Industrial Energy Applications

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IOWA UTILITIES BOARD

NOI-2014-0001

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Iowa Utilities Board
1375 E. Court Ave
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Docket NOI-2014-0001: Response on Distributed Generation Comments

Thank you to the Iowa Utilities Board (IUB) for its continuing interests and for engaging relevant parties in the ongoing dialogue in distributed generation.

Attached are the responses from Industrial Energy Applications, Inc. (IEA), to questions posed by the IUB in this docket.

If there are any questions or comments regarding this matter, please do not hesitate to contact me.

Sincerely,

Randy Portz, President
Industrial Energy Applications, Inc.

Attachment 1

Industrial Energy Applications, Inc. (IEA) Response on

NOI-2014-0001: Distributed Generation

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

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

IEA supports an increase in the cap size and corresponding changes in utility tariffs needed. Larger caps lead to larger projects which lead to lower installed cost basis per kW, increasing the amount of capacity and energy produced, increasing the societal benefit of renewables and distributed generation in general.

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

IEA supports the “virtual net metering” concept. Such a program would promote growth in both distributed and renewable generation by encouraging participation in projects by more customers. Such a feeling of ownership would engender more interest in distributed and renewable energy. It would also enable local governments and non-profit organizations to participate in distributed and renewable energy by joining up with like-minded organizations.

These projects could be funded and operated by a number of different entities. The state’s existing investor owned utilities (IOUs) could offer such programs, as well as a number of private firms and even non-profit associations.

Inevitably, virtual net metering would lead to larger projects which would produce a lower per kW installed basis, decreasing reliance on large central generating stations and transmission systems, as well as displacing more fossil fuels; increasing the societal benefit.

Virtual net metering also supports better land use management. For example, using current PV solar technology, it takes ~2 acres of surface area to install 1 MW of capacity. Rather than use terrestrial mounted arrays, net metering allows the use of roofs of customers that have low intensity electrical energy operations (such as warehouses) and avoids the use of otherwise commercially or agriculturally viable land. Otherwise, the capacity available on the roofs may far exceed the customer’s electrical bills meaning the customer would not realize the benefits of the additional solar or would just install less solar and with less corresponding societal benefit. Utilizing net metering, other like-minded participants could pool their resources and make use of underutilized roof space.

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

IEA supports net metering of CHP and WHP projects, as well as considering the sharing of energy outputs by adjoining property owners, in a way that these exchanges do not constitute "energy sales". ADM and Red Star (located in Cedar Rapids) currently have such an arrangement, but changes in Iowa State Code and utility tariffs might be needed to "loosen" up the requirements so smaller projects (and perhaps projects which are not on adjacent properties, but are within distances to share thermal outputs) can benefit from these arrangements.

Such arrangements would lead to an increase in the number of CHP and WHP plants and plants of larger size and higher overall energy conversion efficiency. The increase in efficient leads to lower emissions from fossil fuel plants since energy conversion occurs locally (i.e., no electrical line losses) and at higher efficiencies (new technologies approach or exceed 40% efficiency exceeding those at 30-35% for older central utility plants) and the thermal outputs are captured and displace fuel otherwise combusted for steam, hot water, hot air, etc. The more fossil fuels displaced, the less reliance on central power plants and transmission systems and the larger the societal benefit.

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

IEA supports an annual cash-out of net metering balances, in the case where the customer has a net credit. Revisiting our example from virtual net meter discussion above, the warehouse would have ample incentive to optimize its roof mounted PV solar array and not just stop at the capacity needed to zero out its own electric bill. Here again, the more fossil fuels displaced, less reliance on central power plants and transmission systems and the larger the societal benefit.

Current avoided cost methodology allows for the payment to facilities that have excess generation under PURPA rules. Allowing annual cash out of the net metering balance would effectively extend the same methodology to DG customers.

Any payout should take into account the value of on peak vs. off peak production.

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

IEA supports metering aggregation for customer with more than one meter on the same property. Interstate Power and Light Company (IPL) already does this for some of its large industrial customers, but the same practice should be extended to all customers.

