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IOWA UTILITIES BOARD

STATE OF IOWA

BEFORE THE IOWA UTILITIES BOARD

IN RE:	)	
	)	**DOCKET NO. NOI-2014-0001**
DISTRIBUTED GENERATION	)	
	)	
	)	**RESPONSE TO BOARD ORDER**
	)	**SOLICITING ADDITIONAL**
	)	**COMMENTS**
	)	

The Environmental Law & Policy Center, Iowa Environmental Council, Iowa Solar Energy Trade Association, Sierra Club, the Vote Solar Initiative, and Solar Energy Industries Association, collectively the "Joint Commenters," jointly file these comments pursuant to the Iowa Utilities Board (Board) Order Soliciting Additional Comments and Scheduling Workshop issued on September 19, 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 that advocates for policies that will facilitate and promote the development of 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.

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.

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

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

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.

<u>Introduction</u>

The Joint Commenters greatly appreciate the continued discussion of the issues and the opportunity to respond to the Board's questions. We support an independent inquisitive approach to this docket. Data and empirical evidence will best equip the Board and stakeholders to prioritize the relevant issues and how to approach them.

In the last round of comments, the Board requested information about the distributed generation currently on the grid in Iowa. The responses provided to the Board about the level of distributed generation allow us to quantify the penetration levels in Iowa. This is particularly important information in the context of the discussion on net metering. As of the June filings, there were only 895 net metered customers statewide. This is less than $1/10^{th}$ of 1 percent of total customers statewide. These net metering customers provide about $1/10^{th}$ of 1 percent of the total statewide utility-owned capacity (the percentage would be even less if compared to all generating capacity, since there is significant wind and other independent power producer capacity in Iowa). Breaking the numbers down further and looking at residential customers who net meter, solar customers who net meter or residential solar customers who net meter, the numbers get even smaller staying below $1/20^{th}$ of 1 percent for both the percent of total customers in those categories and the percent of capacity provided by those categories of distributed generation. This information is summarized in the tables below.

Table 1. Summary DG Net Metering Customer Information

	Alliant	MidAmerican	RECs	Munis	Total
Total average number of customers, all classes	486,066	649,848	225,624	211,407	1,572,945
Residential customers	408,749	558,202	197,168	176,991	1,341,110
Total capacity (utility capacity only, summer nameplate, kW)					12,179,000
Total net metered, all customers classes	464	141	258	32	895
Total capacity net metered customers (kW)	7,446	1,775	3,169	987	13,378
Total solar net metered, all customers classes	347	63	119	25	554
Total capacity solar net metered customers (kW)	4,137	472	1,033	111	5,752
Residential net metered customers	244	108	205	21	578
Residential capacity net metered customers (kW)	1,751	1,122	2,176	98	5,147
Residential solar net metered customers	211	46	102	16	375
Capacity residential solar net metered customers (kW)	1,486	272	919	72	2,748

Note: Customer information from utility annual report filing summaries available on the IUB website. Generating capacity from Energy Information Administration, *Iowa Electricity Profile 2012*. Net metering customer and capacity from utility filings in this docket, filed in June and July (IPL revised).

Table 2. Summary of Net Meter Customer and Capacity Penetration

Percentage of total customers that net meter	0.057%
Net metered capacity as a percentage of total utility capacity	0.110%
Percentage of total customers that net meter with solar	0.035%
Solar net metered capacity as a percentage of total utility capacity	0.047%
Percentage of residential customers that net meter	0.043%
Residential net metered capacity as a % of total utility capacity	0.042%
Percentage of residential customers that net meter with solar	0.028%
Residential solar net metered capacity as a % of total utility capacity	0.023%

Based on the data, Iowa's net metered distributed generation levels are extremely low in comparison to other states and in an absolute sense. This suggests that the most pressing policy and regulatory focus should be on removing barriers to the development of a distributed generation market. Expanding customer options for net metering and updating Iowa's interconnection standards will make the process of choosing to use distributed generation easier for customers.

This docket has also generated significant discussion about rate design related to distributed generation. The data on Iowa's low penetration levels makes clear that the Board and stakeholders have time to approach these issues thoughtfully and to collect the data and conduct the studies necessary for sound decision-making. An independent comprehensive value-of-solar analysis will help inform the direction of distributed generation policy in the state. An independent comprehensive value-of-solar analysis is a prerequisite to determining if policy changes or rate design are necessary, and if changes are necessary, what those changes should look like or seek to accomplish.

We turn to the Board's specific questions below.

1. **Many of the utilities state there are legal issues associated with virtual net metering if retail energy from an off-site DG is wheeled over the utilities' systems.**
   a. **Do you agree? Explain.**
   b. **If yes, provide examples of how other states that offer virtual net metering have addressed these legal concerns.**

The utilities argue that a virtual net metering/shared renewable program would potentially create issues related to Iowa's service territory law.[2] This argument hinges on a shared renewable program falling under the definition of public utility in Iowa Code § 476.1.

[2] NOI-2014-0001, Additional Comments of MidAmerican Energy Company, 4-5 (June 24, 2014); NOI-2014-0001, Interstate Power & Light Company, Additional Comments, 11-12 (June 24, 2014)

The definition of public utility in § 476.1 requires "furnishing . . . electricity to the public for compensation." Net metering is a billing arrangement and not a sale that provides compensation. The Board has described net metering by stating that "net metering does not involve separate purchase and sale transactions but is essentially a metering arrangement."[3] 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."[4] Similarly, virtual net metering is a billing arrangement that involves multiple customers sharing the ownership of single renewable energy facility and receiving bill credits corresponding to the proportion of energy that their ownership in the facility generates.[5] A virtual net metering arrangement would not involve any sale and therefore would not lead to a shared renewable facility falling under Iowa's public utility definition or causing issues with Iowa's service territory statute.

While the utilities raise legal concerns that are unfounded, the underlying utility concern appears to be that a virtual net metering arrangement requires use of the grid. It is important to acknowledge that a virtual net metering customer may use the distribution grid in a different manner than a traditional net metering customer. It is reasonable to value the energy from a shared renewable energy system in a way that fairly credits the utility for the use of the grid while at the same time fairly crediting the program participants for the full value of the

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

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

5 We do note that Iowa's net metering rule only contemplates a single meter. *See* 199 Iowa Administrative Code § 15.11(5). The net metering rule would likely need to be clarified to allow a virtual net metering arrangement.

distributed energy created. IREC's Shared Renewable Model Rules provide a good discussion about how to strike this balance.[6]

2. Is virtual net metering necessary if the utilities offer mechanisms for their customers to participate in renewable energy programs as discussed by Interstate Power and Light Company (IPL) and the Iowa Association of Electric Cooperatives (IAEC)?

Virtual net metering/shared renewable programs (hereafter shared renewable program) will expand distributed generation participation to a broader base of customers including renters and those whose property is unable to accommodate a distributed generation facility, and provide customers with another choice for pursuing renewable generation. Shared renewable programs stimulate innovation, take advantage of economies of scale (in size and number of installations). This value provided by shared renewable programs exists regardless of whether utilities have other renewable energy programs for their customers.

While we welcome the utilities providing their customers options for renewable generation, those utility options should not come at the expense of a customers' freedom to choose how to pursue renewable energy. Utility programs do not always capture what consumers want or structure the programs to allow consumers to capture the full range of benefits associated with renewable generation. For example, utilities do not always invest in renewable energy in the local community or service territory from the funds raised by green power purchase programs. Shared renewable programs provide consumers with an important option for choosing renewable energy. There is a key difference between utility green power purchase programs and a shared renewable program: a shared renewable program can provide customers with the direct economic benefit of a reduced electric bill while customer contributions to a green power purchase

[6] IREC, *Model Rules for Shared Renewable Energy Programs*, 9-12 (2013) *available at* www.irecusa.org/wp-content/uploads/2013/06/IREC-Model-Rules-for-Shared-Renewable-Energy-Programs-2013.pdf.

program do not offer that benefit. A shared renewable program has value to consumers even if their utility offers a program, and therefore, virtual net metering should be pursued regardless of whether utility programs are offered.

