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IOWA UTILITIES BOARD

STATE OF IOWA
BEFORE THE IOWA UTILITIES BOARD

IN RE:	)	
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DISTRIBUTED GENERATION	)	**DOCKET NO. NOI-2014-0001**
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	)	**ADDITIONAL COMMENTS**
	)	

The Environmental Law & Policy Center, Iowa Environmental Council, Sierra Club, Iowa Solar Energy Trade Association (ISETA), Solar Energy Industries Association (SEIA), the Vote Solar Initiative, and Interstate Renewable Energy Council, Inc. (IREC), collectively the "Joint Commenters", jointly file these comments pursuant to the Iowa Utilities Board Order Soliciting Additional Comments on Distributed Generation (DG), Net Metering, and Interconnection and Including Reports issued on May 12, 2014.

Description of the Parties

The Environmental Law & Policy Center (ELPC) is a non-profit corporation with an office in Des Moines, Iowa and members who reside in the State of Iowa. ELPC's goals include promoting clean energy development and advocating for policies and practices that facilitate the use and development of clean energy such as solar and wind power.

The Iowa Environmental Council (IEC) is a broad-based environmental policy organization with over 70 diverse member organizations and a mission to create a safe, healthy environment and sustainable future for Iowa. IEC's work focuses on clean water, clean air, conservation, and clean energy, including the promotion of policies that would facilitate the development of clean energy and clean energy jobs.

The Iowa Solar Energy Trade Association (ISETA) is a non-profit, professional organization for promoting solar photovoltaic and solar thermal industries in Iowa. ISETA promotes the interests of its members through education and public relations about the economic and environmental benefits of solar. ISETA advocates for policies that will facilitate and promote the development of solar photovoltaic and solar thermal energy in Iowa.

The Sierra Club, the nation's oldest grassroots environmental organization, has a mission to explore, enjoy, and protect the planet. The Sierra Club works state-wide and nationally to advocate for clean, renewable energy to reduce air pollution, water pollution, and the effects of climate disruption resulting from fossil fuel extraction and combustion.

The Vote Solar Initiative is a non-profit grassroots organization working to foster economic opportunity, promote energy independence and fight climate change by making solar a mainstream energy resource across the United States. Since 2002 Vote Solar has engaged in state, local and federal advocacy campaigns to remove regulatory barriers and implement the key policies needed to bring solar to scale.

The Solar Energy Industries Association (SEIA)[1] is the national trade association of the United States solar industry. Through advocacy and education SEIA and its 1,100 member companies work to make solar energy a mainstream and significant energy source by expanding markets, removing market barriers, strengthening the industry and educating the public on the benefits of solar energy.

The Interstate Renewable Energy Council, Inc. (IREC) is a non-profit organization that has worked for three decades to accelerate the sustainable utilization of renewable energy

[1] The views represented in this filing are the views of the trade association and not necessarily any of its individual members.

resources through the development of programs and policies that reduce barriers to renewable energy deployment.

Together, the "Joint Commenters" represent a coalition of the leading national, regional and local policy organizations and businesses working on distributed generation policy in Iowa and across the nation. We are well positioned to offer the Board insights from our diverse experiences in states throughout the country, informed by our practical experiences on the ground in Iowa.

Introduction

The Joint Commenters greatly appreciate the IUB's continuing inquiry into the key policies and technical issues affecting the growing market for distributed generation. Even though there is still an extremely low penetration of distributed generation in Iowa in comparison to some other states, there is great potential for growth. The fact that the Board received over 170 comments to its initial round of questions, many from nontraditional participants in Iowa's regulatory process, speaks to the intensity and breadth of interest in Iowa's transition to a more diverse and distributed electricity generating future.

As described in our initial comments, distributed generation provides significant benefits that extend far beyond the location of a project. Distributed generation uses energy near where it is produced, thereby reducing energy losses over transmission and distribution lines and making our energy production more efficient. Distributed generation diversifies our energy, helps with the reliability of the grid, and serves as a hedge against potential future fuel price increases and environmental costs. Distributed generation provides environmental and health benefits by reducing emissions, keeping our air and water clean, and conserving limited water resources. Customer-owned distributed generation provides energy and capacity with private investment that offsets the costs we all would pay for new utility-owned generation and capacity. Finally, distributed generation provides economic benefits by creating local jobs and investment opportunities. If Iowa falls behind on distributed generation, we will lose out on the diverse array of benefits provided by distributed generation.

Distributed generation is one feature of a much more decentralized and highly networked energy and information grid that will soon enable an entire ecosystem of products and services related to energy, mobility, security, and home automation in Iowa. Companies as diverse as Google, Comcast, AT&T, ADT, Lowes, Tesla, Honeywell, GM, Ford, and Whirlpool are making investments in these areas. As noted in the comments of Facebook and Microsoft in this docket, the question is not "if" or even "when", but rather how best to manage this transition in a smooth and rational way.

We appreciate the participation of MidAmerican, IPL, and Iowa's municipal utilities and electric cooperatives in this ongoing conversation. The growth of distributed generation presents new challenges and opportunities for utilities. These challenges and opportunities will require a concerted effort by all stakeholders to work together in good faith to arrive at new business models that reconcile consumer and societal preferences with the utilities' responsibilities to provide safe and reliable electricity service at a low cost. The New York Public Service Commission's "Reforming the Energy Vision" (REV) docket is a good example of this type of collaborative and goal-oriented process that will ultimately be necessary in all 50 states.[2] Regulatory efforts to erect barriers to distributed generation and "protect" the outdated utility business models could significantly hinder this transformation, to the detriment of all of Iowa's

2 *See* NY PSC, Docket 14-M-0101 – Reforming the Energy Vision (REV) *available at* http://www3.dps.ny.gov/W/PSCWeb.nsf/ArticlesByTitle/26BE8A93967E604785257CC40066B91A.

consumers. Forward-looking utilities will find ways to collaborate with nontraditional partners to create value for their customers.[3] We look forward to continuing this conversation in Iowa.

We appreciate the Board's decision to solicit additional comments on net metering and interconnection policies in this round of comments. Net metering and interconnection represent two of the most important "foundational" policies in just about every growing DG market across the country. The Board should take great care not to backtrack on these policies at this early, fragile stage of market growth in Iowa. At the same time, there are significant opportunities to incorporate best practices from other states to improve both policies.

First and foremost, we believe the Board should create a uniform set of expectations and requirements for the DG market in Iowa by extending Iowa's net metering and interconnection standards to all electric cooperatives and municipal utilities in the state. Other high priority recommendations include: (1) expanding or eliminating the net metering system size cap; and (2) updating Iowa's interconnection standards to reflect new best practices, including those adopted recently by FERC.[4] At the same time, the Board should conduct a comprehensive "value-of-solar" analysis to help the future direction for distributed generation policy in the state. Importantly, as noted by expert Karl Rabago, absolutely no assertion about "cross-subsidization" from net metering or other DG policies should be credited without empirical analysis based on cost-of-service and value-of-solar analysis.

We turn now to the Board's specific questions:

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3 For a comprehensive discussion on this topic, see Elizabeth Graffy and Steven Kihm, *Does Disruptive Competition Mean a Death Spiral for Electric Utilities?*, 35 Energy Law J. 1 (May 2014) *available at* http://ecw.org/sites/default/files/graffy-kihm-elj-article-may-2014.pdf.

4 *See* FERC Order 792 (adopting amendments to Small Generator Interconnection Agreements and Procedures) (Nov. 22, 2013) *available at* http://www.ferc.gov/whats-new/comm-meet/2013/112113/E-1.pdf.

Net Metering

Questions for all utility participants:

1. **Various commenters recommended net metering policy changes which are listed below. Discuss the advantages, disadvantages, and the regulatory changes necessary to implement each suggested change.**

   a. **Increase the size cap from 500 kW to 2,500 kW or 5,000 kW**

As a general principle, net metering is one of the most effective policies for supporting customer generation of renewable energy, and is currently enabling customer-sited generation in 43 states and the District of Columbia. The simplicity and understandability of net metering have been pivotal in reducing barriers to consumer uptake of distributed energy technologies such as solar, and is arguably one of most successful market transformation policies for the renewable energy economy.

In our responses to several of the questions below, we refer to IREC's Net Metering Model Rules[5] and Freeing the Grid's Net Metering Guiding Principles and Best Practices,[6] which together reflect national best practices with respect to net metering. Overall, these best practices support expanding access to renewable energy self-generation to more customers, and our comments below support the same goal.

Iowa's net metering policy receives a 'B' in Freeing the Grid, which means that Iowa's policy is "generally good", but that there are still some obstacles to realizing the full promise of

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5 IREC, *Net Metering Model Rules* (2009) *available at* www.irecusa.org/wp-content/uploads/2014/01/IREC_NM_Model_October_2009-1-10_jan14.pdf.

6 Freeing the Grid, Best Practices, *available at* http://freeingthegrid.org/#education-center/best-practices (last visited June 24, 2014). Freeing the Grid is a joint effort of IREC and Vote Solar, supported by the Network for New Energy Choices (NNEC). Since 2007, Freeing the Grid has graded all 50 states' net metering and interconnection policies in an effort to help state policymakers, regulators, advocates and other stakeholders easily understand and improve these pillars of our new energy economy. Freeing the Grid's grading methodology was also adopted for use in the U.S. Department of Energy's SunShot Initiative, which aims to reduce the cost of going solar by 75% before the end of the decade.

net metering.[7] In general, net metering size caps should be increased to enable the market to expand to larger customers and as virtual net metering, other aggregation, and community solar markets grow. Expanding net metering caps in Iowa would be consistent with broad trends across the country over the past fifteen years.[8]

In particular, Freeing the Grid recommends removing system size limitations to allow customers to meet all on-site energy needs.[9] Raising the net metering size cap would be a good step toward this goal. It would allow customers with on-site loads larger than 500 kW, such as institutional, governmental, industrial, agricultural and large commercial customers, to generate their own electricity. With today's 500-kW cap, net metering typically does not make sense for these customers. Moreover, should the Board expand net metering to permit meter aggregation or virtual net metering, discussed in more detail below, the size of the systems necessary to offset these aggregate loads would increase. Therefore, it would become even more important for the Board to reconsider the system size cap. We support raising the cap to 5,000 kW to allow as many customers as possible to self-generate, however raising the cap to 2,500 kW would also be a step in the right direction.

