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VIA FIRST CLASS U.S. MAIL AND EMAIL

Beth E. Heline
General Counsel
Indiana Utility Regulatory Commission
PNC Center
101 W. Washington Street
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Indianapolis, IN 46204

Re: Comments of the Midwest Cogeneration Association
GAO 2017-3 –Commission Inquiry on Indiana Utilities Back-Up, Maintenance, and Supplemental Power Rates

Dear Ms. Heline:

The Midwest Cogeneration Association ("MCA") appreciates the opportunity to provide comments in this proceeding. MCA is a not-profit trade association dedicated to promoting clean and energy efficient cogeneration technologies -- Combined Heat and Power (CHP) and Waste Heat-to-Power (WHP) (collectively referred to herein as "cogeneration" or "CHP") in eight Midwest states, including Indiana. MCA members include representatives of CHP technology manufacturers, distributors, and project developers, as well as owners and operators of CHP systems – many of whom have business operations in Indiana. MCA members have expertise in CHP and WHP technologies, as well as project financing and development.

Why Standby Rates Matter For CHP Projects

MCA Members across the Midwest, including Members doing business in Indiana, report poorly designed back-up, maintenance and supplemental power tariffs ("standby tariffs") are the *number one reason* otherwise economically viable CHP projects are not built in the Midwest. They are faced with complicated, opaque and incomplete tariffs which impose fixed charges, ratchets, and punitive rates that result in overall monthly fees that are greatly in excess of standard tariffs on a *per rata* demand basis. Individual company negotiations with their utilities often result in frustration. After such discussions, CHP projects, which would otherwise "pencil out" financially and benefit both the customer and the utility's other ratepayers, are often shelved.

MCA's Midwest Standby Rate Initiative

Over the past four years, MCA has reviewed and commented on utility standby tariffs in utility rate cases and generic proceedings before utility commissions in Minnesota, Michigan, Missouri, Iowa and Ohio. In the course of this work, we have advocated for cost-based, fair and transparent standby tariffs; compared the charges experienced by standby customers under various utilities' standby tariffs; and created a Conceptual Model Standby Tariff as a guide to implementing best practices in a standby tariff.

In the course of this work, MCA has worked with 5 Lakes Energy, LLC, a Michigan-based energy consulting firm, to analyze standby tariffs in Michigan, Minnesota and Ohio. While MCA and 5 Lakes Energy have not yet had time to complete our analyses of the Indiana utilities' standby tariff charges and confirm our interpretation with the utilities, we plan to do so in the near future and will submit our findings to the Commission. Our preliminary analyses indicates that NIPSCO's Rider 776 – applicable to large industrial customers only - stands out as a model reflecting proportional charges and other best practices. On the other hand, Vectren's and Indianapolis Power & Light's standby tariffs result in charges that are many times higher than NIPSCO's 776 Rider and are among the highest standby charges we have seen in our analyses of utility standby tariffs in four Midwest states. Indiana Michigan Power, Duke Energy, and Indiana Municipal Power Agency have no standby tariffs, which presents a problem of transparency and makes it more difficult for cogeneration developers to independently "pencil out" projects. This also makes it impossible for the customer, MCA or the Commission itself to determine if these utilities' "special contract" terms are fair and non-discriminatory or, instead, are unjustly hindering deployment of cogeneration in Indiana.

General Comments

A. Improper Cost Allocation and Over-Charging for Demand

Standby rates should be designed to recover the fully allocated embedded costs that a utility incurs to provide backup and maintenance service. However, MCA has found that standby tariffs are generally not cost-based, often rely on inaccurate assumptions about the reliability of CHP systems, and are just poorly designed. As a result, standby tariffs often significantly over-charge standby customers and send the wrong price signal for efficient use of grid resources. Unfortunately, that is the case with the standby tariffs submitted by several of the Indiana utilities in this proceeding. Further, because three of the Indiana utilities responded that they do not have standby tariffs, but only provide standby service on a special contract basis, we don't know how they charge or would charge standby customers.

IP&L and Vectren have expressly stated they have allocated costs and designed their standby tariffs on the assumption that they require grid back-up every day of the year and impose fixed (kW) reservation fees and demand charges to collect the same revenue from these partial use customers as they do from full-time use customers.

The Commission must ask: Why would any business invest millions of dollars to generate its own electricity, taking substantial load off the grid and freeing up utility generation, transmission and delivery infrastructure for other ratepayers, when it is required to pay utility demand charges as though it never generated a kilowatt of its own energy? The short answer is: They won't. Not surprisingly, it is difficult to persuade your management and lenders to invest in self-generation when the utility will keep charging you as though you were using utility generation.