Questions for all participants:

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

Advantages are that it allows for a known rate for excess energy produced by distributed generation, without the need, expertise and expense to negotiate a separate purchase power agreement (PPA) with the local utility. Especially for CHP projects, there is often a mismatch between a customer's electrical and thermal energy needs. Many developers prefer to size the CHP plant around the thermal needs of the customer and let the electrical load float on the local utility. When those demands are close together, this is a good strategy. However, when the thermal need is significantly greater than the corresponding electrical demand, the customer will have produced more electricity than it consumes, so the feed-in tariff allows for an alternative to net metering and the annual balance buy-outs. If the customer is forced to live within its electrical demands, it will construct a smaller CHP plant, meaning more of the thermal energy won't result from waste heat; rather, from direct combustion of fuels, lowering the overall efficiently of the project resulting in less fossil fuels displaced, more reliance on central power plants and transmission systems and less societal benefit.

The disadvantages are that the utility will have to purchase more power that will be harder to schedule, since it won't always know how many plants will be on-line and producing as it does its day ahead power purchasing and periodic resource planning. However, this can be overcome with planning, customer interface and real-time production data; the aggregate effect of the matter suggesting that while outputs from individual distributed generation projects might vary, the aggregate will likely vary in predictable ways (solar, due to time of day and change of seasons, the same for wind and with other base load distributed generation more so on plant outages or prime mover trips, which in aggregate, will have little total impact).

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

While the IOUs can rightly argue that allowing for a kWh for kWh exchange at retail rates, negates their price recovery strategies for fixed costs it attempts to recover on each kWh sold, it is also correspondingly true that DG customers do not receive "avoided cost" or capacity credits for central plants and transmission capacity which are not needed or delayed in construction.

Similarly, DG customers are not the sole recipients of the societal benefits that come from renewable electrical energy production or higher efficiencies, lower overall energy consumption and lower fossil fuel consumption yielded by other forms of DG and CHP. The bottom line is there are many layers to the cross-subsidization going on in a DG strategy. You can either calculate them all which can get very complex and difficult to regulate or you can rely on net metering as fair and balanced for all.

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

For a solar system, non-DG customers receive a benefit since their utility does not have to purchase as much capacity during the summer peaking hours, when such capacity is very expensive. The DG customer does not really receive any monetary benefit by helping to reduce the utility's peak capacity, and perhaps should. However, quantifying this benefit would be very difficult. Therefore, we feel the current net metering rules are sufficient. If any change should be made, it would be to allow for a "cash out" for the DG customer in the event there is a net benefit to the DG customer. In order to simplify billing, this could be done on an annual "true-up" basis.

Questions for electric utility customers:

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

a. Type and size of your DG facility;

Solar photovoltaic panels. Approximately 3 KW nameplate rating.

b. Your electric service provider; and

Interstate Power and Light Company (IPL).

c. Positive and negative experiences with net metering.

The experience is generally positive. Because of the type of metering used by the electric service provider, it is difficult to determine at any point in time, how much energy is actually being generated into the utility.

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

The relative advantage and disadvantages of net metering have been discussed previously.

IEA supports a loosening up of the net meter rules to enable more DG projects; however, there will inevitably be conflicts between customers and utilities. Currently, there is no simple way to adjudicate these disputes. If the Utility desires to impose burdensome technical requirements, there is no way for the potential customer to appeal. While generally not a serious issue with smaller systems, larger potential DG system installations could generate such disputes. An unbiased third party appeal mechanism needs to be established that can mediate these disputes in a timely manner without making it a Board or legal matter.

With respect to interconnection, the Board has the following questions for all participants:

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

Current interconnection rules are adequate to provide safe installation and operation of DG systems for both customer and utility personnel. Current interconnection rules and other state rules require sign-off by an electrician licensed by the State of Iowa. The licensing requirement for these electricians is rigorous. No electrician is going to risk their license by performing a substandard installation. Local municipalities have inspection jurisdiction over these installations and state inspectors have jurisdiction over other locations. In addition, the local utility performs an inspection before the system is energized. The combination of using licensed electricians and state or local electrical inspectors is adequate.

To our knowledge there has been no documented evidence of substandard installations. If there were, it would mean that the non-conformances were missed by both the electrical inspector and the utility during its inspection. This is a very unlikely occurrence.

However, it is also appropriate to raise concerns that interconnection agreements have become onerous in their sheer volume of requirements and often to the point when many utilities do not fully understand their own agreements or what they are trying to protect. As a result, they are very reluctant to consider changes and the process can take months or in some cases over a year to get an agreement in place. These timeframes do not foster the growth of DG within the State of Iowa. Additionally, many of the requirements in the interconnection agreements are aimed at the larger installations, such as large wind farms, and not applicable for smaller DG installations.