In addition, while we support increasing the net metering cap, we urge the Board to consider removing the cap entirely as recommended by Freeing the Grid. To mitigate against any concerns related to oversized systems, the Board could incorporate language limiting system size

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7 Freeing the Grid, State Grades – Iowa, *available at* http://freeingthegrid.org/#state-grades/iowa (last visited June 24, 2014).

8 *See* Freeing the Grid *available at* http://freeingthegrid.org/ (last visited June 24, 2014) (interactive timeline on the home pages tracks state progress over time).

9 Freeing the Grid, Best Practices, *available at* http://freeingthegrid.org/#education-center/best-practices (last visited June 24, 2014) ("Individual System Capacity: Any individual system size limitation should be based only on the host customer's load or consumption.").

to 100%–120% of customer load or average annual consumption. We suggest using a percentage greater than 100% to allow the net-metering customer some flexibility.

Because net-metered systems are designed to offset the customer's on-site load or average annual consumption, much of the energy they produce is consumed on-site. If energy is exported, it is largely consumed by nearby customers. As a result, net-metered systems typically do not have a major adverse impact on the electricity grid. Moreover, any grid-impact issues with respect to interconnecting these larger systems would be addressed through Iowa's interconnection procedures, discussed in more detail below.

Furthermore, customer-sited solar generation enabled through the net metering billing arrangement offers many benefits to the electric utility system and by extension to non-solar customers, including but not limited to: reduction in utility energy and capacity generation requirements, particularly during peak periods; reduction in system losses; avoidance or deferral of distribution and transmission investments; localized grid support, including enhanced reliability benefits; fuel-price certainty; and reduction in air emissions and water use. Several recent studies show that the calculated benefits of distributed photovoltaic development often exceed residential retail rates, which implies that net metering provides "rough justice" for solar customers vis-à-vis the utility, and the resulting grid, social, and environmental values benefit solar and non-solar customers alike.[10]

[10] Interstate Renewable Energy Council, *A Regulator's Guidebook: Calculating the Benefits and Costs of Distributed Solar Generation* at 10 (October 2013) *available at* http://www.irecusa.org/publications/.

b. Allow "virtual net metering" where a customer who is not personally able to own a DG facility could invest in a DG facility and receive a benefit from the energy produced by that facility.

Allowing virtual net metering, community solar, and other aggregation techniques will stimulate innovation, exploit economies of scale (in size and numbers of installations), and expand solar participation to a broader base of customers. These approaches are key to overcoming perceptions and allegations of income-level bias and cross-subsidy.

As with increasing the permissible system size, virtual net metering allows more customers to take advantage of renewable energy self-generation, including renters or those whose property is unable to accommodate a generation facility, for example due to a shady roof. In fact, a report from the National Renewable Energy Laboratory (NREL) estimated that only about one-quarter of U.S. residential buildings are physically suitable for installing solar—the most common net-metered technology—on their roofs.[11] This figure does not even take into account the ownership status of the building.

In some states, virtual net metering is limited to instances when the generation facility and the participating customers are on the same or sometimes contiguous property. For example, residents in a multi-tenant building or business in a commercial shopping complex might all share in the benefits of a rooftop solar system via electricity bill credits. Other states use the term to describe what might be more properly considered shared renewable energy—that is, multiple customers receiving the benefits of an off-site facility, which may or may not offset any on-site load beyond parasitic load. For example, multiple residents and businesses in a town might share in the benefits of a renewable energy system installed on the municipal landfill. We support the

[11] Paul Denholm & Robert Margolis, Nat'l Renewable Energy Lab., *Supply Curves for Rooftop Solar PV-Generated Electricity for the United States* 4 (Nov. 2008), *available at* www.nrel.gov/docs/fy09osti/44073.pdf.

broadest possible expansion of access to renewable energy self-generation, which would encompass both of these scenarios.

Some utilities in Iowa are already offering virtual net metering. For example, Farmer's Electric Cooperative (FEC), based in Frytown, currently offers virtual net metering for customers that invest in the coop's community solar garden. Under FEC's arrangement, customers buy and own solar modules that are installed at FEC's community solar garden, which is located by a substation and FEC's main offices. FEC tracks power production from the solar garden and provided bill credits at the retail rate on a monthly basis.[12] There is strong demand among FEC's customers for modules in the solar garden.

For a comprehensive look at virtual net metering and shared renewable energy programs, we refer the Board to IREC's Model Rules for Shared Renewable Energy Programs[13] and the Vote Solar Initiative's Shared Renewables Policy.[14] Among other topics, these resources address bill credit valuation along with a host of other issues relevant to these types of programs, including recommendations to enable:

- on-bill crediting;
- system size of at least 2 MW;
- a wide variety of ownership models including direct, third-party, and where appropriate utility ownership; and
- utility management of the billing system.

We would expect that permitting virtual net metering may require regulatory changes to allow for the allocation of electricity bill credits across multiple customer accounts. IREC's

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12 More information is available at Farmers Electric Cooperative website: sites.google.com/site/feckalona/ (last visited June 24, 2014).

13 IREC, *Model Rules for Shared Renewable Energy Programs* (2013) *available at* www.irecusa.org/wp-content/uploads/2013/06/IREC-Model-Rules-for-Shared-Renewable-Energy-Programs-2013.pdf.

14 The Vote Solar Initiative, Shared Renewables Policy, *available at* http://votesolar.org/policy-guides/shared-renewables-policy-guide/.

Model Rules and Vote Solar's Shared Renewables Policy offer a good starting point for developing these and any other necessary provisions.

c. Include combined heat and power (CHP) and waste heat and power (WHP) as net metering eligible facilities.

CHP is a type of distributed generation technology that produces electricity and useful thermal energy at the same time from a single source of energy. WHP is a type of distributed generation technology that recovers heat that is generated as part of the industrial process and is normally vented in the atmosphere and uses that heat to produce electricity or thermal energy. While traditional methods of producing separate heat and power have a typical combined efficiency of 45%, CHP systems can operate at 80% efficiency or higher.[15] The Energy Resources Center worked with ICF International recently to analyze the technical potential for CHP in MidAmerican and IPL's service territories. There is approximately 1,430 MW of technical potential in these service territories, of which roughly 772 MW are in the industrial sector and 658 MW are in the commercial sector.[16]

All of the Joint Commenters support the expanded use of clean and efficient technologies, including CHP. Some important policies to support CHP include improving the utilities' methodology for calculating avoided costs, improving standby tariffs, including CHP in utility energy efficiency programs, and exploring state tax incentives.

The conceptual foundation for net metering is an extension of PURPA, which favors self-generation and reliance on cleaner and more efficient (from a system perspective) generation options. Because CHP is a distributed energy technology that generates energy at high

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15 U.S. DOE, CHP Technical Assistance Partnerships, About Combined Heat & Power, *available at* http://www.midwestchptap.org/cleanenergy/chp/.

16 Iowa Utilities Board, Docket No. EEP-2012-0001, Graeme Miller Direct Testimony at 9; Iowa Utilities Board Docket No. EEP-2012-0002, Graeme Miller Direct Testimony at 9.

efficiencies, some of the undersigned Joint Commenters would support net metering for CHP in appropriate circumstances.[17] Proposals to extend net metering to CHP should consider best practices from other states, including minimum levels of efficiency for net metering eligibility.[18]

d. Allow an annual cash-out of the net metering balance.

Fundamental design principles of good net metering policy include: monthly roll-over of excess credit balances, full value for offsetting and excess production, regularly updated valuation, and potentially annual cash-out of net metering balances. Freeing the Grid identifies allowing for payment for annual net excess generation at a price no lower than the average daytime wholesale price for the prior year as the national best practice.[19] However, customers should be clearly advised to review potential tax consequences, both state and federal, that may be associated with each aspect of compensation. In order to provide maximum flexibility, we believe customers should continue to have the option to have their credits roll-over into the next year. In this way, customers would be able to participate in the net metering program in a way that makes the most sense for them.

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[17] The Board's net metering rule currently limits net metering to alternate energy production facilities. See 199 IAC 15.11(5). This could potentially include CHP if fueled by one of the fuels listed in the definition for an "AEP facility" in 199 IAC 15.1. The question is extending net metering to include the most common fuel for CHP, natural gas.

[18] For example, New Hampshire's net metering rules for CHP include minimum efficiency requirements for CHP system. *See* EPA Combined Heat and Power Partnership, New Hampshire Net-Metering Rules *available at* http://www.epa.gov/chp/policies/policies/nenewhampshirenetmeteringrules.html (last visited June 24, 2014). In addition, ACEEE has compiled state practices for net metering for CHP in the recent report *Challenges Facing Combined Heat and Power: A State-by-State Assessment* (2011).

[19] Freeing the Grid, Best Practices, *available at* http://freeingthegrid.org/#education-center/best-practices (last visited June 24, 2014)

e. Include aggregate metering for customers who may have more than one meter on their premises.

Aggregate metering, like virtual net metering, provides greater flexibility to customers and allows more customers to enjoy the benefits of renewable energy self-generation. Meter aggregation can be especially appealing to agricultural, institutional or governmental customers, who may have multiple metered loads to offset. For example, an agricultural customer may wish to aggregate meters on pumps and various farm buildings, and offset them by installing one renewable energy system. By aggregating these loads and offsetting them via a single renewable energy facility, these customers can realize economies of scale that allow their investment to pencil out when it otherwise would not.

The reasons for multiple meters at contiguous physical locations are many and varied. There is no physical or technical reason to prohibit aggregate metering for such customers, and there are several efficiency, scale, and interconnection benefits to allowing site aggregation. Potential account aggregation customers include school districts, government jurisdictions (state, county, and city accounts), multifamily housing, commercial rental properties, and others.

2. How does the utility account for energy "purchased" through net metering when reporting fuel type information to the Board, the United States Energy Information Administration, the Federal Energy Regulatory Commission, and others?

Traditional net metering can only be said to create a transfer of ownership and claims related to energy production for production that is excess to consumption over the total netting period – typically, one year. No purchase occurs solely by reason of offsetting up to the point of annual consumption. The Board has described net metering by stating that “net metering does not involve separate purchase and sale transaction but is essentially a metering arrangement.”[20]

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[20] Iowa Utilities Board, Docket No. PURPA Standard 11, Order Regarding PURPA Standard 11 at 3 (August 8, 2006).

