Apples-to-Apples:

Comparing Customer Standby Charges for Improved Rate Design

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Introduction

Interest in cogeneration or combined heat and power (CHP)[1] is growing quickly across the Midwest. As a result, utility policies that impact cogeneration customers, including standby rates, are getting a fresh look. The Minnesota Public Utilities Commission (MN PUC) is on the leading edge of this discussion. In November 2015, after more than a year of stakeholder engagement facilitated by the Minnesota Department of Commerce,[2] the MN PUC requested that Minnesota's four rate-regulated utilities file individual proposals for updated standby service tariffs reflecting comments and discussion around best practices.[3] Comments were filed by a number of interested stakeholders, including the Midwest Cogeneration Association,[4] an organization that has been a leading advocate on this issue through its Midwest Standby Rates Initiative. On October 3, 2017 and April 5, 2018, the MN PUC approved revised standby tariffs that reflect the initial results from this process. Utilities, regulators and stakeholders alike recognized that the process had led to notable improvements over the original standby rate submissions.

In Michigan, the Public Service Commission staff has been similarly concerned about standby rates and the need to ensure that these rates are designed well. From 2016 to 2017, its Standby Rate Working Group seized an "opportune time to determine whether the current standby service tariffs reflect the cost of serving self-generation customers with CHP or solar and address concerns of the self-generation community."[5] The final report from this effort featured recommendations ranging from ways in which the utilities can improve the transparency of their standby tariffs to ways to better incent efficient use of system resources.[6]

In Ohio, utilities AEP Ohio and Dayton Power & Light boast CHP incentive programs developed with the goal of increasing deployment of CHP. This creates a particular interest in understanding the interplay between utility incentives and unintended barriers faced by customers interested in installing CHP systems. In March 2018, the Public Utilities Commission of Ohio (PUCO) held Phase 3 of its PowerForward Initiative, which featured CHP standby rates on a rate design panel.[7] It is clear from discussions with Ohio end-users and analysis of Ohio utility standby rates that charges for standby service pose a potentially significant barrier to the deployment of CHP. The need for further engagement in Ohio continues.

The Indiana Utility Regulatory Commission is also investigating standby rates through its recently initiated Backup, Maintenance, and Supplemental Power Rate Review per Indiana Code 8-1-2.4-4(h).[8] This review aims to examine utility standby rates with an eye toward identifying "the extent to which the rates are cost-based, nondiscriminatory, and do not result in the subsidization of costs within or among customer classes."[9]

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[1] Cogeneration or CHP is "an energy efficient technology that generates electricity and captures the heat that would otherwise be wasted to provide useful thermal energy—such as steam or hot water—that can be used for space heating, cooling, domestic hot water and industrial processes." U.S. EPA CHP Partnership, What is CHP?, *available at* https://www.epa.gov/chp/what-chp

[2] See Minnesota Department of Commerce, Standby Rates: Scoping for Generic Proceeding *available at* https://mn.gov/commerce/industries/energy/distributed-energy/standby-rates.jsp

[3] See Minnesota PUC Docket No. CI-15-115 *available at* https://mn.gov/puc/

[4] Midwest Cogeneration Association website *available at* http://www.cogeneration.org/

[5] MPSC Staff Standby Rate Working Group Report (August 19, 2016), p. 2, *available at* https://mi-psc.force.com/s/filing/a00t0000005pVNCAA2/u177350392

[6] MPSC Staff Standby Rate Working Group Supplemental Report (June 2017), *available at* http://www.michigan.gov/documents/mpsc/SRWG_Supplemental_2017_Report_576352_7.pdf Public Utilities Commission of Ohio (PUCO) PowerForward, Phase 3: Ratemaking and Regulation,

[7] Public Utilities Commission of Ohio (PUCO) PowerForward, Phase 3: Ratemaking and Regulation, *available at* https://www.puco.ohio.gov/industry-information/industry-topics/powerforward/phase-3-ratemaking-and-regulation/

[8] Indiana Utility Regulatory Commission, Backup, Maintenance, and Supplemental Power Rate Review, *available at* http://in.gov/iurc/2954.htm

[9] Ibid.

In addition to the above activity, there has been a collaborative effort ongoing in Missouri around Ameren's standby tariff, in which the Missouri Department of Economic Development is attempting to better align standby rates with the unique characteristics of standby customers as a class.[10] There is also a Public Sector Combined Heat and Power Pilot Program active in Illinois,[11] and a standby rate discussion is being incorporated into the NextGrid effort, in the Illinois Utility of the Future Study.[12]

As interest in CHP grows across the Midwest and states explore ways to remove barriers or encourage its deployment, there is a recognition that any serious effort to promote CHP must be done in the context of a fair, cost-based approach to standby rate design. When standby rates are too high, inflexible, unpredictable, or simply too difficult for customers to navigate, these extra costs imposed on a customer mean that the economics of a CHP system will fail to provide the needed return on investment, and a potential project will not pencil out.

