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STATE OF IOWA

DEPARTMENT OF COMMERCE

UTILITIES BOARD

IN RE: DISTRIBUTED GENERATION	Docket No. NOI-2014-0001

ADDITIONAL COMMENTS OF THE ALLIANCE FOR SOLAR CHOICE

The Alliance for Solar Choice ("TASC") appreciates the opportunity to submit these comments pursuant to the Iowa Utilities Board's (the "Board") September 19, 2014 *Order Soliciting Additional Comments and Scheduling Workshop* ("Order") in the above-captioned docket. The Order requests responses to specific questions posed by the Board in considering the policy and technical issues associated with potential widespread use of distributed generation ("DG") in Iowa.

TASC advocates for maintaining successful distributed solar-energy policies throughout the United States. TASC's members represent the majority of the nation's rooftop solar market. They include SolarCity, Solar Universe, Sungevity, Sunrun and Verengo Solar. These companies are important stakeholders with regard to solar policy at both the state and national levels, and they are responsible for tens of thousands of residential, school, government and commercial solar installations across the United States.

TASC's member companies have participated in stakeholder or regulatory proceedings in many U.S. states that have pursued answers to the same questions the Board poses. TASC previously submitted comments to the Board in this proceeding on February 25, 2014. TASC respectfully submits these comments to further assist the Board with its inquiry. The comments provided by TASC below offer responses only to certain questions posed by the Board that impact TASC's members' businesses.

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.

TASC disagrees with MidAmerican. TASC strongly supports maintaining the current indefinite monthly rollover of any excess net-metering credits in Iowa. Under FERC precedent, no wholesale purchase of electricity is taking place under net metering so long as a retail customer with on-site generation is not a net supplier of electricity over a state-determined billing period.[1] According to FERC regulations, any sale of excess electricity generated over the state-determined net-metering period must be compensated at the utility's full avoided-cost rate.[2]

Although TASC supports maintaining the current indefinite monthly rollover of any excess net-metering credits, TASC also supports allowing net-metering customers to decide to cash out a net balance annually if they prefer to do so. The cash-out option could be considered a wholesale transaction, but the availability of this option would not require FERC approval. Under the Public Utility Regulatory Policies Act of 1978 ("PURPA"), the FERC has exclusive jurisdiction to determine eligibility requirements for qualifying facilities ("QFs").[3] FERC has

1 *MidAmerican Energy Co.*, 94 FERC ¶ 61,340 (2001); *Sun Edison LLC,* 129 FERC ¶ 61,146 (2009).

2 18 C.F.R. § 292.304.

3 16 U.S.C. 796(17)(C), 16 U.S.C. 796(18)(B).

determined that QFs include solar generators (and certain other forms of DG) up to 80 MW in capacity,[4] and that QF status automatically applies to on-site solar generators up to 1 MW in capacity,[5] including solar generators participating in net-metering programs established by states.[6] With respect to photovoltaic ("PV") generators, of the 43 U.S. states that have established a net-metering policy thus far, approximately 15 allow or require an annual cash-out at the utility's avoided-cost rate.[7] In states that allow or require an annual cash-out process at the utility's avoided-cost rate for any remaining net-metering credits, FERC approval is not required for the cash-out process itself.

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

TASC disagrees with MidAmerican's assertion. A cash-out option that involves an annual payment at the utility's avoided-cost rate for any remaining customer net-metering credits would not encourage the over-sizing of DG systems because utilities' avoided-cost rates are insufficient to support such a result.

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?**

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4 18 C.F.R. § 292.203(a) (establishing size, fuel use, and certification criteria), 292.204(a) (establishing maximum size of 80 MW).

5 18 C.F.R. § 292.203(d) (exempting facilities with net power production capacity up to 1 MW from certification requirement).

6 *Sun Edison LLC,* 129 FERC ¶ 61,146 (2009) (recognizing onsite generators that participate in NEM as eligible for QF status even if they make no net sale of electricity to a utility).

7 See *Freeing the Grid.* Available at http://freeingthegrid.org.

There is no legal basis under PURPA for setting a monetary limit on the amount of payments a QF customer may receive. Setting a cap on the dollar amount of a cash-out paid at the utility's avoided-cost rate is not consistent with PURPA.