FERC has also stated that "no sale occurs when an individual homeowner or farmer (or similar entity such as a business) installs generation and accounts for its dealings with the utility through the practice of netting."[21]

Questions for the rural electric cooperatives (REC) and municipal utility associations:

3. **Provide a list of the REC and municipal utilities who currently offer net metering. Also provide the applicable tariff or policy describing the net metering option.**

We think that it is an important step for the Board to collect this information. REC and municipal utility net metering policies currently vary by utility and are not transparent or easy for a customer to access or understand. Developing an understanding of the current net metering practices of RECs and municipal utilities is an important first step to ensuring that all Iowa customers have an opportunity to take advantage of net metering services.

4. **For the REC and municipal utilities currently offering net metering, how do customers learn about the net metering program? For the REC and municipal utilities that do not offer net metering, explain why net metering is not offered.**

See response to question 3.

Questions for all participants:

5. **Currently Iowa does not offer feed-in tariffs. Explain why you think feed-in tariffs should or should not be implemented in Iowa. In your discussion, address the advantages and disadvantages of both net metering and feed-in tariffs.**

There are several different varieties of distributed generation regulatory tools, including net metering, feed-in tariffs, "value-of-solar" tariffs, and many others. Each one of these tools has their own specific characteristics that may be appropriate depending on the specific policy goals of the program and the underlying business, regulatory and political context. Furthermore, states and utilities can construct and implement a combination of these tools in a wide variety of

[21] Federal Energy Regulatory Commission, MidAmerican Energy Company Docket No. EL99-3-000, Order Denying Request for Declaratory Order (March 28, 2001).

different ways. No state net metering or feed-in tariff program is exactly the same, for example, and the details matter a great deal in the ultimate success of the program. Freeing the Grid is a good resource for policymakers to understand and compare best practices between state net metering programs across the country.

In order to parse out the significant concepts and choices at issue when designing programs for distributed generation, it may be helpful to start with some definitions:

1. A **tariff** is a rate charged by or paid by a utility in transactions with its customers, which is established by the utility with approval of the Board. A tariff may be changed from time to time and those changes will affect transactions that occur subsequent to the tariff change. When applied to solar generation by a customer, this means that the amount paid to a customer for solar generation may change from time to time in a manner that is not prescribed by an agreement with the customer.

2. A **power purchase agreement (PPA)** is a contract whereby a utility contracts to accept and pay for power generation for a fixed term. Power purchase agreements typically have duration approaching the remaining life of the generation system and either provide a fixed rate schedule for the entire contract or index the rate to some external reference not controlled by the parties to the agreement. In common usage, a power purchase agreement is agreed either as a result of a reverse auction or custom negotiation.

3. A **standard-offer PPA** is a power purchase agreement in which the utility announces the available terms and enters contracts with anyone who agrees to accept the terms of the offer. A standard-offer PPA foregoes the price-setting precision of a reverse auction but radically reduces the transaction costs of power purchase, and can thereby produce lower total utility purchase costs and/or lower costs to society than a reverse auction. Across the economy, homogeneous and low-cost purchases are commonly done through standard offers, either to buy or sell, while large and heterogeneous purchases are typically done through auctions or negotiations.

4. A **feed-in tariff**, unfortunately named, is a standard-offer PPA in which the price offered for purchased power is often based on an estimate of the payment rate required for the generator to recover their reasonably-incurred costs of owning and operating the generation system, although other methods may be used. This approach assumes that the utility desires, or is required, to purchase power from particular forms of generation. Paying a rate sufficient for the generator to recover

their reasonably-incurred costs of owning and operating the generation system is the way that utilities are compensated in traditional rate-making.

5. An **avoided-costs tariff** assigns value to the generated power based on what it would have cost the utility to provide equivalent power at the same time and place, absent the generation compensated through the tariff. Controversy concerning avoided costs arises predominantly over whether the avoided costs are only short-term operational costs or also include long-term capital costs. An avoided-costs tariff, like an avoided-costs standard-offer PPA, leaves it to the erstwhile generator to determine whether the compensation offered warrants incurring the costs of owning and operating the generation system. In this sense, an avoided-costs tariff or standard-offer PPA functions like a technology-neutral market for purchasing power.

6. An **avoided-costs standard-offer PPA** is a standard-offer PPA in which the terms are based on projected utility costs to provide equivalent power at the same time and place as is to be supplied by the contracted generation. An avoided-costs standard offer PPA may reasonably include a payment for the value of future-cost risks avoided by the utility or its customer through the contract.

7. A **value-of-solar tariff** is a tariff based on summing the utility's avoided costs of generating equivalent power at the same time and place as is supplied by a solar generator PLUS certain additional amounts reflecting additional value to society that are not included in the utility's avoided costs, such as local economic development or avoided pollution.

8. A **value-of-solar standard-offer PPA** is a standard-offer contract in which the terms are based on projected utility costs to provide equivalent power at the same time and place as is projected to be supplied by the contracted solar system PLUS certain additional amounts reflecting additional value to society that are not included in the utility's avoided costs, such as local economic development or avoided pollution. Like avoided-costs standard-offer PPAs, a value-of-solar standard-offer PPA may include a payment for the value of future-cost risks avoided by the utility or its customers through the contract.

9. PURPA defines **net metering** to be "service to an electric consumer under which electric energy generated by that electric consumer from an eligible on-site generating facility and delivered to the local distribution facilities may be used to offset electric energy provided by the electric utility to the electric consumer during the applicable billing period."[22]

[22] 16 U.S.C. § 2621(d)(11).

As mentioned above, any one of these programs and tools may be appropriate in a given situation depending on the particular circumstances and regulatory goals. The choice between tools is not mutually exclusive and they can be deployed in combination to provide strategic and flexible support for a growing distributed generation industry. Therefore, we recommend that as a general rule, policymakers make an effort to provide customers with choices and options so that they can select the program that works best for them**,** depending on term desired, whether customer desires to retain claims relating to attributes, and customer's preferred tax and investment position.

Turning to the specific question about the "advantages and disadvantages" of net metering and feed-in tariffs, there are several considerations to keep in mind:

- Feed-in tariffs require an administrative determination to set the appropriate price. This has proven to be a challenge in many cases because it is difficult to get the rate exactly "right" through an administrative process. If the rate is locked in too high or too low you may have either a stunted market or an overheated market. This can create a "boom-and-bust" effect that is difficult for growing a sustainable market. Thus, net metering may help promote more stable financing because investors know that they will always be dealing with the retail rate, whereas a feed-in tariff may change year by year or periodically depending on how it is structured.

- On the other hand, deployment of a new feed-in tariff can typically catalyze very rapid market growth if that is one of the goals of the program. A feed-in tariff can therefore provide an important "boost" to net metering in markets where retail rates are lower than necessary to catalyze market growth on their own. The feed-in tariff program (or other type of performance-based incentive) can then be "scaled down" in a transparent way to provide a bridge to a longer-term sustainable DG market based on net metering.

- Net metering preserves a customer's ability to self-supply their own property using on-site generation which is very important to some customers and businesses. In contrast, feed-in tariffs are typically structured as a wholesale transaction in which the customer sells (or is credited for) all of their on-site energy production. This can have tax consequences which are important to consider.

- By encouraging generation near the point of consumption, net metering also reduces the strain on distribution systems and prevents losses in long-distance electricity transmission and distribution.

Historically, net metering has served as a fundamental, bedrock policy for supporting customer generation in states that have a healthy and growing DG markets. Thus, we feel it is important to preserve and expand net metering in Iowa at this critical stage of market development. Eliminating net metering would likely chill market development and would send a strong signal to investors and solar developers to focus their attention on other markets – meaning that Iowa would lose out on the wide range of benefits offered by more DG, such as job creation and economic development, grid and reliability benefits, and cleaner air and water. Feed-in tariffs and other appropriately designed regulatory programs should be explored as supplements to a strong net metering program to catalyze the distributed generation market in Iowa and more quickly ramp up growth. Over the longer term, more sophisticated policies and regulatory tools could be developed in the context of a more comprehensive regulatory process that considers the larger paradigm shift to a more decentralized electricity grid.

6. **Comment on whether you believe the Board has jurisdiction to extend the net metering requirement to coops and municipal utilities and if so, whether it should exercise such jurisdiction.**

Net metering and interconnection standards are within the limited jurisdiction the Board has over RECs and municipal utilities. Iowa law provides the Board with more limited authority over RECs and municipal utilities than investor-owned or rate-regulated utilities. Iowa law provides differing levels of Board authority over the RECs and municipal utilities. The language of the code, and the differences between the language for the RECs and municipal utilities helps define the parameters of the Board's jurisdiction.

The statute is clear that RECs "are not subject to the rate regulation authority of the board."[23] The statute is equally clear that RECs "are subject to all other regulation and enforcement activities of the board."[24] The other regulation and enforcement activities of the Board is open ended, but it does include some specific regulatory activities by reference such as "safety and engineering standards for equipment, operations, and procedures,"[25] and "filing alternate energy purchase program plans with the board, and offering such programs to customers."[26] Iowa law also specifically applies sections 476.41 through 476.44 to encourage the development of alternate energy production facilities to RECs.[27]

For municipal utilities, the statute exempts them from Board regulation unless it specifically provides for regulation.[28] The statute provides for regulation related to safety standards, discrimination against users of renewable energy resources, encouragement of alternate energy production facilities, as set forth in sections 476.41 through 476.45 and filing alternate energy purchase program plans with the board, and offering such programs to customers, pursuant to section 476.47.[29]

The Board has established a net metering rule:

> *Net metering.* Each utility shall offer to operate in parallel through net metering (with a single meter monitoring only the net amount of electricity sold or purchased) with an AEP facility, provided that the facility complies with any applicable standards established in accordance with these rules.

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[23] Iowa Code § 476.1A(1).

[24] *Id.*

[25] Iowa Code § 476.1A(1)(b)

[26] Iowa Code § 476.1A(1)(f).

[27] Iowa Code § 476.1A(2).

[28] Iowa Code § 476.1B(1).

[29] Iowa Code § 476.1B(1)(b), (f), (g) and (n).

