky, Oklahoma, and North Carolina.[243] Florida disallows third-party PPAs, but allows third-party leasing.[244]

Table 6: States that explicitly disallow or restrict third-party PV ownership[245]

STATE	FORM OF ACTION
Florida	1987 PUC decision
Georgia	Legislation
Iowa[242]	2012 Iowa Utilities Board Decision
Kentucky	Legislation
Oklahoma	Legislation
North Carolina	Legislation

d) Third-party market activity in other states

Combined, the five largest third-party solar companies are currently offering zero-down financing to at least some residential customers in 14 states and the District of Columbia.

Table 7: Residential lease/PPA market activity (2012)

STATE	SUNRUN[243]	SOLARCITY[244]	CLEAN POWER FINANCE[246]	SUNGEVITY[247]
Arizona	x	x	x	x
California	x	x	x	x
Colorado	x	x	x	x
Connecticut		x		x
Delaware		x		x
Hawaii	x	x	x	
Maryland	x	x		x
Massachusetts	x	x	x	x
New Jersey	x	x	x	x
New York	x	x	x	x
Oregon	x	x		
Pennsylvania	x	x	x	
Texas		x		
Vermont			x	
Washington		x		
Washington, D.C.		x		

The fact that Table 7 doesn't include every state listed on Table 5 indicates that explicit authorization alone does not necessarily trigger short-term market activity. SunRun, SolarCity, and their competitors will likely focus their market-entry efforts on states with a growing market demand, predictable solar incentives (*i.e.*, over a multi-year business investment horizon), and high utility rates (which tend to make onsite solar more competitive in cost-per-kilowatt-hour terms).

CASE STUDY: Colorado third-party ownership

Colorado background

Prior to 2009, Colorado statute defined "public utility" as "[e]very cooperative electric association, or nonprofit electric corporation or association, and every other supplier of electric energy, whether supplying electric energy for the use of the public or for the use of its own members[.]"[252]

As such, third-party solar owners were, together with traditional central-generation utilities, declared by statute to be "affected with a public interest" and thus subject to the jurisdiction, control, and rate regulation of the public utility commission.[253]

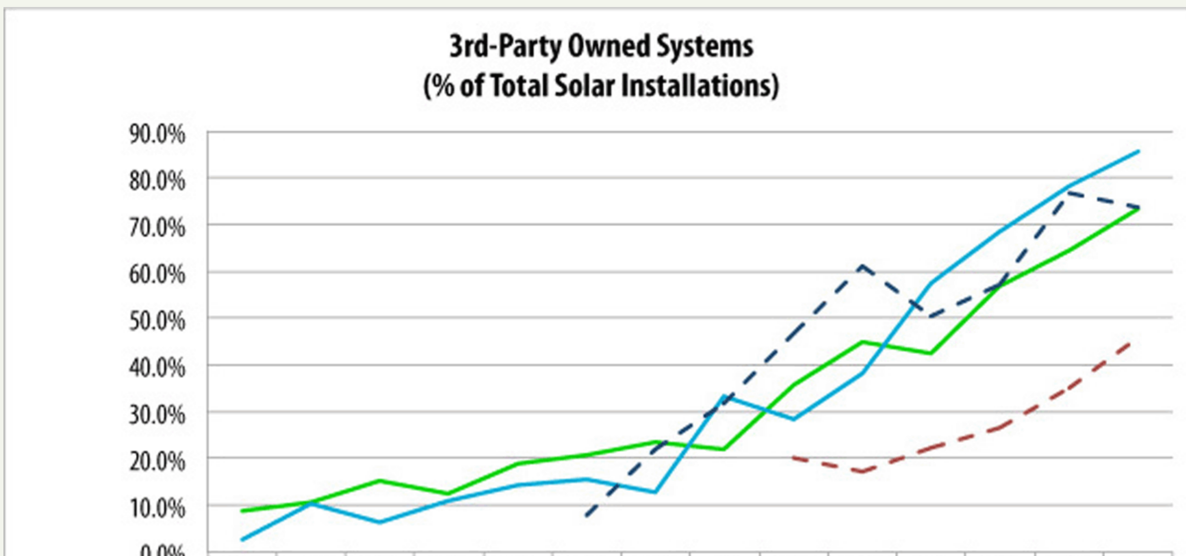
Colorado process

In April 2009, Colorado passed legislation that explicitly allowed third-party ownership of solar installations in the state.[254] Under the statutory definition of "public utility," Senate Bill 09-051 added a paragraph exempting owners of certain third-party owned systems.

The statute, in relevant part, establishes that the supply of onsite solar power or heat from a third-party-owned system "shall not subject the owner or operator of the onsite solar generating equipment to regulation as a public utility by the Commission ...."[255] The exemption is limited to third-party owners that size their solar equipment "to supply no more than one hundred twenty percent of the average annual consumption of electricity by the consumer at that site."

In September 2009, the state's Public Utilities Commission adopted rules to allow third-party owners or operators to service onsite solar customers.[256] At that time, there were virtually no third-party solar installations in the state (see figure below). Since then, third-party ownership of solar installations in Colorado has grown dramatically, with third-party models now claiming a majority of the market (in terms of number of new installations).[257]

Fig. 6: Prevalence of third-party-owned solar PV systems (Q2 2012)[258]



	Q1 2009	Q2 2009	Q3 2009	Q4 2009	Q1 2010	Q2 2010	Q3 2010	Q4 2010	Q1 2011	Q2 2011	Q3 2011	Q4 2011	Q1 2012	Q2 2012
California	8.7%	10.7%	15.2%	12.6%	18.8%	20.7%	23.5%	22.1%	35.7%	44.9%	42.6%	56.7%	64.4%	73.3%
Arizona	2.6%	10.5%	6.3%	10.9%	14.4%	15.4%	12.7%	33.4%	28.5%	38.1%	57.5%	68.4%	78.3%	85.5%
Colorado						7.8%	21.9%	31.7%	46.9%	61.2%	50.5%	57.1%	76.7%	73.8%
Massachusetts									20.2%	17.2%	22.4%	26.5%	35.1%	45.9%

SOLAR OR DISTRIBUTED GENERATION (DG) ENERGY STANDARD

A solar energy standard is a renewable energy standard (RES) that requires utilities to supply a certain percentage of their retail energy sales with solar-generated electricity or thermal energy.

A majority of U.S. states, including Minnesota, currently have a RES in place. Sixteen of these RES policies also contain some form of solar or DG requirement that establishes clear permission (and direction) for utilities to invest in the procurement of solar power.

Minnesota's current RES applies to all utilities, but does not include an explicit solar or DG requirement. Most Minnesota utilities are meeting the current RES requirements through the construction of wind farms and purchase of wind energy as the least-cost eligible resource.

POLICY PURPOSE

Solar energy standards (SES) or portfolio set-asides serve at least two main purposes:

- ***Increased fuel diversity***. The SES supports greater diversity in renewable energy growth, particularly given that the vast majority of RES-driven installed capacity has been in wind resources.[259] With a SES, solar energy development occurs at a utility resource-planning scale, capturing diversity benefits at the system level.
- ***Market transformation.*** The SES serves as a market-based market-transformation tool. The required amount of capacity or generation is defined in the standard, but cost of resource acquisition is left to the market. This has the effect of pushing the solar industry to competitively improve efficiencies, deliver the resources at lower cost, and move closer to an economically self-sustaining industry.

As with traditional fuels, a diverse mix of renewable fuels lowers risk, enhances system and price stability and captures economic and environmental benefits.[260] A technology-neutral RES cannot guarantee resource diversity or jump-start development in immature industries, because utility investment is generally directed to the least-cost eligible resource. To ensure diversity and meet market transformation goals a technology- or size-specific obligation is sometimes employed.

Solar PV in particular may benefit from an explicit requirement within state RES policies. According to the Lawrence Berkeley National Laboratory, a majority of the solar PV deployed in the United States (outside of California) from 2005 to 2009 occurred in states with solar PV or DG requirements.[261] This suggests that solar requirements have played a key role in propelling solar growth.[262]

Solar standards are not, however, without risks and tradeoffs. Emerging distributed-generation sources (including solar PV) may come with higher costs and may put upward pressure on overall costs. Achieving deployment goals and cost targets will depend on whether the policy helps support the development of the market forces necessary to meet the goals (i.e., by being supportive of private-sector contract formation and capital financing).

REGULATORY BARRIERS TO UTILITY INVESTMENT IN SOLAR GENERATION

Solar energy standards may also help reduce the risk faced by utilities. Under traditional utility regulation, the approach used in Minnesota, utilities face several barriers to investing in new technologies and new markets such as solar energy, in spite of a statutory preference for renewable energy and distributed generation. These barriers are presented by other statutory goals and regulatory standards that utilities are also obligated to meet, most notably:

- the obligation to have reasonable rates (*i.e.*, least-cost service)
- the regulatory expectation to follow industry practices regarding new utility investments (*i.e.*, the prudent management requirement)

a) Creating a safe harbor for DG and solar

Under existing regulation, if utilities take actions or make investments that are viewed as failing to meet the state's statutory standards or goals, the utilities face a risk of not being allowed to recover, through rates, the costs associated with those actions or investments. Utilities may thus face regulatory risk for making investments that meet renewable energy goals but are not "least cost."

For instance, when renewable energy and least-cost goals lead to different strategies, some stakeholders have advocated that renewable energy goals should be subordinate to least-cost goals and that costs associated with renewable energy should be disallowed—increasing utility cost-recovery risk.

The establishment of a solar or DG standard can help reduce this risk because while the utility must achieve the standard at least cost, the mere fact of solar or DG procurement will not questioned as imprudent management.

b) Risks and future issues

The adoption of a solar energy standard may, in the long-term, raise questions in regard to undermining least-cost goals and long-term cost recovery of existing utility infrastructure (generation, transmission, and distribution systems).

A 2012 study by the U.S. National Renewable Energy Laboratory (NREL) modeled the extreme limits of integrating renewable energy resources into the national grid.[263] The study concluded that an 80 percent renewable energy mix (with approximately 50 percent variable resources) is achievable and could be made reliable if the overall system was designed toward that end.

For perspective, Minnesota utilities are currently on track to provide an average of 27.5 percent renewable electricity by 2025.

Minnesota's solar PV capacity at the end of 2012 was roughly 12 megawatts, equivalent to much less than one percent of utility sales.[264] In per-capita terms, Minnesota has roughly two watts of solar PV installed per person. The table below shows the ratio of installed solar watts per capita for various leading solar states as of 2011 (the last full year for which cross-state data is available).

Table 8: Installed solar watts per capita (various states, 2012)[265]

STATE	INSTALLED SOLAR WATTS PER CAPTIA (2012)	STATE	INSTALLED SOLAR WATTS PER CAPTIA (2012)
Arizona	171	Delaware	51
Hawaii	146	Vermont	44
Nevada	129	Massachusetts	32
New Jersey	109	Oregon	15
New Mexico	98	Pennsylvania	13
California	68	Wisconsin	4
Colorado	60	Minnesota	2

In addition to NREL's technical analysis (referenced above), market experience thus also suggests that Minnesota can achieve much higher levels of solar PV deployment without causing utility reliability issues (assuming best practices for technical interconnection and utility monitoring).

In the long term, increasing the use of variable and distributed resources may require changes to the structure and management of utility systems, and may include changes to utility business models themselves.

Moreover, changing the configuration of the utility system to incorporate high levels of renewable energy may decrease the "usefulness" of some existing utility infrastructure prior to its full cost recovery, creating a risk of stranded or underutilized costs.

But the risk of incurring significant stranded costs with deployment of solar PV at levels of less than five percent appears to be limited. Some utilities in Hawaii, California, and elsewhere are already operating above the five-percent level.

By increasing the solar requirement over a period of years, a solar energy standard can mitigate risk to existing investment and enable a lower-cost transition through alignment with normal infrastructure replacement and upgrade schedules.

TYPES OF POLICY APPROACHES

States typically use two main methods for applying a SES and measuring progress toward the goal: requirements and multipliers. Both methods are aimed at meeting the SES policy goals of improved resource diversity and market transformation.

a) Solar PV requirements

Solar energy requirements (variously known as solar set-asides, carve-outs, or add-ons) are the most common approach. In general, they give policy makers a degree of certainty and control regarding the overall level of solar penetration, the rate of solar growth, and how that growth is allocated among different generator types.

However, the nature of a solar requirement may risk putting upward pressure on the cost to comply with an overall RES policy, especially if solar is more expensive than other eligible technologies.[266] For this reason, policy safeguards to mitigate upward rate pressure are sometimes employed.

The following table shows the states that have adopted an explicit solar PV or distributed generation requirement.

(Note, state RES targets are typically expressed as a target percentage of energy sales at the utility level.)

b) DG requirements

At least five states have some form of a renewable DG standard. These standards generally include most categories of solar PV, but exclude large ground-mounted, "utility-scale" solar facilities.

Two states, Colorado and Arizona, have a DG-only standard, with no separate solar PV set-aside. Two other states, Illinois and New Mexico, have separate set-asides for both DG and solar. Utility-scale solar projects may count toward the utility's solar requirement, but not toward their DG requirement. New York has a solar PV set-aside nested within a larger DG set-aside.