The Interstate Renewable Energy Council (IREC – one of the Joint Commenters) offers the following "guiding principles" for the design of shared renewable energy programs:

- First, shared renewable energy programs should expand renewable energy access to a broader group of energy consumers, including those who cannot install renewable energy on their own properties.
- Second, participants in a shared renewable energy program should receive tangible economic benefits on their utility bills
- Third, shared renewable energy programs should be flexible enough to account for energy consumers' preferences.
- Fourth, and finally, shared renewable energy programs should be additive to and supportive of existing renewable energy programs, and not undermine them.[7]

Each of these principles is discussed in more detail in IREC's Model Rules for Shared Renewable Energy Programs.

3. **MidAmerican Energy Company (MidAmerican) suggests that if combined heat and power (CHP) or waste heat to power (WHP) facilities were considered eligible for net metering, the Board should retain the 500 kW size cap and the requirements that they be at one site and used primarily to serve the facility owner, as it is in its Rate NM. Do you have any additional comments on this proposal?**

In our comment submitted on June 24, 2014, we noted that some members of our coalition would support net metering for CHP in appropriate circumstances including meeting minimum levels of efficiency for eligibility. We also noted that the existing net metering rules appear to allow net metering for CHP as long as the CHP technology uses a fuel source listed in the Chapter 15 definition of an alternative energy production (AEP) facility for at least 75% of its fuel needs (e.g., resource recovery, refuse-derived fuel, or biomass). If the Board allows net metering for CHP or WHP facilities fueled by other sources, such as natural gas, some members

[7] *Id.*

of our coalition would support those facilities being subject to the same net metering rules as other facilities. In our June 24 comments, we urged the Board to consider removing the cap for net metered projects as recommended by IREC's Freeing the Grid project.[8] We specifically suggested that the Board consider incorporating language limiting system size to 100%-120% of customer load or average annual consumption to mitigate against concerns about oversized systems. We refer the Board to our previously filed comments for additional detail.

4. **As with virtual net metering, there are legal issues discussed by both IPL and MidAmerican such as whether the delivery of excess power from a CHP facility would be considered a wholesale transaction subject to Federal Energy Regulatory Commission (FERC) jurisdiction and the claim that CHP and WHP facilities are not included in Iowa's alternate energy production (AEP) definition. Provide any comments you have on this topic.**

As discussed above, net metering is a billing arrangement and not a sale. Energy produced by a CHP or WHP facility under a net metered billing arrangement would not be considered a wholesale transaction and would not be subject to FERC jurisdiction.

The definition of alternate energy production in Iowa statute incorporates the definition of a qualifying facility under the Public Utilities Regulatory Practices Act. The code specifically states that "[a] facility which is a qualifying facility under 18 C.F.R. pt. 292, subpt. B is not precluded from being an alternate energy production facility under this division.[9]" Cogeneration facilities are specifically included as qualifying facilities under 18 C.F.R. pt. 292, subpt. B. Therefore, cogeneration facilities fit under Iowa's statutory alternate energy production definition. However, the Board's Chapter 15 rules limit the eligible fuels for alternate energy production facilities and do not include natural gas as an eligible fuel. Natural gas is the most common fuel for CHP, so many CHP facilities would not be eligible for net metering under

[8] See www.freeingthegrid.org, for the annual publication grading net metering and interconnection procedures by state, produced by IREC and the Vote Solar Initiative.

[9] Iowa Code § 476.42(1)(b).

current Board rules. CHP facilities that use any of the fuels listed in the definition of an AEP facility should be eligible for net metering under current rules. As noted in previous comments, some members of our coalition would support expanding the eligibility for CHP to include facilities fueled by natural gas, provided minimum efficiency levels are required along with other appropriate requirements.

5. **MidAmerican and IPL believe that it is more appropriate for larger CHP and WHP facilities to be served under the standby tariff. Do you agree? Explain why or why not.**

As noted in our comments submitted June 24, 2014, some members of our coalition would support net metering for CHP in appropriate circumstances including meeting minimum levels of efficiency for eligibility. We also think that standby tariffs can support CHP and WHP, but it is important that those standby tariffs are designed appropriately.

In Iowa, we have significant concerns about how the standby tariffs present a barrier to CHP development. In 2012 and 2013, ELPC and IEC worked with MidAmerican Energy to revise its standby tariff in advance of its 2013 rate case. ELPC and IEC emphasized certain principles including that standby tariffs should be transparent, flexible, and provide incentives for economically efficient consumption. ELPC and IEC had a number of recommendations to move MidAmerican's standby tariff in the direction of these principles. MidAmerican worked in good faith and made significant improvements to its standby tariff. While the standby tariff approved as part of MidAmerican's rate case is not perfect, it is vastly improved from the previous standby tariff and can support the development of CHP in some circumstances. Unfortunately, the same cannot be said for IPL's standby tariff.

IPL's current standby tariff presents significant economic barriers to customer-owned CHP. IPL's standby tariff does not allow customers that install CHP and therefore significantly reduce utility energy consumption to realize a similar reduction in energy costs. The standby tariff includes high demand charges, high standby charges, and a peak summer demand ratchet, among other problems. Customers on this tariff pay high fixed costs, regardless of whether they reduce utility electricity use. In addition to presenting a significant barrier to CHP, the tariff does not recover costs from standby customers in a way that is consistent with how those customers incur costs.

Luther College comments in this NOI docket highlight the barriers created by IPL's standby tariff:

> [T]he Midwest Clean Energy Action Center at the University of Illinois-Chicago has concluded that Luther is a good site for CHP. Recently, however, the Center completed an economic viability study that revealed Alliant Energy's standby rates make the project financially unattractive. If Luther were in MidAmerican's service territory, however, the project would be financially viable. Under Alliant's rates the CHP project would have a 55-year payback, but under MidAmerican's recently revised rates the project would have a 15-year payback.

Until IPL makes revisions to its standby tariff to increase transparency, flexibility and incentives for economically efficient consumption, IPL's standby tariff is not an appropriate way to support CHP.

6. **Several commenters assert that including CHP and WHP projects as eligible facilities in the net metering rules would encourage the development of small CHP and WHP projects. Assuming it is legally possible, would you object to including these types of projects as facilities eligible for net metering if they fall under the 500 kW size cap? Explain why or why not.**

<u>For Utility Participants</u> - Not applicable.

7. **MidAmerican states that a cash-out option may require Federal Energy Regulatory Commission (FERC) approval because it may be considered a wholesale transaction instead of a net metering arrangement. Do you agree? Explain.**

If a cash-out option is allowed and that cash-out rate is set at a properly calculated utility avoided cost rate then the cash-out option would not need FERC approval. A properly calculated avoided cost rate would need to account for the benefits to the electric utility system provided by distributed generation, 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. [10] Iowa avoided cost rates do not currently account for many of these benefits, and Iowa still needs to do the underlying analysis to quantify the value of several of these benefits. Several recent studies[11] show that the calculated benefits of distributed photovoltaic generation 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.[12] Continuing Iowa's current policy of indefinitely rolling over net metering credits avoids FERC jurisdictional issues in the absence of having properly valued credits for distributed generation. This works reasonably well, but fails to give customers an incentive to pursue energy efficiency, as discussed in question 8.

8. Provide comments on MidAmerican's assertion that a cash-out option encourages overbuild of a DG system.

Iowa's current net metering policy that allows indefinite month-to-month roll over of net metering credits is an effective means of encouraging a distributed generation customer to build

[10] *See* 18 C.F.R. § 292.304(e); Interstate Renewable Energy Council, *Unlocking DG Value: A PURPA-based approach to promoting DG growth* (May 2013) *available at* http://www.irecusa.org/2013/05/new-irec-concept-paper-takes-fresh-look-at-decadesold-dg-policy/.

[11] *See* Rocky Mountain Institute eLab, *A Review of Solar PV Benefits and Costs Studies*, at 22 (Sept. 2013) *available at* http://www.rmi.org/elab_emPower.

[12] 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/.

a distributed generation system that is not significantly larger than that customer's energy demand.

If a cash-out option is based on a properly calculated avoided cost rate that accounts for the benefits to the electric utility system provided by distributed generation, then any generation built at that rate would provide commensurate value to the electric system. In that scenario, the net excess generation would be compensated at the value the systems provide to the utility and all ratepayers. As such, the compensation would be fact-based and alleviate any concern about appropriate compensation or net excess generation, or even the existence of net excess generation. As we noted in our previous comments, Iowa should conduct an independent valuation of distributed generation to appropriately address these issues.

It is also important to note that a cash-out option could provide an incentive for a distributed generation customer to implement energy efficiency in the future. A system may be sized to a meet a customer's energy demand when it is first installed, but if that customer implements energy efficiency measures during the life of the system that customer would have excess credits. In this scenario, a cash-out option is important to encourage continued implementation of energy efficiency.