> In the alternative, by choice of the facility, the utility and facility shall operate in a purchase and sale arrangement whereby any electricity provided to the utility by the AEP facility is sold to the utility at the fixed or negotiated buy-back rate, and any electricity provided to the AEP facility by the utility is sold to the facility at the tariffed rate.[30]

The Board has allowed waivers of the rule to limit the size of AEP facilities that can net meter to 500 kw and to allow net metering customers to carry forward excess generation amounts to be used in future billing months.[31] The net metering rule is only for rate regulated utilities and is implemented pursuant to Iowa Code sections 476.41 to 476.45.[32] The Board has noted that while Iowa statute does not explicitly authorize the Board to mandate net metering for distributed generation, the "authority is implicit through the Board's enforcement of PURPA and the Alternate Energy Production statutes, Iowa Code 476.41 through 476.47."[33] The same code statutes that provide the implicit authority for the net metering rule and its application to investor owned utilities apply to RECs and municipal utilities. This includes the legislative statement that "[i]t is the policy of this state to encourage the development of alternate energy production facilities and small hydro facilities in order to conserve our finite and expensive energy resources and to provide for their most efficient use."[34] The implicit authority derived from the legislative policy and Iowa statute that allowed the Board to issue the net metering rule in the first place, would allow the Board to expand the net metering rule to apply to RECs and municipal utilities.

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30 199 Iowa Administrative Code § 15.11(5).

31 IUB Docket WRU-02-8-156, Order Granting Waiver and Approving, with Clarifications, Tariff at 6 (March 8, 2002).

32 199 Iowa Administrative Code §15.2(e).

33 IUB Docket No. PURPA Standard 11 (199 IAC 15.11(5)), Order Regarding PURPA Standard 11 at 2 (August 8, 2006).

34 Iowa Code § 476.41.

The Iowa code provides authority for the Board to extend net metering to RECs and municipal utilities. The next question is whether federal law preempts state law and prevents the Board from using that authority. The Federal Energy Regulatory Commission (FERC) specifically addressed whether PURPA preempted a state imposed net metering requirement on a non-rate-regulated utility in a case that dealt with an Iowa electric cooperative. FERC explained:

> It is the state through its legislature, however, which decides whether, and to what extent, a utility is regulated. Here it appears that the state legislature has attempted to regulate utility cooperatives such as the members of CIPCO by requiring utilities to offer net metering arrangements to facilities that are alternative energy facilities as defined by state law. . . . To the extent that the state legislature has required that an electric cooperative such as Midland is required to offer a net metering arrangement to a facility [], the electric cooperative is not a nonregulated utility. Nothing in PURPA preempts the state from making such a decision.[35]

The Iowa Supreme Court cited the FERC Order and noted that "PURPA does not preclude state regulators from requiring net metering by a utility that is not rate-regulated." [36]

Iowa law provides the Board with authority and the policy imperative to apply net metering to RECs and municipal utilities. Customers should not be deprived of the opportunity to self-generate and net meter solely because they are served by an REC or municipal utility. The Board should exercise its jurisdiction and expand net metering to cover RECs and municipal utilities.

7. If you believe that net metering results in cross subsidization of DG customers by non-DG customers, how should the net metering rule be revised to reduce or eliminate such cross-subsidization?

As described in more detail in Karl Rábago's additional comments (Attachment A), this question is premature. Absolutely no assertion about cross-subsidization should be credited

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35 *Swecker v. Midland Power Cooperative*, 105 F.E.R.C. P61,238 at 62,270 (Nov. 19, 2003).

36 *Windway Technologies, Inc. v. Midland Power Cooperative*, 696 N.W.2d 303, 308 n.3 (Iowa 2005) (citing *Swecker v. Midland*).

without empirical analysis based on cost-of-service and value of solar analyses. A discussion of a cross-subsidization before such analyses presupposes a problem before one has been identified.

Today, the best practice in evaluating the costs and benefits of net metering starts with development of a valuation methodology and conducting an analysis of distributed generation value, all in the context of an open stakeholder process. This general approach has now been followed in several other jurisdictions, some of which are described in Karl Rábago's expert report. The Rocky Mountain Institute and IREC have issued comprehensive reports on DG valuation methodologies that are essential resources should Iowa choose to explore this issue in more depth.[37]

At this time, however, there is absolutely no evidence of any significant customer cross-subsidization occurring as a result of net metering in Iowa. Iowa should maintain and expand net metering to enable the state's nascent DG market to sustainably grow. At the same time, stakeholders should be working together to identify mutually beneficial new regulatory models and ratemaking principles that will work better than the traditional cost-of-service paradigm to maximize clean distributed generation and energy efficiency. The states of New York and Massachusetts have recently embarked on comprehensive new regulatory "visioning" exercises that could provide excellent examples of a process to develop "win-win" solutions to help utilities successfully transition and evolve to a future that will inevitably involve more decentralization and disruptive competition.[38]

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[37] *See* Rocky Mountain Institute eLab, *A Review of Solar PV Benefits and Costs Studies* (Sept. 2013) *available at* http://www.rmi.org/elab_emPower; Interstate Renewable Energy Council, *A Regulator's Guidebook: Calculating the Benefits and Costs of Distributed Solar Generation* (October 2013) *available at* http://www.irecusa.org/publications/.

[38] *See* New York PSC "Reforming the Energy Vision" (REV), Docket14-M-0101, http://www3.dps.ny.gov/W/PSCWeb.nsf/All/26BE8A93967E604785257CC40066B91A?OpenDocument

8. If you believe that net metering does not take into account the benefits that DG provides to non-DG customers, how should the net metering rule be revised to account for such value?

As described in question 7 above, a cost and benefit study should be conducted before any discussion of a revision to the compensation methodology in the current net metering rule. Until then, the credit for self-generation/consumption offset and excess production should be at least equal to retail value. Objective, empirical analysis based on cost-of-service and value of solar analysis must precede any changes in net metering. Karl Rabago's additional comments (Attachment A) describe some of the studies that have taken place in other jurisdictions. IREC's *Regulators' Guidebook* describes a recommended methodology for performing a valuation study for distributed solar that could be used as a model in Iowa.[39]

Questions for electric utility customers:

9. For customers who currently use net metering, provide the following information:

a. Type and size of your DG facility;
b. Your electric service provider; and
c. Positive and negative experiences with net metering.

We think that the Board's approach to solicit feedback from customers is a good first step. The Board should consider direct outreach to customers and installers to get a more comprehensive set of responses and experiences. Generally, customers and installers who have access to net metering have had positive experiences. Net metering is an important policy to help get distributed generation projects built in Iowa. Anecdotally, we have heard from both customers and installers that their ability to take advantage of net metering varies significantly

[39] Interstate Renewable Energy Council, *A Regulator's Guidebook: Calculating the Benefits and Costs of Distributed Solar Generation* (October 2013) *available at* http://www.irecusa.org/publications/.

among RECs and municipal utilities. It can be difficult to even understand what policy applies with some of the RECs and municipal utilities.

10. Provide the advantages and disadvantages of the current net metering rules. Are there specific changes that need to occur to these rules to encourage additional DG in Iowa?

At this time, we think that the best option is to maintain Iowa's existing net metering rules while a comprehensive study of distributed generation costs and benefits is completed. If we revisit Iowa's net metering rules, we think that it should be a data-driven process that supports Iowa's legislative policy goal to encourage alternate energy production. Please see our initial comments and the answers above highlighting the changes to Iowa's net metering that we recommend, including expanding the cap on the size of facilities eligible for net metering, considering CHP eligibility for net metering, and expanding net metering to REC and municipal utilities.

Interconnection

1. Do the current interconnection rules ensure that DG installations are safe for customers and utility employees? If not, what specific changes are needed to ensure safe installation and operation of DG equipment? Include specific examples of safety problems, if any, and customer or utility behaviors that may compromise safety.

Iowa's current interconnection standards in Chapter 45 of the Board's rules are working well, to our knowledge. At the time the rules were adopted in 2010, they were built on best practices drawn from the FERC Small Generator Interconnection Procedures (SGIP) and other state rules, including Illinois. The FERC procedures are comprehensively vetted by utilities and other industry stakeholders and rely on national standards that prioritize safety and reliability. We are not aware of any safety or reliability problems associated with systems that were properly installed under the Iowa interconnection standards.

In November 2013, FERC updated its SGIP to better accommodate higher levels of DG penetration.[40] Several states have also updated their standards or are in the process of updating them, including North Carolina, Ohio and Illinois.[41] While Iowa's current standards have been working well at low levels of renewable energy penetration, we recommend updating Iowa's standards consistent with FERC's updated SGIP in anticipation of higher penetrations. In this way, Iowa will be able to avoid problems that have occurred in other states and take advantage of the solutions already developed elsewhere and adopted by FERC.

Specifically, we recommend considering the following changes to Iowa's procedures:

- **Include a pre-application report**.[42] This would allow a potential applicant to submit a written request and obtain, for a fee, pre-specified data related to a proposed project at a specific site. A structured pre-application report can reduce unnecessary interconnection applications by providing information about system conditions at a proposed point of interconnection. Without this information, developers may submit multiple applications to find out which of many potential project locations have the lowest costs, resulting in a high volume of applications. Utilities may find it increasingly difficult to keep up with the number of applications they have to review and it is inefficient for utilities to have to process applications that are unlikely to result in projects. It also raises the overall costs of development when developers are forced to try a scatter-shot approach to identify the lowest-cost opportunities.

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40 Order No. 792, *Small Generator Interconnection Agreements and Procedures*, 145 F.E.R.C. ¶ 61,159 (2013).

41 IREC, Regulatory Reform News, *Ohio Joins Top States Improving Interconnection Procedures for Renewables available at* http://www.irecusa.org/2013/12/ohio-joins-top-states-improving-interconnection-procedures-for-renewables; *See* NCUC Docket E-100, Sub 101 (Joint Petition for Approval of Model Small Generation Interconnection Standards & Associated Application to Interconnect & Interconnection Contract Forms; OH Case No. 12-2051-El-ORD In the Matter of the Commission's Review of Chapter 4901:1-22, Ohio Administrative Code, Regarding Interconnection Services, Finding and Order Updating Procedures (Dec. 4, 2013) *available at* http://dis.puc.state.oh.us/TiffToPDf/A1001001A13L04B42903E62593.pdf; Illinois Commerce Commission Rulemaking Docket, 14-0135.

42 FERC SGIP § 1.2; *see also* IREC Model Interconnection Procedures § II; NREL, *Updating Small Generator Interconnection Procedures for New Market Conditions* 12-15 (Dec. 2012), *available at* www.nrel.gov/docs/fy13osti/56790.pdf [hereinafter NREL Interconnection Report].