Table 9: States with solar PV or DG requirements (by start year)[267]

STATE	START YEAR	SOLAR PV TARGET	BY
Nevada	2005	1.5%	2025
New Jersey	2005	4.1%	2028
Pennsylvania	2007	0.5%	2021
Washington, D.C.	2007	2.5%	2023
Arizona*	2007	4.5%	2025
Maryland	2008	2.0%	2020
Delaware	2008	3.5%	2525
Ohio	2009	0.5%	2024
New Hampshire	2010	0.3%	2014
New York*	2010	0.4092%	2015
North Carolina	2010	0.2%	2018
Massachusetts	2010	400 MW	2020
Colorado*	2011	3.0%[264]	2020
New Mexico*	2011	4.0% (0.6% DG)	2020
Oregon	2011	20 MW	2020
Missouri	2011	0.3%	2021
Illinois*	2013	1.5% (0.25% DG)	2025

*Indicates states with a special carve out for distributed generation.

As the table above shows, states with distributed generation standards have elected to cover (or not cover) a range of generation technologies. For comparison, Minnesota's current Renewable Electricity Standard recognizes the following eligible technologies: solar thermal electric, photovoltaics, landfill gas, wind, biomass, hydroelectric under 100 megawatts, municipal solid waste, hydrogen, co-firing, and anaerobic digestion.

Table 10: States with DG requirements (by start year)[270]

STATE	START YEAR	DG TARGET	BY	ELIGIBLE TECHNOLOGIES
Arizona	2007	4.5%	2025	solar water heat, solar space heat, solar thermal electric, solar thermal process heat, photovoltaics, landfill gas, wind, biomass, hydroelectric, geothermal electric, geothermal heat pumps, chp/cogeneration, solar pool heating (commercial only), daylighting (non-residential only), solar space cooling, solar hvac, additional technologies upon approval*, chp only counts when the source fuel is an eligible renewable energy resource, anaerobic digestion, fuel cells using renewable fuels, and geothermal direct-use.
New York	2010	0.4092%	2015	solar water heat, photovoltaics, landfill gas, wind, biomass, hydroelectric, fuel cells, chp/cogeneration, anaerobic digestion, tidal energy, wave energy, ocean thermal, ethanol, methanol, biodiesel, and fuel cells using renewable fuels.
Colorado	2011	3.0%	2020	solar thermal electric, photovoltaics, landfill gas, wind, biomass, hydroelectric, geothermal electric, recycled energy, anaerobic digestion, and fuel cells using renewable fuels.
New Mexico	2011	0.6%	2020	solar thermal electric, photovoltaics, landfill gas, wind, biomass, hydroelectric, geothermal electric, zero emission technology with substantial long-term production potential, anaerobic digestion, and fuel cells using renewable fuels.
Illinois	2013	0.25%	2025	solar thermal electric, photovoltaics, landfill gas, wind, biomass, hydroelectric, anaerobic digestion, and biodiesel.

CASE STUDY: Colorado DG energy standard

Colorado's Renewable Energy Standard requires investor-owned utilities to obtain 30 percent of their retail electricity sales from renewable energy by 2020 and each following year.[286] Within that requirement is a DG requirement (or carve-out), under which investor-owned utilities must obtain three percent of their retail electricity sales from wholesale or retail distributed generation sources by 2020 and each following year.[287]

Colorado defines "retail" DG as "a renewable energy resource that is located on the site of a customer's facilities and is interconnected to the customer's side of the meter." The state defines "wholesale" DG as "a renewable energy resource in Colorado with a nameplate capacity of 30 megawatts or less and that does not qualify as retail distributed generation."

Eligible DG technologies include solar thermal electric, photovoltaics, landfill gas, wind, biomass, hydroelectric, geothermal electric, recycled energy, anaerobic digestion, and fuel cells using renewable fuels.[288] Colorado utilities may use any of these technologies to satisfy their DG requirement.

c) Credit multipliers

Seven states have adopted some form of solar PV or DG credit multiplier. Under this approach, qualifying generation technologies earn more renewable energy credits (RECs) than non-qualifying technologies for producing the same amount of energy.

Table 11: States with solar PV or DG credit multiplier[271]

STATE	MULTIPLIER
Colorado	Various solar PV multipliers
Delaware	3x credit for solar PV
Michigan	3x credit for solar PV
Texas	2x credit for non-wind (500 MW goal)
Utah	2.4x for solar-electric
Washington	2x credit for DG
West Virginia	Various technology-specific DG multipliers

One purpose of credit multipliers is to encourage utilities to diversify their renewable energy investments, rather than focus entirely on the least-expensive renewable energy sources. The approach is intended to incentivize specific technologies, but may not stimulate growth if a specific technology is not cost-competitive with other sources of generation even after accounting for the multiplier credit.

Multipliers also reduce the total amount of renewable energy generation achieved by giving greater credit to certain technologies for similar megawatt-hours produced. Given these concerns, multipliers have not proven particularly effective at stimulating solar growth.[272]

d) Utility categories covered

Utilities of different sizes have faced different levels of risk and reward from a solar energy standard (SES) policy. Different states have made a variety of choices about which utilities and utility categories (investor-owned, municipal, or cooperative) are required to meet the SES.

For example, Colorado has a 30-percent renewable energy target for investor-owned utilities, a 10-percent target for electric cooperatives, and a 10-percent target for municipal utilities serving more than 40,000 customers.[273]

Utilities with smaller and less diverse loads may face a higher risk for cost impacts or stranded investment at lower penetration rates than larger utilities. However, SES capacity increments are generally quite small and are unlikely to ramp up too rapidly to allow for mitigation of cost risk.

OWNERSHIP, MEASUREMENT, AND PRICING OF SOLAR CREDITS

Most states with an RES policy, including Minnesota, use renewable energy credits (RECs) to measure and track renewable energy generation, and to enable accurate utility compliance towards RES goals. By law, a single REC (or credit) is created for every megawatt-hour generated by a qualifying renewable energy facility.[274]

States that have a solar-specific requirement track compliance using solar RECs, also known as SRECs.

State RES policies will often also employ REC-related market-supporting mechanisms (such as property rights, sale by contract, and commodity exchanges) to help drive down long-term utility compliance costs.

Similarly, some states with SES policies have adopted SREC-based price mechanisms to support the economic feasibility of customer-sited solar investments.

a) Solar credit ownership and property rights

According to the Interstate Renewable Energy Council (IREC), 22 states assign initial REC ownership to the owner of the renewable energy generation device (*e.g.*, a "customer-generator"), subject to pre-existing contractual and legal obligations.[275] For example, Arkansas, Colorado, Kentucky, and Pennsylvania tie initial REC ownership to the generator through statute, while California and Connecticut assign REC ownership through a Commission action.[276]

Three states assign initial REC ownership to the customer-generator's utility, while two others assign ownership to either party depending on the specific situation.[277] IREC reports that the remaining states, including Minnesota, do not explicitly establish whether initial REC ownership will vest in the customer-generator, the utility, or someone else.

While Minnesota does not establish initial REC ownership in statute, the Commission has resolved a number of case-specific contractual disputes regarding REC ownership.[278]

For example, in a September 9, 2010 order, the Commission determined that Xcel owned the RECs for utility power purchase agreements (PPAs) entered into pursuant to Minnesota's wind and biomass statutory mandates, "unless the generator could otherwise demonstrate that the PPA at issue is not silent" as to REC ownership, and determined that for PPAs entered into pursuant to the Federal Public Utility Regulatory Policy Act (PURPA), the generators own the RECs.[279]

At the same time, Xcel Energy and three other utilities (Great River Energy, Interstate Power & Light, Otter Tail Power Company) report current PPAs for which "the assignment of the RECs is not known."[280]

It thus appears that there may be ambiguity regarding the initial ownership of RECs in Minnesota. This ambiguity and uncertainty (and the related investment risk) will likely apply to the RECs associated with a new solar or DG requirement, absent an effort to clarify initial ownership.[281]

In states where initial ownership is established by statutory definition, the statute may be designed so as to not void or otherwise unsettle any current contractual agreements. In general, such definitions do not prevent transfer of RECs, but rather support contract transfer of RECs by reducing ambiguity.

b) Solar credit metering and tracking

There appears to be general agreement that SRECs are a useful mechanism for recording solar production and tracking utility progress towards a state SES. Establishing a solar (or distributed generation) standard implies the need to develop rules to meter, measure, track, and transfer SRECs.

A number of states with solar standards (including Delaware, Maryland, New Mexico, and Ohio) rely on their regional REC tracking systems for this purpose, in which case "the same protocols related to REC measurement and tracking apply to solar resources as to other types of renewable generation."[282] In Minnesota, the Midwest Renewable Energy Tracking System (M-RETS) currently tracks RECs associated with the RES.

Because existing REC metering and measurement protocols may not fit well for small rooftop solar projects, other states have developed separate, more-tailored rules and procedures for SRECs. For example, a number of jurisdictions (including Colorado, Missouri, Nevada, New Jersey, North Carolina, Pennsylvania, and Washington D.C.) have adopted protocols that provide SRECs to PV systems "smaller than a specified size threshold (typically 10 to 15 kilowatts), based on engineering calculations of system output rather than on metered electricity generation."[283]

c) Impact of SREC prices on customer-sited project economics

Some states with solar energy standards have also adopted SREC-based price mechanisms to support the economic feasibility of customer-sited solar investments. Broadly speaking, there are two main ways this is done.

Floating SREC price approach: The SREC price is set by market supply and demand. The experience in states following this approach has been mixed. Some states, such as New Jersey, have experienced significant SREC price volatility, which has created uncertainty about how to value long-term solar investments.

Utility incentive approach: In Colorado, Xcel Energy's Solar*Rewards program offers production-based incentives for customers who install solar generation facilities on their property, in addition to the state's net metering program. In exchange for these incentives, Xcel takes ownership of the

SRECs associated with said generation facility, which is then used to meet its SES obligations.

In both approaches, SREC prices ultimately depend on the utility demand for demonstrating compliance with renewable energy requirements. As utilities get closer to satisfying their requirements, the value of new SRECs will generally decrease.

d) Price transparency, volatility, and uncertainty

In the Midwest, the REC market is managed on the M-RETS system. Renewable energy credit transactions on M-RETS are private, with limited public disclosure regarding the prices at which RECs trade. This price transparency issue may limit the effectiveness of supporting project capitalization.

Other states have sought to reduce SREC-related price risk and facilitate project financing through a variety of policy designs, including: adopting "minimum contract duration" requirements, offering financial incentives or financing programs, conducting centralized procurement of RECs, and developing other novel procurement models, including direct utility ownership of distributed PV assets.[284]

For example, there is a risk that utilities are unwilling or unable to enter into the long-term SREC contracts needed to fund renewable energy projects. To overcome this concern, Colorado, Maryland, and Nevada have established minimum contract duration requirements for all solar energy contracts of 20, 15, and 10 years, respectively.[285]

COMMUNITY-OWNED SOLAR

DESCRIPTION

Community-owned solar, also known as shared solar, is a form of solar development in which multiple parties invest in a single solar installation and share the benefits of the energy production.

A number of community solar models exist, from informal donation-funded projects sited on a public or community-owned site, to formal subscriber-funded projects that benefit participants directly via a production credit on their utility bill.[289]

This section focuses on the formal subscription-based approach to community solar.[290]

a) Individual participation

In a community-shared solar project, individuals (or subscribers) may buy into a solar development and receive a proportional share of the system's monthly solar production. The individual's share of the production is provided as a credit on their utility bill through **virtual net metering**.[291] Other benefits of solar production, such as the associated solar renewable energy credits (SRECs), may also be allocated proportionately.

a) Operating structure

Community-shared solar projects can be located on the property of a subscriber, a third party, or the electric utility.

Project development and operation is typically managed by a facility manager, which can be the system host, a utility, or any other qualified entity.

Project capital and operation and management costs may be provided through project subscription fees, an assessment on electric production, or through other means. The production may be used by the system host or put onto the distribution grid of the local utility, which compensates the project subscribers through a bill credit.

POLICY PURPOSE

Community solar may help overcome market barriers and failures that limit many Minnesota residents, businesses, and nonprofit organizations from participating in solar development. Community solar projects:

- **Expand access to solar** by allowing tenants and property owners to purchase solar energy generation from a community solar PV facility.[292] Community solar opens the solar market to **renters, low income households, business tenants, and property owners** with suboptimal solar resource of their own.
- Allow homeowners and small businesses to access the **economies of scale** that can be realized in large projects.[293] For instance, in 2012, the national median installed cost for small rooftop PV systems (under 2 kilowatts) was $7.10/watt, while the installed cost for larger systems (sized 100 to 250 kilowatts) was $4.60/watt.[294]
- Decrease the **minimum required investment** for solar ownership.[295] A typical residential-sized system

may have an initial cost of $15,000 or more, before available rebates.[296]

- Reduce the **complexity and transaction costs** associated with onsite solar PV.
- Allow for **optimal project siting and solar production**. For example, community solar overcomes residential rooftop orientation, shading, and structural barriers common among residential rooftops.[297]

CASE STUDY: Wright-Hennepin solar community program

In 2012, the Wright-Hennepin Cooperative Electric Association announced plans to host the first formal, subscriber-funded community solar project in the state of Minnesota.

The 40-kilowatt project will be managed by a private third-party entity, and available to subscribing customers within the Wright-Hennepin service territory.[298]

All available shares have been fully subscribed by participating utility customers, at a cost of $869 per each 180-watt panel.[299] That works out to an installed cost of $4.83 per watt.[300] In return for this initial fee, subscribers will receive a $0.12 credit on their Wright-Hennepin utility bill for each kilowatt-hour produced.[301]

According to the facility manager, Clean Energy Collective, subscriptions have an estimated 20-year pay-back period. Clean Energy Collective warranties the project for 50 years.[302]

The project is also notable for being the first community-owned solar array in the nation to feature battery storage, which will allow the utility to dispatch power.[303] Clean Energy Collective expects to complete commission of the system by mid-2013.[304]

POLICY CONSIDERATIONS

Although some pilot community solar projects are being developed in Minnesota, current policy limits community solar development. Several distinct policy or regulatory clarifications or changes are needed to allow community solar.

a) Minnesota utility definition statute

As described in the third-party financing section, Minnesota's utility definition statute covers any entity that operates, maintains, or controls electric "equipment or facilities for furnishing at retail…electric service to or for the public…."[305] Although it is hard to predict how a regulator or court might interpret this statute, an argument can be made that the statute's wording covers community-owned solar projects, which would subject shared solar projects to regulation as a public utility.