The assumption that standby customers impose the same load on utility generation, transmission and distribution resources as do full-time use customer has been rejected by numerous studies, public utility commissions, and utilities themselves. Here, IP&L, and Vectren have not supported their assumptions and disproportionately high tariffs with valid cost of service studies ("COSS") actually reflecting standby customer use. Further, their assumption that they are required to reserve capacity for standby customers at all times is not correlated with how CHP systems operate or their demonstrated reliability of > 95%. Notably, many CHP system manufactures offer guarantees of a minimum 95% operational reliability (i.e., less than a < 5% forced outage rate). Further, a 2004 U.S. Department of Energy's Oak Ridge National Lab commissioned study of over 120 cogeneration systems, of all types, documented that the actual average forced outage rates for these systems is 2-3%. [1] Finally, the assumption that cogeneration systems within a utility's territory could all require utility standby service at the same time is prohibited by the federal Public Utility Regulatory Policies Act, 18 C.F.R. 292.305(a)(1)(ii).

B. Examples of Proportional Standby Charges

In Michigan, where state law requires cost-based utility tariffs, the Public Service Commission just completed rate cases for Consumers Energy Company and DTE Electric Company. *PSC Case Nos. U-18322 and U-18255* Although neither of those utilities' standby tariffs used the glaring "100% of full-time use" assumption that IP&L and Vectren have admitted to using here, the PSC nonetheless found that Consumers' and DTE's own data demonstrated that they had been overcharging standby customers for demand based on documented historic standby customer use. In the Consumers' rate case, No U-18322, the PSC ordered that Consumers provide a cost of service study using "actual and projected peak metered demand billing determinants for [its standby tariff] customers, including any ratchet that would be applied. In addition, if the company chooses to rely on contracted demand, Consumers shall provide justification for its departure from the standardized framework." See *PSC Order, March 30, 2018, Case No. 18322, p p. 113-114.*

In the DTE rate case, the PSC ordered that in the absence of a valid COSS for the standby class, DTE's reservation fee for standby customers should be reduced to 5% of that of the base tariff full-time use customer charge (based on the 5% outage rate of CHP systems) and

[1] *See* Energy and Environmental Analysis, Inc., Final Report: Distributed Generation Operational Reliability and Availability Database (January 2004), prepared for Oakridge National Laboratory, available at https://www.energy.gov/sites/prod/files/2013/11/f4/dg_operational_final_report.pdf

its demand charges should be reduced to 1/10th of the base tariff demand charge for unscheduled standby use and 1/20th of the base tariff demand charge for scheduled standby use. See *PSC Order, April 18, 2018, Case No.U-18255, pp. 76-77.*

Here in Indiana, the Commission has a model of a proportional standby tariff in NIPSCO's Rider 776 which charges a *daily*, rather than fixed, demand charge based on standby use during peak hours. In Minnesota, Xcel Energy Company's standby use demand charges are even more closely proportionate to actual standby use and utility costs because they are based on the actual *hours* of use of standby (kWh) and apply only during peak hours. In a recent Minnesota Public Utility Commission docket examining four utilities' standby tariffs (Docket No. E999/CI-15-115), the MN PUC also recently approved a negotiated settlement reducing Xcel Energy's standby reservation fee to reflect the 5% outage rate of CHP systems. *PUC Order, April 5, 2018, Docket No. E999/CI-15-115.*

In another example of proportionate charges, Minnesota Power Company's standby tariff reservation fee is based on the standby customer's actual outage rate after the first year of operation and is adjusted annually – providing a clear price signal for minimizing outages. In contrast, fixed reservation fees and demand charges that don't reflect a customer's actual standby usage or that ratchet maximum usage in one month over the next eleven months send the wrong price signal to standby customers for efficient use of grid resources and optimization of CHP systems. Why try to minimize use of the utilities' resources if you are paying for it anyway?

C. Best Practices for Standby Rates

Well-crafted standby tariffs can promote economic and energy efficiency as well as system reliability. They are characterized by fairness, simplicity, and transparency, imposing costs on the partial use CHP customer that are proportional to the costs it imposes on the utility.