Opportunities for Improved Rate Design

Standby rates are a type of electric utility tariff charged to customers with on-site distributed generation such as CHP systems. The rates are intended to help the utility recover costs related to being ready to provide electricity during scheduled and unscheduled outages of the customer's CHP system.

In order to be considered reasonable and prudent, standby rate structures should follow the accepted guidelines of utility rate design. James C. Bonbright, the renowned utilities scholar whose principles have guided utility regulation and rate design since the 1960's, highlighted the following three primary objectives of sound rate design:

(a) Effectiveness in meeting the utility's revenue requirement;
(b) Fairness of the specific rates in the apportionment of total costs of services among the different consumers; and
(c) Encouraging optimum-use of utility services.[13]

Experts at the Regulatory Assistance Project (RAP) offer rate design recommendations[14] tailored to standby rates, and it is easy to trace their roots to Bonbright's objectives:

- Generation reservation demand charges[15] should be based on the utility's cost and the forced outage rate of customers' generators on the utility's system (i.e., fair apportionment);
- Standby rate design should not assume that all forced outages of on-site generators occur simultaneously, or at the time of the utility system peak (i.e., fair apportionment);
- Transmission and higher-voltage distribution demand charges should be designed in a manner that recognizes load diversity (i.e., fair apportionment);
- Standby rate design should assume that maintenance outages of on-site generators would be coordinated with the utility and scheduled during periods when system generation requirements are low (i.e., fair apportionment and optimum-use);

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[10] Missouri Public Utilities Commission, Case No. ER-2016-0179, rebuttal testimony of Jane Epperson of the Missouri Department of Economic Development filed January 24, 2017.

[11] Illinois Department of Commerce and Economic Opportunity, Public Sector Combined Heat and Power (CHP) Pilot Program, *available at* https://www.illinois.gov/dceo/whyillinois/TargetIndustries/Energy/Pages/CHPprogram.aspx

[12] NextGrid Illinois website available at https://nextgrid.illinois.gov/about.html

[13] Bonbright, J.C., Principles of Public Utility Rates (October 1960), *available at* http://www.raponline.org/wp-content/uploads/2016/05/powellgoldstein-bonbright-principlesofpublicutilityrates-1960-10-10.pdf

[14] Brubaker & Associates, Inc. and Regulatory Assistance Project, Standby Rates for Combined Heat and Power Systems: Economic Analysis and Recommendations for Five States (February 2014), prepared for Oak Ridge National Laboratory, *available at* https://info.ornl.gov/sites/publications/Files/Pub47558.pdf

[15] Demand refers to the quantity of power that a customer uses in any time interval. Demand charges are billed per kW and are often based on the customer's highest demand during each billing cycle.

- Daily maintenance demand charges should be discounted relative to daily backup demand charges to recognize the scheduling of maintenance service during periods when the utility generation requirements are low (i.e., optimum-use);
- Pro-rated, daily, as-used demand charges for backup power and shared transmission and distribution facilities should be used to provide an incentive for generator reliability (i.e., optimum-use).[16]

There is no question that a utility should aim to recover its required revenues through rates, including standby rates. Problems arise, though, when standby customers are overcharged for standby service through rates that fail to meet the rate design objectives of fair apportionment and encouraging optimum use of utility services.

Basics of CHP System Outages

A CHP system owner elects (or may be required) to sign up for standby service from a utility in case they experience a CHP system outage. Many CHP system owners are motivated by reliability concerns[17] when they install CHP in the first place, so being able to rely on utility backup service to ensure uninterrupted business operations is important to these customers. However, CHP systems are historically quite reliable, with average forced outage rates[18] on the order of less than 5%.[19] This means that the chances of an outage are minimal, but still require a contingency plan.

To keep a CHP system running efficiently, and to prevent unnecessary forced outages, scheduled maintenance outages are necessary at various times throughout the year. These scheduled CHP system outages can be and often are planned and communicated ahead of time in ways that minimize costs to the utility. As a result, scheduled outages have little downside, and create the additional benefit of reducing more costly unscheduled outages (helping to achieve optimum use). For these reasons, scheduled maintenance outages should be encouraged by a utility through communication with the customer and intentional standby rate design.

Depending on when they occur, unscheduled or forced outages can sometimes be more costly for the utility and might impose more of a burden on the grid. For this reason, there may be additional cost-justified standby charges to the customer associated with unscheduled CHP system outages. However, it is important that these increased charges are reasonable and aligned with cost-of-service principles to ensure fair apportionment in rates.

Standby Rates as Barrier to CHP Deployment

Because CHP system owners pay standby charges every month, even when their CHP systems are running perfectly, poorly-designed standby rates can be a barrier to the development of otherwise economically-viable CHP projects. As mentioned above, when standby rates are too high, inflexible, unpredictable, or simply too difficult for customers to navigate, these extra costs may mean that a CHP system will fail to provide the required return on investment. In other words, because of unreasonable standby rates, a potential CHP project may not pencil out economically. When this happens, it represents a significant missed opportunity, not just for that customer, but for the grid as a whole.