9. **Some commenters recommend setting a cap on the amount of cash-out the customer could receive.**
    a. **Do you agree that a cap is needed?**
    b. **If yes, at what level and why that level?**

If a cash-out option is based on a properly calculated avoided cost rate that accounts for the benefits to the electric utility system provided by distributed generation, then any generation built at that rate would provide commensurate value to the electric system. In that scenario, the net excess generation would be compensated at the value the systems provide to the utility and all ratepayers. As such, the compensation would be fact-based and alleviate any concern about appropriate compensation or net excess generation, or even the existence of net excess generation. As we noted in our previous comments, Iowa should conduct an independent valuation of distributed generation to appropriately address these issues.

10. If the customer is allowed to cash-out a net balance, should it be:

a. On a monthly basis or an annual basis? Explain why.

Iowa's current net metering policy reflects a goal for distributed generation to be sized to meet the customer's annual load, and the current policy is an effective means of encouraging that. If the goal of the policy is to have the customer size the system to meet the customer's annual load, then the cash-out would work better on annual basis. The annual cash-out would allow a distributed generation system to take advantage of seasonal differences to smooth out energy production over the whole year.

b. Required or optional? Explain why.

In order to provide maximum flexibility, we believe customers should continue to have the option to have their credits roll-over into the next month and 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.

11. Comment on the potential impact of IPL's suggested rule change that would consider net metered kWh as a cost of purchased power recoverable through the energy adjustment clause.

As discussed above, net metering is a billing arrangement and not a purchase or sale of energy. It is therefore not appropriate to consider net metered kilowatt-hours to be 'purchased' power. Furthermore, IPL does not treat distributed generation as a resource for planning purposes, but instead accounts for distributed generation as part of its load forecasting. It would therefore be inconsistent to treat net metered kilowatt-hours as purchased power for cost recovery purposes.

We are not opposed to finding ways for utilities to recover actual costs or remove financial disincentives from administering renewable energy programs such as net metering. However, we think that this process needs to take into account the true value of the resource to the utility in a way that balances both the costs with the benefits provided by distributed generation. In order to understand this issue and determine an appropriate way to account for costs and benefits of distributed generation, we recommend conducting an independent value of solar study as we have proposed in our comments previously submitted in this docket.

12. Although there was no consensus, the commenters discussed whether a cash-out rate should be based on the utility's avoided cost rate or the utility's retail rate. Explain which one you believe is the appropriate rate and why.

If a cash-out option is allowed, the cash-out rate should be set at a properly calculated utility avoided cost rate for distributed generation. A properly calculated avoided cost rate would need to account for the benefits to the electric utility system provided by distributed generation, 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. Iowa avoided cost rates either do not currently account for many of these benefits or do not account for the full value of these benefits. Iowa must revise the methodology the utilities use for calculating the avoided cost rate before the avoided cost rate would be appropriate to use as a cash-out rate. The value of solar analysis that we have suggested in our previous comments would be a very useful analysis to help establish appropriate rates.

13. IPL and MidAmerican discuss connecting the meters on a DG customer's premises in order to aggregate meters, while the Iowa Nebraska Equipment Dealers Association (INEDA) believes no physical connection is necessary. Comment on this.

There is no need to connect the meters with distribution lines to allow for aggregated net metering. Net metering is a billing arrangement. Aggregate net metering allows a customer to build one distributed generation facility and use the generation for multiple metered facilities receiving power from the same utility. If the metered facilities are on the same property, the utilities argue that the customer should build a separate set of distribution lines between the customer's facilities for this purpose. This is costly and unnecessary. One of the benefits of distributed generation is that any excess generation that flows back on the grid will be used nearby rather than transmitted long distances resulting in lines losses. This is particularly the case with aggregated net metering by one customer for multiple metered buildings on one property.

In the case of aggregated net metering where a customer may have multiple meters spread out across multiple properties in the utility service territory, aggregate net metering could still work. In this case, the customer would use the utility distribution system, and it would be appropriate for the customer to compensate the utility for the use of the distribution system or alternatively to provide a monetary value for the bill credit that takes into account the customer's use of the utility grid. Where the meters are on the same circuit, the utility effectively bears no more cost than if the facility were only netting against a single meter, so an added charge would be inappropriate.

MidAmerican also suggests that aggregation is retail wheeling that would be prohibited by Iowa's service territory law. The analysis to Question 14 addresses this point.

14. MidAmerican suggests that meter aggregation needs to occur behind the meter and the utility's distribution system cannot be used to aggregate the meters; otherwise, FERC would consider it retail wheeling. Do you agree? Explain why or why not.

This analysis is similar to the analysis for the virtual net metering issue discussed in Question 1 above. MidAmerican expressed two different concerns: 1) aggregate net metering is a sale of power subject to FERC regulation; and 2) aggregation is retail wheeling that is prohibited by Iowa's service territory statute.[13]

FERC has 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."[14] MidAmerican argues that "[a]ggregation was not envisioned by FERC in *MidAmerican* with its illustration of single farms, homes or similar entities, so it may result in a wholesale sale of power subject to regulation of the FERC."[15] The key to the analysis in the *MidAmerican* decision is that no sale occurs in a net metering billing arrangement. The fact that the netting occurs over multiple meters owned by one customer does not change the key operative fact that no sale occurs. Therefore, FERC regulation would not be triggered by an aggregate net metering arrangement.

In order for an entity using aggregate net metering to be subject to the service territory statute, it must fall under the definition of public utility in Iowa Code § 476.1. The definition of public utility in § 476.1 requires "furnishing . . . electricity to the public for compensation." Net

13 NOI-2014-0001, Additional Comments of MidAmerican Energy Company, 4 (June 24, 2014) ("[T]he assignment of service territory applies to all elements of electric power and energy sold in Iowa – generation, transmission and distribution – so retail wheeling is not authorized in Iowa.").

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

15 NOI-2014-0001, Additional Comments of MidAmerican Energy Company, 9 (June 24, 2014)

metering is a billing arrangement and not a sale that provides compensation. The Board has described net metering by stating that "net metering does not involve separate purchase and sale transactions but is essentially a metering arrangement."[16] Furthermore, an aggregate net metering situation involves only one customer.

15. For more accurate reporting to the Board, the U.S. Energy Information Administration, and FERC, IPL suggested changing 199 IAC 20.9(2) to reflect that all energy produced in excess of that used by the net metering customer would be considered an energy purchase. Do you agree with this suggested change? Explain your response.

As discussed above, net metering is a billing arrangement and not a purchase or sale of energy. FERC has 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."[17] IPL's suggested change would lead to less accurate reporting since it would make Iowa's reporting inconsistent with FERC's approach to net metering. We assume that IPL's suggestion is to treat all energy exported by a net metered as a utility purchase, which we think would be inappropriate. It would be reasonable to treat kWh purchased by the utility under a cash-out option as a reportable energy purchase.

16. IPL, MidAmerican, and the Consumer Advocate Division of the Department of Justice (Consumer Advocate) suggested a rate design change for DG customers such as a time-of-use (TOU) or demand rate. According to MidAmerican, this would remove any possible cross-subsidization between DG customers and non-DG customers. Is this a reasonable solution to this issue? Explain.

This question takes as its premise that there is cross-subsidization. Before making any major rate design or policy changes because of purported cross-subsidization, the issue of cross-subsidization should be thoroughly studied to determine if there is cross-subsidization, and its

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

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

direction and magnitude, if any, of that cross-subsidization, and the magnitude of the cross subsidization. Rate changes cannot remove any possible cross-subsidization unless the scope of that alleged cost-shifting is understood. For example, the rates associated with each time of use period, or the level of a demand charge, cannot be set without knowing how and when any potential cost-shifting is occurring. These questions should be answered before Iowa utilities embark on major tariff redesigns. As we have previously discussed in comments in this docket, a value of solar study is necessary to understand these issues.