Potential financial and regulatory bypasses to this definitional barrier have been suggested by community solar advocates.[306] However, most suggestions have legal uncertainty or would require a favorable court interpretation of the law.[307]

Minnesota law does create a statutory exemption that shelters entities that "produce[] or furnish[] service to less than 25 persons" from regulation as a utility.[308] Notwithstanding other limitations, this exemption may act as a cap, limiting community solar projects to a maximum of 24 subscribers.

b) Net energy metering

Minnesota statute limits eligibility for net metering to solar facilities under 40 kilowatts in size.[309] It is unclear whether this limit would apply to an entire community solar array, or to individual subscription levels. For the Wright-Hennepin project (see case study above), the overall array was sized at 40 kilowatts.

c) On-utility bill credit sharing

In states where community solar is enabled under state law, subscribers receive an energy credit on their monthly utility bill for their share of the solar production. Lowering the electric customer's billed energy usage to account for energy produced at a different site is a process generally referred to as virtual net metering. In Minnesota, rate regulated utilities generally cannot virtual net meter under either net metering law or within existing rate structures.[310] Public or co-operative utilities that are not rate regulated can choose to implement virtual net metering (as done by Wright-Hennepin) or not.

A related mechanism is available under a value-of-solar tariff (as discussed in the Solar Energy Rates and Tariffs section). In this approach, the utility could credit the subscriber's utility bill for the dollar value of the solar electricity produced and supplied to the grid based on the solar tariff rate.

d) Utility billing systems

Utilities may need to upgrade or modify their customer billing systems in order to allow for virtual net metering. Community solar programs elsewhere in the country allow for administrative fees to cover costs of upgrading billing systems.[311] In some cases, the required software functionality may be provided by a third-party that specializes in developing community-owned solar projects. For example, Clean Energy Collective (a Colorado-based developer) is providing the special utility-billing functionality for the Wright-Hennepin community-owned solar project.[312]

Photo: Minneapolis, MN (4 kW, 2009) Photographer: Rebecca Lundberg

e) Solar renewable energy credits (SRECs)

Some community solar subscribers are interested in the SRECs associated with their subscription to a community solar facility. A business, for instance, can use the SRECs as part of green building certification under the U.S. Green Building Council's Leadership in Energy and Environmental Design (LEED) program.

However, current Minnesota law is not clear about who owns the SRECs, and the ownership uncertainty could affect the viability of a community solar market.[313]

f) Delivery charges

Some utilities and regulators raise the issue of distribution costs that are imposed on the system by the community solar development. To address such concerns, regulators would need to determine the net impact of the solar development on the utility's distribution system. It is widely recognized that distributed generation can lower or defer distribution system investment, thereby resulting in a savings to the utility even as revenue from the customer also decreases. If net delivery costs are identified, subscribers may receive a lower rate of production compensation.

g) Subscriber-hosted projects

Under some project models, the host of a shared solar project may also be a subscriber. For example, the community solar project may be sited on the roof of a public building, small business, or place of worship. This dual host-subscriber role may introduce novel policy considerations around delivery charges and subscriber markets.

h) Subscriber markets

Community solar may raise several issues related to markets and exclusive service territories. Issues include:

- **Contract length**: Subscribers and solar developers are making infrastructural investments. Contract terms that reflect this long-term commitment with stable and certain compensation values will offer certainty to developers.
- **Subscription or share liquidity**: Subscriptions are geographically limited.[314] A secondary market may help enable subscribers to enter and exit and the community solar market over time.[315]
- **Securities law**: Some ownership models for community solar developments may require compliance with securities laws, thereby increasing the complexity and costs associated with community solar development.
- **System performance**: Minimum performance standards help protect subscribers from the risk of underperforming equipment. Standards for performance and reliability may also help establish utility resource planning expectations.
- **Unsubscribed compensation:** In the event that a portion of community-shared solar facility is unsubscribed, a compensation rate for the facility manager may be established. Setting this rate below the compensation rate for a project subscriber would discourage facility managers from holding unsubscribed shares. Other mechanisms could also be used to encourage facility managers to achieve full subscription.

MANAGING LOCAL REGULATION OF SOLAR ENERGY

Although Minnesota may see the development of large utility-scale solar projects, the majority of systems installed in Minnesota are likely to be distributed rooftop solar PV systems.

For this reason, most of the state's solar energy installations will be regulated by local governments under local land use codes and permitting processes. Moreover, other local controls on development, such as those associated with homeowners' associations or common interest communities (CICs) can also affect the ability of individuals to use the solar resources on their land and buildings.

POLICY PURPOSE OF STATE POLICIES REGARDING LOCAL REGULATION OF SOLAR ENERGY

- ***Consistent public regulation.*** Local development regulations differ considerably across local jurisdictions. Setting a state standard for solar development would ensure that solar resources and solar development is treated with some consistency across the state.
- ***Consistent private property limitations.*** CICs may treat solar development differently than the local community. Further, different CICs within a given community can have different standards. A state policy standard would ensure consistent treatment of solar development by CICs.
- ***Predictable permit fees.*** Minnesota state policy limits solar permit fees to the cost that government units actually incur in managing permits. But the policy allows a proxy standard based on the value of the project, which may overstate the cost and complexity of permitting solar projects.

Minnesota has identified a number of best practices to allow local units of government to incorporate solar energy development into their regulatory processes. The best practices are geared to both meet the community's goals and allow individuals and businesses to develop their available solar resources.

To date, these best practices have been adopted on a community-by-community basis. An alternative to local action is the adoption of state-level policies to ensure an appropriate balance of local property interests and allow for the capture of local solar resources.

Consistent with the purposes noted above, policy options fall generally into three categories:

1. state guidance on local land use planning and regulation for solar energy
2. state standards for building code permitting issues for solar energy
3. state standards on how common interest communities can regulate solar energy development

Photo: Minneapolis, MN (40 kW, 2010)

LOCAL LAND-USE PLANNING AND REGULATION

Local governments have planning and regulatory authority over most land use development that occurs within their jurisdictions.[316]

Local governments within the seven-county metropolitan area are required to adopt and implement comprehensive plans consistent with the Metropolitan Council's regional plan.[317] Local governments outside the metropolitan area are not required to adopt land use plans or regulation. Regardless, many larger Greater Minnesota cities have adopted a land use plan and/or zoning and subdivision ordinances.

Solar energy in land use plans

The Metropolitan Land Planning Act states that land-use plans within the Metropolitan Council jurisdiction shall include a protection element "for protection and development of access to direct sunlight for solar energy systems."[318] Therefore, current state policy already sets a minimum for solar land-use planning standards for communities that are required to create a comprehensive plan.

To better administer this solar planning requirement, the Metropolitan Council recently developed guidance and examples for how local governments can address solar energy resources in their plans (with assistance from the Minnesota Solar Challenge program).[319]

Outside of the metropolitan area, local governments have discretion over whether to include a solar energy element in their comprehensive plan or other planning policy.

Solar energy in land use regulation

No Minnesota law directly requires that local governments must zone for solar development. Likewise, no statute or rule guides how solar development fits into zoning or subdivision standards.

Local governments thus have discretion over whether to include solar development in their local zoning or subdivision regulations. As a service to these local governments, the Minnesota Solar Challenge program has developed best practice voluntary guidance on zoning and other land use regulation through the Minnesota Solar Challenge program.

Some states do set statewide standards or guidelines for how local governments can regulate solar development through zoning or other land use regulation.[320] These statewide policies provide cross-community consistency, but may also restrict communities from applying community standards to development.[321] Statewide standards may also be perceived by some communities as an unreasonable infringement of local control.

LOCAL ENFORCEMENT OF THE BUILDING CODE

In part because solar PV is a relatively new building-related technology, the permit and inspection process can hold significant uncertainty for both local government officials and contractors, and thus increase costs to the consumer.[322]

The Rooftop Solar Challenge program has a market-transformation goal of helping create a more predictable and transparent system for local permitting and inspections—reducing the time that permit officials and contractors must spend interpreting unclear permit and inspection requirements. Fortunately, national solar best practices have been developed to minimize costs and time spent in the code-regulatory processes without compromising safety standards and allowing for recovery of local government costs for administering the code.[323]

In Minnesota, rooftop solar PV installations are subject to the electric code (sometimes enforced by the state and sometimes by local jurisdictions) and other elements of the building code (generally enforced by local jurisdictions). Minnesota has a statewide "max-min" building code, meaning that the code applies to all construction in the state, and local governments cannot modify the code to either be more restrictive or less restrictive than the state code.[324] However, some local variations are built into the code, and local building officials have some discretion on how code details are applied to the local building stock.[325]

Code officials, inspectors, and solar contractors in Minnesota have a wide range of continuing education training available to them, and a large number of inspectors and contractors have attended trainings on solar energy provisions of the code. At least one recent survey of contractors indicated that the inspections process has improved significantly in recent years.[326]

In some jurisdictions, however, securing a building permit remains an uncertain process in terms of requirements, time, and variation in permit fees. The Minnesota Solar Challenge program has adapted the national permitting best practices to Minnesota local conditions and is working with local governments to make the permit process more consistent across jurisdictions.

In considering what other states have done, Minnesota has some options for addressing permitting processes and permit fees through state policy. Policy options include:

- Setting standards for permit fees, such as a fee cap for residential rooftop PV installations that do not require structural modifications to the building.

- Creating a consistent standard for "solar-ready" construction, where new buildings are designed to accommodate solar development and avoid retro-fit problems.

As noted in regard to development regulation, statewide fee standards can result in unintentional revenue issues for building departments and are sometimes perceived as an infringement on local control.

COMMON INTEREST COMMUNITY (CIC) DESIGN REVIEW STANDARDS

A substantial portion of the residential solar energy market is within areas governed by CICs. At the national level, roughly one in five Americans live in housing governed by a homeowner association.[327] Currently, there are over 1,200 registered homeowners associations in Minnesota.[328]

In spite of this sizable potential market, however, there has been relatively little adoption of rooftop solar in CICs in Minnesota.[329]

Common interest communities and their governing bodies—generally referred to as homeowner associations (HOAs)—are private-sector property management arrangements among a community of homeowners. Their functions include regulating certain aspects of land use within their geographic jurisdiction. For instance, in a townhome or condominium development, there are parts of the development held in common by all landowners (such as the roof in condominium). New subdivisions of single-family homes also are frequently organized as CICs and similarly designate certain amenities or property rights of individual parcels as being controlled in common.

A CIC must have a board of directors (the association) and a set of governing bylaws to which all property owners are subject.[330] The board, or association, administers the bylaws, including setting and enforcing rules regarding the use and operation of the community and the individual units.

a) Exterior design standards

Common interest communities often set design and aesthetic standards that govern what individuals can and cannot do on their lot and to their buildings. The standards are intended to ensure the subdivision retains a community character consistent with the desire of the developer (while the developer owns a majority of lots) and of the residents (after the developer is no longer vested in the project).

Changes to a building, such as installing a solar energy system, are frequently subject to a design review process administered by the HOA or an appointed subcommittee. Unless the solar energy systems are specifically enumerated as allowed under design standards, CIC design review processes can prevent individual homeowners from developing their solar resource. (As noted above, each CIC design review process may be different, with a few including prohibitions against rooftop solar PV.)

CIC design review can, and does, create conflicts between the individual's interest in solar development on their property, and the interest of neighbors in retaining a common look, feel, or character of the subdivision. Even with the low number of installations in CICs in Minnesota, several lawsuits have been brought over the right of a homeowner to capture solar energy through a solar PV system.[331]

b) Standard to accommodate solar development

Most CIC design review actions are made without the benefit of design standards, or with only cursory standards. Given the large number of homes within CICs, these unclear standards may be a significant barrier to developing Minnesota's residential solar energy market.

Design standards may, however, be created in such a way as to balance aesthetics, community character, and the ability of individual property owners to develop their solar resources.[332]

There are at least three potential pathways to developing a CIC solar energy standard:

- **Private sector standard**

  A review of the three potential private sector standards-setting bodies—Community Associations Institute, CIC Midwest (a division of the Minnesota Multi Housing Association), and Cooperative Development Services—reveals that none have announced plans to develop or promulgate a solar energy standard or guideline.[333]

- **Action at the municipal or metropolitan level**

  Local governments can and do exercise control over CIC bylaws (and required responsibilities) during the subdivision process. In practice, however, it is relatively uncommon for cities to exercise control over the homeowner association design review process without explicit state-level authorization.[334]

One notable exception is Chapel Hill, North Carolina, which passed a 2003 ordinance limiting homeowner's associations' ability to restrict residential solar.[335] Four years later, the State of North Carolina passed a statute that achieved a similar effect statewide.[336]

- **State action to establish standard guidelines**

  A state could address inconsistent CIC design guidelines and review processes (along with any solar-directed restrictive covenants) by enacting statewide standards ensuring the ability of homeowners to develop their solar resources.