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[16] Ibid, p. 5

[17] Utility outage rates can exceed 10%, whereas CHP systems offer more than 95% reliability. See Xcel Energy, Minnesota PUC Docket CI-15-115, May 19, 2016, p. 7 ("Company generation on average is available to service customer load 89 percent of the time, and 11 percent of the time is unavailable for either scheduled or forced outages.")

[18] Forced outage rate is a measure of a CHP system's reliability that expresses the probability that a generating unit will not be available. See U.S. EPA CHP Partnership, Valuing the Reliability of Combined Heat and Power (January 2007), *available at* https://www.epa.gov/.../valuing_the_reliability_of_combined_heat_and_power.pdf

[19] 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

CHP offers many important benefits to customers and the grid, such as increased reliability and efficiency, reductions in operating costs and grid stress, and increased generating capacity. While two-thirds of the fuel used to generate electricity in the U.S. is wasted by venting or dissipating unused thermal energy, CHP systems generate both heat and electricity from a single fuel source and can operate at efficiency levels as high as 80%.[20] This creates energy and cost savings as well as reduced emissions. A modern grid in which the flexibility of CHP is fully embraced also brings numerous gains to the grid, including reductions in operating costs and grid stress, and increased generating capacity.[21]

Methodology

As described above, in November 2015, the MN PUC requested that Minnesota's four rate-regulated utilities file individual proposals for updated standby service tariffs reflecting comments and discussion around best practices.[22] When the utilities initially filed their proposals in May 2016, it was clear that understanding the similarities and differences among the proposals would be no easy task. Each utility used its own terminology and structure. Further, while the utilities had filed billing simulations to demonstrate how their proposed tariffs would function for a hypothetical customer, the sample system size and customer characteristics differed across the utility filings. To meaningfully engage in the proceeding, stakeholders needed a way to examine how each proposed standby tariff would treat a variety of CHP system outage scenarios, including outages that were scheduled and unscheduled, and those that took place during on-peak and off-peak times.

To provide a side-by-side comparison of the effects of each utility's proposed standby tariff on the monthly bills of customers with CHP systems, 5 Lakes Energy calculated standby bills for a hypothetical customer experiencing a range of CHP system outages. This analytical method, herein called the "apples-to-apples" comparison, enables a standardized evaluation across different utility tariffs. Subsequently, 5 Lakes Energy has completed this same analysis of existing utility standby service tariffs in a number of other states, including in Michigan and Ohio.[23]

The sample customer[24] used in the analysis exhibited the following characteristics:

- 2,000 kW in standby load backing up a CHP system;
- 3,000 kW in supplemental[25] load;
- Service taken at the primary distribution level.

For each sample customer, the "apples-to-apples" standby rate analysis compared calculated bills for the following outage scenarios:[26]

- a "no outage" month;
- a scheduled 16-hour outage occurring during off-peak times;
- a scheduled 16-hour outage occurring during on-peak times;
- a scheduled 32-hour outage occurring during on-peak times; and
- an unscheduled 8-hour on-peak/8-hour off-peak outage.

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[20] U.S. EPA Combined Heat and Power (CHP) Partnership, CHP Benefits, *available at* https://www.epa.gov/chp/chp-benefits

[21] Jones, D. and Kelly, M., ICF, Supporting Grid Modernization with Flexible CHP Systems (November 2017), p. 7, *available at* https://www.icf.com/resources/white-papers/2017/supporting-grid-modernization-with-flexible-chp-systems

[22] Minnesota PUC Docket No. CI-15-115

[23] As of June 2018, 5 Lakes Energy has applied the "apples to apples" standby rate comparison methodology in Minnesota, Michigan, Ohio, Pennsylvania, Indiana and Illinois.

[24] Sample customer characteristics were developed using Minnesota Power's billing simulations provided in Minnesota PUC Docket No. E-999/CI-15-115 and adapted for a General Service customer served at the Primary Distribution level.

[25] Supplemental load describes the portion of the site load not served by self-generation and billed according to the utility's full requirements tariff.

[26] Outage scenarios were designed to tease out various aspects of utility standby rates, including treatment of on-peak and off-peak outages, and any differentiation between scheduled and unscheduled (forced) outages.

Value of "Apples-to-Apples" Comparison

In the course of completing this work, it became clear that the exercise of completing the "apples-to-apples" standby rate analysis offers a range of benefits. First, the analysis serves to identify and highlight potential areas of concern in a proposed utility standby service tariff. This can focus stakeholder efforts and illuminate areas where further examination needs to be conducted. Second, the analysis helps to evaluate both the transparency and understandability of a utility's published standby tariff. To accurately conduct the analysis, it is necessary to have clear, complete standby rate information from a utility. As a result, the process of conducting the analysis enables 5 Lakes Energy to provide feedback regarding a utility's level of openness and cooperation in working with a stakeholder to verify interpretation of the utility tariff. It is clear that an indecipherable standby tariff or hostile utility interaction might have a negative impact on the deployment of an otherwise cost-effective CHP project.

