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Julie Baldwin, Manager
Renewable Energy Section
Electric Reliability Division
Michigan Public Service *Commission*

Re: PSC Standby Rate Working Group – Combined Heat & Power
Final Comments and Recommendations of the Midwest Cogeneration Association and the Great Plains Institute

Dear Ms. Baldwin:

The Midwest Cogeneration Association (MCA) and the Great Plains Institute (GPI) would like to thank you for the time and effort you and the Michigan Public Service Commission ("Commission") Staff have devoted over the course of the last year to examining Michigan utility standby rate (SBR) tariff design for combined heat and power customers. We appreciate having been included in the Standby Rate Working Group.

In these final Comments, we would like to make some final observations and to provide the Commission Staff with our recommendations for improving Michigan utility standby tariffs for combined heat and power (CHP) customers.

## OBSERVATIONS

In the Working Group meetings, 5 Lakes Energy LLC ("5 Lakes"), a Michigan-based energy consulting firm engaged by GPI, provided an "Apples-to-Apples" comparison of the impact of DTE's and Consumers Energy's existing standby service tariffs on a hypothetical customer with onsite cogeneration capacity. *(Attachment A)* These side-by-side comparisons illustrate that DTE and CE have allocated costs to standby customers differently and have designed their standby tariffs differently. As a result of these differences, the charges imposed on the same customer receiving the same level of standby service in different utility territories are often quite different.

**TABLE 1**
Overview of Total Standby Bills[1]

| | Consumers | DTE[2] |
|---|---|---|
| No Outage | 8300 | 10,535 |
| Scheduled 16-hour off-peak | 9246 | 11,657.24 |
| Scheduled 16-hour on-peak | 11,645 | 18,653 |
| Scheduled 8-hour on peak, 8-hour off-peak | 11,191 | 13,405 |
| Scheduled 32-hour on-peak | 14,833 | 30,272 |
| Unscheduled 8-hour on-peak, 8-hour off-peak | 11,191 | 17,545 |

This comparison of the overall standby bills demonstrates a trend of higher standby charges for DTE customers. As can be seen in the more detailed comparisons below, this overall difference is driven by high demand charges.

In the Tables below, we provide 5 Lakes' break-out tables showing the differences in the types and amount of charges imposed under each utility's Standby Tariff and how those differences apply under a number of different scenarios. While some differences are to be expected, the substantial differences in some of these charges should be a "red flag" to the Commission that these charges require further review and cost justification.

TABLE 2
No Outage Scenario

| | Consumers | DTE |
|---|---|---|
| Service Charge | 200 | 275 |
| Delivery Capacity/Distribution Charge | 8100 | 6760 |
| Reservation Fee | 0 | 3500 |
| Demand Charges | 0 | 0 |

[1] Based on 2,000 kW in standby contract capacity, with customer served at primary voltage level. Consumers Energy outages are assumed to have taken place in March; DTE outages are assumed to have taken place in April.

[2] DTE determines standby contract capacity based on actual measured output of the system at a pre-determined moment in time, rather than adopting a system's nameplate capacity. DTE representatives in the Standby Rate Working Group explained that this can have an effect on the level of standby service reserved under the contract, at times reducing the amount by up to 30%. For purposes of the "Apples-to-Apples" comparison here, we have not reduced the contracted standby demand, and assume 2,000 kW are reserved and utilized by the customer when there is an outage.

| | | |
|---|---|---|
| Energy Charges | 0 | 0 |
| … | | |
| Subtotal of Monthly Delivery and Customer Charges | 8300 | 7035 |
| Subtotal of Monthly Reservation and Daily Demand | 0 | 3500 |
| Subtotal of Energy Charges | 0 | 0 |
| TOTAL | 8300 | 10,535 |

Both Consumers Energy and DTE calculate standby bills during "no outage" months based on standby contract capacity. Neither utility takes into account a system's forced outage rate (FOR) in calculating this minimum monthly standby bill.