  At least 12 states have standardized HOA rooftop solar guidelines at the state level, including: Florida, Vermont, Wisconsin, California, Massachusetts, New Jersey, and Hawaii. (In Hawaii, the state required HOAs to develop and document their own rooftop solar guidelines.) Minnesota has passed statewide limitation on HOA restrictions for other types of individual homeowner actions.[337]

State legislation designed to protect homeowners who wish to install solar panels on their homes tend to allow "reasonable" regulation by HOAs, while restricting explicit or implicit bans on the installation of rooftop solar PV.

CASE STUDIES OF STATE POLICIES

At least 21 states and the U.S. Virgin Islands have enacted laws that regulate solar energy and restrictive covenants. These laws range from very simple laws, such as Arizona's, that broadly prohibit unreasonable restrictions but have been the subject of litigation to resolve ambiguity, to more detailed laws, such as California's, that have carefully defined the scope of HOA authority in response to on-the-ground experience.

Because homeowner association restrictions may take many forms, state laws related to HOA solar prohibitions must be broad enough to address existing restrictions (in various forms), along with restrictions that might otherwise be added to existing or new homeowner association agreements. At the same time, state laws should also be sensitive to the property rights and health and safety concerns of other homeowners in the community (including in the context of multifamily or condominium developments with shared infrastructure).

To accommodate the diversity of property rights, while at the same time ensuring sufficient breadth of law, some states have adopted a statutory formula with two components:

(1) restrictive language that voids HOA conditions that explicitly or effectively ban solar installations

(2) permissive language that allows HOAs to impose limited restrictions necessary to protect legitimate concerns

For example, Florida and Vermont prohibit restrictive HOA conditions related to solar installations, but allow HOAs to determine the specific location of solar panels as long as such placement does not impair operation.

Hawaii and New Jersey void prohibitions on solar installations and instead require that HOAs adopt installation rules in accordance with state law that allows differing degrees of restrictions depending on the level of common ownership (more restrictions are allowed on multifamily than single family structures).

California and New Jersey void HOA prohibitions but allow reasonable restrictions, where reasonableness is defined by the cost or the efficiency impact of the restriction. New Jersey limits the impact of HOA restrictions to 10 percent or less of the total cost of the installation. California allows HOAs to increase costs by up to $2,000, but prohibits restrictions that decrease a solar system's efficiency by more than 20 percent.[338]

Some states have established procedural and dispute resolution requirements that prevent "passive" bans on solar installations resulting from non-action by HOAs while at the same time encouraging constructive dialogue and permitting rather than acrimony and litigation.

Some statutory language simply prevents HOAs from banning solar installations (as used in Arizona, Wisconsin and Massachusetts). These standards have the downside of effectively leaving the task of fleshing out the details to the state courts. Some argue that this in turn leads to continued market uncertainty, and the potential for expensive and unnecessary litigation between homeowners and their HOAs.

JUNE 2013 ADDENDUM TO REPORT

The 2013 Minnesota legislative session concluded in May 2013 with multiple new policies affecting future solar development in the state. This addendum summarizes those legislative outcomes relevant to the solar policies discussed in this report.

SOLAR ELECTRICITY STANDARD

The state adopted a solar electricity standard to obtain 1.5 percent of retail electricity sales from solar electricity by the end of 2020. The new law is limited to investor-owned utilities (IOUs) with cooperatives and municipal utilities being exempted. Mining and paper mills, which are some of Minnesota's largest electricity users, are also exempted. There is a 10 percent carve out for small-scale solar PV systems with a capacity of less than 20 kilowatts. The statute creates a goal of obtaining 10 percent of the entire state's retail electricity sales from solar electricity by 2030.

NET ENERGY METERING

The legislature made a number of updates to the state's thirty-year-old net-metering law. The updates, which apply to distributed generation systems connected to IOUs, include an increased individual system capacity limit of 1,000 kW, exemption from standby charges up to 100 kW capacity, and aggregation of meters. For IOU-interconnected net-metered systems that are larger than 40 kW, annual netting is permitted with annual excess generation compensated at avoided cost and individual system sizes restricted to 120 percent of the customer's on-site maximum electric demand for wind generation systems, or 120 percent of the customer's on-site annual electric energy consumption for solar photovoltaic and other distributed generation. An IOU may ask the Public Utilities Commission (PUC) to limit the cumulative generation of net-metered facilities when it has reached four percent of the utility's annual retail electricity sales. Statewide (IOUs, municipal utilities, and electric cooperatives), the prior net-metering law still applies to systems less than 40 kilowatts with monthly net excess compensated at the average retail utility rate.

VALUE-OF-SOLAR TARIFF (VOST)

As an alternative to net metering, investor-owned utilities may apply to the PUC for a value-of-solar tariff that compensates customers through a credit (*i.e.*, moves the netting from the meter to the bill) for the value to the utility, its customers, and society for operating distributed PV systems interconnected to the utility and operated by the customer primarily for meeting their own energy needs. The Department of Commerce must establish the methodology no later than January 31, 2014. The methodology must include at least the value of energy and its delivery, generation capacity, transmission capacity, transmission and distribution line losses, and environmental value. The credit will represent the present value of the future revenue streams of these components. The PUC may not approve a rate that is less than retail until three years after the tariff is first approved. A twenty year contract at a fixed rate is required. Once a utility VOST has been established, new solar customer-generators will not have access to traditional net metering.

MADE IN MINNESOTA SOLAR INCENTIVES

The legislature established an incentive program for IOU consumers who install PV systems using solar modules certified as manufactured in Minnesota. The program will be developed and administered by the Department of Commerce with an annual budget of up to $15 million for ten years. The program will be funded with 5 percent of each public utility's total annual Conservation Improvement Program (CIP) budget. The Xcel Renewable Development Fund will supplement this amount to bring the total incentives available to $15 million. There are two eligibility tiers for certification of crystalline solar module manufacturers determined by the specific production processes completed within Minnesota. Incentives are performance-based and established by a system's energy production and paid over 10 years rather than the historical capacity-based incentive. This structural change to past program design is intended to encourage high performance systems and maximize the public benefit. Systems must have a nameplate capacity of less than 40 kW to be eligible. Beginning in 2014 through 2023, applications will be accepted annually between January 1 and February 28 each year.

SOLAR PRODUCTION BASED INCENTIVE (XCEL ENERGY)

The state's largest utility, Xcel Energy, will develop and operate a performance-based incentive—to be funded by the Xcel Renewable Development Fund—beginning in 2014 for a period of five years. The annual program budget is $5 million and Xcel Energy will file a plan to operate the program with Commerce. The program will offer incentives to Xcel customers in Minnesota for systems with a nameplate capacity up to 20 kW with a size limit of 120 percent of the customer's on-site annual energy consumption. The production incentive will be paid for ten years. Xcel may elect to file a request with Commerce to remove Solar*Rewards from its CIP program given this newly mandated program.

COMMUNITY SOLAR GARDENS

Xcel Energy will develop and administer a community solar program subject to approval by the Public Utilities Commission. Other investor-owned utilities may elect to develop community solar programs as well. Eligible projects may be up to 1,000 kW in size. A community solar project will be open to subscribers within the same or a contiguous county where a solar project is located. The minimum individual subscription is 200 watts. Maximum ownership by any one subscriber is 40 percent of the total system size. Subscribers will receive a credit on their electricity bill proportional to their subscription ownership through virtual net metering. There is no limit on the number of community solar projects that can be developed.

COMMERCIAL PROPERTY ASSESSED CLEAN ENERGY (C-PACE)

Prior legislation allowed local governments to offer C-PACE programs for their constituents through the issuance of bonds to investors. The existing C-PACE legislation was expanded from 10 year annual assessments to 20 year annual assessments to enable commercial and industrial businesses to complete energy improvements. The program is intended as an alternative to conventional financing of energy efficiency and renewable energy for businesses. Extending the special assessment payment period from 10 years to 20 years allows for deeper energy retrofits and solar projects which are more costly than other energy efficiency measures.

See MN Laws, 2013, Chapter 85 HF 729, Articles 7-13
https://www.revisor.mn.gov/laws/?id=85&doctype=Chapter&year=2013&type=0

A map of electric utility service territories is available at:
http://www.mngeo.state.mn.us/chouse/utilities.html#service

ENDNOTES

[1] Lopez, A. July 2012. *U.S. Renewable Energy Technical Potentials: A GIS-Based Analysis*. National Renewable Energy Laboratory (NREL). Accessed Jan. 2013. http://www.nrel.gov/gis/re_potential.html ("Lopez, NREL 2012")

[2] *See* U.S. Department of Energy. 2012. *SunShot Vision Study*. DOE/GO-102012-3037. http://www1.eere.energy.gov/solar/sunshot/vision_study.html (Accessed Jan. 2013)

[3] Geologists and energy analysts also categorize fossil fuel deposits into distinct types of reserves (proved reserves, unproved reserves, possible and probable reserves, etc.).

[4] Lopez, NREL 2012. NREL accounts for shading, rooftop orientation, and other relevant factors, but does not account for future improvements in solar panel efficiency or a post-2015 increase in building stock. (For its analysis, NREL used solar capacity factor of 0.189, an average module efficiency of 13.5%, and a power density of 110 W/m^2 for flat roofs and 135 W/m^2 for non-flat roofs.)

[5] Lopez, NREL 2012.

[6] Based on total 2011 Minnesota electric retail sales of 68,532 GWh. U.S. Energy Information Administration, *Retail Sales of Electricity by State by Sector by Provider*. 1990-2011. Accessed Jan. 2013. http://www.eia.gov/electricity/data.cfm#sales ("EIA, Retail Sales 2012")

[7] Lopez, NREL 2012. NREL further divides its technical potential estimate for utility-scale solar into rural (6,510 GW and 10,792,814 GWh/yr) and urban (20 GW and 33,370 GWh/yr) components. According to NREL, Minnesota's technical potential for rural utility solar ranks fifth in the country (behind only Texas, New Mexico, Arizona, and Kansas).

[8] Lopez, NREL 2012.

[9] Note, the size of Minnesota's solar PV technical potential could increase over time (e.g., due to improved solar PV conversion efficiencies or other technology- or market-based changes).

[10] National Renewable Energy Laboratory. Renewable Resource Data Center, PVWatts. Accessed Jan. 2013. http://www.nrel.gov/rredc/pvwatts/ (Solar production is estimated in terms of kilowatt hours produced per kilowatt of system capacity over the course of an average year, or kWh/kW/year.)

[11] NREL PVWatts. See also IKEA USA press release dated August 28, 2012. Accessed Jan. 2013. http://www.csrwire.com/press_releases/34515-Minnesota-s-Largest-Solar-Array-Now-Plugged-In-Atop-IKEA-Store-as-Company-Reaches-a-Solar-Presence-of-70-of-its-U-S-Locations (Estimating that its Bloomington, MN rooftop solar PV array will produce 1,145 kWh/kW/year.)

[12] Interstate Renewable Energy Council, "U.S. Solar Market Trends 2012" (July 2013), available at http://www.irecusa.org/wp-content/uploads/2013/07/Solar-Report-Final-July-2013-1.pdf.

[13] Customer-sited solar PV tends to become economically competitive earlier in states that have higher average electric utility rates.

[14] Minn. Stat. 216H.02 Subd. 1

[15] Minn. Stat. 216C.05 Subd. 2

[16] *Id.*

[17] Minn. Stat. 216C.05 Subd 1.

[18] Minn. Stat. 216B.2422 Subd. 4

[19] Minn. Stat. 216B.164 Subd. 1

[20] Minn. Stat. 216B.241 Sub. 5a

[21] Minn. Stat. Section 297A.67, Subd.29

[22] Minn. Stat. 272.02

[23] Minn. Stat. 463.357, Subd. 6(2)

[24] *Id.*

[25] Minn. Stat. 500.30 Subd. 3

[26] Minn. Stat. 473.859 Subd. 2(b)

[27] SolarFlow, presentation to Xcel Renewable Development Fund Board, January 2011. http://www.xcelenergy.com/staticfiles/xe/Corporate/Renewable%20Energy%20Grants/RDFSolarflowEnergyPresentation.pdf

[28] *Id.*

[29] Annual Minneapolis Saint Paul Solar Cities Report to the Legislature 2011. http://archive.leg.state.mn.us/docs/2011/mandated/110427.pdf

[30] K. MacLaury, Center for Energy and Environment, "Assessing Minnesota's Solar Resource: Revenue implications of solar PV system orientation and rate structure", Minneapolis Saint Paul Solar Cities Program (2011), accessible at http://mn.gov/commerce/energy/images/SolarValueReport.pdf

[31] *Id.*

[32] Doris, E., Busche, and Hockett. National Renewable Energy Laboratory (NREL) technical paper. December 2009. *Net Metering Policy Development in Minnesota: Overview of Trends in Nationwide Policy Development and Implications of Increasing the Eligible System Size Cap*. ("Doris NREL 2009") www.nrel.gov/docs/fy10osti/46670.pdf

[33] Minnesota Department of Commerce, Division of Energy Resources. Distributed Generation workshop. Nov. 15, 2011. http://mn.gov/commerce/energy/images/DG-Summary-Cover.pdf

[34] Minnesota Department of Commerce, Division of Energy Resources. Distributed Generation webpage, accessed Jan. 2013. http://mn.gov/commerce/energy/topics/clean-energy/distributed-generation/

[35] *Id.*

[36] U.S. Energy Information Administration (EIA) Form 826, MN Qualifying Facility Reports, Minnesota Department of Commerce presentation, Aug. 15, 2012.

[37] Communication from Nathan Franzen, Geronimo Energy, August 29, 2012.

[38] The low income housing sub-market is comprised of real property and building stock similar to the overall rental market, and they face the same solar-related issues, except for in the area of financing, where the two are very different. The

low income housing market has distinct ownership and capital structures, along with a distinct set of federal regulations and financial restrictions (owing to the market's federal funding). The market also has a distinct set of institutions, including regulated lenders, who are working to develop economically-attractive project-financing structures.