To date in Iowa, there is no data available to determine whether distributed generation customers have usage patterns that differ from residential customers generally, or whether distributed generation customers impose costs that are out of sync with their average fixed cost recovery through rates. The Utah Public Service Commission recently ruled on this very issue in PacifiCorp's 2014 General Rate Case (Docket No. 13-035-184). In that proceeding PacifiCorp, another Berkshire Hathaway Energy subsidiary, proposed a "residential net metering facilities charge" to recover from net metered customers an amount that will produce the same average monthly revenue per customer for distribution and customer costs that is recovered in energy charges from all residential customers based on the cost of service study."[18]

PacifiCorp presented an exhibit indicating that residential net metering customers in its service territory "purchase less energy on average, about 518 kilowatt hours ("kWh") per month, than the residential class average of 698 kWh per month."[19] Like the Iowa utilities, PacifiCorp collects some portion of fixed costs through its variable energy charge, and PacifiCorp argued

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18 *In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations*, Docket No. 13-035-184, Report and Order of Aug. 29, 2014 at page 20.

19 *Id.* at 22.

that its net metered customers were not paying their fair share of utility fixed costs. PacifiCorp estimated that "the cost shift from net metered customers to all customers is $4.65 per month per customer, or $116,794 per year, based on forecasted test period billing units for residential customers."[20] It further argued that it was "important to create an appropriate price structure for residential net metered customers before the shifting of distribution and customer costs from net metered customers produces a much larger cost burden on non-participating customers."[21]

The Utah Commission rejected the utility's proposal, finding that the testimony and exhibits in the case "fall well short of providing the Commission the substantial evidence necessary to make a determination."[22] First, the Utah Commission found that PacifiCorp's testimony and exhibits "contain no discussion at all of net metering program benefits."[23] The Utah Commission also found PacifiCorp failed to provide adequate evidence to support its argument that net metering customers, as a class, are any different than any other class of customers on a cost of service basis. Specifically, it held that the utility failed to present evidence "showing that the level of usage or the load characteristics of net metered customers are materially different from the typical residential customer."[24] The Utah Commission found the absence of load characteristic data for residential net metered customers to be a "significant gap" in the record.[25]

> We cannot determine from the record in this proceeding that this group of [net metering] customers is distinguishable on a cost of service basis from the general body of residential customers. Simply using less energy than average, but about

[20] *Id.* at 23.

[21] *Id.* at 21.

[22] *Id.* at 58-59.

[23] *Id.* at 59.

[24] *Id.* at 62.

[25] *Id.*

> the same amount as the most typical of PacifiCorp's residential customers, is not sufficient justification for imposing a charge, as there will always be customers who are below and above average in any class. Such is the nature of an average. In this instance, if we are to implement a facilities charge or a new rate design, we must understand the usage characteristics, e.g., the load profile, load factor, and contribution to relevant peak demand, of the net metered subgroup of residential customers. We must have evidence showing the impact this demand profile has on the cost to serve them, in order to understand the system costs caused by these customers.[26]

Based on its review of the record, the Utah Commission concluded that the evidence was "inconclusive, insufficient, and inadequate" to support PacifiCorps' proposed rate design changes and that more "thorough analysis" such as a "load research study" and a "measurement of net metered customer usage at the time of system coincident peaks" would be necessary to justify any potential future proposals.[27] The Utah Commission noted that the "relatively small" number of net metering customers on the Company's system provided PacifiCorp with time to gather and analyze the necessary data:

> We note there is at least a consensus among the parties in this proceeding that the current number of net metered customers on PacifiCorp's system at this time is relatively small. Numerically, the rate of annual growth in net metered customers is also small, although more dramatic in percentage terms. We also note the distribution and customer intra-class cost shift asserted by PacifiCorp and supported by the Division and the Office is very small, at about 1 cent per customer per month. We conclude under these circumstances the better course is for PacifiCorp and interested parties to gather and analyze the necessary data, including the load profile data that is foundational to this analysis, and present to us their results and recommendations in a future proceeding.[28]

The utilities in Iowa are in a similar situation as PacifiCorp. The number of net metered customers is relatively small. MidAmerican has asserted that if 25% of its residential customers adopt solar photovoltaics (PV), it could require an 8.5% increase in rates to the non-

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[26] *Id.* at 68.

[27] *Id.* at 63, 66.

[28] *Id.* at 67.

participants.[29] While the data underlying this assumption has not been shared and likely does not account for the benefits of solar, MidAmerican's hypothetical scenario will not be reality in Iowa anytime soon. MidAmerican has 558,000 residential customers. MidAmerican would need to reach 139,500 residential customers with solar to hit 25% of residential customers with solar. According to MidAmerican's filing in this docket, at the end of 2013, MidAmerican had 46 residential customers with solar PV, or .008% of total residential customer with solar PV. Even with exponential solar growth for the next decade, MidAmerican will be well short of the 25% solar penetration that will allegedly lead to the 8.5% rate increase, and, as mentioned before, there are likely significant grid benefits of solar that would offset MidAmerican's projections and lead to lower overall electricity rates. There is no urgency to make rate design or policy changes. We have time to study the issues and collect Iowa specific data to inform any rate changes.

While there needs to be significant study before we address rate design issues, we do not necessarily oppose time of use rates, which have long been recognized as consistent with fairness and cost-causation principles, and as a tool to shift consumption to off-peak times and reduce peak system demand. However, time of use rates should be implemented for the right reasons, and designed to achieve peak demand reduction that will benefit all ratepayers, and not adopted to address a problem that may not exist. Moreover, if implemented, time of use rates should apply to all customers within a class, and not just to net metering customers and should be implemented on a voluntary, opt-in basis.

[29] NOI-2014-0001, Response of MidAmerican Energy Company, at 3 (Feb. 25, 2014).

17. **Comment on IPL's suggestion that DG customers should have their own specific customer class for rate design purposes since their load profiles and service needs differ from non-DG customers.**

IPL has provided no evidence that customer load profiles and service needs differ from non-DG customers. As noted above, there are significant issues that should be studied and understood before proposing significant rate designs.

IPL's proposal that DG customers have their own specific customer class for rate design violates Iowa law that prohibits discrimination against renewable generation. Iowa Code Section 476.21 states:

> A municipality, corporation or cooperative association providing electrical or gas service shall not consider the use of renewable energy sources by a customer as a basis for establishing discriminatory rates or charges for any service or commodity sold to the customer or discontinue services or subject the customer to any other prejudice or disadvantage based on the customer's use or intended use of renewable energy sources.

IPL's proposal would establish different rates or charges based on the customer's use of a renewable energy source.

There are a number of factors that can change the load profile of a given customer. Customers who implement energy efficiency measures have different load profiles than customers who do not. The type of energy efficiency measure implemented or the number of measures implemented can have an effect on load profile. A customer who uses a programmable thermostat will have a different load profile compared to a customer who has installed LED lights or an energy efficient refrigerator or insulation, but does not use a programmable thermostat. A customer with a 4,000 square foot house will have a different load profile than a customer with a 1,200 square foot house. A customer who works from home with a home office will have a different load profile than a customer in a similar sized and equipped home who works outside of the home. The examples could continue. Customer load profile is not uniform, and there are many technologies or customer use patterns that alter customer profiles and the way the customer uses the system. To pick distributed generation among all the technologies and customer behaviors and impose a different rate solely because the customer uses distributed generation violates Iowa law.

Furthermore, several members of the Joint Commenters have issued guiding principles (attached as Appendix A). One of the guiding principles is non-discriminatory rate practices and policies.

> **Insist Upon Non---Discriminatory Rate Practices And Policies**: Utility rates should treat reductions in energy sales and utility revenues due to net metered solar and other [distributed solar systems] in a manner that is fully comparable to, and non---discriminatory relative to, reductions due to other consumer behaviors including energy efficiency and demand response. Any rate treatment not generally applied to all similarly situated customers must be cost-justified and seek to avoid unintended consequences. Furthermore, any utility charges created specifically for the purpose of recovering embedded fixed costs from customers with [distributed solar systems] systems must be cost-based, and should only recover *net* fixed costs, after accounting for all benefits and offsetting cost reductions due to the distributed solar. Similarly, any utility *credits* created for the purpose of assuring that economic benefits resulting from the deployment of [distributed solar systems] systems are properly assigned back to the [distributed solar systems] customer(s) should only reflect *net* benefits, after accounting for all utility costs.

Discrimination against any customer class should always be avoided to the maximum extent possible. Furthermore, discriminatory practices based on conjecture should be swiftly denied.

18. Some parties suggest that a study be done showing the benefits of DG compared to the costs of DG to determine if there is cross-subsidization.

a. Is this an appropriate approach to resolve this issue?