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

Current interconnection rules are adequate to provide safe operation of DG systems operated in parallel with the utility distribution system. We have previously addressed the personnel safety issues above. To our knowledge there are few if any documented examples of system reliability impacts caused by DG operation in the State of Iowa. In most cases, this is because the interconnect agreements are effective in establishing appropriate protective device settings for DG electrical output and DG sources are so small relative to the capacity of the utility distribution (and transmission system) that they can have little more than localized (substation level) impacts before either the DG output breaker's own protective relaying package or the local utilities protective schemes would isolate the impact.

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

Firstly, DG needs to be defined because it would not be appropriate for a 300 MW project and a 3kW project to have the same interconnect cost structure. Secondarily, utilities have no incremental costs for negotiating an interconnect agreement, so DG customers should not be obligated to pay fees associated with obtaining the interconnect agreement. As it relates to the physical interconnection, the charges should be based on the actual expenses (both labor and materials) incurred by the utility to facilitate the interconnection.

The fee structure for DG interconnection should not depend on the technology.

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

It depends on how you define the cut-off for DG. A 300 MW peaking plant requiring 10 miles of transmission should not receive the same consideration as a smaller DG installation or CHP plant. Where the benefits are confined to a DG system, those benefits are felt across the utility foot print, in terms of renewable electrical energy production or higher efficiencies, lower overall energy consumption and lower fossil fuel consumption and avoided or delayed central power plants or transmission or distribution system upgrades. Where the upgrades are very localized, to a substation at the customer's site, those charges should be treated as "excess facility charges". However, where they are remote, they should be treated as costs of serving all customers and factored into rates borne by all customers.

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

Existing protection is adequate for both personnel and grid safety; see prior comments from above.

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

FERC's jurisdiction is transmission voltages, and Order 792 applies to interconnections with the transmission system. For the most part, DG projects are going to be interconnected at the distribution level, where Order 792 would not apply.

199 IAC 45 governs the electric interconnection of DG facilities and is based heavily on IEEE 1547, Standard for Interconnecting Distributed Resources with Electric Power Systems, and its companion Application Guide for IEEE Standard 1547.

IEEE 1547 is a consensus standard developed by a cross section of industrial users, academics, regulatory members and public citizens. It has been in place for over ten years and is quite adequate to govern the installation of DG systems for the foreseeable future. To attempt to "meld together" two sets of rules, where each have divergent uses, would be counterproductive at the current time.

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

Compare a DG installation to the installation of a utility scale generating plant. The utility demonstrates the need for the plant, and is awarded "rate making principals" which allows the utility to receive a guaranteed rate of return for a specified period of time. It is this guarantee which allows the utility to secure financing to build the plant.

A DG installation could be considered in much the same way. The DG owner needs certainty that they are going to be able to monetize the facility over a number of years. Without this, the DG owner will not be able to receive financing. Even if self-financed, the DG owner needs the certainty so as to determine whether to invest in the DG facility or pursue some other investment.

If a DG system owner is going to be required to remain interconnected for a specific period of time, then the DG owner needs to be rewarded with certainty as to the economics of the installation, similar to a power purchase agreement (PPA) or a grandfathered rate on a feed in tariff. This is the only way these projects will ever be financed. To propose requiring a long term interconnection without a long term economic assurance is only an attempt to throw up additional roadblocks to DG projects so as to assure that they do not succeed.

If the concern is cross-subsidization by other utility customers for projects which fall short of their predicted life and who gets left “holding the bag” on excess or stranded assets, one must consider the alternative argument i.e., is there an extra credit for those projects which live on beyond their projected life? If not, fairness dictates you cannot have it both ways. If you want to promote DG in Iowa, you will have to create a solid economic and financing basis and secondly, acknowledge and accept there may be some failures. These same concepts apply to utility projects, when not all of them are “home runs”. IOUs still recover their costs and expected returns and are allowed “another turn at bat”. In any portfolio of projects there will be hits and misses, but the performance of the overall portfolio is what matters, not necessarily the individual projects.

a. Does the interconnection process timeline take longer than necessary? If so, what are
the problems and how can they be solved?

It depends. For small straight forward projects such as a simple solar array, they should be approved in a matter of days not weeks. For larger DG projects it should take only a few weeks not months to get a standard agreement. Admittedly agreements involving negotiations take longer.