Third, the exercise illustrates how a utility treats scheduled versus unscheduled outages, and on-peak versus off-peak outages. By considering the "no outage" scenario, the analysis also calculates the minimum standby bill a potential owner of a CHP system would incur. These results are particularly important in flagging whether a utility's standby rate structure violates the rate design objectives of cost apportionment and optimum-use. While reference to a utility's revenue requirements and underlying cost-of-service study are necessary to fully evaluate the strengths and weaknesses of a utility's standby rate approach, this simple "back of the envelope" approach allows utilities, regulators and other stakeholders to quickly identify potential areas of concern.

Fourth, because the analysis was conducted for standby service tariffs proposed by utilities across different states, there is a broad basis for comparison. This means that outliers stand out, sometimes dramatically, enabling the identification of areas for further discussion and investigation.

Apples-to-Apples Comparison: Results

The following tables present estimated monthly standby bills based on a the sample CHP system (2,000 kW; taking general service at the primary distribution level). The Minnesota analysis is based on the proposals originally filed by the utilities in MN PUC Docket No. CI-15-115 on May 19, 2016.[27]

Table 1: Minnesota – Total Estimated Bills by Outage Scenario

	No Outage	Scheduled 16 hr Outage (off-peak)	Scheduled 16 hr Outage (on-peak)	Scheduled 8 hrs on-peak, 8 hrs off-peak	Scheduled 32 hr Outage (on-peak)	Unscheduled 8 hrs on-peak, 8 hrs off-peak
Minnesota Power	$1,007	$2,699	$2,699	$2,699	$4,391	$20,180
Xcel Energy	$4,966	$5,935	$5,935	$5,935	$7,958	$6,135
Otter Tail Power	$1,632	$3,167	$4,113	$3,640	$6,594	$4,408
Dakota Electric	$6,594	$20,127	$20,127	$20,127	$22,561	$20,127

27 As activity under the docket progressed, each utility made revisions to their original proposal. The MN PUC approved a final revised tariff for Minnesota Power, OTP and DEA on October 3, 2017 and for Xcel MN on April 5, 2018.

The Michigan analysis was conducted based on the Consumers Energy Rate GSG-2 and the DTE Energy Rider 3 in effect as of February 2017, as well as the UMERC and UPPCO tariffs in effect as of March 2017.

Table 2: Michigan – Total Estimated Bills by Outage Scenario

	No Outage	Scheduled 16 hr Outage (off-peak)	Scheduled 16 hr Outage (on-peak)	Scheduled 8 hrs on-peak, 8 hrs off-peak	Scheduled 32 hr Outage (on-peak)	Unscheduled 8 hrs on-peak, 8 hrs off-peak
Consumers	$8,300	$9,246	$11,645	$11,191	$14,833	$11,191
DTE	$10,535	$11,657	$18,653	$13,405	$30,272	$17,545
UMERC	$0	$2,218	$3,098	$2,658	$6,196	$30,536
UPPCO	$0	$2,911	$3,883	$3,397	$7,766	$31,631

The Ohio analysis was conducted based on utility riders in effect as of August 2017.

Table 3: Ohio – Total Estimated Bills by Outage Scenario

	No Outage	Scheduled 16 hr Outage (off-peak)	Scheduled 16 hr Outage (on-peak)	Scheduled 8 hrs on-peak, 8 hrs off-peak	Scheduled 32 hr Outage (on-peak)	Unscheduled 8 hrs on-peak, 8 hrs off-peak
Duke Energy	$19,531	$21,063	$21,063	$21,063	$22,661	$22,011
AEP	$0	$13,120	$22,360	$22,360	$24,436	$22,360
DP&L	$6,357	$7,952	$18,547	$18,547	$20,143	$18,547

Selected Findings by State

Minnesota

Table 4: Minnesota – Total Estimated Bills by Outage Scenario

	No Outage	Scheduled 16 hr Outage (off-peak)	Scheduled 16 hr Outage (on-peak)	Scheduled 8 hrs on-peak, 8 hrs off-peak	Scheduled 32 hr Outage (on-peak)	Unscheduled 8 hrs on-peak, 8 hrs off-peak
Minnesota Power	$1,007	$2,699	$2,699	$2,699	$4,391	$20,180
Xcel Energy	$4,966	$5,935	$5,935	$5,935	$7,958	$6,135
Otter Tail Power	$1,632	$3,167	$4,113	$3,640	$6,594	$4,408
Dakota Electric	$6,594	$20,127	$20,127	$20,127	$22,561	$20,127

When 5 Lakes Energy first analyzed the Minnesota utilities' standby tariffs in 2016, Otter Tail Power fared well through both the "apples-to-apples" analysis and in the MN PUC standby rate docket overall. Though the utility was encouraged to make minor changes, its standby rate design appeared to align well with accepted rate design principles. Furthermore, the utility served as a model for clear customer communication. The Midwest Cogeneration Association applauded

the company's use of a clear, concise one-sheeter to convey its standby tariff, and has encouraged the adoption of a similar model by the other utilities in Minnesota and in other jurisdictions.[28] This recommendation was adopted as to the other Minnesota utilities by the MN PUC in its order dated October 3, 2017.[29]