MCA attaches here its Conceptual Model Standby Tariff (*Attachment A*) which MCA created to reflect the best practice principles for standby tariffs discussed by the Regulatory Assistance Project ("RAP") in its 2014 study prepared for the U.S. Department of Energy "Standby Rates for Combined Heat and Power Systems Economic Analysis and Recommendations for Five States."[2] MCA believes that well-designed, energy efficient, and cost neutral tariffs:

1. Reward customers for optimizing their CHP systems to use grid backup service as little as possible by applying variable demand charges, rather than fixed or ratcheted, reservation or demand charges, as well as variable energy charges that reflect the proportion of time the customer actually uses grid back-up energy and infrastructure;

[2] http://www.consultbai.com/images/stories/News/standbyrates_256206.pdf ; Also see, RAP 2006 presentation to the Commission on standby rate use and best practices: http://www.raponline.org/wp-content/uploads/2016/05/rap-lazar-distributiongeneration-2006-04-13.pdf

2. Encourage customers to maintain CHP systems and thereby minimize unplanned “forced outages” by providing lower reservation/demand charges for pre-planned maintenance that can be scheduled for off-peak hours and/or during low demand seasons;

3. Reward customers who can shift load to minimize use of back-up service during peak hours by providing rates that differentiate between peak and non-peak time of use; and

4. Fairly reflect the utilities actual time-of-use energy costs, rather than apply punitive higher rates.

Comments on the Individual Indiana Utility Tariffs

A. NIPSCO

● Negotiated Rider 776 for Large Industrial Customers Reflects Many Best Practices

Best Practices

1. No duplicative reservation fees. It appears NIPSCO is recovering it infrastructure costs in a single proportionate demand charge, rather than both a demand charge and a fixed reservation fee.
2. NIPSCO Rider 776 charges a *daily* demand charge for backup power based on the rate in the underlying base tariff. In other words, standby demand charges are prorated from the base tariff based on the actual number of days that standby service is taken. This is a fair approximation of the costs imposed on the utility and a proportional approach.
3. NIPSCO’s demand charges for maintenance in winter and shoulder months are low - $0.45/kW/day and $0.25/kW/day. This reflects the utility’s excess capacity in those months.
4. NIPSCO customers can contract for Temporary Service in addition to Backup and Maintenance. Temporary service allows a temporary increase in load without setting a new base tariff billing peak. This allows flexibility in the customer’s operation and may even provide an ancillary benefit to the utility.
5. Demand charges are low for temporary service and they increase as customer takes more service (range $0.59 -$2.36). This is a best practice sending a price signal for minimizing use of grid resources.
6. NIPSCO customers can “buy through” on the wholesale market if the company denies “temporary service” and incur no demand charge. This is a fair approach.
7. For Backup service, NIPSCO rider 776 customers pay the Real time LMP energy charge plus a small surcharge (kWh). For Maintenance and Temporary service, they are charged the base tariff energy rate. This is a fair approach.

Areas for Improvement

1. It appears that NIPSCO's demand charges in the underlying tariff Rate 732 are ratcheted over 12 months. This results in higher charges under Rider 776 than are warranted by utility costs.
2. Maintenance should be allowed in the summer months (June- Sept) as well. Providing lower costs for maintenance year round minimizes forced outages.
3. NIPSCO's definition of peak and off-peak hours in underlying Rate 732 is ambiguous and appears to require that a minimum of 11 hours be considered "peak" on Monday through Friday. This is an unusually long "peak" period.
4. NIPSCO's rider 776 is limited by Rate 732 to customers with a minimum of 15 MW of base tariff demand and by Rate 733 to customers with a high load factor. NIPSCO should provide similar standby service for smaller industrial and commercial customers (<15 MW base tariff contract) operating under different base tariffs.

B. Indianapolis Power and Light (IP&L)

● **No "Cost of Service Level of Documentation" Provided; Instead Improper Cost Assumptions:** IP&L's response provides no "cost of service" data or analysis and instead expressly states that it is allocating costs to standby customers as though they were full-time customers, the faulty assumption that is prohibited by PURPA and widely disproven. IP&L states "… the current rate structure [for commercial and industrial customers] assumes that the cost incurred by the Company to provide backup, maintenance and supplementary power is equivalent to the cost incurred by the Company to provide service to service to a full-requirements customer." Response p. 2; In Rider No. 10 (Back-up service), IP&L again justifies its high rates on this same faulty assumption, saying: "The Company continues to carry the fixed costs of capacity on a year-round basis so that it can stand ready to serve customers who want backup service. As a result, the cost incurred to serve customers who qualify for backup service is similar to that for a standard full-requirements customer. The customers receiving backup service should be charged the fully-allocated cost based rates associated with the applicable rate class tariff."(Response, p. 3)

● **12-month Demand Ratchet:** IP&L commercial and industrial customers are required to pay monthly demand charges based on the highest "peak total demand" set in the 11 prior months for both scheduled and unscheduled standby service. Ratcheted charges such as these are widely acknowledged to be unjustified and counter-productive. Ratcheting of charges is punitive, not cost-based, and sends the wrong price signal for efficient use of grid resources.