An independent study of the benefits of distributed generation compared to the costs of distributed generation is important for informed policymaking. Parties can assert that there is cross-subsidization, but without an independent study, there is no way to know if there actually is any cross-subsidization, the direction of the cross-subsidization (does the customer investing in distributed generation provide more benefit to the grid than benefit they receive from net metering or does net metering provide the customer greater benefit than the distributed generation system provides to the grid), and the amount, if any, of the cross-subsidization. Iowa has longstanding policy "to encourage the development of alternate energy production facilities."[30] Any change in rules or rate design could discourage renewable energy development. If Iowa is going to change rules or rate design in a way that could adversely impact a longstanding policy priority, it is important to make sure that those changes will address a real, well understood concern.

b. Is this the appropriate time to expend the resources to conduct such a study or should the study be done when DG penetration reaches a level where it becomes a bigger issue for utilities?

We think that a study assessing the benefits and costs of distributed generation should be done before there are significant policy or rate changes. The study should inform any future policy or rate changes. We think that the distributed generation market in Iowa is currently too small to have a significant impact on utility revenues or utility costs savings, and therefore, it would make sense to conduct this study once distributed generation penetration is higher. As noted in our introduction, the customers from all classes that net meter account for .057% of total utility customers. These customers net meter with generating capacity that would account for .11% of utility-owned generation. In other words, whether looking at the number of customers or their net metered generating capacity, we are looking at 1/10th of 1 percent or less of utility customers or capacity. However, if the Board plans to consider any policy or rate changes in the near term, the study should be conducted now even though penetration levels are low.

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[30] Iowa Code § 476.41

c. If your response to part (b) is that a study should be delayed until DG penetration increases, what level of penetration do you believe would justify the study?

Lawrence Berkeley National Laboratory (LBNL) released a study in September 2014 looking at the financial impacts on utilities and ratepayers of net-metered PV[31] for both a vertically integrated utility in the southwest and a wires-only utility and default service supplier in the northeast.[32] The study modeled impacts of PV over a 20-year period, estimating changes to utility costs, revenues, average rates, and utility shareholder earnings and return-on-equity.[33] For the vertically integrated utility, the study found that at 2.5% PV penetration the impacts on revenues and costs are roughly equivalent.[34] At a 2.5% PV penetration scenario, the study found a 0.1% (one-tenth of one percent) increase in average rates for the vertically integrated utility and 0.2% increase for the wires-only utility.[35] The LBNL study suggests that an Iowa-specific study on the costs and benefits of solar could be done once Iowa reaches a 1% penetration level and still be completed well before even the smallest of rate impacts would start to be felt.

According to the utility filings in this docket in June, IPL, MidAmerican, IAEC and IAMU collectively had approximately 7.4 MW of solar PV on their system at the end of 2013 (most of the PV included in the filings is through 2013 but a few systems installed in 2014 were included). This includes all PV, whether it is net metered or not, although most is net metered.

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31 Satchwell, Andrew et al., Lawrence Berkeley National Laboratory, "Financial Impacts of Net-Metered PV on Utilities and Ratepayers: A scoping Study of Two Prototypical U.S. Utilities" (2014) (hereinafter "Financial Impacts of Net-Metered PV) *available at* http://emp.lbl.gov/sites/all/files/LBNL%20PV%20Business%20Models%20Report_no%20report%20number%20(Sept%2025%20revision).pdf.

32 *Id.* at viii.

33 *Id.*

34 *Id.*

35 *Id.* at ix.

The 7.4 MW of solar PV equals .061% of utility-owned capacity (12,179 MW of summer nameplate capacity). If distributed PV were to more than double to 15 MW, it would only account for .123% of utility-owned capacity. Distributed PV would need to reach 120 MW before accounting for approximately 1% of utility-owned capacity and that is the point at which we feel a study is first reasonable to pursue.

d. Who should perform the study?

In our initial comments, we recommended that the Board select an independent consultant to undertake the study. We think the independence of the consultant is critical to ensure accurate findings as well as acceptance of those findings by all stakeholders. Examples of consultants who could do this type of study include but are not limited to Crossborder Energy, Clean Power Research, Synapse Energy Economics, and Black & Veatch.

e. Who should pay for the study?

If the utilities are pushing for rate design and/or policy changes in the short term, the utilities should fund the study since the utilities have the burden to support their case for modified tariffs. Even though the utilities would fund the consultant, the study should still be conducted independently, with a process for stakeholder input regarding appropriate base case assumptions and sensitivities. If we have more time to fund such a study, we would be willing to work with other stakeholders to encourage the legislature to fund an independent study that looks at the cost and benefits of distributed generation.

19. INEDA points to Minnesota, Illinois, Arizona, and Colorado meter aggregation rules for Board consideration. Could any of these approaches be appropriate for Iowa?

We think that the IREC Net Metering Model Rules provide the best starting point for developing an approach to aggregate net metering.[36] A rulemaking to adopt aggregate net metering in Iowa should start with the IREC Model Rules and could also consider the approaches taken in these other states. According to Freeing the Grid, 17 states allow meter aggregation, including Minnesota and Colorado.[37] Arizona's meter aggregation rules are considered marginal (only scoring half a point), and Illinois is not listed as having functional meter aggregation rules.

20. The IAMU notes that at least one municipal utility offers virtual net metering. How is this being done, given the legal concerns expressed by some commenters?

While this question was not directed to us, we think that the same analysis used in our response to question 1 applies. We do not see any legal problems with municipal utilities implementing shared renewable programs.

21. For those electric cooperatives and municipal utilities that do not currently offer net metering, explain why you do not offer net metering, whether you intend to offer net metering in the future, and if so, when.

The June filings by the Iowa Association of Electric Cooperatives (IAEC) and the Iowa Association of Municipal Utilities (IAMU) that list the Rural Electric Cooperatives (RECs) and municipal utilities indicate that 23 RECs and 17 municipals offer net metering. The net metering tariffs and policies offered by many, if not all, of these utilities are significantly more restrictive than the net metering tariffs offered by MidAmerican and Alliant. For example, Calhoun County

[36] 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.

[37] See www.freeingthegrid.org and select "Download FTG". A summary table is on pp. 90-91 of the report, showing scores by criterion, including meter aggregation.

REC, East-Central REC, and Franklin REC impose a very low total system cap for all net metered customers. Once the cap is reached, no more customers interested in net metering are allowed to participate. The Calhoun County cap is 40 kW. In other words, if four residential customers each install a 10 kW solar array, the cap will be met and no more Calhoun County REC customers will be allowed to net meter. Calhoun County also imposes an individual system cap of 40 kW. While this is very low, it also means that a single customer installing a 40 kW wind or solar project would reach the total system cap and prevent any other customer from net metering. Similarly, East-Central REC has a total system cap of 250 kW and Franklin REC has a total system cap of 100 kW. These caps are very low and also limit net metering to just a few customers. It is not appropriate to represent the net metering policies offered by these utilities as generally available to their customers.

In response to the Board request to provide the applicable tariff or policy describing the net metering option, the IAEC filing indicates that the applicable tariffs are on file with the Board. After some searching, we were unable to locate the net metering tariffs for many of these utilities on the Electronic Filing System or on the individual utility websites. We request that the IAEC and IAMU file copies of the applicable tariffs for each utility listed in their June comments with the Board in this docket. This will allow all participants the opportunity to read and better understand the net metering tariffs offered by these utilities.

22. **Is there a need to adopt FERC SGIP standards as recommended by the Environmental Law and Policy Center (ELPC) and others? Specify sections of the standards that should be adopted and explain the value these sections would bring to the Board's existing rules.**

Yes. As we stated in our comments filed on June 24th, we believe Iowa's current interconnection standards are working relatively well today with Iowa's low level of distributed renewable energy penetration, but that updating the standards will help Iowa prepare for higher penetrations of DG. In addition, there are already some areas of Iowa that are experiencing problems with the existing rules as indicated by recent waiver request filings from IPL. Updating the Iowa procedures will help avoid the need for unnecessary and costly interconnection studies or future case-by-case waiver requests. Iowa should use the updated FERC SGIP as a starting point, since Iowa's current standards are based on a previous version of FERC SGIP and because the FERC SGIP is well-vetted and consensus-based. In addition, Iowa should use best practices found in the latest IREC Model Interconnection Procedures. Both FERC SGIP and IREC Model Interconnection Procedures were released in 2013. Finally, Iowa should use the state adoption of FERC SGIP and IREC procedures by leading states as additional guidance.