The 2016 "apples-to-apples" analysis highlighted concerns with the proposed tariffs from Minnesota Power, Dakota Electric Association, and Xcel Energy (MN) as detailed below. The results for Minnesota Power's standby tariff proposal showed a significant increase in charges between scheduled and unscheduled outages. While a difference in cost between scheduled and unscheduled outages is expected, the level of increase in this case deserved some inquiry as to cost-justification. As Bonbright observed, "Rates found to be far in excess of cost are at least highly vulnerable to a charge of 'unreasonableness.'"[30]

With such a drastic difference between charges for scheduled and unscheduled outages, it is also important to examine the tariff language to determine how the utility defines scheduled outages. In its original proposal, Minnesota Power restricted the scheduling of outages to the months of April, May, October and November. This meant that a customer could do little to avoid exorbitant unscheduled outage charges, even for scheduled off-peak maintenance outages during eight months of the year. In its October 2017 revised filing with the MN PUC, Minnesota Power amended this policy to indicate that customers would be permitted to schedule outages during the months of April, May, October and November during any hours, and that they could schedule outages during off-peak times the rest of the year. A quick glance at the "apples-to-apples" results ($2,699 versus $20,180) for scheduled and unscheduled outages illustrates the significance of this change.

In addition to the differences between scheduled and unscheduled outages, Minnesota Power's "no outage" charges stood out as relatively low. This was due to the fact that under the terms of the tariff, the utility takes into account a CHP system's forced outage rate in calculating the reservation fee. A utility charges a reservation fee to cover the costs of "reserving" standby power for a customer, even if standby service ultimately is not needed in a given month. According to the Regulatory Assistance Project, "Generation reservation demand charges should be based on the utility's cost and the forced outage rate of customers' generators on the utility's system."[31] Because a CHP system's forced outage rate is a measure of the system's reliability, factoring the forced outage rate into the calculation of the reservation fee provides the customer with an incentive to invest in and proactively maintain the most reliable CHP technology, thus reducing cost and stress to the grid.

Dakota Electric Association's May 2016 standby tariff proposal stood out for its consistently high standby charges driven by a fixed high level of demand charges through all outage scenarios in the analysis. Demand charges can pose a challenge for standby customers, since these charges are fixed based on the highest capacity of standby power used and spread out over an entire month, even if the customer experiences a very short CHP system outage. Demand charges are under scrutiny as increased levels of distributed generation, such as CHP, are integrated into the grid. According to the National Association of Regulatory Utility Commissioners (NARUC) Manual on Distributed Energy Rate Design and Compensation (November 2016), "[R]egulators should be cautious if implementing demand charges to protect a utility's revenue recovery for the distribution grid is the goal, especially if the DER benefits to the grid are not accounted for in any way."[32]

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[28] March 17, 2017 Standby Rate Working Group Comments by Midwest Cogeneration Association/Great Plains Institute, *available at* http://www.michigan.gov/documents/mpsc/MCA__GPI_-_MI_PSC_SBR_Working_Group_-_Final_Comments__Recommendations_Final_555620_7.pdf

[29] Minnesota PUC Docket No. CI-15-115, Order dated October 3, 2017.

[30] Bonbright, J.C., Principles of Public Utility Rates (October 1960), p. 67, *available at* http://www.raponline.org/wp-content/uploads/2016/05/powellgoldstein-bonbright-principlesofpublicutilityrates-1960-10-10.pdf

[31] Brubaker & Associates, Inc. and the Regulatory Assistance Project, Standby Rates for Combined Heat and Power Systems: Economic Analysis and Recommendations for Five States (February 2014), prepared for Oak Ridge National Laboratory, p. 5, *available at* https://info.ornl.gov/sites/publications/Files/Pub47558.pdf

[32] National Association of Regulatory Utility Commissioners (NARUC), Distributed Energy Resources Rate Design and Compensation Manual, November 2016, p. 108, *available at* https://pubs.naruc.org/pub/19FDF48B-AA57-5160-DBA1-BE2E9C2F7EA0

Another concern raised by Dakota Electric's proposed tariff was the lack of differentiation between charges for scheduled and unscheduled outages. There should be some difference between scheduled and unscheduled outages, and between off-peak and on-peak standby usage, based on the cost-of-service under these different conditions. According to NARUC, "Time-variant rates (TVRs) are designed to recognize differences in a utility's cost-of-service and marginal costs at different times (e.g., hour, day, or season)."[33] Unwavering fixed charges like the ones resulting from Dakota Electric Association's standby tariff mean that a customer must pay punishing standby charges no matter what measures they may undertake to use the grid in an efficient manner. As the utility continues to work to improve its standby approach, there appears to be an opportunity to better encourage optimum use of the grid through cost-based differentiation between on- and off-peak use, and between scheduled and unscheduled outages.