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.

b. Required or optional? Explain why.

TASC believes the current indefinite monthly roll-over of any excess net-metering credits in Iowa should be maintained. TASC also strongly supports expanding energy choice for consumers in Iowa. TASC therefore supports allowing net-metering customers to choose to cash out a net balance annually (i.e., receive payment for excess kilowatt-hours generated over an annual period, if they prefer to do so). A few U.S. states, including California, Delaware and Virginia, currently allow net-metering customers to choose an annual cash-out or indefinite monthly roll-over of excess credits.[8]

An annual cash-out option is preferable to a monthly cash-out option because the former allows DG customers to utilize the full value of the electricity they generate throughout a one-year cycle, thereby mitigating any differences in monthly and/or seasonal production by a DG system. Furthermore, an annual cash-out option is less administratively burdensome and more consistent with practices established by other U.S. states seeking to encourage the development of customer-sited DG. With respect to PV generators, of the 43 U.S. states that have established a net-metering policy thus far, roughly three-quarters have either defined a net-metering period as an annual cycle (with monthly roll-over of kWh credits at retail value) or allow the indefinite

[8] See *Freeing the Grid.* Available at http://freeingthegrid.org.

roll-over of excess net-metering credits (at retail value) until the net-metering customer leaves the utility's system.[9]

In addition, a cash-out option would be beneficial to residential PV customers with energy needs that likely will change over the course of a typical system's 25-year lifetime (e.g., a reduction in the number of family members living at the home).

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.

TASC does not agree that "banked kWh" under a net-metering arrangement may be considered a cost to the utility. Within any state-determined net-metering period, no sale of electricity by the DG customer to the utility occurs; there is merely an exchange of kWh between the DG customer and the utility. Accordingly, the netting that takes place within the annual net-metering period does not constitute a "cost of purchased power" and therefore should not be recovered through the energy adjustment clause. IPL's assumption that "banked kWh" may be considered a "cost" to utilities lacks merit because a comprehensive, unbiased analysis of DG costs and benefits in Iowa has not been conducted yet. TASC supports such an analysis, conducted by the Board's Staff or an outside consultant, after the DG market in Iowa has matured. (Please see our response to Question 18.)

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.

TASC believes that the annual cash-out rate should be paid at the utility's avoided-cost rate, not at the utility's retail rate. This approach is consistent with PURPA, and with net-

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[9] *Id.*

metering policies established by many other U.S. states that allow or require an annual cash-out process.

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.

TASC does not agree with IPL's suggested change. Under net metering, the only energy that is actually *purchased* from a DG customer by a utility is the energy that is purchased during a cash-out process at the end of a state-determined net-metering period. Within any given net-metering period, no sale of electricity by the DG customer to the utility occurs; there is merely an exchange of kWh between the DG customer and the utility. For net-metering customers who choose to receive an annual cash-out payment at the utility's avoided-cost rate (rather than choosing to rolling over credits indefinitely), the annual cash-out payment those customers receive could be considered an 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.

TASC strongly opposes IPL, MidAmerican and Consumer Advocate Division proposals to discriminate against DG customers with regard to retail rate options. Iowa law and Federal law both prohibit discrimination against DG customers. Iowa Code § 476.21 specifically prohibits discrimination in the treatment of rates or charges on the basis of a customer's choice to self-supply electricity needs with renewable energy sources:

> "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."

Federal law also prohibits discriminatory charges in electric utility rates charged to customers with on-site solar generators. FERC's regulations require that rates charged to QFs for energy and capacity be "just and reasonable and in the public interest," and "not discriminate against any qualifying facility in comparison to rates for sales to other customers served by the electric utility."[10] Any new rate or classification must be based on accurate utility data and make use of consistent statewide costing principles.[11]

Under PURPA, rates are nondiscriminatory to the extent that the rates charged to QFs also apply to other customers with similar load or cost-related characteristics. Any discriminatory rate treatment for net-metering customers would face a heavy burden of demonstrating that the cost of serving customers that self-supply electricity with on-site solar generation varies significantly enough from the cost of serving customers with similar load characteristics that do not generate their own solar energy that different rate treatment is justified. If, due to the installation of a PV system, a customer's electric consumption from the utility is reduced from slightly higher than average to somewhat lower than average, and that

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[10] 18 C.F.R. § 292.305(a)(1).