[39] According to the U.S. Census Bureau (2011), Minnesota has 2,339,293 housing units, including 1,578,212 single-family detached homes. U.S. Census Bureau. *Selected Housing Characteristics for Minnesota, 2011 American Community Survey 5-year estimates*. Accessed Jan. 2013. http://factfinder2.census.gov/faces/nav/jsf/pages/index.xhtml ("U.S. Census, 2011")

[40] U.S. Census, 2011.

[41] Paidipati, J., et al. February, 2008. *Rooftop Photovoltaics Market Penetration Scenarios*. National Renewable Energy Laboratory. http://www.nrel.gov/docs/fy08osti/42306.pdf ("The results should not be confused with the share of homes that are not suitable for PV, however, since the study is focusing on roof space.")

[42] Written communication: Anthony Lopez, National Renewable Energy Laboratory GIS Analyst on Jan. 11, 2013.

[43] From a statewide telephone poll of 500 Minnesota voters, conducted Jan. 6-8, 2013 for the Minnesota Environmental Partnership by the bipartisan research team of Fairbank, Maslin, Maullin, Metz & Associates and Public Opinion Strategies. The margin of sampling error for full statewide samples is 4.4 percentage points, plus or minus; margins of error for subgroups within the sample will be larger.

[44] Hoen, B. et al. April 2011. *An Analysis of the Effects of Residential Photovoltaic Energy Systems on Home Sale Prices in California*. Lawrence Berkeley National Laboratory (LBNL). http://eetd.lbl.gov/ea/ems/reports/lbnl-4476e.pdf

[45] Minnesota Solar Energy Industries Association, database of solar manufacturing jobs. (Solar supply chain companies span the state and directly employ nearly 2,000 full-time workers.) Accessed Jan. 2013.

[46] In a 2012 survey of electric-vehicle owners (sponsored by the California Air Resources Board), 39 percent of respondents said they have solar PV on their home, while another 31 percent said they are considering adding solar PV within a year. California Center for Sustainable Energy, press release dated August 28, 2012. http://energycenter.org/index.php/news-a-media/ccse-press-releases/3271-first-ca-electric-vehicle-survey-shows-broad-benefits (Accessed Jan. 2013)

[47] Barbose et al., *Tracking the Sun V: An Historical Summary of the Installed Price of Photovoltaics in the United States from 1998 to 2011*. Lawrence Berkeley National Laboratory (Nov. 2012). Available at http://emp.lbl.gov/sites/all/files/LBNL-5919e-REPORT.pdf ("Barbose, LBNL 2012")

[48] A substantial body of literature defines market barriers and failure in the context of energy efficiency and renewable energy markets. See e.g., Gillingham K. and Sweeney. 2010. *Market Failure and the Structure of Externalitie*s. Oak Ridge National Laboratory. Available at http://www.yale.edu/gillingham/research.htm (Accessed Jan. 2013)

[49] *Id*.

[50] Bjornstad, D. and Brown. 2004. *A Market Failures Framework for Defining the Government's Role in Energy Efficiency*. Oak Ridge National Laboratory. www.ornl.gov/sci/mkt_trans/pdf/2004_02marketfail.pdf

[51] This market barrier is reflective of the various policy choices (e.g., in the building codes and the rules for platting and subdivision) that lead to the today's residential-sector infrastructure.

[52] Minn. Stat. 216B.02 Subd. 4. See also third-party financing section of this report.

[53] Testimony of L. Schedin, reply comments of Solar Rate Reform Group, MPUC Docket No. E-002/GR-10-971

[54] DSIRE, Database of State Incentives for Renewables and Efficiency ("DSIRE Solar"): Minnesota. http://www.dsireusa.org/solar/incentives/index.cfm?re=0&ee=0&spv=1&st=1&srp=0&state=MN (Accessed Jan. 2013) Minnesota Power offered incentives under its Solar Sense program in 2012 ($2.00 per watt, up to a 10kW system, unless the installed costs fall below a low threshold), but has not announced details of any 2013 rebate program.

[55] $2 per watt up to 40 kW or $4,000, whichever is less. DSIRE Solar: Minnesota, Brainerd Public Utilities – Renewable Incentives Program. Accessed Dec. 2012. http://www.dsireusa.org/solar/incentives/incentive.cfm?Incentive_Code=MN167F&re=0&ee=0

[56] DSIRE Solar: Minnesota, Moorhead Public Service Utilities – Renewable Incentives Program. Accessed Jan. 2013. http://www.dsireusa.org/solar/incentives/incentive.cfm?Incentive_Code=MN168F&re=0&ee=0 ($2/watt up to 100 kW, $20,000 or 60% of total system cost, whichever is less. Equivalent phase-out threshold is approximately $3.33 per solar watt installed.)

[57] DSIRE Solar: Minnesota, New Ulm Public Utilities – Solar Electric Rebate Program. Accessed Jan. 2013. http://www.dsireusa.org/solar/incentives/incentive.cfm?Incentive_Code=MN173F&re=0&ee=0

[58] $1 per watt up to 10 kW or $10,000, whichever is less, applicable across all sectors. DSIRE Solar: Minnesota, New Ulm Public Utilities – Solar Electric Rebate Program. Accessed Jan. 2013. http://www.dsireusa.org/solar/incentives/index.cfm?re=0&ee=0&spv=1&st=1&srp=0&state=MN

[59] $1.50 per watt up to 40 kW or $60,000, whichever is less. DSIRE Solar: Minnesota, Xcel Energy – Solar*Rewards Program and MN Made PV Rebate Program. Accessed Oct. 2012. http://www.dsireusa.org/solar/incentives/incentive.cfm?Incentive_Code=MN138F&re=0&ee=0

[60] DSIRE Solar: Colorado, Net Metering. Accessed Jan. 2013. http://www.dsireusa.org/solar/incentives/incentive.cfm?Incentive_Code=CO26R&re=0&ee=0.

[61] *Id*.

[62] Paidipati, J., et al. February, 2008. *Rooftop Photovoltaics Market Penetration Scenarios*. National Renewable Energy Laboratory. http://www.nrel.gov/docs/fy08osti/42306.pdf

[63] Written communication: Anthony Lopez, National Renewable Energy Laboratory GIS Analyst on Jan. 11, 2013.

[64] Lopez, NREL 2012.

[65] *Solar Means Business: Top Commercial Solar Customers in the U.S*. Group. September 12, 2012. http://www.slideshare.net/SEIA/top-corporatesolar (Accessed Jan. 2013)

[66] Haugen, Dan. August 8, 2012. “Minnesota Coal Plant Couldn’t Compete with Wind, Natural Gas.” *Midwest Energy News*. http://www.midwestenergynews.com/2012/08/08/minnesota-coal-plant-couldnt-compete-with-wind-natural-gas/ (Accessed Jan. 2013)

[67] Barbose et al., *Tracking the Sun V: An Historical Summary of the Installed Price of Photovoltaics in the United States from 1998 to 2011*. Lawrence Berkeley National Laboratory (Nov. 2012). Available at http://emp.lbl.gov/sites/all/files/LBNL-5919e-REPORT.pdf (“Barbose, LBNL 2012”)

[68] K. MacLaury, Center for Energy and Environment, “Assessing Minnesota’s Solar Resource: Revenue implications of solar PV system orientation and rate structure”, Minneapolis Saint Paul Solar Cities Program, 2011, accessible at http://mn.gov/commerce/energy/images/SolarValueReport.pdf

[69] Manufacturer’s typically guarantee solar panel production up to 80% of rated output for 20 -25 years. Older panels (30-years and older) that have been tested for performance are still at or close to 80% of rated output, and degradation rates for silicone modules is typically less than 1% per year. See NREL Performance and Reliability website, accessed Jan. 2013. http://www.nrel.gov/pv/performance_reliability/real_time.html

[70] *See* Barbose, LBNL 2012, 2.

[71] *See* Interstate Renewable Energy Council (IREC) “Model Interconnection Procedures” (2009), available at http://irecusa.org/wp-content/uploads/2010/01/IREC-Interconnection-Procedures-2010final.pdf

[72] The intended purpose a rate or tariff is grounded in a state’s adopted policy goals – cost-based ratemaking and volumes of economic theory notwithstanding.

[73] Economic theory recognizes that rates generally serve four economic functions: production-motivation, efficiency incentive, consumer-rationing, and compensatory income transfer. Bonbright, et al., Principles of Public Utility Rates, Public Utilities Reports, 1988.

[74] In contrast to barriers leading to under-investment, a number of stakeholders have argued that some solar rate policies elsewhere have arguably resulted in economic overinvestment in solar development, where the solar rate reflects a long-run marginal cost that is higher than justified, as noted later in this section.

[75] Minn. Stat. 216B.164 Subd. 1.

[76] These are consistent with the six principles identified by Freeing the Grid, available at http://www.freeingthegrid.org/#education-center/best-practices/. (Accessed Jan. 2013) These principles define net metering best practices: right to self-generate, right to reduce energy use without penalty, full valuation of solar electricity, non-discriminatory cost-of-service recovery, standardized statewide application, and transparency in tariff structure and data.

[77] EIA Annual Energy Review.

[78] 18 C.F.R.292.101(b)(6)

[79] Minn. Stat. 216B.164 Subd. 1

[80] Solar America Board for Codes and Standards, iii.

[81] Beach, R. and McGuire, Crossborder Energy, “Evaluating the Benefits and Costs of Net Metering in California” (Jan. 2013), 7. Available at http://votesolar.org/wp-content/uploads/2013/01/Crossborder-Energy-CA-Net-Metering-Cost-Benefit-Jan-2013-final.pdf (“Crossborder Energy 2013”)

[82] Minn. Stat. 216B.164 Subd. 3. *See also* Public Utility Regulatory Policies Act of 1978 (PURPA), codified at 16 U.S.C. 12 §824a-3 (defining “qualifying” cogeneration and small power production “facilities”).

[83] To interconnect to the utility grid, qualifying facilities must also satisfy utility interconnection equipments.

[84] Keyes, J. and Wiedman, Solar America Board for Codes and Standardsm, *A Generalized Approach to Assessing the Rate Impacts of Net Energy Metering*, iii (2012). (“Solar ABCs”) Available at http://www.SolarABCS.org/rateimpact (Accessed Jan. 2013)

[85] See FERC website at http://www.ferc.gov/about/overview.asp (Accessed Jan. 2013)

[86] For instance, FERC allows, but does not require, states to include environmental costs in avoided cost, to set separate avoided costs for different types of resources that are supported in state policy, and to use or disregard pricing information from market transactions in setting avoided costs.

[87] Elefant, C. “Reviving PURPA’s Purpose: The Limits of Existing State Avoided Cost Ratemaking Methodologies In Supporting Alternative Energy Development and A Proposed Path for Reform” (2010).

[88] Crossborder Energy 2013, 7.

[89] Minnesota’s NEM uniform contract is published at Minn. R. 7835.9910.

[90] According to U.S. EIA, as of 2011 Minnesota had 117 net-metered solar PV systems, with the residential market having 72.6% of NEM systems, 57% of aggregate NEM capacity, and 76.5% of NEM solar generation. (Apart from being somewhat stale, EIA’s 2011 data may also be incomplete. Their data collection may have also been tied to a targeted incentive program, which could potentially skew the data.)

[91] E. Doris, S. Busche S. Hockett, *Net Metering Policy Development in Minnesota: Overview of Trends in Nationwide Policy Development and Implications of Increasing the Eligible System Size Cap*, NREL/TP-6A2-46670, 2009

[92] See Solar Ready Building Design Guidelines (Sept. 2010), available at http://mn.gov/commerce/energy/images/Solar-Ready-Building.pdf). (A general rule of thumb holds that 100-150 square feet is needed for 0.8 - 1.0 kW solar PV system.)

[93] Doris NREL 2009, 24.

[94] Keyes, J. and Wiedman, Solar America Board for Codes and Standardsm, *A Generalized Approach to Assessing the Rate Impacts of Net Energy Metering*, 3 (2012). Available at http://www.SolarABCS.org/rateimpact (Accessed Jan. 2013)

[95] Barbose et al., *Tracking the Sun V: An Historical Summary of the Installed Price of Photovoltaics in the United States from 1998 to 2011*. Lawrence Berkeley National Laboratory (Nov. 2012), 2. Available at http://emp.lbl.gov/sites/all/files/LBNL-5919e-REPORT.pdf (“Installed prices exhibit significant economies of scale[.]”)

[96] University of Minnesota Initiative for Renewable Energy in Architecture (re-ARCH), “Case study: Quality Bicycle

Products." http://www.rearch.umn.edu/case_qb.html (Accessed Jan. 2013)

97 Jamie Borell, Innovative Power Systems, personal communication Sept. 20, 2012.

98 Hawaii's capacity limit applies to individual distribution circuits rather than to the entire utility system.

99 Interstate Renewable Energy Council, "Net Metering Model Rules" (2009). Available at http://www.irecusa.org/wp-content/uploads/2009/11/IREC_NM_Model_October_2009-1-51.pdf ("IREC, Net Metering Model Rules"). ("[A]ggregate caps ignore the fact that many large systems do not export energy yet disproportionately count towards meeting a cap, limiting the number of small systems that are eligible.")