● **Capacity Credit for Scheduled Maintenance:** In Rider No. 11 (Scheduled Maintenance), IP&L differentiates scheduled service from unscheduled service and provides a Capacity Credit for Scheduled Maintenance depending on the service elected. This is a best practice encouraging planned maintenance and minimizing forced outages.

But, this credit is applied to a demand charge based on maximum demand ratcheted over a 12-month period. No cost basis is provided for charging a ratcheted maximum demand charge for service during company pre-approved and scheduled periods.

C. Vectren

● No "Cost of Service Level of Documentation" Provided; Instead Improper Cost Assumptions:

Vectren states " …A customer electing Firm Generation service under Rate BAMP requires Vectren to maintain generation capacity to serve the customer's load at all points." Response, p. 2. Again, this is an impermissible assumption, rather than the cost of service documentation for standby customers that the Commission requested. Based on the data provided it appears that a *firm* standby customer is paying 84% of what a full-time customer pays; not the 38% shown by Vectren which is for *non-firm* standby. Non-firm service is of little value to most standby customers who seek standby as a back-up to support critical non-interruptible business operations. As discussed above, studies and manufacturers' warranties demonstrate that cogeneration customers should be paying no more than 5% of the full-time use rate.

● Distribution and Transmission is priced at 100% of contract capacity at the same rates as full-time customers:

Distribution and Transmission service is priced at the same fixed rate as full-time customers based on fixed contract capacity. See comment above.

● Capacity is charged at 120% of capacity component of the current Rate CSP

Vectren states"Firm generation is priced with a capacity charge related to the Cogeneration and Small Power Production rate…" (Response, p. 2); however, the tariff indicates Backup power is charged at 120% of the capacity component of the current Rate CSP and that this is a fixed monthly charge based on contract capacity rather than actual use.

D. Indiana Michigan Power Company (I&M) and Duke Energy

● Standby Power Available Only By Special Contract: I & M have no standby tariff or rider for cogeneration standby customers with cogeneration systems of 100kW or greater. This lack of transparency discourages standby projects and makes it impossible to evaluate whether contracted rates are non-discriminatory. Alternatively, taking service for standby under a full-service tariff results in extremely high rates based on the inherent assumption of full-time use which is reflected in charges based on fixed contract capacity rather than actual use of grid resources.

E. Duke Energy

● **Standby Power Available Only By Special Contract:** Duke states that it has no standby tariff, and will provide standby service only by special contract. This lack of transparency discourages standby projects and makes it impossible to evaluate whether contracted rates are non-discriminatory. Alternatively, taking service for standby under a full-service tariff results in extremely high rates based on the inherent assumption of full-time use.

F. Indiana Municipal Power Agency

● **Standby Power Available Only By Special Contract:** IMPA states that it has no retail sales and its only member community with a potentially applicable tariff has said it would provide standby power only by special contract. As noted above, this lack of transparency discourages standby projects and makes it impossible to evaluate whether contracted rates are non-discriminatory. Alternatively, taking service for standby under a full-service tariff results in extremely high rates based on the inherent assumption of full-time use.

Recommendations for Further Proceedings

The Commission's inquiry has generated important information and shed light on deficiencies in all six Indiana utilities' tariffs as to how they address – or don't address – the special concerns of standby customers. This is a good start, but a more in depth review of these utilities tariffs has been shown to be necessary to achieve fair, cost-based standby tariffs. Based on our experience in Michigan and Minnesota, MCA recommends that the IURC Report on this process make the following recommendations for continuing this review:

1) The subject of Indiana utility standby rates and their impact on the deployment of cost and energy efficient cogeneration in Indiana should be taken up in a Legislative Summer Study Committee; and

2) The formation of an Commission-led stakeholder working group to discuss standby tariff issues and practices, culminating in an Commission Report with recommendations for standby rate tariff reforms, if any, that the Commission finds are needed.

MCA appreciates the opportunity to present these comments and looks forward to continuing engagement of this topic with the Commission and other stakeholders.

Respectfully submitted,

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