As FERC stated in Order 792, "the package of reforms adopted in this Final Rule will reduce the time and cost to process small generator interconnection requests … maintain reliability, increase energy supply, and remove barriers to the development of new energy resources."[38] In our June 24th comments, we recommended several specific provisions to consider adopting from the updated FERC SGIP including:

- Include a pre-application report;
- Modify Level 2 eligibility requirements;
- Incorporate the clearer Supplemental Review process;

In addition to the updated FERC SGIP, we also recommend additional changes based on IREC's Model Interconnection Procedures. Specifically, we recommend:

- Increasing the Level 1 review threshold to 25 kW;
- Modify the "no construction screen" in Levels 1 and 2;
- Eliminate the Feasibility Study;
- Do not allow the utility to require an external disconnection switch for inverter-based facilities;
- Require utilities to dedicate a webpage to interconnection;

[38] Order No. 792, *Small Generator Interconnection Agreements and Procedures*, 145 F.E.R.C. ¶ 61,159 (2013) at 4.

- Require utilities to allow online applications and electronic signatures;

More details for each of these specific recommendations can be found in our June 24th comments.

23. Some parties suggest that adoption of these standards would be counterproductive. Explain why adoption of these sections is not counterproductive.

FERC SGIP updates are well-vetted, consensus-based standards. As indicated in more detail elsewhere, we support Iowa updating its standards using FERC SGIP and other similar model or leading standards.

We note that only one party used the word ‘counterproductive’ in discussing adoption of the latest FERC SGIP (several other parties used brief and similar or identical language to not ‘revert to a lesser program overseen by FERC.’) This party, Industrial Energy Applications, indicated that trying to ‘meld together’ FERC rules with IEEE 1547 would be counterproductive because of issues regarding FERC jurisdiction and differences in how FERC SGIP and IEEE 1547 are promulgated.

The question is not whether to try to meld together the FERC SGIP and IEEE 1547. The updated FERC SGIP—just like the old version of the FERC SGIP that Iowa’s rules are based on—already specifically references and incorporates IEEE standards. For example, the FERC Small Generator Interconnection Agreement states that the

> Interconnection Customer agrees to construct its facilities or systems in accordance with applicable specifications that meet or exceed those provided by the National Electrical Safety Code, the American National Standards Institute, IEEE, Underwriter’s Laboratory, and Operating Requirements in effect at the time of construction and other applicable national and state codes and standards.

FERC Small Generator Interconnection Agreement, Article 1.5.4. In other words, Industrial Energy Applications is mistaken that adopting the updated FERC rules would require any change in the underlying technical standards that apply to interconnection. Instead, the updated FERC procedures simply streamline the way that the IEEE 1547 technical standard is applied. For the same reasons, adopting the updated FERC procedures would not require Iowa to "revert to a lesser program" or a program "overseen by FERC" as some parties have suggested. Iowa's utilities would continue to conduct interconnection reviews in Iowa and the IUB would continue to "oversee" the process. Iowa's existing procedures are based on an outdated version of the FERC SGIP. Thus, the proposed revisions would just ensure that Iowa stays up to date with the current industry standards rather than relying on an old and inefficient process.

24. Is there a need to adopt the Interstate Renewable Energy Council's Model Interconnection Procedures, as recommended by ELPC and others? Explain the additional value these standards would bring to the Board's existing rules.

IREC's latest Model Interconnection Procedures, issued in 2013, incorporate the updates and procedures found in the latest FERC SGIP as well as the procedures adopted recently by leading states (e.g., Ohio) or in the process of being adopted by such states (e.g., Illinois). We recommend that Iowa use the latest FERC SGIP and IREC model procedures as a starting point to update the Chapter 45 rules and consider making minor adjustments as appropriate for Iowa. We recommend that Iowa also use the recent state adoption of the FERC SGIP and IREC models, such as Ohio and Illinois (in process).

25. Comment on the need to develop a supplemental periodic installation review process after the installation of DG.

- **a. What elements (frequency of installation inspection, duration etc.) should be included in the review process?**
- **b. Who should develop, implement, and conduct the review process?**
- **c. Do you have any suggestions on which Board rules need revision to incorporate your recommendations?**

Iowa's current Chapter 45 interconnection rules already include provisions to address the operation and maintenance of distributed generation facilities. The standards require interconnection customers to operate their systems in compliance with the IEEE 1547 standard, which "provides requirements relevant to the performance, operation, testing, safety considerations, and maintenance of the interconnection."[39] For example, the Level 1 Standard Interconnection Agreement states that the "distributed generation facility shall be installed, operated and tested in accordance with the requirements" of IEEE 1547.[40] The interconnection customer can only begin operating the DG facility after several key inspections occur: an electrical inspection has been conducted to establish that the DG facility meets state or local electrical code requirements and the utility has an opportunity to conduct a witness test "to ensure all equipment has been appropriately installed and operating as designed and in accordance with the requirements of IEEE 1547."[41] The current Iowa rules also require the operator of the DG facility to "adopt a program of inspection of the generator and its appurtenances and the interconnection facilities in order to determine necessity for replacement and repair.[42]

Before considering changes to these aspects of the Iowa rules, more information and data are needed regarding the type and degree of concerns or problems that have occurred to date and why the current or updated Iowa rules are insufficient to address these concerns.

26. Who has the authority to inspect a DG installation for improper installation, maintenance, or operation? Provide legal standards that apply.

As discussed in our answer to Question 25, Iowa's current interconnection rules require an inspection by an electrical inspector prior to operation and provide the utility with an opportunity to conduct an in-person witness test and inspection of the DG facilities, also prior to

[39] The Institute of Electrical and Electronics Engineers, Inc., *1547: IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems* (2003) at ii.

[40] 199 IAC 45.14 Appendix A at 20.

[41] *Id.* See also 199 IAC 45.8(2)(e); 199 IAC 45.9(5); 199 IAC 45.10(4); 199 IAC 45.11(10).

[42] 199 IAC 45.3(4).

operation. The electrical inspection is intended to "establish that the distributed generation meets local code requirements."[43] In the absence of a local electrical code, the state electrical code applies and the inspection is conducted by a state electrical inspector. The utility witness test is intended "to ensure that all equipment has been appropriately installed and operating as designed and in accordance with the requirements of IEEE 1547."[44]

27. Who has the authority to penalize a DG installation for improper installation, maintenance, or operation? Provide legal standards that apply.

The standard interconnection agreements in Chapter 45 for Level 1 and Levels 2-4 include clear provisions for interconnection customer compliance and penalties for failure to comply, such as utility disconnection (which can be permanent unless cured by the customer). For example, the Level 1 standard agreement provides for a list of conditions that allow the utility to disconnect the DG facility, including "creating safety, reliability, or power quality problems" and "improper installation."[45]

If parties are concerned about this issue, then it could be further investigated when Iowa updates the interconnection rules. During that time, the utilities could provide additional information on the number of interconnections that have failed witness tests or have been disconnected due to adverse system impacts, improper installation, etc.

28. Comment on IPL's proposal to give preference to existing customers. Explain your response. What problems would this create or solve?

Iowa's interconnection rules require that the interconnection "review order position is established by the date that the utility receives the completed interconnection request."[46] This is

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[43] 199 IAC 45.14 Appendix A.

[44] *Id*.

[45] 199 IAC 45.14, Appendix A at 21.

[46] 199 IAC 45.1.

appropriate given the obligation of utilities to serve all customers equally, whether they are existing or new. The Iowa interconnection rules also include reasonable time frames. If a utility – such as IPL – is experiencing any difficulty meeting the established time frames, we suggest exploring ways to streamline and improve the time it takes to process and review interconnection requests. Many of the updates, improvements, and best practices included in the revised FERC SGIP and IREC Model Interconnection Procedures, as discussed in our answers to Questions 22 and 24, will allow for this.

29. Provide MidAmerican's reasons to extend the notice period, a reference to the notification requirement that it seeks the Board to amend, and proposed language changes needed to extend the 30-day advance notice discussed in MidAmerican's response to Board Interconnection Question 2 in the May 12, 2014, order.

Not applicable.

30. What, if any, specific Board rule changes are necessary to allow for the study of DG installations in new developments or neighborhood service areas?

Updating Iowa's interconnection standards with the revised FERC SGIP and IREC Model Interconnection Procedures, as discussed in response to Questions 22 and 24, should be sufficient for studying DG installations in most new developments or neighborhood service areas.