A key concern that emerged as to Xcel Energy's standby tariff was the definition of standby service itself and whether a customer could mitigate potential standby charges during a CHP system outage by reducing supplemental demand. Under the tariff language proposed by Xcel Energy in 2016 and again in 2017, the customer lacked this flexibility. This issue was not resolved in the April 5, 2018 order from the MN PUC and will likely continue to be a topic of discussion in Minnesota.

Overall, from the Minnesota Department of Commerce stakeholder process to the standby-specific proceeding at MN PUC, Minnesota has been a leader in pursuing an important exploration of standby rates as a potential barrier to CHP, and how standby rates can better reflect rate design best practices. As this discussion of standby rates in Minnesota continues into the future, it will build upon a solid foundation of stakeholder engagement and collaboration.

Michigan

Table 5: Michigan – Total Estimated Bills by Outage Scenario

	No Outage	Scheduled 16 hr Outage (off-peak)	Scheduled 16 hr Outage (on-peak)	Scheduled 8 hrs on-peak, 8 hrs off-peak	Scheduled 32 hr Outage (on-peak)	Unscheduled 8 hrs on-peak, 8 hrs off-peak
Consumers	$8,300	$9,246	$11,645	$11,191	$14,833	$11,191
DTE	$10,535	$11,657	$18,653	$13,405	$30,272	$17,545
UMERC	$0	$2,218	$3,098	$2,658	$6,196	$30,536
UPPCO	$0	$2,911	$3,883	$3,397	$7,766	$31,631

The "apples-to-apples" comparison methodology was applied to Michigan's two major investor-owned utilities, Consumers Energy and DTE Energy, as part of the Michigan Public Service Commission Staff Standby Rate Working Group in 2016-2017.[34] An analysis for UMERC and UPPCO was subsequently included in comments submitted in response to the working group's CHP-focused supplemental report.[35]

In the case of Consumers Energy, what jumped out the most from the "apples-to-apples" comparison was the lack of differentiation between scheduled and unscheduled outages. In addition, both Consumers and DTE charged standby customers a relatively high fee for the "no outage" scenario, which is driven by a high fixed delivery charge in their rate designs. Unlike in the case of Minnesota Power, Consumers Energy and DTE Energy do not take into account a

[33] Ibid. at p. 26

[34] Michigan Public Service Commission Staff, Standby Rate Working Group, http://www.michigan.gov/mpsc/0,4639,7-159-16377_47107-376753--,00.html

[35] 5 Lakes Energy, Standby Rate Working Group Comments, March 17, 2017, *available at* http://www.michigan.gov/documents/mpsc/UPPCO_UMERC_5Lakes_Analyses_03202017_568776_7.docx

system's forced outage rate in calculating charges for a "no outage" month, which could run afoul of the rate design principle of fair apportionment of cost. Particularly when there is no CHP system outage, it is important to evaluate whether charges assessed to standby customers are based on cost-of-service, which is the "the basic standard of reasonableness."[36]

Upon review of DTE Energy's "apples-to-apples" analysis results, one notices that the utility's standby charges are high across all scenarios, sometimes extremely so, due to high demand charges. Such extremes deserve inquiry as to cost justification to ensure that the utility is not over-recovering from standby customers and creating barriers to deployment. NARUC recognized this potential problem in its Manual on Distributed Energy Rate Design and Compensation in which staff observed, "With the increase of DER systems on the grid, some parties fear that utilities are assessing these charges to discourage customers from investing in DER systems because projects become uneconomic with standby fees even though the DER project may be providing benefits to the grid."[37]

The two major utilities serving the Upper Peninsula of Michigan – Upper Michigan Energy Resources Company (UMERC) and Upper Peninsula Power Company (UPPCO) – stood out for their approach to (not) applying standby charges to the "no outage" scenario. It is notable that these utilities charge their standby customers nothing in months when the CHP system is fully functional, as long as the customer has also contracted for a certain minimum level of supplemental (non-standby) service. While an absence of standby charges in a no outage month may be welcome to many customers, from a rate design perspective it is important to ensure that such an arrangement is cost-of-service based. Rather than assessing "no outage" charges based on the level of a customer's supplemental contract with the utility, it is instead recommended that a customer's cost to reserve standby service be based on the reliability of the customer's CHP system (i.e., the forced outage rate). This creates an incentive for investment in and maintenance of reliable CHP technology, which delivers benefits to the grid.

The UP utilities were also notable in their treatment of unscheduled outages, for which a large increase in charges was observed. While one expects some cost differentiation when a customer fails to schedule an outage in advance, it is important to examine the level of differentiation to ensure that it is reasonably tied to cost-of-service.