[11] Burns, Robert E., Rose, Kenneth, *PURPA Title II Compliance Manual*, Sponsored by the American Public Power Association, Edison Electric Institute, National Association of Regulatory Utility Commissioners, National Rural Electric Cooperative Association. At P 48. March 2014.

customer is not an atypical customer within the rate class, there is no justification to treat customers differently.

Furthermore, the avoided-cost benefits of on-site PV systems must be factored into whether the cost to serve PV customers is lower than the cost to serve customers that do not have PV systems. A utility may not require net-metering customers to take service under particular rates under Federal law unless it can satisfy the heavy burden of showing through accurate utility data and the use of consistent statewide costing principles that discrimination is justified. That burden certainly has not been met in Iowa. TASC is aware of no cost-of-service study or cost-benefit analysis conducted in Iowa that in any way suggests that discrimination is justified. In the absence of a factual determination, limiting the retail rate options for DG customers would be discriminatory and therefore prohibited by both Federal and Iowa law.

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.

Under both Federal law and Iowa law, a utility may not establish separate rate classes for net-metering customers unless it can satisfy the heavy burden of showing through accurate utility data and the use of consistent statewide costing principles that discrimination is justified. That burden has not been met in Iowa. In the absence of a factual determination, a separate rate class for net-metering customers would be discriminatory. (Please see our response to Question 16.)

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?

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?**

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?**

d. **Who should perform the study?**

e. **Who should pay for the study?**

TASC supports conducting a comprehensive study to analyze and compare the benefits and costs of customer-sited DG systems in Iowa. However, because Iowa's DG market is still nascent compared to many other U.S. states' DG markets, there is insufficient DG currently interconnected in Iowa (and insufficient data related to those systems) to justify the resources needed to conduct a comprehensive study of the issues. Indeed, through the end of 2013, only 4.6 MW of PV had been interconnected in Iowa, compared to 5,183.4 MW in California, 1,563.1 MW in Arizona, 1,184.6 MW in New Jersey, and 469 MW in North Carolina.[12]

TASC believes that it would be more appropriate to conduct a comprehensive study when Iowa's DG industry has exhibited broader growth.

As detailed in comments previously filed by TASC in this proceeding,[13] numerous recent studies provide the Board with insight into the best ways to understand DG benefits and costs. More recently, in July 2014, the Nevada Public Utilities Commission published a study[14] that it

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[12] *U.S. Solar Market Trends 2013*. Interstate Renewable Energy Council, Inc. July 2014. At P 29. Available at http://www.irecusa.org/wp-content/uploads/2014/07/Final-Solar-Report-7-3-14-W-2-8.pdf.
[13] See *Comments of the Alliance for Solar Choice*, submitted in Iowa Utilities Board Docket No. NOI-2014-0001 on February 25, 2014.
[14] *Nevada Net Energy Metering Impacts Evaluation*. Prepared for the Nevada Public Utilities Commission by Energy + Environmental Economics (E3). July 2014. Available at

commissioned to analyze and forecast the costs and benefits of renewable-energy systems that qualify for Nevada's net-metering program. That study, which involved input from the Nevada Public Utilities Commission and stakeholders, concluded that net metering in Nevada will present a net benefit to non-participants in 2014 and 2015, with a "nearly neutral" impact in subsequent years.[15] Specifically, the report states:

> "We estimate a total NPV benefit of 2004-2016 NEM systems to non-participating ratepayers of $36 million during the systems' lifetimes. Whether NEM systems are a net cost or net benefit to non-participants is sensitive to some key input assumptions … but in either case should be relatively small."[16]

Nevada ranks sixth nationally among U.S. states in terms of aggregate installed PV capacity, with a total of 424 MW.[17] As of December 2013, over 3,300 individual systems were enrolled in NV Energy's net-metering program, totaling more than 60 MW of installed capacity, 50 MW of which were distributed PV systems.[18]

TASC drew upon conclusions reached in many of those studies to offer five recommendations in its February 25, 2014 comments: (1) any cost-benefit analysis of DG should follow best practices; (2) diverse perspectives should be utilized to evaluate DG benefits; (3) a long-term perspective on DG value is important to fully capture the benefits DG resources bring to the grid over their useful life; (4) a comprehensive analysis of DG costs and benefits is premature in Iowa at this time; (5) however, if the Board chooses to move forward with a

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http://puc.nv.gov/uploadedFiles/pucnvgov/Content/About/Media_Outreach/Announcements/Announcements/E3%20PUCN%20NEM%20Report%202014.pdf?pdf=Net-Metering-Study.