We would be interested in exploring a cluster review option to make the process more efficient for new developments that have an interest in putting solar on all of the units in a new development. A cluster review option could be further investigated when Iowa updates the interconnection rules.

31. Is there a need to revisit the 15 percent screen standard discussed in rules 199 IAC 45.8(1)"a" and 45.9(1)"a"? Explain your response.

Yes. The 15 percent of peak or maximum load screen in the Iowa rules is an imperfect screen. A better screen is available in the FERC SGIP Minimum Load Screen, which evaluates the DG facility based on whether aggregate DG facilities account for less than 100% of the minimum load on a distribution line section. The 15 percent screen was adopted as a proxy for minimum load, which is the more important and relevant consideration.[47]

Areas of Iowa are already experiencing problems with the 15 percent screen, as indicated by three waiver request filings from IPL.[48] As the waiver requests indicate, the 15 percent screen can cause unnecessary study time and expense for utilities and delays for customer interconnections. The 100% minimum load screen has been adopted by the FERC SGIP and also adopted by some states, like Ohio, or in the process of adoption in other states, like Illinois and North Carolina. Iowa should update its rules to adopt this supplemental review screen as well.

32. What are the potential impacts of revising the 15 percent limit of the maximum load normally supplied by the distribution circuit to a higher limit?

We are not advocating for a higher limit to the 15% of peak load screen. Rather, we are advocating for use of a new supplemental review process that evaluates the proposed interconnection with additional or supplemental screens. Iowa's current standards use the technical screen that is 15% of peak or maximum load, while the supplemental review uses the technical screen that is 100% of minimum load. If a proposed project fails the 15% of peak load screen, it can still be approved using the supplemental 100% of minimum load screen (along with additional safety, reliability and power quality screens).

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[47] Michael Coddington, Benjamin Kroposki, Barry Mather (National Renewable Energy Laboratory); Kevin Lynn, Alvin Razon (Department of Energy); Abrahim Ellis, Roger Hill (Sandia National Laboratories); Tom Key, Kristen Nicole, Jeff Smith (Electric Power Research Institute), *Updating Interconnection Screens for PV System Integration,* National Renewable Energy Laboratory Technical Report NREL/TP-5500-54063 (January 2012), at p. 2, *available at* www.nrel.gov/docs/fy12osti/54063.pdf

[48] *See* In Re: Interstate Power & Light Company, Docket No. WRU-2014-0011-0150; In Re: Interstate Power & Light Company, Docket No. WRU-2014-0014-0150; In Re: Interstate Power & Light Company, Docket No. WRU-2014-0016-0150

The 100% of minimum load screen has been discussed and vetted extensively by independent experts including many utilities. Safety and grid reliability remain the paramount objectives of interconnection standards and the supplemental review procedures were designed and vetted with this in mind.

33. What, if any, higher limit should be adopted? Explain the reasoning and data that support why such a higher limit is reasonable.

We are not advocating for a higher limit to the 15% of peak load screen. Rather, we are advocating for use of a new supplemental review process that evaluates the proposed interconnection with additional or supplemental screens. Iowa's current standards use the technical screen that is 15% of peak or maximum load, while the supplemental review uses the technical screen that is 100% of minimum load. If a proposed project fails the 15% of peak load screen, it can still be approved using the supplemental 100% of minimum load screen (along with additional safety, reliability and power quality screens).

34. Comment on IPL's proposal to increase the Level 1 and Level 2 application fees to $250, including any justification for keeping fees the same or raising them to IPL's recommended level.

Level 1 systems should be able to be reviewed quickly. A $250 fee is very high for the review needed for these systems and very high compared to the majority of other states' fees. Better options are available to reduce the utility's time and expense reviewing Level 1 applications, including allowing for on-line and electronic applications and using updated and streamlined interconnection standards (e.g., the FERC SGIP and IREC models discussed in previous answers).

IPL suggested including the cost of conducting a witness test in every application, even if it does not conduct the witness test. It is not reasonable or equitable for IPL to charge customers for tests that IPL does not conduct. More information is needed from IPL on the real costs for processing applications and what it has or could do to reduce those costs, rather than consider increasing the costs at this time.

A change that should be considered at this time is increasing the Level 1 application to 25 kW. There is very little difference from the utility perspective in reviewing a 10 kW application compared to a 25 kW application. From the customer perspective, there is a significant difference. Many developers will undersize systems to get below the 10 kW fast track threshold. This makes a difference for many small systems because it is less cost-effective for customers to have a system that is undersized when there is not a good technical or economic reason for doing so. This change should not be controversial. Illinois recently made the change and ComEd and Ameren did not oppose the change.

35. <u>For MidAmerican and IPL:</u> What number of DG customers would be required before you would be able to conduct cost of service studies to determine DG class rates? Does either utility have a cost study today to show that the true interconnection costs exceed the current fees?

There is a significant difference between cost of service and cost of interconnection. This question is in the interconnection section and presumably related to interconnection costs. The interconnection standards appropriately require DG customers to pay for the costs of interconnection as long as the costs are justified by that interconnection. A study on the cost of interconnection would be a limited look at the costs associated with interconnecting a customer. In most cases, these costs would be reviewing the interconnection application and maybe the cost of a witness test. It could also include additional study and costs of distribution upgrades necessitated by interconnecting DG. If a study on the cost of interconnection is conducted, it is important that the study properly account for who is causing the need for distribution upgrades. The cost of a distribution upgrade that is already needed in an area before a customer submits an interconnection application should not be attributed to that customer or expected to be paid by that customer. Some utilities are taking advantage of the DG interconnection process to charge DG customers for distribution system upgrades that the utility would have had to make anyway. If a distribution system upgrade would need to be made in the absence of DG, it should be ratebased across all of the utility customers and not allocated to a DG customer because that customer happened to submit an interconnection application at that time.

A cost-of-service study would look at the total cost to serve customers. We do not think that it is appropriate to single out DG customers for a separate cost of service study. As noted above, discrimination on the basis of DG would violate Iowa law. On the other hand, as we have previously discussed, we do think that it is appropriate to do a comprehensive valuation study that addresses both the costs and benefits of distributed generation.

36. MidAmerican has indicated that a DG owner is a different type of customer and should be treated as a separate class. Provide comments on how this should be done, if it should be done, or if there is a different way to account for differences between customers.

See the response to questions 16 and 17.

37. Should utilities require DG operators to install a lockable external disconnect switch? Explain your response and provide the pros and cons of such a requirement from cost and technology perspectives separately.

Iowa's interconnection rules currently require use of an external disconnect switch ("EDS") that is clearly marked and accessible by utility personnel as a redundant safety measure. An EDS allows utility employees to manually disconnect a customer-owned generator from the electricity grid. In instances of power outage, there is a possibility that a grid-tied system may continue generating electricity and export it to the grid, putting utility workers at risk of encountering energized lines. However, if a generating facility uses a certified inverter that prevents it from exporting power when the grid is de-energized, then many states have found they can waive the requirement or prohibit utilities from requiring an EDS for small generators without risking the safety of line workers or causing system impacts.

The National Renewable Energy Laboratory (NREL), the Solar America Board of Codes and Standards, several states, and many utilities have all determined that an EDS is not necessary for small inverter-based PV systems. According to the 2013 *Freeing the Grid* report, Florida, New Hampshire, New Jersey, New York, Utah, Washington, and West Virginia allow for a waiver of the EDS requirement for small inverter-based systems. NREL concluded that the switch is made redundant and unnecessary by UL and IEEE standards, the presence of an "inverter," which automatically de-energizes the system upon loss of power from the grid, and the extensive safety training utility workers receive and the procedures they must follow to ground wires.[49] In addition, the Solar America Board of Codes and Standards (Solar ABCs) conducted a comprehensive review of this issue and similarly concluded that for "properly designed and installed code-compliant PV systems, the U[tility] EDS provides little, if any, additional safety, beyond what is already present."[50] Iowa requires that generators employ lab-certified equipment, including specifically UL 1741-certified inverters. As such, the EDS requirement for these systems is unnecessary. The proposed rules provide for a waiver for systems smaller than 25 kW because these systems are less able to absorb the substantial, additional cost associated with an EDS through economies of scale.

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49 M. Coddington, R.M. Margolis, and J. Aabakken, NREL, *Utility-Interconnected Photovoltaic Systems: Evaluating the Rationale for the Utility-Accessible External Disconnect Switch*, Technical Report: NREL/TP-581-42675 (Jan. 2008), *available at* www.nrel.gov/docs/fy08osti/42675.pdf.