100 California adopted a 0.5 percent aggregate NEM capacity limit in 2006, but later raised its limit to 2.5 percent, and then again to 5 percent. DSIRE Solar, accessible at www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=CA02R&re=1&ee=0 (Accessed Jan. 2013) Similarly, in 2009 Utah increased its aggregate NEM capacity limit for investor-owned utilities from 0.1 percent to 20 percent. DSIRE Solar, http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=UT04R&re=0&ee=0) (Accessed Jan. 2013)

101 Minn. Administrative Rule 7835.9910.

102 Net Metering Summary, 2011 DG workshops, http://mn.gov/commerce/energy/images/Net-Metering-Summary.pdf

103 Doris NREL 2009, 5.

104 *Id.* at 8.

105 *Id.* at 7. See also Minn. Stat. 216B.164.

106 See Keyes, J. and Wiedman, Solar America Board for Codes and Standardsm, *A Generalized Approach to Assessing the Rate Impacts of Net Energy Metering*, iii (2012). Available at http://www.SolarABCS.org/rateimpact ("Solar ABCs")

107 K. MacLaury, Center for Energy and Environment, "Assessing Minnesota's Solar Resource: Revenue implications of solar PV system orientation and rate structure", Minneapolis Saint Paul Solar Cities Program (2011), accessible at http://mn.gov/commerce/energy/images/SolarValueReport.pdf

108 Xcel Energy Solar Load Profile Study Compliance Filing, Draft Reply Comments of the Solar Rate Reform Group (SRRG), Docket No. E002/GR-10-971, January 11, 2013.

109 Beach, R. and McGuire, Crossborder Energy, "Evaluating the Benefits and Costs of Net Metering in California" (Jan. 2013), 40. Available at http://votesolar.org/wp-content/uploads/2013/01/Crossborder-Energy-CA-Net-Metering-Cost-Benefit-Jan-2013-final.pdf ("Crossborder Energy 2013") ("In the commercial and industrial market, NEM is clearly cost-effective today. The challenge in the C&I market is to reduce the use of rate design elements such as demand charges which solar customers cannot easily avoid and thus which undervalue the avoided cost benefits of NEM exports to the grid.")

110 Binz, Ron. Former Chair of the Colorado Public Utilities Commission.

111 Solar ABCs, 1.

112 *Id.*

113 This assumes that the utility's load forecast is not accounting for the growing DG market.

114 Leslie Brooks Suzukamo, "Solar power growth in Minnesota faces generation gap," *St. Paul Pioneer Press*, January 28, 2013 (quoting Laura McCarten, regional vice president for Minneapolis-based Xcel Energy). http://www.twincities.com/business/ci_22452214/generation-gap-solar-power-growth?IADID=Search-www.twincities.com-www.twincities.com (Accessed Jan. 2013)

115 Deb Birgen, Missouri River Energy Services, comments submitted to Minnesota Dept. of Commerce, Division of Energy Resources (Nov. 2, 2012), available at http://mn.gov/commerce/energy/topics/clean-energy/distributed-generation/2012-workshops/index.jsp. (Accessed Jan. 2013)

116 Crossborder Energy, 2013.

117 Solar ABCs, 5.

118 Arizona Public Service (APS), Austin Energy (Austin, TX), Pacific Gas & Electric (PG&E), Sacramento Municipal Utility District, San Diego Gas & Electric (SDG&E), Southern California Edison, Duquesne Light Co., PPL Utilities Corp, PECO Utilities Corp, Jersey Central P&L, PSE&G, and Atlantic Electric.

119 Solar ABCs, 20.

120 *Id.* See also Crossborder Energy 2013, 32 (NEM in the C&I market "is generally cost-effective for non-participating ratepayers, across a wide range of customer sizes and rate schedules with different rate designs").

121 Crossborder Energy 2013, 3, 8, 14 (finding that the net costs of NEM in California decreased as the size of commercial and industrial-sited solar PV installations increase).

122 Doris, NREL, 2009.

123 *Id.* at 23.

124 L. Trudeau presentation, Minnesota Department of Commerce DG webinar 8/15/12

125 Lacy, et al., Rocky Mountain Institute, "Net Energy Metering, Zero Net Energy and the Distributed Energy Resource Future" (2013), accessible at http://www.rmi.org/Knowledge-Center/Library/2012-02_PGENetZero. (Accessed Jan. 2013)

126 See Bonbright, Principles of Public Utility Rates, (1988) at 391 ("rates as whole should cover costs as a whole, so the rates for any given class of service should cover the costs of supplying that class. And so the rates charges to any single customer within that class should cover the costs of supplying this one customer ... Unfortunately, no such simple identification of reasonable rates with rates measured by costs of service is attainable.")

127 Illinois increased its net metering system cap from 40 kW as part of a large package of solar reforms adopted under Illinois S.B. 1652.

128 DSIRE Solar. Table excludes states with that have no statewide net metering policy / standard contract.

129 See Doris NREL 2009 for pre-2009 cross-state policy analysis.

[130] Interstate Renewable Energy Council, "Net Metering Model Rules" (2009). Available at http://www.irecusa.org/wp-content/uploads/2009/11/IREC_NM_Model_October_2009-1-51.pdf ("IREC, Net Metering Model Rules")

[131] Karl Ràbago, *Net Metering 2.0: The Value of Solar Tariff*, presentation for Minnesota Department of Commerce Distributed Generation / Net Metering Stakeholders, January 9, 2013.

[132] *See e.g.*, Kristi Robinson, Steele-Waseca Electric Cooperative, comments submitted to Minnesota Dept. of Commerce, Division of Energy Resources on January 4, 2012.

[133] *See, e.g.*, Runestone Electric Association, Comments on Net Metering Summary, December 12, 2011. http://mn.gov/commerce/energy/images/DistGenComments.pdf

[134] DSIRE Solar.

[135] *Id*. See also California Public Utilities Commission, Net Energy Metering (NEM), http://www.cpuc.ca.gov/PUC/energy/DistGen/netmetering.htm (Accessed Jan. 2013)

[136] IREC, Net Metering Model Rules, 6.

[137] *Id*.

[138] NSP Minnesota Electric Rate Book, filed 11-3-10. Standby Service Rider at Section No. 5, Sheet No. 101-107.

[139] Keyes, J. and Wiedman, Solar America Board for Codes and Standardsm, *A Generalized Approach to Assessing the Rate Impacts of Net Energy Metering*, 5 (2012). Available at http://www.Solar ABCS.org/rateimpact (Accessed Jan. 2013)

[140] *See e.g.*, Gainesville Public Utilities, Feb. 13, 2009 presentation, available at www.slideserve.com/isi/utility-planning-perspective-for-a-solar-feed-in-tariff-fit (Accessed Jan. 2013)

[141] Presentation by Mike Bull, Xcel Energy, at Jan. 14, 2010 Minnesota Renewable Energy Society monthly meeting.

[142] DB Climate Change Advisors, "The German Feed-in Tariff for PV: Managing Volume Success with Price Response," May 23, 2011, available at www.dbadvisors.com/content/_media/DBCCA_German_FIT_for_PV_0511.pdf

[143] "Days are numbered for German feed-in tariff," Wynn, G; Reuters.com, Feb. 19, 2013.

[144] *Id*.

[145] Karl Ràbago, January 2013.

[146] Customer participation in a VOST may be voluntary or required as a condition of interconnecting with the utility. In the latter case, the utility may act a monopoly buyer, or monopsony, with a degree of control over the relevant market.

[147] Hansen, L., Rocky Mountain Institute, "Exploring the Costs and Values of Distributed Resources," presentation to Minnesota DG Workshop, October 11, 2012.

[148] Ràbago, et al., D*esigning Austin Energy's Solar Tariff Using a Distributed PV Value Calculator*, 2012.

[149] Austin Energy also established a time-limited and declining solar production incentive on top of the solar tariff.

[150] Hansen, L., Rocky Mountain Institute, "Exploring the Costs and Values of Distributed Resources," presentation to Minnesota DG Workshop, October 11, 2012.

[151] *Id. See also* Clean Energy Research DG Valuator Value of Solar Calculator.

[152] See, e.g., PUC DOCKET NO. E-002/M-08-440, 2010 (holding that RECs belong to the customer-generator when the price paid for the power is not a premium over non-renewable power and the enabling statute does not obligate the utility to a renewable energy standard.)

[153] Minn. Stat. 216B.1611. See also Minnesota Public Utility Commission Order, Interconnection Process for Distributed Generation Systems, Docket No. E-999/CI-01-1023. August 2001.

[154] Minnesota Public Utility Commission. Order Establishing Generic Standards for Utility Tariffs for Interconnection and Operation of Distributed Generation Facilities. Docket No. E-999/CI-01-1023. September 28, 2004. http://www.puc.state.mn.us/portal/groups/public/documents/puc_pdf_orders/008982.pdf (attachment 1 at 30).

[155] Interstate Renewable Energy Council. Model Interconnection Procedures. 2009. http://irecusa.org/wp-content/uploads/2010/01/IREC-Interconnection-Procedures-2010final.pdf (IREC, Model Interconnection 2009). IREC is planning to release a revised 2013 edition (mostly to prove fine grained interconnection guidance for states and utilities experiencing especially high levels of solar interconnection).

[156] The 2004 Distributed Generation Interconnection order established general guidelines for utility interconnection, but did not establish a standardized process across utilities.

[157] For example, the DG Interconnection Order provides that a utility may take 15 business days to "respond" to an interconnection application. Respondents to the Minnesota Solar Challenge solar installer & developer survey, Fall 2012 (twenty-three unique respondents) indicated that, while often utilities met this deadline, in some cases a response wasn't received for a month or more.

[158] See Minnesota Department of Commerce, Division of Energy Resources. Technical Interconnection Standards Workshop. Meeting Notes. May 31, 2012. http://mn.gov/commerce/energy/images/DistGenMtgNotesMay2012.pdf, Xcel presentation. May 31, 2012. http://mn.gov/commerce/energy/images/DistGenLimogesNetwork.pdf, and NREL presentation. May 31, 2012. http://mn.gov/commerce/energy/images/DistGenCoddingtonMinnSecNetworks.pdf.

[159] IREC claims to incorporate the best practices of small-generator interconnection procedures developed by various state governments, the Federal Energy Regulatory Commission (FERC) standards, the National Association of Regulatory Utility Commissioners (NARUC), and the Mid-Atlantic Distributed Resources Initiative (MADRI). ("IREC, Model Interconnection 2009")

[160] Disclosure: DOE has adopted the IREC best practices as one measure against which it measures DOE SunShot Rooftop Challenge grantees, including the Minnesota Department of Commerce.

[161] IREC, Model Interconnection 2009.

[162] *Id*. at 6-8.

[163] *Id*. at 8-11.

[164] *Id*. at 11.

[165] *Id*. at 11-14.

[166] Freeing the Grid, "Best Practices in State Net Metering Policies and Interconnection Procedures," accessed Jan. 2013. http://freeingthegrid.org/#education-center/best-practices ("Freeing the Grid, 2013")

[167] Freeing the Grid, 2013. Minnesota received an "F" in 2012 and 2013. Some Minnesota stakeholders question the accuracy of these negative grades. http://freeingthegrid.org/#state-grades/minnesota (Accessed Jan. 2013)

[168] Freeing the Grid 2013 identifies Minnesota's external-disconnect-switch requirement as a negative grading factor.

The U.S. Department of Energy also considers the requirement a negative grading factor. Coddington, M., Margolis, and Aabakken. January 2008. *Utility-Interconnected Photovoltaic Systems: Evaluating the Rationale for the Utility-Accessible External Disconnect Switch*. National Renewable Energy Laboratory. http://www.nrel.gov/docs/fy08osti/42675.pdf. (Explaining that modern, UL-listed inverter components make external disconnect switches redundant.)

Respondents to the Minnesota Solar Challenge solar installer & developer survey (Fall 2012, twenty-three unique respondents) reported that the additional cost of installing this electrical device may range between $100 and $2,000, depending on the building configuration.

[169] IREC, Model Interconnection 2009. Interviews with Minnesota solar installers and developers indicate these requirements are not generally seen as a area of concern, as property owners may meet the requirement through their existing insurance policy.

[170] For example, Minn. Stat. § 216B.1611 could be interpreted to prevent the Commission for implementing a multi-tiered application-review process.

[171] Delaware State Senate 145th General Assembly, Senate Bill no. 677, *An Act to Amend Title 26 of the Delaware Code Relating to Net Energy Metering*. http://legis.delaware.gov/LIS/lis145.nsf/vwLegislation/SB+267/$file/legis.html (Accessed Jan. 2013) See also: 26 Del. Code. Sect. 1014. http://delcode.delaware.gov/title26/c010/index.shtml

[172] DSIRE Solar: Delaware, Interconnection Standards. Accessed Aug. 2012. http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=DE05R&re=1&ee=1 *See also* Delaware Public Service Commission, Order No. 7984 (June 2011), available at http://depsc.delaware.gov/orders/7984.pdf

[173] Delmarva Power webpage. *Interconnection Application/Agreement* forms. Accessed Feb. 2013. http://www.delmarva.com/home/requests/interconnection/.

[174] Delaware Public Service Commission, Order No. 7984 (June 2011), available at http://depsc.delaware.gov/orders/7984.pdf

[175] DSIRE Solar: Delaware Interconnection Guidelines. Accessed Aug. 2012. http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=DE05R&re=1&ee=1

[176] *Id*.

[177] Delaware's five utilities are Calpine, City of Milford Electric Department, Delmarva Power (a subsidiary of Pepco Holdings, Inc.), Delaware Electric Cooperative, and NRG Energy. The same resource reports that the state of Minnesota has over 170 traditional electric utilities. Wikipedia, List of United States electric companies webpage. Accessed Feb. 2013. http://en.wikipedia.org/wiki/List_of_United_States_electric_companies

[178] DSIRE Solar: Delaware, Interconnection Standards. Accessed Jan. 2012 (Florida, which provides another model, has eliminated liability insurance requirements for small inverter-based systems up to 10 kW, reducing the cost of residential solar installations. See DSIRE Solar: Florida, Interconnection Standards. Accessed Oct. 2012. http://www.dsireusa.org/solar/incentives/incentive.cfm?Incentive_Code=FL20R&re=0&ee=0).