[15] *Id.* at 7.

[16] *Id.* at 7-8.

[17] *U.S. Solar Market Trends 2013*. Interstate Renewable Energy Council, Inc. July 2014. At P 29. Available at http://www.irecusa.org/wp-content/uploads/2014/07/Final-Solar-Report-7-3-14-W-2-8.pdf.

[18] *Nevada Net Energy Metering Impacts Evaluation*. Prepared for the Nevada Public Utilities Commission by Energy + Environmental Economics (E3). July 2014. At P 2. Available at http://puc.nv.gov/uploadedFiles/pucnvgov/Content/About/Media_Outreach/Announcements/Announcements/E3%20PUCN%20NEM%20Report%202014.pdf?pdf=Net-Metering-Study.

comprehensive analysis at this time, despite the current low level of interconnected DG in Iowa, TASC believes a rigorous examination of costs and benefits of DG requires an unbiased analysis conducted either by the Board's Staff or an outside consultant.

TASC believes it would be appropriate to conduct a comprehensive study when the aggregate capacity of net-metering systems in either MidAmerican's or Interstate Power and Light's Iowa service territory reaches 3 percent of the utility's previous year's peak demand, or three years from the date of the Board's final order in this proceeding, whichever comes sooner. At this time, TASC takes no position regarding who should pay for the study, provided that the study is unbiased and conducted either by the Board's Staff or a qualified outside consultant.

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.

TASC believes that FERC's updated SGIP[19] effectively balance utilities' interests in safety, reliability and power quality with DG developers' interests in transparency, efficiency and cost-effectiveness, and that the Board should adopt the FERC's updated SGIP, making any modifications necessary for the FERC's updated SGIP to comport with State law.

The dynamic and rapidly growing DG markets in many regions of the United States prompted FERC to update its SGIP "to ensure that the rates, terms and conditions under which public utilities provide interconnection service to Small Generating Facilities remain just and reasonable and not unduly discriminatory."[20] In addition, FERC stated in its order adopting the

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[19] Order No. 792, *Small Generator Interconnection Agreements and Procedures*, 145 FERC ¶ 61,159 (Nov. 22, 2013).

[20] *Id.* at 2.

updated SGIP that "the time is ripe to promulgate such changes in light of the increased penetration of small generator resources, the continued focus by states and others on the development of distributed resources, and the need for this Commission to have its regulations and policies ensure just and reasonable rates, terms and conditions of service."[21]

TASC believes FERC's updated SGIP presents individual U.S. states with a strong, modernized platform on which to build or expand vibrant DG markets and additional energy options for consumers. Indeed, FERC stated explicitly that that the updated SGIP should serve as a model for state interconnection rules.[22] California, Hawaii, Ohio and Massachusetts have recently updated their interconnection procedures and they are largely parallel with FERC's SGIP, and the North Carolina Utilities Commission is currently considering doing this same.

Harmonizing state and Federal interconnection procedures to the fullest extent possible would be extremely beneficial to the expansion of DG in Iowa. TASC encourages the Board to adopt the updated SGIP so that Iowa's utilities and DG developers are not forced to wrestle with incompatible state and Federal DG interconnection requirements.

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

TASC believes the updated FERC SGIP embraces the current best practices for interconnection procedures from around the United States, having incorporating during a 21-month process period feedback from a broad array of stakeholders representing many interests, as well as specific policy improvements that have been adopted by individual U.S. states. FERC acknowledged that it was necessary to update its SGIP because the DG market is extremely dynamic in many regions of the country, and because it is important that interconnection

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[21] *Id.* at 2.
[22] NOPR, FERC Stats. & Regs. ¶ 32,697 at P 18.

procedures keep up with growing DG deployment. Adopting the updated FERC SGIP is not counterproductive because doing so would harmonize State and Federal interconnection procedures, which are currently disparate, and because it would encourage DG growth and the expansion of energy choices and services for consumers.