- **Modify Level 2 eligibility requirements**.[43] In its revised SGIP, FERC adopted a more sophisticated method for determining eligibility for its Fast Track review, which relies on a combination of facility size, distribution line voltage, and distance from the substation. The distribution line voltage at the point of interconnection is one of the key factors in determining whether a project can interconnect without full study. Likewise, larger generators may pose a lower likelihood of imposing impacts that require study when located close to the substation and on main feeder lines.

- **Incorporate a clearer Supplemental Review process**.[44] Although Iowa permits "additional review" if a facility fails to meet one or more of the Level 2 screens,[45] this process is relatively vague and open-ended. A clear, more transparent additional review—or as FERC refers to it, Supplemental Review—process can enable efficient interconnections at higher penetrations while still ensuring system protection. Specifically, it can maintain a fast process for projects in low-penetration areas, but can provide utilities with sufficient time to conduct additional analysis in higher penetration cases where full study is not necessary. The full study process (Level 4) is typically lengthy and costly; however, an abbreviated study process may be appropriate for certain projects, such as projects that do not exceed 100 percent of minimum load on a circuit. In addition to benefiting generators by minimizing their review time and costs, a robust Supplemental Review process may help to minimize congestion in utility study queues. A Supplemental Review process similar to the one in the FERC SGIP has been adopted in Ohio, and is under consideration in Illinois and North Carolina.

In addition to these changes based on the FERC SGIP, we recommend some additional changes based on IREC's Model Interconnection Procedures, which reflect best practices nationally.

- **Increase the Level 1 review threshold to 25 kW**.[46] At the time that the FERC SGIP and many other state interconnection procedures were adopted, most residential solar systems were well under 10 kW. The market is growing, however, and so is this size of the average installation. Although the average size remains under 10 kW today, as the volume of residential and small commercial interconnection increases, it makes sense to ensure continued administrative ease in the interconnection of these generators. Examples from other states have demonstrated that it is unlikely that utilities need a more complicated application form or interconnection agreement for generators up to 25 kW.

43 FERC SGIP § 2.1; *see also* IREC Model Interconnection Procedures § III(B)(2)(a)

44 FERC SGIP § 2.4; *see also* IREC Model Interconnection Procedures § III(D).

45 199 IAC § 45.9(6).

46 IREC Model Interconnection Procedures § III(A); *see also* NREL Interconnection Report at 15-16.

Because all generators all still subject to the Level 1 screens, increasing eligibility to 25 kW will not reduce the protections applied to ensure safety, reliability, and power quality.

- **Modify the "no construction screen" in Levels 1 and 2**.[47] Iowa prohibits generating facilities that pass other technical screens for expedited interconnection review from obtaining an interconnection agreement if they require construction of any facilities by the utility on its system.[48] This "no construction screen" results in unnecessary studies and can be particularly problematic for generating systems wishing to interconnect in locations without onsite load. In contrast, the approach taken in IREC's Model Procedures gives a utility additional time to provide a cost estimate along with an interconnection agreement if it determines that upgrades are necessary, with timeframes dependent on whether these are minor system modifications or something more.

- **Eliminate the Feasibility Study.**[49] Many states have moved to a one- or two-study process in the interest of efficiency and cost-effectiveness. The role of the Feasibility Study in particular is fairly limited since much of the crucial detail of interest to generators and utilities does not come until the later studies.

- **Do not allow the utility to require an external disconnect switch for an inverter-based facility**.[50] It is well established that inverter-based systems, such as solar PV systems, can be safely and effectively connected to the grid without an external disconnect switch.[51] An external disconnect switch fails to provide the "fail safe" protection that is its justification, is redundant if employed on systems with UL- and IEEE-listed inverters, and adds unnecessary cost to a PV system. Alternatively, if the Board chooses to continue to allow utilities to require an external disconnect switch, the Board might consider requiring a utility to reimburse applicants for the cost of the switch.

- **Require utilities to dedicate a webpage to interconnection**.[52] This page should include the utility's interconnection procedures, applications, agreements and other attachments in an electronically searchable format, and the utility's point of contact for submission of interconnection applications, including email and phone number. This accessibility

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47 IREC Model Interconnection Procedures §§ III(A)(5), III(B)(5); *see also* NREL Interconnection Report at 28-29.

48 199 IAC §§ 45.8(1)(e), 45.9(1)(j).

49 *See* NREL Interconnection Report at 31-34.

50 IREC Model Interconnection Procedures § IV(D)(5).

51 *See* Michael T. Sheehan, P.E., IREC, *Utility External Disconnect Switch: Practical, Legal, and Technical Reasons to Eliminate the Requirements* (Solar ABCs) (Sept. 2008), *available at* www.solarabcs.org/about/publications/reports/ued/pdfs/ABCS-05_studyreport.pdf; M.H. Coddington et al., NREL, *Utility-Interconnected Photovoltaic Systems: Evaluating the Rationale for the Utility-Accessible External Disconnect Switch* (Jan. 2008), *available at* http://www.nrel.gov/docs/fy08osti/42675.pdf.

52 IREC Model Interconnection Procedures § IV(A)(2).

should make it easier for applicants to undertake the process and require the utility to field fewer questions.

- **Require utilities to allow online applications and electronic signatures to be used for interconnection applications.**[53] Online applications are efficient because they shorten the time it would take for a utility to process a complete interconnection request. They can also help to quickly identify deficiencies in an application, for both the applicant as well as the utility. In addition, online applications create an electronic trail that increases accountability. Electronic signatures are similarly more efficient. Moreover they are generally recognized in commercial activities, and 47 states have adopted the substance of the Uniform Electronic Transaction Act (UETA), a model act developed by the National Conference of Commissioners on Uniform State Laws.

2. Is there an issue with customer DG installations occurring without the knowledge of the utility? If so, what is the magnitude of this problem, and how should it be addressed?

No, not to our knowledge. If this is occurring, the state should investigate and take appropriate action to stop it and enforce existing Iowa rules. Iowa's interconnection standards require customer-generators to work with the utility to ensure safety and reliability of their systems. Iowa Code also provides for a 30 day notification requirement to the utility by the customer who is installing an AEP facility.[54]

3. Are rule changes necessary to ensure system reliability is not harmed due to the interconnection of DG resources? Provide specific examples of reliability effects from the interconnection of DG.

We are not aware of any specific reliability effects from systems that have been installed appropriately pursuant to Iowa's interconnection standards. The technical screens used in the expedited review levels (Levels 1 through 3) explicitly provide protection against reliability impacts of systems permitted expedited treatment.[55] All of these screens are conservative by design. For example, the penetration screen (15% of peak load) used in both Levels 1 and 2 is

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53 IREC Model Interconnection Procedures § IV(A)(1), (3); *see also* NREL Interconnection Report at 17-19.

54 Iowa Code § 476.6A.

55 *See* 199 IAC §§ 45.8 – 45.10.

intended to ensure that the combined DG on a line section, including the interconnection applicant, is well less than the minimum load (15% of peak load is approximately 50% of minimum load), thereby ensuring that the risk of unintentional islanding, voltage deviations, and other potentially negative impacts is effectively eliminated.[56] If a project fails any of the screens, then it must undergo a thorough study process (Level 4), during which the utility has the opportunity to ensure that the reliability of the system is not affected by the proposed interconnection.[57] For example, the impact study explicitly "evaluates the impact of the proposed interconnection on both the safety and reliability of the utility's electric distribution system."[58] However, as discussed above, some rule changes are recommended in order to adequately prepare for a future in Iowa with a higher penetration of DG devices.

4. Considering the benefits that accrue to the system from DG, what is the correct price to charge for interconnection of DG systems? Should this price be technology dependent?

Interconnection fees and charges are typically scaled so that simple interconnections that do not require further study or distribution system upgrades can be interconnected quickly and inexpensively while more complex systems that have the potential to require study and grid upgrades must pay the cost of the necessary studies and work to ensure safe and reliable operation. Any changes to Iowa's interconnection fees should be based on data demonstrating the utility costs and that the utility has implemented modern practices to minimize interconnection costs. Utilities in jurisdictions with higher DG penetrations are increasingly moving to automated or "web-based" interconnection applications, which further streamlines and

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[56] 199 IAC §§ 45.8(1)(a), 45.9(1)(a); *see also* Michael Coddington et al., *Updating Technical Screens for PV Interconnection* 1-2 (Aug. 2012), *available at* www.nrel.gov/docs/fy12osti/54103.pdf (explaining rationale behind 15% screen).

[57] *See* 199 IAC § 45.11.

[58] 199 IAC § 45.11(6).

lowers the utilities' costs of interconnection review.[59] Interconnection standards are generally technology neutral and are not intended to "compensate" DG for the benefits that they create for the grid. Other policies (such as net metering, feed-in tariffs, "value-of-solar" tariffs) serve the function of appropriately compensating DG for the values it creates.

5. How should distribution or transmission system upgrade costs associated with DG installation be properly allocated? Are there specific benefits that all customers (DG-owning and non-DG owning) receive from DG required transmission or distribution upgrades and, if so, what are the specific benefits?

There are benefits such as overall savings from line losses and a reduction in need for future transmission and transmission upgrades that accrue to all customers from DG related distribution and transmission upgrades. These benefits should be reflected in the allocation of costs related to DG transmission and distribution system upgrades. In addition, it is important to think through issues of cost sharing for upgrades across developers. Approaches should be considered that avoid placing the entire cost of an upgrade on the first/unlucky developer who triggers the upgrade when other developers and ratepayers will benefit from that upgrade. Quantifying these benefits and assigning costs is complicated. There are efforts underway in states with greater DG penetration to tackle this issue in a fair, comprehensive, data-driven way. IREC's Integrated Distribution Planning Concept Paper addresses many of these issues and can provide guidance for Iowa as we look forward.[60]

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[59] *See, e.g.*, Commonwealth Edison (Illinois) Online Interconnection and Net Metering home page *available at* https://interconnect.comed.com/ComEd/Home/?ReturnUrl=/&_ga=1.263272970.783641903.1403587069 (last visited June 24, 2014).

[60] *See generally*, IREC, *Integrated Distribution Planning Concept Paper: A Proactive Approach for Accommodating High Penetrations of Distributed Generation Resources* (May 2013), *available at* www.irecusa.org/wp-content/uploads/2013/05/Integrated-Distribution-Planning-May-2013.pdf.