Problems often stem from the technical resources deployed by utilities. Often they are not up to understanding and unable to accept reasonable alternatives, particularly when it comes to protective relaying devices and setpoints. We know of an example where a customer bought full paralleling switchgear and ultimately had to accept “closed transition” operation because the utility could not specify what was needed in terms of relay settings. In this case, the customer had no appeal process to resolve the issues (See answer to question 10 above). The net effect was a process lasting over a year and the customer spending tens of thousands of dollars with no benefit and reducing the overall reliability of their DG scheme. So utilities need more knowledgeable, better trained technical resources to support the interconnection process.

With respect to consumer protection and education, the Board has the following questions for all participants:

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

Yes, but IEA believes this should be left to the market place; while, the Board should limit its role to enabling DG.

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

Here again, this would be better be served by market place participants, with the Board limiting its role to that of an enabler.

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

First and foremost, firefighters and first responders are ultimately responsible for their own safety. This isn't meant to shirk responsibility, merely a recognition that safety starts with those with a vested interest. Secondarily, a system of hazard identification, reporting, placarding and record retention on the part of fire departments is essential in alerting firefighters to any hazard on customer premises for legitimate purposes. Lastly, customers have to provide information via timely reporting.

The existing hazardous material policies are an effective, time tested model for these processes.

a. Should customers be required to provide local fire officials information regarding their solar installations?

Yes, no different than filling out the hazardous material inventory and appropriately placarding and posting required for them.

b. Should fire officials be required or encouraged to maintain detailed logs regarding solar installations in their community or fire district?

Yes, adopting a similar means as for hazardous materials.

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

It depends. If complaints are commercial in nature, they should be directed to the Attorney General. If complaints relate to tariffs, interconnection, etc. then they should be directed to the IUB or entity with IUB oversight.

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

From a safety standpoint, the current interconnection rules and other state rules require sign-off by an electrician licensed by the State of Iowa. The licensing requirement for these electricians is rigorous. No electrician is going to risk their license by performing a substandard installation. In addition, local municipalities have inspection jurisdiction over these installations and state inspectors have jurisdiction over other locations.

In addition, the local utility performs an inspection before the system is energized. The combination of using licensed electricians and state or local electrical inspectors is adequate.

Additional bureaucracy in the form of additional licensing/certifications is not needed. There are plenty of protections for the consumer in the form of state and local regulations. A supplier/installer is incented to do a good job of installation by the future word-of-mouth advertising that they will receive (good or bad).

While some may be looking for exclusive rights to be the "installer of choice", State certifications are not needed. This is more of a market place issue, since safety and reliability are not of concern.

Questions for all participants

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

Iowa's goal should be to foster diversity, flexibility, environmental impact reduction and cost competitiveness on a going forward basis. To this extent competition and a mixture of all participants in a more open market benefits all class of customers. This is not to suggest that investor own utilities (IOUs) cannot and should not play a role.

A more open market lessens the utility monopoly on generation and may invite in independent power producers. If this isn't the Board's intention, then specific language to exclude these entities from the market would need to be addressed. If the market is "too wide open" it might undercut the benefits of DG. Also a "too wide open" market may undercut the long-term financial viability of the IOUs.

A more wide-open market would help foster DG adoption and its corresponding financial, environmental and societal benefits enumerated in prior responses.

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

Historically, utilities grew from a background in DG. Many started as small companies with a single power plant feeding a large town or city. As they grew, they merged with neighbors or assimilated their territory and power plants. In time, utilities recognized central power generation as more cost effective, efficient and easier to control and opted for this model of electrical generation. As time has passed and technologies have changed, a melding of both strategies is proving viable and desirable.

Utilities are neither incentivized nor dis-incentivized to pursue DG as an investment strategy. Understandably utilities do not foster DG incentives for their customers, as it represents an erosion of their customer base. Asking utilities to foster DG puts them in the same quandary as asking them to foster energy efficiency programs. While they may be in a good position in the market place to do so they are being asked to work at cross purposes and serve two masters. As a result, tax incentives are a better means of transferring benefits to DG adopters.
Peak demand is certainly one of, but not the only viable target for DG. CHP can help reduce base load projects. DG and CHP can both assist with grid stabilization and voltage support, particularly as utilities close down smaller coal plants and combustion turbine peaking plants.