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.

The Interstate Renewable Energy Council, Inc.'s (IREC) *Model Interconnection Procedures*,[23] which were last updated in 2013, were highly influential in the development of FERC's updated SGIP, and significant overlap exists between the two models. TASC agrees that the adoption of IREC's model would also be beneficial to the development of DG in Iowa. However, in the spirit of maximizing the consistency of Federal and State interconnection procedures for DG in Iowa and in other states, TASC recommends that the Board adopt the FERC's updated SGIP.

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.

TASC believes it is appropriate to revisit the 15 percent screen standard discussed in rules 199 IAC 45.8(1)"a" and 45.9(1)"a" because that standard, in its current context, has become a barrier to DG deployment in other regions of the United States. After observing several years of robust DG industry growth in many regions of the country, FERC affirmed the need to re-examine the 15 percent screen established in its original SGIP. FERC reasoned that because generation penetration levels were causing projects to fail the 15 percent screen, that screen

[23] *Model Interconnection Procedures*. Interstate Renewable Energy Council, Inc. 2013. Available at http://www.irecusa.org/wp-content/uploads/2013-IREC-Interconnection-Model-Procedures.pdf.

should be reviewed to determine if revisions could be made to allow projects to continue to participate in the less costly and time-consuming Fast Track Process (rather than the Study Process), while maintaining system safety and reliability.[24] Indeed, FERC found that due to vast changes in DG markets in many regions, especially in the case of distributed solar, "the existing record does not support the finding that the [previous] SGIP and SGIA are unjust, unreasonable and unduly discriminatory."[25] In short, one of the primary reasons why FERC decided to update its SGIP is that the 15 percent screen, as initially adopted, had become a barrier to expanded DG deployment and increased energy supply in many regions of the country. TASC believes that it would be prudent for the Board to address and remove that barrier in this proceeding.

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?

FERC's updated SGIP did not modify the existing 15 percent screen or any existing Fast Track Process screens, and the language of the 15 percent screen[26] (which applies both to the 10 kW Inverter Process and Fast Track Process) in FERC's updated SGIP remains similar to the language of the 15 percent screen discussed in rules 199 IAC 45.8(1)"a" and 45.9(1)"a". Instead, FERC modified the supplemental review process following failure of any of the Fast Track Process screens to include three supplemental review screens. FERC noted that in regions of the United States where DG penetration levels are not high enough to cause DG systems to fail the 15 percent screen, transmission providers generally will continue to evaluate the penetration

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[24] Order No. 792, *Small Generator Interconnection Agreements and Procedures*, 145 FERC ¶ 61,159 at P 11 (Nov. 22, 2013).
[25] *Id.* at 40.
[26] See Section 2.2.1.2 of the Federal Energy Regulatory Commission's *pro forma* Small Generator Interconnection Procedures. Available at http://www.ferc.gov/industries/electric/indus-act/gi/small-gen/procedures.docx

level of generation based on the 15 percent screen.[27] However, FERC also noted that in regions of the country where the 15 percent screen has caused DG customers to fail the Fast Track Process screens (which also apply to the 10 kW Inverter Process), the revised supplemental review will offer an opportunity to continue to be evaluated under the Fast Track Process, thereby helping customers avoid delays and unnecessary project costs.[28]

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

Rather than considering a higher limit as a sole solution to address an issue that quickly evolved into a significant barrier elsewhere in the United States, TASC encourages the Board to embrace the broader applicable SGIP updates adopted by FERC, for the reasons discussed above. To reiterate, TASC believes the best course of action is for the Board to adopt FERC's revised SGIP, which embraces the current best practices for interconnection procedures from around the United States, having incorporating during a 21-month process period feedback from a broad array of stakeholders representing many interests, as well as specific policy improvements that have been adopted by individual U.S. states.

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.