6. **Is there adequate protection for distribution assets from improperly installed DG equipment? If not, what additional protections are needed?**

We are not aware of any problems. Iowa's interconnection standards are based on nationwide technical standards such as IEEE 1547 and UL 1741 that have been specifically designed to ensure the safety and reliability of distribution assets. If problems exist, it is likely due to lack of compliance with Iowa's existing standards.

7. **Should the Board revise its interconnection rules in 199 IAC 45 to make them consistent with FERC's updated interconnection rules, which were adopted on November 11, 2013, in Docket No. RM13-2-0001 (Order No. 792) and can be found at 145 FERC ¶ 61,159? In what specific ways should the Board's rules be revised?**

Yes. The Board should initiate a rulemaking docket to revise Iowa's interconnection standards to incorporate best practices from the FERC SGIP and other state rules. See response to question 1 above.

8. **Should the Board require any customer installing DG with a view toward selling excess generation to the utility to commit to remaining interconnected for a specific period of time, to maintain the DG system in good working order for that entire time period, and to either obtain a similar commitment from any subsequent purchaser of the property or to remain responsible for the commitment for that entire period of time. If so, why? If not, why not?**

This is not an interconnection issue. This is also not a net metering issue. In a net metering billing arrangement, there is no intent to "sell" excess generation. Because net-metered systems are designed to offset the customer's on-site load or average annual consumption, much of the energy they produce is consumed on-site. If energy is exported, it is largely consumed by nearby customers. As a result, net-metered systems typically do not have a major adverse impact on the electricity grid. To the extent that this is a PURPA issue, federal law does not require a commitment to remain interconnected for a specific period of time.

This appears to be an integrated resource planning issue and perhaps could be usefully considered in that context. Currently, the Iowa investor-owned utilities, MidAmerican Energy

Company and Interstate Power & Light Company, do not include distributed generation or energy efficiency as resources in their integrated resource plan. Instead, the utilities reflect distributed generation and energy efficiency in their load forecast. This approach undervalues distributed generation resources in calculating avoided costs and in integrated resource planning. Rather than require a commitment to remain interconnected, the Board should require electric service providers to account for the long-term performance of distributed generation and distributed energy resources, particularly in the aggregate, and evaluate them as separate resource option. The long-term performance should be data driven based on Iowa experience, and where there is not sufficient Iowa and Iowa utility specific experience, Iowa utilities should look to system performance data from other states with a longer distributed generation history.

9. **For customers that have installed DG, what have been the positive and negative experiences when interconnecting with the utility and what specific changes would you suggest? (Identify whether the DG facility was renewable or nonrenewable and which utility you interconnected with.)**

    a. **Does the interconnection process timeline take longer than necessary? If so, what are the problems and how can they be solved?**
    b. **Has any DG owner-commenter experienced difficulty interconnecting a DG project with the system of any non-rate-regulated utility or utilities? If so, please describe the difficulty experienced and whether/how the difficulty was resolved.**

We think that the Board's approach to solicit feedback from customers is a good first step. The Board should consider direct outreach to customers and installers to get a more comprehensive set of responses and experiences. Generally, we have heard that customers and installers who work with the investor owned utilities have had positive experiences on interconnection or have been able to work through problems within a reasonable timeframe. The exception is that Alliant interconnections have recently slowed down significantly. We have also heard anecdotally from both customers and installers that their experience interconnecting with

RECs and municipal utilities is significantly more varied. It can be difficult to even understand what policy applies with some of the RECs and municipal utilities, and in some cases, they face a series of roadblocks or delays.

10. Comment on whether you believe the Board has jurisdiction to extend its interconnection rules to coops and municipal utilities and if so, whether it should exercise such jurisdiction.

Net metering and interconnection standards are within the limited jurisdiction the Board has over RECs and municipal utilities. The analysis summarized in response to net metering question six above applies for interconnection standards as well. As that analysis demonstrated, RECs are subject to "all other regulation and enforcement activities of the Board,"[61] and municipal utilities are subject to Board regulation related to statutorily specified areas. The Board has explained that this authority "extends to, among other things, safety standards, assigned areas of service, and prohibition from discrimination against users of renewable energy."[62]

Iowa has adopted interconnection standards.[63] Interconnection standards have nothing to do with rates. Instead, they address safety and fair treatment of all utility customers – areas that the Board has explicit authority to regulate.[64] Furthermore, the Board has never found that it lacked such authority to create a standard interconnection process across the state. In past

[61] Iowa Code § 476.1A.

[62] IUB Docket No. NOI-06-4, Order Adopting Preliminary Model Interconnection Procedures, p. 6 (April 25, 2007).

[63] *See* 199 Iowa Administrative Code § 45.

[64] *See, e.g., In re. Iowa Lakes Electric Cooperative*, IUB Docket No. WRU-06-19-978, Order Denying Waiver Request (Sept. 5, 2006) (holding that electric cooperatives are subject to the Board's rules limiting charges for meter testing, even though the cooperatives are not rate-regulated utilities).

interconnection proceedings, the Board simply found that the jurisdictional issue was "unsettled."

Differences and discontinuities between utility interconnection procedures creates inefficiencies and market confusion that can unnecessarily raise costs for DG project development. Multiple states have adopted statewide interconnection procedures that apply to municipal utilities and RECs.[65] Customers should not be deprived of the opportunity to interconnect and self-generate under standard procedures solely because they are served by an REC or municipal utility. When the Board updates the interconnection rules, it should extend the applicability of those rules to RECs and municipal utilities.

Consumer Protection & Education

1. **Is there a need to educate customers about DG issues such as economics, tax incentives, utility requirements, reputable installers, and similar considerations? If so, whose role is it and what type of education should be provided?**

Customer education is always needed with emerging markets and technologies. The more a customer knows about the technology and its costs and benefits, the more likely they are to adopt it. Customer education should come from all parties, including utilities, commissions, and operators, and the IUB should ensure that all education is transparent as to the benefits and costs of going solar or installing other forms of DG.

Providing information on reputable dealers, utility requirements, and other considerations would make the integration of DG by customers much more seamless. Having all information needed for purchase and integration would likely increase DG usage. With a higher percentage of DG customers, the Board could also incentivize larger investment in grid infrastructure

[65] *Freeing the Grid 2013: Best Practices in State Net Metering Policies and Interconnection Procedures*, at 26 and 98 (2013) *available at* http://freeingthegrid.org/#download-ftg/.

modernization like some of the pilot projects being seen across the country on microgrids, better emergency management, and advanced metering technology.

Here are some comparative examples of state outreach:

- **California** has the most solar in the nation, they are currently aggregating their best resources on their website to aid with customer adoption. http://www.gosolarcalifornia.ca.gov/ CA has an entire governmental outreach website as a resource to customers interested in implementing rooftop PV. This includes savings calculators, an event calendar, contact listings, and incentive programs.

- **Arizona**, another national leader, engages customers through a collaborative effort led by the AZ Corporation Commission and implemented by the utilities. http://arizonagoessolar.org/ The group explains renewable energy standards, provides solar maps, mentions state and federal incentives, and lists residential program details for each utility in the state.

- In 2003, the **New Jersey** Board of Public Utilities (BPU) established the Office of Clean Energy to administer New Jersey's Clean Energy Program (NJCEP). Representatives from government and industry, energy experts, public interest groups, and academics helped establish committees to engage stakeholders in NJCEP's development and provide input to the BPU regarding the design, budgets, objectives, goals, administration, and evaluation of New Jersey's Clean Energy Program. Committee meetings are open to the public and all are invited to participate. http://www.njcleanenergy.com/whysolar

- **Massachusetts** has developed the Mass. Clean Energy Center; it is a partnership effort between local and international clean energy companies, the investment community, research institutions, workforce development organizations, and business and residents. They appear to provide information online for customers and provide information on all fronts of clean energy development in the state, including informational resources, solar and wind programs, and recent developments. http://www.masscec.com/

2. **Should the Board develop a checklist to assist customers in understanding the process and responsibilities associated with installing DG or does one already exist? What issues should consumers consider when installing DG (both renewable and nonrenewable)?**

Outreach and education is always helpful and the simpler the information, typically the easier it is for the customer to digest. Having a quick reference for DG-interested customers could help the market operate more smoothly and entice new investment and development. The checklist should be objective and not serve as a barrier to solar adoption. Customers should consider:

- Retail rates offered by utilities and confirmation that there is no discriminatory charge for onsite generation;
- Rooftop vs. community solar projects and their comparative benefits;
- Home rooftop solar financing resources and considerations; and
- Receiving bids from a variety of providers.

The Board should be mindful and wary of Homeowner's Associations rules or civic ordinances restricting the development of solar in Iowa. Iowa Code currently enables city councils and county boards of supervisors to prohibit deeds for property located in new subdivisions from containing restrictive covenants that include unreasonable restrictions on solar. *See* Iowa Code § 564A.8. The Iowa Code should be extended to all neighborhoods and broader protections should be put into place to prevent restrictive covenants prohibiting solar implementation. Many states have laws that protect the right of homeowners to install solar PV systems, including Arizona, California, Colorado, Delaware, Florida, Maine, Maryland, Massachusetts, Nevada, New Jersey, North Carolina, Oregon, Vermont, Virginia, and Wisconsin.[66]

3. **With respect to public safety, who is primarily responsible for the issue of firefighter safety and fire suppression activities, the customer or the local fire officials?**

    a. **Should customers be required to provide local fire officials information regarding their solar installations?**
    b. **Should fire officials be required or encouraged to maintain detailed logs regarding solar installations in their community or fire district?**

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[66] *See* DSIRE, Rules, Regulations & Policies for Renewable Energy *available at* http://www.dsireusa.org/summarytables/rrpre.cfm (last visited June 24, 2014) (access laws).

The issues related to fire safety and solar PV are being evaluated, studied and addressed with a combination of improved and revised building and fire codes, including the 2012 International Fire Code, and firefighter training and education. We recommend consulting nationally-available resources and best practices on these topics to guide next steps in Iowa, including specific fire safety information and resources available from the Solar Energy Industries Association[67] and the Solar ABCs.[68]

4. **Do current Iowa consumer protection laws adequately address the responsibilities of the DG suppliers/distributors? Who should be responsibility for resolving consumer complaints regarding DG suppliers/distributors (Iowa Utilities Board, the Attorney General's office, or some other agency)?**

The Iowa Attorney General's office has responsibility for enforcing consumer protection complaints regarding DG suppliers and distributors in Iowa. Iowa consumer protection laws provide sufficient remedies to adequately address the consumer issues that have arisen to date. The current framework is appropriate.