Ohio

Table 6: Ohio – Total Estimated Bills by Outage Scenario

	No Outage	Scheduled 16 hr Outage (off-peak)	Scheduled 16 hr Outage (on-peak)	Scheduled 8 hrs on-peak, 8 hrs off-peak	Scheduled 32 hr Outage (on-peak)	Unscheduled 8 hrs on-peak, 8 hrs off-peak
Duke Energy	$19,531	$21,063	$21,063	$21,063	$22,661	$22,011
AEP	$0	$13,120	$22,360	$22,360	$24,436	$22,360
DP&L	$6,357	$7,952	$18,547	$18,547	$20,143	$18,547

In August 2017, the "apples-to-apples" comparison methodology was applied by 5 Lakes Energy to the following Ohio utilities: AEP Ohio, Duke Energy and Dayton Power & Light. AEP Ohio quickly emerged as a leader in customer communications with its bill calculation spreadsheets on its website.[38] Dayton Power & Light now features a commercial bill calculator, as well.[39]

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[36] Bonbright, J.C., Principles of Public Utility Rates (October 1960), p. 66, *available at* http://www.raponline.org/wp-content/uploads/2016/05/powellgoldstein-bonbright-principlesofpublicutilityrates-1960-10-10.pdf

[37] National Association of Regulatory Utility Commissioners (NARUC), Distributed Energy Resources Rate Design and Compensation Manual, November 2016, pp. 120-121, *available at* https://pubs.naruc.org/pub/19FDF48B-AA57-5160-DBA1-BE2E9C2F7EA0

[38] AEP Ohio Rates website *available at* https://www.aepohio.com/account/bills/rates/AEPOhioRatesTariffsOH.aspx

[39] Dayton Power & Light Commercial Bill Calculator Guides *available at* https://www.dpandl.com/customer-service/account-center/understand-your-bill/commercial-bill-calculator-guides/

In the case of Duke Energy, the extremely high charges, including in the "no outage" scenario, stood out immediately. Similar to Dakota Electric Association in Minnesota, Duke Energy charges consistently high charges, driven by fixed demand charges, with little differentiation between off-peak and on-peak use and scheduled versus unscheduled outages.

However, unlike Dakota Electric Association, Duke Energy charges almost as much for a "no outage" month as it does for a 32-hour on-peak CHP system outage. Examination of Duke Energy's underlying cost-of-service data is warranted to better understand whether these charges are appropriately tied to the cost of serving standby customers. Additional inquiry around the utility's assumptions regarding system reliability and standby service may also be required. According to NARUC, "Without a study of the actual costs of additional reserves required for system reliability, it is possible that a naïve calculation of the standby charge may overstate the actual costs to the system and the needs of the customers. Any charge would need to be justified directly and not be allowed to discourage the investment by customers."[40]

Dayton Power & Light's standby charges are not as high as those of Duke Energy, though the utility follows the same pattern of not differentiating between scheduled and unscheduled outages, as does AEP Ohio. In the case of AEP, the "no outage" scenario stands out because, in a manner similar to Michigan's UP utilities, the utility does not charge a customer for a "no outage" month, as long as the customer contracts for a certain level of supplemental (non-standby) service. As with the Michigan UP utilities, charges during a "no outage" month change depending on a customer's contracted level of supplemental (non-standby) service. It's important that customers are made aware of this wrinkle. Utilities and policymakers should also be aware of the potentially unintended incentives this policy creates regarding CHP system size.[41]

Comparison of the standby service tariffs for the Ohio utilities presented a new opportunity to apply the "apples-to-apples" comparison to CHP incentive programs at AEP Ohio and Dayton Power & Light and assess the impact of both incentives and standby charges on overall project economics. Both AEP Ohio and Dayton Power & Light offer incentive programs for the installation of CHP projects. While Dayton Power & Light's program is aimed at smaller projects, larger systems, such as the sample customer in the "apples-to apples" comparison are eligible for AEP Ohio's program. What follows is an analysis of how AEP Ohio's CHP incentive program would operate in relation to its standby rates for the "apples-to-apples" sample customer.

AEP Ohio's Combined Heat and Power and Waste Energy Recovery Program (CHP/WER) "supports the installation of high efficiency, sustainable and cost-effective projects in AEP Ohio's service territory as allowed by SB 315."[42] CHP projects are eligible for the incentive if they meet minimum efficiency requirements of 60% overall efficiency and create 20% useful thermal energy. CHP incentive payments are based on production of kWh recovered by the project, and incentive rates for projects approved in 2017 are $0.035 per kWh recovered for systems larger than 1000 kW. There is a yearly cap of $500,000. In a "no outage" month, the "apples-to-apples" sample customer would generate 1,440,000 kWh of electricity, which would yield a rebate from AEP Ohio of $50,400 per month. However, given the annual cap of $500,000, the maximum monthly rebate would be $41,666.67. Table 7 highlights the impact of standby rates on the net benefit to the customer of AEP Ohio's CHP incentive program:

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[40] National Association of Regulatory Utility Commissioners (NARUC), Distributed Energy Resources Rate Design and Compensation Manual, November 2016, p. 123, *available at* https://pubs.naruc.org/pub/19FDF48B-AA57-5160-DBA1-BE2E9C2F7EA0