[179] Perez et al., The Value of Distributed Solar Electric Generation to New Jersey and Pennsylvania, Clean Power Research (2012), at 21.

[180] For example, the median size residential rooftop system (5.0 kW) at a total installed cost of $8/watt (85th price percentile) would cost $40,000 before incentives and without roof replacement. See Barbose et al., *Tracking the Sun V: An Historical Summary of the Installed Price of Photovoltaics in the United States from 1998 to 2011*. Lawrence Berkeley National Laboratory (Nov. 2012), 2. Available at http://emp.lbl.gov/sites/all/files/LBNL-5919e-REPORT.pdf

[181] Brown, M. *Increasing Energy Projects in the Private Sector*. Presentation at Minnesota Department of Commerce-sponsored workshop. November 13, 2012.

[182] See CEE Commercial Energy Efficiency Loan Program, available at http://www.mncee.org/Find-Programs-Financing/CEE-Commercial-Energy-Efficiency-Loan-Program/ (Accessed Jan. 2013)

[183] *Id*.

[184] Conversations with Jim Hasnik, CEE Senior Loan Officer, and Judi Mortenson, CEE Lending Manager. (CEE considers solar PV projects eligible under its HVAC and electrical-energy-efficiency project categories. Data on the extent of CEE's solar financing is anecdotal because CEE does not track this info.)

[185] (CEE, 2011) This could take the form of senior lien status and robust collection mechanisms (providing lender security), paired with off-balance sheet financing.

[186] Brown, M. 2012. *Statewide Approaches to Commercial PACE in Minnesota*. Presentation from Harcourt Brown and Carey. http://mn.gov/commerce/energy/images/StateApproachesCommPACENov2012.pdf

[187] *See*: Minn. Stat. 429.101 (lists eligible improvements to property, including sidewalk and alley repairs, the installation or repair of water service, and the operation of street lighting systems)

[188] PACENow.org, "What is PACE?", available at http://pacenow.org/about-pace/what-is-pace/ (Accessed Jan. 2013)

[189] The typical life span of a solar photovoltaic systems is 30 years or more.

[190] See, e.g., Minn. Stat. 216C.436 Subd. 2.

[191] Minn. Stat. 216C.43 through 216C.436

[192] Minn. Stat. 216C.435 Subd. 5

[193] The U.S. Federal Housing Finance Agency (FHFA) has expressed a blocking concern regarding the "senior" status of residential PACE assessments, which might increase default risk for existing mortgage lenders. See: Federal Housing Finance Agency. *Statement on Certain Energy Retrofit Loan Programs*. July 6, 2010. http://www.fhfa.gov/webfiles/15884/PACESTMT7610.pdf

[194] Minn. Stat. 216C.436 Subd. 4

[195] Minn. Stat. 429.101 Subd. 2 ("Any special assessment levied under subdivision 1 shall be payable in a single installment, or by up to ten equal annual installments as the council may provide.")

[196] At least one other Minnesota city, The City of Maple Grove, has passed a resolution in support of developing a PACE program at the regional level. City of Maple Grove, Resolution 12-126 "Establish PACE Special District."

[197] PACENow.org list of PACE programs, accessible at http://pacenow.org/resources/all-programs/ (Accessed Jan. 2013)

[198] City of Edina, Minnesota. *Emerald Energy Program Report and Administrative Guidelines*. Revised May 1, 2012. http://pacenow.org/wp-content/uploads/2012/08/EEEP-Administrative-Guidelines.pdf

[199] Ten years is the maximum special assessment term allowed under Minn. Stat. 429.101 Subd. 2.

[200] Haugen, Dan. "Picking Up the PACE." *Twin Cities Business Magazine*. Sept. 20, 2012. Available at http://tcbmag.com/Opinion/Columns/Fuel-for-Thought/Picking-Up-the-PACE (Accessed Jan. 2013)

[201] Eutectics Consulting LLC. Salut Bar Americain Case Study, available at http://mnpace.com/wp-content/uploads/2012/10/Salut_PACE_CaseStudy.pdf ("Eutectics, Salut Bar")

[202] Eutectics, Salut Bar.

[203] *Id*.

[204] Haugen, Dan. "Picking Up the PACE." *Twin Cities Business Magazine*. Sept. 20, 2012. http://tcbmag.com/Opinion/Columns/Fuel-for-Thought/Picking-Up-the-PACE (Accessed Jan. 2013) (On the investor side, commercial PACE bonds may be appealing because the 4-6% rate of return exceeds the 2-3% rate on traditional municipal bonds.)

[205] *Id*.

[206] Minn. Stat. 429.101 Subd. 2, supra.

[207] The relationship between the local government and the authority could be governed, by example, through a joint powers agreement.

[208] Clean Energy Finance Investment Authority's purposes are codified in Connecticut General Statutes section 16-245n.

[209] Bailey, J. Commercial and Industrial Property Assessed Clean Energy. Presentation on behalf of Clean Energy Finance Investment Authority to Connecticut Conference of Municipalities (Dec. 14, 2012), available at http://www.ctcleanenergy.com/Portals/0/C-PACE%20Presentation%20CCM%20Dec%2014.pdf

[210] Clean Energy Finance Investment Authority. C-PACE website. Accessed Feb. 2013. http://www.c-pace.com/site/page/view/resources#content-participating-municipalities

[211] *Id*.

[212] Minnesota Department of Commerce, Office of Energy Security, "Assessing the Feasibility of Third Party Owned Solar Photovoltaic Installations in Minnesota Schools" (Dec. 2010), 3-4. Available at http://www.state.mn.us/mn/externalDocs/Commerce/Feasibility_of_Solar_Photovoltaic_Installations_in_Minnesota_Schoo_122010014226_SolarPVMNSchools.pdf

[213] 26 USC § 48 (The federal investment tax credit also applies, with varying degree, to other generation and heating technologies including solar hot water, small wind, geothermal heat pumps, combined-heat-and-power (CHP) systems, fuel cells, and micro turbines.) See also id.

[214] DSIRE Solar: Tax Credits. http://www.dsireusa.org/solar/solarpolicyguide/?id=13 (Accessed Jan. 2013)

[215] Production risk is the risk that a system's actual performance will not live up to the vendor's projections.

[216] The typical size of a residential solar system may range from two to six kilowatts or larger. But even at this scale, the costs of replacing a power inverter near the end of its planned 10-year life can be significant.

[217] Farrell, John. "Treasury Dept. Fingers SolarCity in Exploration of the Dark Underbelly of Solar Leasing" October 10, 2012, available at http://www.ilsr.org/treasury-dept-fingers-solarcity-leasing/

[218] Himmelman, J. August 9, 2012. "The Secret to Solar Power." New York Times. http://www.nytimes.com/2012/08/12/magazine/the-secret-to-solar-power.html?pagewanted=all&_r=0 (Accessed Jan. 2013)

[219] Fresh Energy, 2013.

[220] Solar Energy Industries Association. *Report: U.S. Solar Market Spikes in Q2 2012, More than Doubling Q2 2011 Market Size*. September 10, 2012. http://www.seia.org/news/report-us-solar-market-spikes-q2-2012-more-doubling-q2-2011-market-size (Accessed Jan. 2013)

[221] *See* Minn. Stat. 297A.67, Subd. 29. (Solar energy systems purchased on or after August 1, 2005, are exempt from Minnesota sales tax.) Interviews with two large system hosts reveal inconsistent understandings about whether state sales taxes apply to power purchased from a third-party system owner.

[222] DSIRE Solar: Maryland Sales and Use Tax Exemption for Residential Solar and Wind Electricity Sales. May 2012. http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=MD73F&re=1&ee=0 (Accessed Jan. 2013)

[223] DSIRE Solar: Wisconsin, Renewable Energy Sales Tax Exemptions. July 2012. http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=WI62F&re=1&ee=0 (Accessed Jan. 2013)

[224] Sundial Solar, "Praise God, We're Going Solar!" available at http://www.sundialsolarenergy.com/news-archive/15-praise-god-were-going-solar.html (Accessed Jan. 2013)

[225] The reduction in a customers' monthly utility bill minus the monthly lease payment equals net cost savings.

[226] National Renewable Energy Laboratory, Newsroom. "Solar Leases Attracting New Demographic". April 3, 2012. http://www.nrel.gov/news/features/feature_detail.cfm/feature_id=1816 (Accessed Jan. 2013)

[227] Kollins, K., Speer, and Cory. February 2010. *Solar PV Project Financing: Regulatory and Legislative Challenges for Third-Party PPA System Owners*. National Renewable Energy Laboratory. p V.

[228] For example, Illinois imposes consumer safeguards (analogous to truth-in-lending requirements) and requires third parties to disclose that they're not affiliated with the applicable electric utility. See 220 Illinois Compiled Statutes 5/16-115C.

[229] Minn. Stat. 216B.02, Subd. 4

[230] The Commission could attempt to clarify the utility definition through rule making. But a state court could later rule the Commission's definition of law flawed and reverse substantial agency effort.

[231] Minn. Stat. 216B.02, Subd. 4

[232] For similar reasons, Minnesota's current utility definition would appear to potentially also cover "shared" or "community-owned" solar installations, described later in this report.

[233] Minn. Stat. 216B.02, Subd. 4

[234] See Minn. Stat. 216B.164

[235] (The seven utilities are Xcel Energy, Minnesota Power, and municipal utilities in Austin, Brainerd, Moorhead, Owatonna, and Rochester.) DSIRE Solar: Minnesota, available at http://www.dsireusa.org/solar/incentives/index.cfm?re=1&ee=1&spv=1&st=1&srp=0&state=MN (Accessed Dec. 2012)

[236] Xcel Energy. Solar* Rewards webpage. http://www.xcelenergy.com/Save_Money_&_Energy/Find_a_Rebate/Solar*Rewards_-_MN (Accessed Jan. 2013)

[237] Minnesota Power. Solar Electric webpage. http://www.mnpower.com/EnergyConservation/SolarElectric

[238] DSIRE Solar: 3rd-Party Solar PPA Policies, available at http://www.dsireusa.org/documents/summarymaps/3rd_Party_PPA_map.pdf.

[239] *Id.*

[240] *Id.*

[241] DSIRE Solar, http://www.dsireusa.org/solar/index.cfm?ee=1&RE=1&spf=1&st=1 (Accessed Jan. 2013)

[242] U.S. Energy Information Administration. Status of Electricity Restructuring by State (Dec. 2010), available at http://www.eia.gov/cneaf/electricity/page/restructuring/restructure_elect.html (accessed Jan. 2013). See also Regulatory Assistance Program. *Electricity Regulation in the US: A Guide*. Mar. 2011. p 14. http://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=1&sqi=2&ved=0CC8QFjAA&url=http%3A%2F%2Fwww.raponline.org%2Fdocument%2Fdownload%2Fid%2F645&ei=KcgSUaCROaSayQGq0YG4BA&usg=AFQjCNFSxAO43qfw4ECrQCWbH2GYD41MQQ&bvm=bv.41934586,d.aWc (Accessed Jan. 2013)

[243] After this report was drafted, Iowa authorized third-party ownership under an April 2013 district court decision. *SZ Enterprises LLC v. Iowa Utilities Board*, Iowa Dist. Court for Polk County, Case No. CVCV009166 (Apr. 8, 2013), accessible at http://www.midwestenergynews.com/wp-content/uploads/2013/04/iowa-solar-ruling.pdf.

[244] Kollins, K., Speer, and Cory. February 2010. *Solar PV Project Financing: Regulatory and Legislative Challenges for Third-Party PPA System Owners.* National Renewable Energy Laboratory. p VII.

[245] DSIRE Solar. Accessed Jan. 2013. http://www.dsireusa.org/solar/index.cfm?ee=1&RE=1&spf=1&st=1

[246] The U.S. Energy Information Administration lists Iowa as a traditionally regulated state. See U.S. EIA, *Status of Electricity Restructuring by State* (Dec. 2010), available at http://www.eia.gov/cneaf/electricity/page/restructuring/restructure_elect.html. (Accessed Jan. 2013)

[247] Sunrun. Home Solar by State webpage. Accessed Feb. 2013. http://www.sunrunhome.com/solar-by-state/ (Sunrun offers both lease and PPA options to residential customers.)

[248] SolarCity, Power your home with cleaner, more affordable energy webpage. Accessed Jan. 2013. http://www.solarcity.com/residential/ (SolarCity offers both lease and PPA options to residential customers.)

[249] SunPower. SunPower webpage. Accessed Jun. 2012. http://us.sunpowercorp.com/ (SunPower offers lease options for residential customers.)

[250] CleanPowerFinance. Financing webpage. Accessed Jan. 2013. http://www.cleanpowerfinance.com/products/financing/ (CPF offers both lease and PPA options to residential customers.)

[251] Sungevity webpage. Accessed Jan. 2013. http://www.sungevity.com/go-solar

[252] Colorado S.B. 09-051, Renewable Energy Financing Act of 2009.

[253] *Id.*

[254] Colorado Senate Bill 09-051, section 10 40-1-103 (2)(c). Renewable Energy Financing Act of 2009.