Under both the updated FERC SGIP and IREC's Model Interconnection Procedures, the application fee for Level 1 DG systems is limited to $100. TASC generally supports that limit, but TASC also recommends waiving the application fee for Level 1 DG systems that will be net-

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[27] Order No. 792, *Small Generator Interconnection Agreements and Procedures*, 145 FERC ¶ 61,159 at P 18-19 (Nov. 22, 2013).
[28] Order No. 792, *Small Generator Interconnection Agreements and Procedures*, 145 FERC ¶ 61,159 at P 19 (Nov. 22, 2013).

metered. California and other U.S. states with strong DG markets have established a fee of $0 for net-metered systems.[29] TASC does not oppose a maximum application fee of $250 for Level 2 DG systems. However, to reiterate, TASC believes that it would be significantly more beneficial for the Board to adopt the revised FERC SGIP standards than solely to adjust application fees.

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.

Under both Federal law and Iowa law, a utility may not establish separate rate classes for DG customers, including net-metering customers, unless the utility can satisfy the heavy burden of showing through accurate utility data and the use of consistent statewide costing principles that discrimination is justified. That burden has not been met in Iowa. In the absence of a factual determination, a separate rate class for DG customers would be discriminatory. (Please see our full response to Question 16.)

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.

Utilities should not be authorized to require inverter-based DG systems to include an external disconnect switch. Two comprehensive studies funded by the U.S. Department of Energy[30,31] flatly concluded that for smaller, inverter-based systems, an external disconnect

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[29] *Model Interconnection Procedures* at P 9. Interstate Renewable Energy Council, Inc. 2013. Available at http://www.irecusa.org/wp-content/uploads/2013-IREC-Interconnection-Model-Procedures.pdf.

[30] *Utility External Disconnect Switch: Practical, Legal, and Technical Reasons to Eliminate the Requirement*. Prepared by Michael T. Sheehan, P.E., for the Interstate Renewable Energy Council, Inc. Published by Solar America Board for Codes and Standards Report (Solar ABCs), September 2008. Available at http://www.solarabcs.org/about/publications/reports/ued.

switch is unnecessary and that requirements for such switches should be eliminated. The Solar ABCs study[32] specifically found that: (1) the functionality of external disconnect switches is redundant; (2) external disconnect switches fail to provide the protection that allegedly justifies their installation; and (3) external disconnect switches add unnecessary costs to PV systems. The Solar ABCs study cites several reasons why an external disconnect switch is rarely ever used, including technical, jurisdictional and operational realities that utilities face.[33] For example, because the Occupation Safety and Health Administration ("OSHA") requires that utility line workers must always determine that a line is de-energized and attach grounding equipment before servicing a particular line, the presence of the external disconnect switch provides little additional protection for line workers.[34] Moreover, many utilities are reluctant to undertake the onerous documentation requirements necessary to record and update external disconnect switch locations on utility circuit maps.[35]

In fact, in recent years, several major electric utilities, including Pacific Gas & Electric and Sacramento Municipal Utility District (both in California), Consolidated Edison (in New York), and Florida Power & Light have voluntarily abandoned previous requirements for an external disconnect switch for smaller PV systems that meet applicable safety standards. Most states with advanced DG markets, including California, Colorado, Massachusetts, New Jersey

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[31] *Utility-Interconnected Photovoltaic Systems: Evaluating the Rationale for the Utility-Accessible External Disconnect Switch*. M.H. Coddington, R.M. Margolis, and J. Aabakken. Published by National Renewable Energy Laboratory, January 2008. Available at http://www.nrel.gov/docs/fy08osti/42675.pdf.

[32] *Utility External Disconnect Switch: Practical, Legal, and Technical Reasons to Eliminate the Requirement*. Prepared by Michael T. Sheehan, P.E., for the Interstate Renewable Energy Council, Inc. Published by Solar America Board for Codes and Standards Report (Solar ABCs), September 2008. Available at http://www.solarabcs.org/about/publications/reports/ued.

[33] *Id.* at 5-6.

[34] *Id.* at 3.

[35] *Id.* at 6.

and North Carolina, do not require an external disconnect switch for smaller, inverter-based systems.

Respectfully submitted this 24th day of October, 2014.

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