Table 3

Scheduled Outage 16 hours Off-Peak Scenario

| | Consumers | DTE |
|---|---|---|
| Service Charge | 200 | 275 |
| Delivery Capacity/Distribution Charge | 8100 | 6760 |
| Reservation Fee | 0 | 3500 |
| Demand Charges | 0 | 0 |
| Energy Charges[3] | 946 | 1122.24 |
| … | | |
| Subtotal of Monthly Delivery and Customer Charges | 8300 | 7035 |
| Subtotal of Monthly Reservation and Daily Demand | 0 | 3500 |
| Subtotal of Energy Charges | 946 | 1122.24 |
| TOTAL | 9246 | 11,657.24 |

Both Consumers Energy and DTE differentiate between on-peak and off-peak capacity and energy use. Here, because the outage takes place during off-peak times, there are no demand charges, and the off-peak energy rate applies.

TABLE 4

Scheduled Outage 16 Hours On-Peak

| | Consumers | DTE |
|---|---|---|
| Service Charge | 200 | 275 |
| Delivery Capacity/Distribution Charge | 8100 | 6760 |
| Reservation Fee | 0 | 0 |
| Demand Charges | 2232 | 10,400 |
| Energy Charges | 1113 | 1218 |

[3] Energy charges calculations for Consumers Energy provided by Consumers Energy.

| … | | |
|---|---|---|
| Subtotal of Monthly Delivery and Customer Charges | 8300 | 7035 |
| Subtotal of Monthly Reservation and Daily Demand | 2232 | 0 |
| Subtotal of Energy Charges | 1113 | 1218 |
| TOTAL | 11,645 | 18,653 |

As can be seen above, both Consumers Energy and DTE differentiate between on-peak and off-peak capacity and energy use. Here, because the outage takes place during on-peak times, there are demand charges. In the case of DTE, those demand charges are significant, and the reservation fee is waived. In addition, the on-peak energy rate applies.

TABLE 5
Scheduled Outage 8 Hours On-Peak, 8 Hours Off-Peak Scenario

| | Consumers | DTE |
|---|---|---|
| Service Charge | 200 | 275 |
| Delivery Capacity/Distribution Charge | 8100 | 6760 |
| Reservation Fee | 0 | 0 |
| Demand Charges | 1116 | 5200 |
| Energy Charges | 1775 | 1170 |
| … | | |
| Subtotal of Monthly Delivery and Customer Charges | 8300 | 7035 |
| Subtotal of Monthly Reservation and Daily Demand | 1116 | 5200 |
| Subtotal of Energy Charges | 1775 | 1170 |
| TOTAL | 11,191 | 13,405 |

Because Consumers Energy treats scheduled and unscheduled outages the same, the total here for Consumers Energy is the same as in the unscheduled outage scenario below. By contrast, DTE treats scheduled and unscheduled outages differently by charging a higher demand charge rate for unscheduled outages, resulting in lower charges here and higher charges in the unscheduled outage scenario.

TABLE 6
Scheduled Outage 32 Hours On-Peak Scenario

| | Consumers | DTE |
|---|---|---|
| Service Charge | 200 | 275 |
| Delivery Capacity/Distribution Charge | 8100 | 6760 |

| | | |
|---|---|---|
| Reservation Fee | 0 | 0 |
| Demand Charges | 4463 | 20,800 |
| Energy Charges | 2070 | 2436 |
| … | | |
| Subtotal of Monthly Delivery and Customer Charges | 8300 | 7035 |
| Subtotal of Monthly Reservation and Daily Demand | 4463 | 20,800 |
| Subtotal of Energy Charges | 2070 | 2436 |
| TOTAL | 14,833 | 30,272 |

For both utilities, this outage translates into a four-day multiplier for demand charges, further highlighting the magnitude of the demand charges experienced by DTE standby customers.