[255] *Id.*

[256] Colorado Public Utility Commission Docket No. 08R-424E. Decision C09-0990. Proposed Amendments to the Rules of the Colorado PUC Relating to the Renewable Energy Standard. September 2009. Available at http://www.dora.state.co.us/puc/docketsdecisions/decisions/2009/C09-0990_08R-424E.pdf

[257] Solar Energy Industry Association. *Solar Market Insight Report 2012 Q12* webpage. Accessed Feb. 2013. http://www.seia.org/research-resources/solar-market-insight-report-2012-q2. See also IREC, 2012 Annual Report (reporting that Colorado solar installations as a whole more than doubled from 2009 to 2011).

[258] U.S. Dept. of Energy, On-Site Renewable Energy, Third-Party Solar Financing, available at http://apps3.eere.energy.gov/greenpower/onsite/solar_financing.shtml. (Accessed Jan. 2013)

[259] Wiser, R. and Barbose. October 2010. *Supporting Solar Power in Renewables Portfolio Standards: Experience from the United States.* Lawrence Berkeley National Laboratory. http://eetd.lbl.gov/ea/emp/reports/lbnl-3984e.pdf (Wiser, 2010)

[260] *Id.*

[261] *Id.*

[262] *Id.*

[263] Mai, T., Wiser, Sandor, Brinkman et al., *Exploration of High-Penetration Renewable Electricity Futures: Vol. 1 of Renewable Electricity Futures Study*. National Renewable Energy Laboratory. http://www.nrel.gov/analysis/re_futures/ (Accessed Jan. 2013)

[264] Estimated statewide solar PV capacity provided by the Minnesota Department of Commerce, Division of Energy Resources.

[265] Interstate Renewable Energy Council, "U.S. Solar Market Trends 2012" (July 2013), available at http://www.irecusa.org/wp-content/uploads/2013/07/Solar-Report-Final-July-2013-1.pdf. State population statistics from U.S. Census.

[266] Wiser, 2010.

[267] DSIRE Solar

[268] Colorado's 3.0% solar target applies to investor-owned utilities only. DSIRE Solar: Colorado, Renewable Energy Standard, available at http://www.dsireusa.org/solar/incentives/incentive.cfm?Incentive_Code=CO24R&re=1&ee=1. (Accessed Jan. 2013)

[269] DSIRE Solar

[270] *Id*.

[271] *Id*.

[272] Wiser, 2010.

[273] *Id*.

[274] Midwest Renewable Energy Tracking System (M-RETS) "Frequently Asked Questions" available at http://www.mrets.net/about/FAQ.asp. (Accessed Jan. 2013)

[275] Interstate Renewable Energy Council. *State and Utility Net Metering Rules for Distributed Generation* webpage. Accessed Feb. 2013. http://www.irecusa.org/irec-programs/connecting-to-the-grid/net-metering/

[276] Id. IREC considers it a best practice to assign initial REC ownership to the generator, at least in the net-metering context. See also Interstate Renewable Energy Council, "Net Metering Model Rules" (2009). Available at http://www.irecusa.org/wp-content/uploads/2009/11/IREC_NM_Model_October_2009-1-51.pdf (IREC, Net Metering Model Rules) ("A Customer-generator owns the Renewable Energy Credits (RECs) associated with the electricity it generates, unless such RECs were explicitly contracted for through a separate transaction independent of any net metering or interconnection tariff or contract.")

[277] IREC, Net Metering Model Rules. (Kansas, New Mexico, and North Carolina assign REC ownership to utilities, while North Dakota and Utah assign ownership differently in different contexts).

[278] Minnesota Public Utility Commission. *In the Matter of Xcel Energy's Petition for a Determination of Entitlement to Renewable Attributes of Energy Purchases Pursuant to Renewable Energy Requirements*. Docket No. E002/M-08-440.

[279] Minnesota Department of Commerce, Division of Energy Resources. *Report to the Minnesota Legislature: Progress on Compliance by Electric Utilities with the Minnesota Renewable Energy Objective and the Renewable Energy Standard*. Docket No. E002/M-08-440 (Jan. 14, 2012), available at http://archive.leg.state.mn.us/docs/2013/mandated/130073.pdf

[280] *Id*.

[281] See e.g., DHL Corporation v. Commissioner, 76 T.C.M. 1122 (U.S. Tax Court, 1998), available at http://www.leagle.com/xmlResult.aspx?page=45&xmldoc=1998119876hrtcm1122_1973.xml&docbase=CSLWAR2-1986-2006&SizeDisp=7 (Accessed Jan. 2013) ("A marketability discount is generally thought to be necessary where the buyer may incur out-of-pocket expenses or other costs due to some aspect or defect in the asset being purchased.")

[282] Wiser, 2010.

[283] *Id*.

[284] *Id*.

[285] *Id*.

[286] DSIRE Solar: Colorado, available at http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=CO24R. (Accessed Jan. 2013). Colorado's list of RES-eligible resources includes "recycled energy", which is defined as "energy produced by a generation unit with a nameplate capacity of not more than 15 megawatts (MW) that converts the otherwise lost energy from the heat from exhaust stacks or pipes to electricity and that does not combust additional fossil fuel."

[287] Colorado Revised Statutes § 40-2-124.

[288] *Id*.

[289] B. Ross, CR Planning, "Creating and Implementing Your Community Solar Plan," Minnesota Renewable Energy Society, 2007; R. Hoyem, "Community Solar Background Report," Minnesota Renewable Energy Society (June 2013). Available at http://www.mnrenewables.org/sites/mnrenewables.org/files/Community_Solar_Report_Hoyem_June2013.pdf.

[290] U.S. DOE separates this formal ownership model into three additional types: the utility-sponsored, special-purpose entity, and non-profit "buy and brick" models ("A Guide to Community Solar: Utility, Private, and Non-Profit Project Development", 2010).

[291] On the electric bill, the subscriber's energy production is treated as if it was produced on the site of the subscriber's electric meter, allowing for "virtual" on-site production.

[292] According to a recent estimate by the U.S. National Renewable Energy Laboratory, only 22% of residential roof space in Minnesota has an optimal solar resource. See Lopez, A. et al., Lawrence Berkeley National Laboratory, "U.S. Renewable Energy Technical Potentials: A GIS-based Analysis" (July 2012), 4.

[293] Barbose et al., T*racking the Sun VI: An Historical Summary of the Installed Price of Photovoltaics in the United States from 1998 to 2012*. Lawrence Berkeley National Laboratory (July 2013), 2. Available at http://emp.lbl.gov/sites/all/files/lbnl-6350e_0.pdf.

[294] *Id*. at 23.

[295] See Wright-Hennepin case study in text. (A given community solar project may also allow its subscribers to purchase additional solar panels over time, as new project capacity and subscriber funds become available).

[296] Assuming a 3 KW system and an installed cost of $5 per watt.

[297] Lopez, A. et al., July 2012. *U.S. Renewable Energy Technical Potentials: A GIS-based Analysis*, 4, Lawrence Berkeley National Laboratory.

[298] Farrell, John. "Local Solar: Minnesota Develops Its First Community Solar Project." Thinkprogress.org. December 20, 2012, accessed Jan. 2013. Available at http://thinkprogress.org/climate/2012/12/20/1360501/local-solar-minnesota-develops-its-first-community-solar-project/?mobile=nc. ("Farrell, Local Solar")

[299] Shaffer, David. "Crowd-funding for solar power." *Minneapolis Star Tribune*, January 14, 2013, available at http://www.startribune.com/business/186565751.html?page=1&c=y&refer=y. (Accessed Jan. 2013)

[300] Farrell, Local Solar.

[301] *Id*.

[302] *Id*.

[303] Shaffer, David. "Crowd-funding for solar power." *Minneapolis Star Tribune*, January 14, 2013, available at http://www.startribune.com/business/186565751.html?page=1&c=y&refer=y. (Accessed Jan. 2013)

[304] Communication from Paul Spencer, Clean Energy Collective, January 18, 2013.

[305] Minn. Stat. 216B.02, Subd. 4

[306] Such as structuring a shared solar project so that subscribers own specific solar panels, rather than a share of the entire project.

[307] The fact that the legislature has carved out exceptions for other circumstances implies that the general definitions should be interpreted broadly, leaving it to the legislature to carve out exceptions where necessary.

[308] Minn. Stat. 216B.02, Subd. 4

[309] Minn. Stat. 216B.164. Subd. 3

[310] Although if the owner of the solar development is the incumbent utility, some options may exist to virtual net meter on a case by case basis with approval of regulators.

[311] Conversation with Joseph Weidman, Interstate Renewable Energy Council (IREC) and Keyes, Fox and Wiedman LLP, January 23, 2013.

[312] Conversation with Paul Spencer, Clean Energy Collective, September 10, 2012. See also Clean Energy Collective, "Utility scale Clean Energy Without Any Cost" http://www.easycleanenergy.com/utilities.aspx (Accessed Jan. 2013)

[313] Under Minnesota law, there is currently uncertainty around whether initial REC ownership would vest with the subscribers, the facility manager, or another entity. *See also* Midwest Renewable Energy Tracking System (M-RETS) "Frequently Asked Questions" available at http://www.mrets.net/about/FAQ.asp. (Accessed Jan. 2013) M-RETS assigns a REC for every megawatt-hour of energy produced by a registered renewable energy generator in Minnesota. RECs hold value for utilities seeking to comply with Renewable Energy Standards or for businesses looking to offset their carbon emissions.

[314] Virtual net metering or value compensation crediting does not transfer across utilities, should the subscriber move out of the service territory. Moreover, some states have set addition geographic limitations to minimize distribution system imbalances; Colorado requires the solar development and the subscriber to be located within the same city or county. Colorado Rules. 723-3 3665(a)(I)(C)

[315] Colorado law allows subscriber shares to be assigned and reassigned to different people, limited only in that one subscriber cannot own more than 40% of a project. Colorado Rules 723-3. 3665.(a)(ii)

[316] Minn. Stat. 462 (cities), Minn. Stat. 394 (counties)

[317] Minn. Stat. 473

[318] Minn. Stat. 473.859 Subd. 2(b)

[319] Metropolitan Council Local Planning Handbook, Sect. 3 pg. 10. Available at http://www.metrocouncil.org/Communities/Planning/Local-Planning-Assistance/Local-Planning-Handbook.aspx.

[320] DSIRE Solar.

[321] Development standards are a well-recognized application of the police powers vested at the local-government level.

[322] U.S. Department of Energy. *Permitting, Interconnection and Inspection* webpage. Accessed Feb. 2013. http://www1.eere.energy.gov/solar/sunshot/permitting_interconnection_inspection_costs.html

[323] *See* Solar America Board of Codes and Standards (Solar ABCs) website, http://www.solarabcs.org/. (Accessed Jan. 2013).

[324] Minn. Stat. 326B.121 Subd 2(c)

[325] For instance, snow loading standards vary, and acknowledgement is made in the statute for localized geological conditions that might require more stringent standards.

[326] Minnesota Solar Challenge solar installer & developer survey, Fall 2012 (23 unique respondents).

[327] The United States is host to 314,200 CICs, comprised of 25.1 million homes and more than 62 million residents. Community Association Institute. Industry Data, National Statistics webpage. 2011. Accessed July 2012. http://www.caionline.org/info/research/Pages/default.aspx.

[328] Customized search of Minnesota Secretary of State records for nonprofit organizations that contain "Homeowner(s) Association" in their registered business name (conducted Jan. 18, 2003).

[329] Minnesota Solar Challenge solar installer & developer survey, Fall 2012 (23 unique respondents). Only ten respondents reported any installation activity in a Minnesota-based common interest community. Of those ten, four reported a negative experience (e.g., the rooftop solar project was disallowed).

[330] Minn. Stat. 515B

[331] Galbraith, K. May 15, 2009. "Homeowners Associations: The Enemy of Solar?" *N.Y. Times* Green Blog. http://green.blogs.nytimes.com/2009/05/15/homeowners-associationsthe-enemy-of-solar/. (Accessed Jan. 2013). Grossfield, E. November 9, 2012. "Rochester council member is sued over solar panels." Rochester Post-Bulletin. http://postbulletin.com/news/stories/display.php?id=1514466 (Accessed Jan. 2013)

[332] The City of Saint Paul developed a set of design guidelines to allow solar development while minimizing “visual impacts.” Minnesota has also developed model solar energy standards that provide examples of mitigating visual impacts while allowing solar development.

[333] See Community Associations Institute, http://www.caionline.org/about/who/Pages/default.aspx; CIC Midwest, http://www.mmha.com/CICMIDWEST/tabid/8934/Default.aspx; and Cooperative Development Services, www.CDSUS.coop. (Accessed Jan. 2013)

[334] Usually, local governments require action (such as managing storm water facilities or conservation easements), rather than forbidding action (such as protecting solar development during design review).

[335] Chapel Hill, N.C., Ordinance Appendix A – Land Use Management, § 4.67. Available at http://townhall.townofchapelhill.org/planning/planning_development/pdfs/lumo_art4.pdf

[336] N.C. Gen. Stat. § 22B-20. Available at http://www.ncga.state.nc.us/EnactedLegislation/Statutes/HTML/ByArticle/Chapter_22B/Article_3.html (Accessed Jan. 2013) See also DSIRE Solar: North Carolina, Town of Chapel Hill – Land-Use Management Ordinance. http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=NC02R&re=0&ee=0 (Accessed July 2012)

[337] For example, a 2005 revision to Minn. Stat. 500.215 limits the ability of CICs to place restriction on how homeowners may fly the American flag. See 168 S.F. No. 1231. https://www.revisor.mn.gov/laws/?id=168&doctype=Chapter&year=2005&type=0. (Accessed Jan. 2013)

[338] While the percentage values in these “bright line” standards may appear arbitrary, they serve to clearly define HOA authority and limit the need for expensive litigation.

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