50 Michael T. Sheehan, P.E., IREC, *Utility External Disconnect Switch: Practical, Legal, and Technical Reasons to Eliminate the Requirement* 2, SolarABCs (Sept. 2008), *available at* www.solarabcs.org/about/publications/reports/ued/pdfs/ABCS-05_studyreport.pdf.

38. For each reported DG facility, indicate whether capacity and generation data is reported to the Energy Information Administration (EIA). In other words, do any DG facilities file either EIA 860 or EIA 923 reports? If so, identify those facilities.

Not applicable.

39. Did you include all CHP installations in the data you provided? If not, provide comparable data for all CHP installations in your service territories.

Not applicable.

40. Based on the data provided, it appears that hourly load data is available for the DG capacity associated with all residential customers for both IPL and MidAmerican; for 10 percent of the non-residential DG capacity for MidAmerican; and for 59 percent of IPL's non-residential DG capacity. Is this statement accurate? If no, what are the correct percentages? If yes, discuss what would be required in order to get hourly data for the remaining DG capacity.

Not applicable.

41. On July 11, 2014, the Iowa Supreme Court issued its opinion in No. 13-0642, SZ Enterprises, LLC d/b/a Eagle Point Solar v. Iowa Utilities Board, a Division of the Department of Commerce, State of Iowa, et al. What are the legal impacts, if any, of this decision on DG policies or practices in general and particular policies or practices such as net metering (both traditional and virtual)? Does the decision impact any of your prior comments or responses in this docket? If so, explain.

The Eagle Point Solar decision clarifies Iowa law and allows third-party power purchase agreements as a financing mechanism for distributed generation systems. The decision does not have any impacts on DG policies or practices because the method that a customer chooses to finance their DG system does not affect the design or operation of the DG system in any way. In other words, a customer may choose to finance a DG system via a cash purchase, a traditional bank loan, or through a power purchase agreement offered by a third-party developer. The DG system will be identical in all respects and will have to comply with all other Iowa DG policies, including interconnection and net metering standards, regardless of the financing method the customer selects. The Eagle Point decision can and should be implemented within Iowa's current policy framework, and the IUB should make sure that utilities are implementing the law and not discriminating against DG systems based on ownership or financing mechanism.

DG Checklist

We think that education has a valuable role to play in helping consumers understand the energy implications of distributed generation. A well designed, easy-to-use checklist can help a consumer think through the implications of distributed generation, better equip them to make important decisions, and help them navigate the process from idea to installation.

We think that the simpler the information is in both presentation and substance, the easier it is for consumers to digest and effectively use. Several of us were able to participate in the Board's workshops and made suggestions along these lines. We will repeat a few general items here.

We think that the checklist is too long. It could be streamlined to avoid repetition and to eliminate some items. Many items fall into the category of consumer best practices or items to consider before any major purchase or home contracting project. Some of these items could be eliminated, and some could be organized into a general consumer checklist referenced as part of a distributed generation checklist. There may also be value in creating separate checklists by type of technology.

It is also important to think about the role of the installer. Many of the items on the checklist are issues that the installer will assist a customer with during the course of the project. There is value in helping the customer think through these things, but placing them in the context of work the installer can do is important and will help the consumer have a better, more productive interaction with the installer.

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Respectfully submitted,

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Guiding Principles for Distributed Solar Generation Policy & Rate Design

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As distributed solar generation (DSG) and energy efficiency applications continue to become more accessible and affordable, we are likely to see increased adoption of technologies that manage and reduce customers' use of electricity from the grid.

Regulatory policies and electric rate design establish the critical framework for growth of DSG and related innovative 'behind-the-meter' technologies. Environment America, Environmental Law and Policy Center, Greenpeace, Pace Energy and Climate Center, Sierra Club, Southern Environmental Law Center, and Vote Solar support the following guiding principles to ensure fairness for all customers during this significant transition in our electricity infrastructure. Policymakers should consider only regulatory policies and electric rate design options that comport with these principles.[1]

1. **Preserve individual customers' rights to self-determination:** Each customer can choose the amount of energy to purchase from the grid, the amount to self-produce and consume, and the amount to save through efficiency measures that reduce consumption. These rights include the installation of solar generation equipment at the customer's site, and interconnection to the utility grid without discrimination.[2] While any electrical devices connected to the grid must not compromise safety, reliability, or power quality, utilities do not have the right to restrict the decisions of customers regarding how to manage energy use on their own property. Most electric utilities operate under a regulatory compact where the electric utilities are required to do business within the confines of the public interest and are required to serve the needs of all customers within their territory in exchange for an exclusive monopoly franchise. Utilities are required to provide as much or as little electricity as the customer desires to purchase and consume.[3]

2. **Capture the Full Range of DSG Benefits and Values:** Customer-sited solar generation offers many benefits to the electric utility system and by extension to non-solar customers. These include avoiding current variable utility costs such as fuel costs, near to long term demand-related utility costs such as building new power plants and other energy infrastructure including transmission and distribution investments, and societal costs including but not limited to health costs resulting from fossil fuel-generated air and water pollution. The values and benefits should be quantified, and solar customers should be adequately compensated for the value their solar energy is delivering to all customers.

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[1] These principles are designed for distributed solar generation but are generally applicable to other distributed energy resources as well.

[2] http://www.ferc.gov/industries/electric/gen-info/qual-fac/benefits.asp

[3] Notable exceptions are made for very large, usually industrial, customers that require significant investments in infrastructure and sometimes generation. Such customers could have significant impacts on a utility were they to move or shut down.

3. **Promote Policies and Rates Favorable to Next Generation Distributed Technologies**: Regulatory policies and electric rate design should not inhibit the deployment of DSG, demand response, combined heat and power (e.g. fuel cells), storage or other innovative technologies that are currently available or will be available in the foreseeable future. Thus, when discussing changes to current rate structures, the ability of a customer to integrate DSG with storage to avoid fees and charges should be considered. Such a technology package could mitigate the effect of demand charges, but not increased fixed monthly customer charges. Tariffs and policies that create roadblocks to customer adoption of next generation technologies (e.g. customer-sited storage) should not be adopted.

4. **Insist Upon Non-Discriminatory Rate Practices And Policies**: Utility rates should treat reductions in energy sales and utility revenues due to net metered solar and other DSG in a manner that is fully comparable to, and non-discriminatory relative to, reductions due to other consumer behaviors including energy efficiency and demand response. Any rate treatment not generally applied to all similarly situated customers must be cost-justified and seek to avoid unintended consequences.[4] Furthermore, any utility charges created specifically for the purpose of recovering embedded fixed costs from customers with DSG systems must be cost-based, and should only recover *net* fixed costs, after accounting for all benefits and offsetting cost reductions due to the distributed solar. Similarly, any utility *credits* created for the purpose of assuring that economic benefits resulting from the deployment of DSG systems are properly assigned back to the DSG customer(s) should only reflect *net* benefits, after accounting for all utility costs.

5. **Due Process Is Essential:** Facilitating the deployment of distributed solar generation is critical for developing the energy structure of the future. Thus, it is of paramount importance that DSG rate policies be determined in regulatory forums guided by the rules of law where stakeholders have access to transparent and verifiable data. Claims of intra-class and inter-class cross-subsidies, and the comparative benefits of larger scale wholesale PV systems can be addressed most effectively where adequate data is available and transparent, and due process prevails. A transparent and data driven analysis that assures stakeholder due process rights are protected is likely to optimize the chances for an outcome that is best for customers. Utilities should not be able to undermine a regulatory proceeding by limiting data access or proposing an overly aggressive schedule that limits meaningful stakeholder participation.

6. **Ensure that the benefits of rooftop solar are shared with low-income customers:** Within resource and grid planning processes, regulators must ensure that utilities effectively realize the present and future benefits that distributed solar provides in terms of freeing up capacity on the distribution and transmission system and reducing the need for infrastructure upgrades. These cost savings must be equally shared among all ratepayers, including low-income ratepayers, through thoughtful rate design.

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[4] Example: Segregating net metered customers into their own rate class and designing rates that recover fixed costs through increased monthly customer charges and/or adding a demand charge can result in a much lower energy rate. This result can motivate high consumption customers, aka the wealthy, to install a minimal solar system (1-2 solar panels) to qualify for the rate and significantly reduce their utility bills, resulting in a far more dramatic reduction in revenue to the utility.