5. **Should DG suppliers/distributors be required to be certified as qualified to supply/install the equipment/project in question? Who should perform the certification? Who, if anyone, should maintain a listing of certified DG contractors/installers?**

While we believe that existing rules, such as local permitting and inspection requirements and state-level interconnection rules, already provide sufficient consumer protection, if the Board chooses to require installer certification, we recommend relying on NABCEP or another nationally established and well respected certification program. Installer certification can be a useful consumer protection measure in early-stage markets, but it can also be abused in anti-

[67] SEIA, Issues & Policies, Fire Safety & Solar *available at* http://www.seia.org/policy/health-safety/fire-safety-solar (last visited June 24, 2014).

[68] Solar America Board for Codes and Standards, Fire Fighter Safety in Buildings with PV Modules *available at* http://www.solarabcs.org/current-issues/fire_safety.html (last visited June 24, 2014).

competitive ways, for example by municipalities requiring and charging fees for community-specific licenses. Since DG installers operate regionally, this can be a major market barrier. According to IREC and Vote Solar Best Practices in Solar Permitting, community-specific licenses should not be required.[69] If certification is used for solar installers, IREC and Vote solar recommend accepting North American Board of Certified Energy Practitioners (NABCEP) PV installer and solar thermal certification.[70] NABCEP already provides a locator for certified installers.[71]

Distributed Generation

Question for all utility participants:

1. **For calendar year 2013, provide the following detailed information (in an Excel file) related to each DG facility connected to your utility system:**

    a. **Nameplate capacity;**
    b. **Date interconnected;**
    c. **Fuel type;**
    d. **Include all applicable classifications (i.e., qualified facility (QF), alternate energy production (AEP), net metering, and any others that may apply);**
    e. **For AEP interconnections, indicate whether this facility contributes to compliance with your AEP purchase obligation;**
    f. **Indicate whether this facility is subject to a tariffed or contracted rate;**
    g. **The applicable retail tariff customer class; and**
    h. **Indicate whether hourly load data are available for this facility.**

It is difficult to track the DG market and adoption rate in Iowa on a statewide basis. We think that it is an important step for the Board to help collect this information.

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69 IREC and Vote Solar, *Project Permit: Best Practices in Residential Solar Permitting* (July 2013) *available at* www.irecusa.org/wp-content/uploads/2013/08/Solar-Permitting-Best-Practices_July2013_revisedC.pdf.

70 See www.nabcep.org for more information.

71 NABCEP, Certified Locator *available at* www.nabcep.org/certified-installer-locator (last visited June 24, 2014).

Questions for all participants

2. **Should Iowa have a policy goal to increase and diversify alternate energy production? If so, should that policy be achieved with utility-owned centralized generation, utility-owned distributed generation, customer-owned distributed generation or a mix of these alternatives? Discuss the advantages and disadvantages of these approaches.**

Iowa has a clear statutory policy goal to increase and diversify alternate energy production. Iowa Code section 476.41 states "It is the policy of this state to encourage the development of alternate energy production facilities and small hydro facilities in order to conserve our finite and expensive energy resources and to provide for their most efficient use." Consistent with the strong policy directive enshrined in Iowa code, the Board should look at policies that encourage a range of options for building alternative energy and should not create barriers to any particular option for developing alternative energy.

Iowa has had significant success with utility-owned centralized wind generation. That success should be applauded, encouraged and replicated, but it does not mean that Iowa should not encourage customer-owned distributed generation to further achieve the policy goal of increased alternative energy production. Public policy in Iowa has continued to support customer distributed wind generation with state production tax credits. Similarly, if Iowa utilities were interested in developing additional utility-owned renewable generation whether it be centralized or distributed, our groups would encourage and support those efforts. We would also continue to encourage and support customer-owned distributed generation. The two are not mutually exclusive. In fact, Iowa policy makers recently took steps to encourage and support customer distributed solar generation with the enactment of SF 2340 expanding Iowa's upfront solar tax credit. The Board should continue to implement Iowa's policy to encourage alternative energy production and support a mix of options to accomplish the goal.

3. **What are the current incentives, if any, for the utility to promote DG and for the customer to own DG? Should alignment of DG production with utility peak demand be the target of an incentive?**

There is currently a mix of state and federal incentives for customers to own or install distributed generation, outlined below. The eligibility for these incentives can vary widely, meaning a customer may only be eligible for one or two of the available incentives.

- Tax incentives. Federal tax incentives include the upfront 30% credit for solar PV (and other types of DG) for homeowner and business taxpayers as well as depreciation incentives for business taxpayers. Iowa provides an upfront tax incentive for solar PV and solar thermal that matches 60% of the federal credit for homeowner and business taxpayers. The Iowa tax incentive is capped at $5,000 for homeowners and $20,000 for businesses.
- Loan and grant programs. The Iowa Energy Center offers a low-interest loan program for renewable energy systems. The U.S. Department of Agriculture offers both loan and grant programs for which farm and rural business applications of DG are eligible. Iowa has a good track record of securing USDA grants and loans under this program for both DG and non-DG purposes.
- Utility incentives. Utility incentives are important to help offset upfront costs and directly encourage adoption of DG, but few utilities in Iowa currently offer incentives for customers to own or invest in DG. Alliant Energy has ended its customer-sited renewable energy incentive program, although the program is still winding down in 2014. Several municipal and cooperative utilities offer some form of incentive, such as the upfront rebate offered by the Ames Municipal

Utility and a range of incentive options offered by Farmer's Electric Cooperative (based in Frytown).

Utility incentives should focus on maximizing the value of DG overall, in terms of the total benefits summed against the costs on a levelized basis. The comprehensive DG study will identify and quantify these benefits and costs and allow for incentives to be designed to maximize these values. Aligning DG production with utility peak demand is one of these values and should be considered in the context of all values rather than alone.

4. Do utilities include distributed generation in their resource planning? If so, how is DG accounted for? If not, why and is this likely to change?

Currently, the Iowa investor-owned utilities, MidAmerican Energy Company and Interstate Power & Light Company, do not include distributed generation or energy efficiency as resources in their integrated resource plan. Instead, the utilities reflect distributed generation and energy efficiency in their load forecast. The current approach undervalues distributed generation resources in a variety of areas such as avoided cost calculations and integrated resource planning.

The large and continuous decline in the cost of solar resources indicates the possibility that solar generation in Iowa will be a cost-effective resource when compared to conventional resource options in the near future. The possibility of solar as a cost-effective resource implicates resource planning, and the NREL recently published a report on this issue.[72] Together with the Solar Electric Power Association, NREL interviewed thirteen electric sector representatives, including those from nine utilities, about incorporating solar into their resource planning

[72] *See generally* NREL, *Treatment of Solar Generation in Electric Utility Resource Planning* (2013).

processes.[73] Subsequently a questionnaire was developed and distributed to a number of utilities, twenty-eight of which responded from twenty-two states.[74]

Through its research, NREL concluded that most responsive utilities currently treat distributed generation as a net load impact rather than a resource.[75] This option essentially embeds distributed penetration variability within the load forecast, which, while expedient, can make it difficult to capture the direct impact of distributed solar on the system.[76] Accordingly, another option that some utilities incorporate involves treating distributed generation as a generation resource explicitly. This can enable an independent investigation of customer load profiles, which can be more effective in long-term planning.[77] Utilities could then incorporate distributed generation into capacity expansion models and toggle inputs to optimize the distributed generation resource.[78]

This docket should look at how Iowa utilities can take steps to treat distributed generation as a resource and appropriately capture the benefits and impact of distributed generation on the system during their integrated resource planning. Incorporating distributed generation into resource planning requires thinking about a number of issues including but not limited to scale (e.g. minimum planning size for T&D offset value), fuel costs (especially fuel price volatility risk), regulatory risk (especially environmental regulatory risk), water requirements, deployment risk, and valuation of customer investment as an offset to revenue requirement. Iowa has the

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73 *Id.* at 3.

74 *Id.*

75 *Id*. at 25.

76 *Id.* at 3, 34.

77 *Id.* at 25.

78 *Id.* at 12, 35.

opportunity to work through resource planning issues in a thoughtful way before significant amounts of distributed generation are on the grid in Iowa, and the Board should seize it.

5. What is the rate of DG adoption currently experienced by each utility and what is the rate projected to be in the next five to ten years? Do these adoption rates cause problems with transmission and distribution planning? How do utilities cope with this challenge?

It is difficult to track the DG market and adoption rate in Iowa on a statewide basis. Utilities file limited information with the Board on the size, location and types of DG facilities that have interconnected on their systems, and often file this information confidentially. The approximately 175 separate utilities serving Iowa are also subject to different or nonexistent filing requirements. We think that it is an important step for the Board to help collect this information.

Despite these difficulties, we believe the adoption rate for DG technologies like solar PV in Iowa is currently slower than most states and significantly slower than leading states. By way of example, in 2012, North Carolina installed 132 MW of solar PV while Iowa installed approximately 1-2 MW.[79] These states have a similar solar resource and similar electric costs.

At the current rates of DG adoption, we would not expect any problems with transmission and distribution planning. Integration issues can arise from widespread adoption of DG, but the evidence suggests that problems occur only at very high deployment levels and should thus not be an issue in Iowa now or in the foreseeable future. A useful case study is California, where Black and Veatch recently studied the impacts of DG on transmission and distribution systems for the California Public Utilities Commission as part of a legislative mandate.[80] By the end of 2012, customer-sited DG installations accounted for 1,785 MW in

[79] SEIA/GTM Research, *U.S. Solar Market Insight: 2012 Year in Review* (2013).

[80] *See* Black and Veatch, *Biennial Report on Impacts of Distributed Generation* (2013).

California.[81] Even with nearly 1.8 GW of DG on its grid, which far eclipses the amount of DG presently available in Iowa, California experienced relatively few impacts on its distribution and transmission systems.[82]

In order to project a DG adoption rate for Iowa, a study could be conducted that takes into account (a) the existing policies, (b) electricity prices, (c) empirical evidence from similarly-situated jurisdictions, and (d) future expectations for policies. Although this study could be difficult, a general idea of a future adoption curve for DG could then be used in transmission and distribution planning.

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Respectfully submitted,

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[81] *Id.* at 1-2.