[41] The relationship between supplemental and standby service in the calculation of a customer's standby charges creates an economic incentive for a customer to size their CHP system at less than half of their total load. This incentive may contradict the technical or reliability needs of a customer. The U.S. EPA recommends that CHP systems "are sized to meet the base thermal requirements of the facility so that 100% of the system's thermal output can be used on site. This approach to CHP system design is the most fuel efficient, most environmentally beneficial, and usually provides the best return on investment." U.S. EPA Combined Heat & Power Technical Assistance Partnership, Level 1 Feasibility Study, July 2015, p. 2, *available at* https://www.epa.gov/sites/production/files/2015-07/documents/combined_heat_and_power_chp_level_1_feasibility_analysis_industrial_facility.pdf

[42] AEP Ohio Combined Heat and Power and Waste Energy Recovery Program website available at https://www.aepohio.com/save/business/programs/CombinedHeatandPower.aspx

Table 7: AEP Ohio CHP Incentive with Standby Charges

	CHP Incentive	Standby Charges	Net Incentive
No outage	$41,667	$0	$41,667
Scheduled 16 hrs off-peak	$41,667	$22,360	$28,547
Scheduled 8 hr on-peak 8 hr off-peak	$41,667	$18,547	$19,307
Scheduled 32 hrs on-peak	$41,667	$18,547	$17,231
Unscheduled 8 hrs on-peak 8 hrs off-peak	$41,667	$18,547	$19,307

These numbers demonstrate the importance of understanding the full context of barriers and incentives facing customers interested in deploying CHP. While it is encouraging to see utilities putting into place programs to incent the installation of CHP systems, any serious effort to promote CHP must be done in the context of a fair, cost-based approach to standby rate design.

Conclusion

Since the first "apples-to-apples" analysis was completed in 2016, there has been notable progress toward improving many of the utility standby service tariffs described throughout this paper. Business groups interested in promoting the use of CHP, including the Midwest Cogeneration Association, the Alliance for Industrial Efficiency[43] and the Michigan Energy Innovation Business Council are actively engaged in educating their members and advocating for improved standby rates. In Minnesota, over the last two years, extensive stakeholder engagement and comments have been included in the docket, and in October 2017 and April 2018 the MN PUC approved tariff revisions for all four utilities, with commitments by some to continue to look at additional future improvements. In Ohio, Dayton Power & Light recently updated its standard service offer (SSO) tariff to eliminate generation demand charges, resulting in a noticeable reduction in estimated standby charges.[44] And in Michigan, the recommendations from the MPSC Staff Standby Rate Working Group have begun to be incorporated into general rate case proceedings, where the 5 Lakes Energy "apples-to-apples" comparison is being employed as part of a larger conversation about cost-of-service. As a tool for gauging the effect of various proposed tariff changes, the 5 Lakes Energy "apples-to-apples" methodology continues to play an important role in flagging areas for further cost-of-service evaluation and potential rate design improvement.

[43] The Alliance for Industrial Efficiency (AIE) has created a helpful fact sheet highlighting the "apples to apples" standby comparison, *available at* https://alliance4industrialefficiency.org/alliance-publishes-factsheet-need-standby-rate-reform-support-chp-deployment/

[44] Dayton Power & Light revised SSO Tariff (effective November 1, 2017), *available at* https://www.dpandl.com/images/uploads/G10%20-%20Standard%20Offer%20Rate.pdf

Additional Resources

- Brubaker & Associates, Inc. and the Regulatory Assistance Project, Standby Rates for Combined Heat and Power Systems: Economic Analysis and Recommendations for Five States (February 2014), prepared for Oak Ridge National Laboratory, *available at* https://info.ornl.gov/sites/publications/Files/Pub47558.pdf

- David Jones an Meegan Kelly, ICF, Supporting Grid Modernization with Flexible CHP Systems (November 2017), *available at* https://www.icf.com/resources/white-papers/2017/supporting-grid-modernization-with-flexible-chp-systems

- Energy Resources Center, Analysis of Standby Rates and Net Metering Policy Effects on Combined Heat and Power (CHP) Opportunities in Minnesota (April 2014), prepared for Minnesota Department of Commerce, Division of Energy Resources, *available at* http://mn.gov/commerce-stat/pdfs/card-report-anal-standby-rates-net-metering.pdf

- James C. Bonbright, Principles of Public Utility Rates (October 1960), available at http://www.raponline.org/wp-content/uploads/2016/05/powellgoldstein-bonbright-principlesofpublicutilityrates-1960-10-10.pdf

- Michigan Public Service Commission Staff, Standby Rate Working Group Supplemental Report (June 2017), *available at* http://www.michigan.gov/mpsc/0,4639,7-159-16377_47107-376753--,00.html.

- NARUC Manual on Distributed Energy Rate Design and Compensation (November 2016), *available at* https://pubs.naruc.org/pub/19FDF48B-AA57-5160-DBA1-BE2E9C2F7EA0

- U.S. EPA CHP Partnership, Valuing the Reliability of Combined Heat and Power (January 2007), *available at* https://www.epa.gov/sites/production/files/2015-07/documents/valuing_the_reliability_of_combined_heat_and_power.pdf

For More Information

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