[82] *Id.* at 4-2.

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Comments of Karl R. Rábago, Rábago Energy LLC

In Response to

ORDER OF IOWA UTILITIES BOARD

SOLICITING ADDITIONAL COMMENTS ON DISTRIBUTED GENERATION, NET METERING, AND INTERCONNECTION AND INCLUDING REPORTS

DOCKET NO. NOI-2014-0001 (Issued May 12, 2014)

COMMENTER BACKGROUND

Karl R. Rábago has more than 24 years experience as a leader and innovator in the electric utility sector. He has served as a public utility commissioner on the Public Utility Commission of Texas, and as vice-chair of the NARUC Efficiency and Renewable Energy Committee. As a Deputy Assistant Secretary for Utility Technologies at the U.S. Department of Energy, he managed a portfolio of technology and policy research and development covering renewable energy, hydrogen, high-temperature superconductivity, and other areas. In the private sector, Mr. Rábago has held the position of Vice President for Distributed Energy Services at Austin Energy, the municipal electric utility serving Austin, Texas. He has also served as Director of Global Regulatory Affairs for the AES Corporation, and as Director of Regulatory Affairs for AES Wind. While a Managing Director at the prestigious Rocky Mountain Institute, Mr. Rábago co-authored "Small Is Profitable," the definitive book on valuing the operational, engineering, economic, and financial benefits of right-sized energy resources. Mr. Rábago developed the Value of Solar rate concept at Austin Energy and has testified and lectured on solar valuation and ratemaking in dozens of formal and informal proceedings over the last two years. A veteran of more than twelve years service in the U.S. Army, Mr. Rábago holds a degree in management from Texas A&M University, a juris doctorate from the University of Texas School of Law, and post-doctorate LL.M. degrees in Military and Environmental Law from the U.S. Army Judge Advocate General's School and Pace University Law School, respectively.

RESPONSES TO QUESTIONS 7 & 8

7. If you believe that net metering results in cross subsidization of DG customers by non-DG customers, how should the net metering rule be revised to reduce or eliminate such cross-subsidization?

Response:

The allegation of cross-subsidy in this context is superficially appealing in its simplicity. It must be thoroughly "unpacked" in order to understand whether it gives rise to any appropriate policy, regulatory, or ratemaking response.

The net metering cross subsidy argument has the following components, with several imbedded and essential assumptions:

> 1. The utility set its rate assuming a certain volume of sales. Because residential customers do not pay a separate demand charge, that rate includes both fixed and variable, both demand- and energy-based cost components.
>
> 2. When the customer uses less energy than the utility planned in the last rate case when the rate was set, the utility faces a short-fall in expected fixed and variable cost recovery.
>
> 3. The shortfall against planned earnings must be recovered somewhere, so the utility will have no choice but to collect those earnings from other customers.
>
> 4. In some cases the argument also assumes that since earnings must be recovered only within the residential class, the recovery for the alleged net metering shortfall will come from customers who do not have solar, often characterized as customers who cannot and will never be able to afford solar.

Each component should be examined individually.

1. The utility set its rate assuming a certain volume of sales. Because residential customers do not pay a separate demand charge, that rate includes both fixed and variable, both demand- and energy-based cost components.

This component is a true and simple statement of how ratemaking is done. It is important to note that this rate setting process should fully account for customers buying and installing solar systems during the coming year. Forecasting sales and variations in sales is routinely undertaken in rate filings and is often an issue contested by the parties to the rate case. A utility that fails to plan for some reasonable level of solar deployment is deficient in its filing.

2. When the customer uses less energy than the utility planned in the last rate case when the rate was set, the utility faces a shortfall in expected fixed and variable cost recovery.

The shortfall in revenue recovery only arises if one assumes that the utility has an absolute right to recover from customers the costs associated with its approved rate design. This right is not absolute, but is governed by a test of reasonableness. For example, the utility that unreasonably forecasts high sales will set a lower rate than would be reasonable. There is no principle of ratemaking that grants a utility the right to charge a customer, *post hoc*, for the energy that they *thought* the customer would use, especially a customer operating a qualifying facility.

The shortfall in revenue recovery only arises from error in utility forecasting in the rate case in which rates were set. A shortfall or excess earnings from incorrect forecasting is a common occurrence. The major drivers of changes in consumption rates and revenue over- or under-recovery are associated with the weather, the general state of the economy, and short-term variations in commodity fuel prices. Traditional ratemaking adjusts for deviations from planned earning in several ways. When the financial integrity of the utility is threatened by a shortfall, the utility can either file a rate case or request the implementation of a rider, surcharge, or other mechanism designed to cure regulatory lag.

The implication that the revenue shortfall from solar customers is material must be tested with actual data and analysis. It should only apply to customers who have added solar since the last rate case, and for purposes of administrative efficiency, the issue should be dealt with only after much more significant variations in earnings that typically occur have been addressed.

The shortfall in revenue recovery is also limited by the extent to which costs are not actually avoided when the solar customer reduces their use against planned sales. A solar customer who reduces their use of energy from the utility allows the utility to avoid energy costs, to avoid fuel costs, and because they make less use of utility infrastructure, to avoid fixed and capacity costs. It would be error to assume that the net metered customer avoids all fixed costs by offsetting some of their consumption. Offsetting is not avoiding***.***

If a customer who reduces their use fails to pay their fair share of fixed costs simply by reducing their volume of use, the error is in the rate design, not in the act of reducing use.

To properly calculate the impact of a solar customer, the utility should offer a properly conducted cost-of-service study that characterizes the actual costs and avoided costs that accompany a solar generator's operation. Such a calculation has not been conducted by any utility in Iowa to date, to the best of this commenter's knowledge.

The calculation should start with the mechanics of the net metering itself. Net metering, as its name implies, is about charging a customer for their ***net*** consumption from the utility. The customer with net metering is fully charged for all the fixed and variable costs associated with their consumption of energy from the utility – this is the result of the forward motion of the meter and it reduces the value that the customer could receive from their solar generator. The customer with solar generation also "spins the meter backward" to unwind consumption charges when solar energy is generated under net metering. The result is the net use that the customer makes of the utility services; the solar customer pays for all the use that is not offset by their generation.

The only other way to argue a revenue shortfall is to assume that a kilowatt hour of customer-generated solar electricity used by the customer to meet some of their demand for electricity is worth less than an exactly equivalent kWh of electricity delivered by the utility to same load on the customer's premises. Since cost of service rates are set based on the full costs necessary to serve the load for a particular class of customer, the argument that there is any difference in the value of those two kWh is logically unfounded. This expends to rate of return, the premium awarded to utilities for putting shareholder capital at risk; the customer who installs their own solar system puts *their* capital at risk, and assumes operating and insurance risk. If the solar kWh is worth less than the utility kWh, then the utility is overcharging.

In any event, no implied valuation of the kWh generated by the customer-generated should be accepted or assumed without the cost-of-service and value of solar analysis necessary to substantiate that claim.

3. *The shortfall against planned earnings must be recovered somewhere, so the utility will have no choice but to collect those earnings from other customers.*

As previously discussed, traditional ratemaking recognizes that there will be variations from forecast for virtually every utility rate. The reasons for these under- and over-recoveries are also varied. There is no sound ratemaking principle supporting the notion that when some members fail to meet forecast levels of consumption, the utility should surcharge all customers in the class to make up for the shortfall from plan.

It is true that chronic and material reductions in consumption levels have the potential to "strand" uneconomic investments in plant and infrastructure, and if, and only if, the investments are both prudent and used and useful, the result may be an increase in rates in a subsequent rate case. In the event that decreased consumption by solar customer-generators leads to such rate increases in the short term, it is even more important that these increases be weighed against a full and fair evaluation of the costs that the solar generator imposes and avoids.

4. In some cases the argument also assumes that since earnings must be recovered only within the residential class, the recovery for the alleged net metering shortfall will come from customers who do not have solar, often characterized as customers who cannot and will never be able to afford solar.

This argument is fraught with dubious and somewhat cynical assumptions. These include that non-solar customers are overwhelmingly low-income, that non-solar customers receive no benefit from increased deployment of solar generation in the utility service territory, that the utility or third-parties cannot design and implement solar programs that work for low income customers, and that the utility has already exhausted all meaningful opportunities to reduce burdens on low income customers, such as targeted energy efficiency programs.

Conclusion: Absolutely no assertion about cross-subsidization should be credited without empirical analysis based on cost-of-service and value of solar analysis.

8. If you believe that net metering does not take into account the benefits that DG provides to non-DG customers, how should the net metering rule be revised to account for such value?

Objective, empirical analysis based on cost-of-service and value of solar analysis must precede any changes in net metering. Action should not be taken on the important net metering policy based on beliefs, but on analysis. Today, best practice in evaluating alternatives to net metering starts with development of a valuation methodology and the conduct of an analysis of distributed generation value, all in the context of an open stakeholder process. This general approach has now been followed in several other jurisdictions:

- The California Public Utility Commission undertook at least two rounds of cost-benefit analysis for distributed solar in the course of evaluating the California Solar Initiative. The CPUC staff is currently developing alternatives to the state's net metering system under a recently passed law.
- Arizona Public Service managed an "Arizona's Energy Future" process that considered several separate valuation, integration, and cost-benefit studies relating to solar energy.
- The Colorado Public Service Commission considered several valuation studies in review of Xcel Colorado's net metering program.
- Austin Energy, the municipal electric utility in Austin, Texas, used a value of solar methodology to support its new rate alternative to net metering, included and approved in its most recent rate review.
- The State of Minnesota passed legislation that directed the Department of Commerce to develop a Value of Solar Methodology for potential use by utilities in offering a rate alternative to net metering. The Minnesota Public Utilities Commission is considering application of the value of solar methodology to community solar programs.
- The North Carolina Utilities Commission opened its most recent biennial avoided cost docket with an invitation to parties to offer evidence on distributed solar valuation concepts.
- Georgia Power Corporation offers a special rate for solar power in its Advanced Solar Initiative that it developed using value of solar methods, and that is higher than its "regular" avoided cost.
- The Michigan Public Service Commission ordered the creation of a staff-led solar working group in its latest review of Detroit Edison's latest renewable energy plan. The working group process, which has issued a draft report, created a value of solar subcommittee.
- The Maine legislature recently passed a law requiring the development of a value of solar methodology. The state Public Utilities Commission is requesting proposals for the conduct of that work as of these comments.