TABLE 7
Unscheduled Outage 8 Hours On-Peak, 8 Hours Off-Peak Scenario

| | Consumers | DTE |
|---|---|---|
| Service Charge | 200 | 275 |
| Delivery Capacity/Distribution Charge | 8100 | 6760 |
| Reservation Fee | 0 | 0 |
| Demand Charges | 1116 | 9,340 |
| Energy Charges | 1775 | 1170 |
| … | | |
| Subtotal of Monthly Delivery and Customer Charges | 8300 | 7035 |
| Subtotal of Monthly Reservation and Daily Demand | 1116 | 9340 |
| Subtotal of Energy Charges | 1775 | 1170 |
| TOTAL | 11,191 | 17,545 |

As previously discussed, because Consumers Energy treats scheduled and unscheduled outages the same, the total here for Consumers Energy is the same as in the 8 hour on-peak/8 hour off-peak scheduled outage scenario above. By contrast, DTE treats scheduled and unscheduled outages differently by charging a higher demand charge rate for unscheduled outages, resulting in higher charges here and lower charges in the scheduled outage scenario above.

While Consumers Energy's restraint in not over-reacting to unscheduled outages is welcome, a failure to differentiate between scheduled and unscheduled outages raises the question whether customers who pre-schedule outages are actually subsidizing customers who experience unscheduled outages under this rate design. Scheduled and unscheduled outages should be treated differently in standby rates to promote efficient use and proactive maintenance of the CHP system. Cost-based differentiation of scheduled and unscheduled

Standby Service also ensures the utility will recover its actual costs for providing backup standby service.

In practice, scheduled outages should be relatively inexpensive for the customer and easy to arrange, as regular pro-active maintenance can help reduce the likelihood of a more costly unscheduled outage. When appropriately and transparently tied to costs incurred, unscheduled outages might be more expensive than schedule outages, within reason. Any extra charges should be narrowly tailored to recover the actual cost of standby service, and should not attempt to over-recover costs by assuming a "worst case scenario" (*e.g*., assuming all unscheduled outages take place during a system peak).

This point is further highlighted by some new information 5 Lakes Energy has developed for two Upper Peninsula utilities. 5 Lakes is currently working with two Upper Peninsula utilities – Upper Michigan Energy Resources Corporation (UMERC) and Upper Peninsula Power Company (UPPCO) – to confirm estimated standby bills based on the same "Apples-to-Apples" comparison used for Consumers Energy and DTE. Snapshots comparing the charges for Scheduled and Unscheduled 8 hour on-peak/8 hour off-peak outages, including charges under the DTE and CE Standby Tariffs as well as 5 Lakes' preliminary results[4] for the two Upper Peninsula utilities, are shown in Tables 8 and 9 below.

TABLE 8
Scheduled Outage 8 Hours On-Peak, 8 Hours Off-Peak

| | Consumers | DTE | UMERC[5] | UPPCO[6] |
|---|---|---|---|---|
| Service Charge | 200 | 275 | 0 | 0 |
| Delivery Capacity/Distribution Charge | 8,100 | 6,760 | 0 | 0 |
| Reservation Fee | 0 | 0 | | |
| Demand Charges | 1,116 | 5,200 | 1182 | 1106 |
| Energy Charges | 1,775 | 1,170 | 1476 | 2291 |
| TOTAL | 11,191 | 13,405 | 2658 | 3397 |

[4] 5 Lakes Energy is currently working to verify its interpretation of standby provisions for UMERC and UPPCO. The following calculations reflect a reasonable preliminary interpretation based on a reading of each rate book and early conversations with representatives from each utility. 5 Lakes Energy is open to receiving feedback and clarification regarding these calculations.

[5] Based on UMERC Tariff Cp-1M, Primary Voltage, assuming 250 annual peak days. Customer is a full requirements customer taking 3,000 kw of normal customer demand in addition to 2,000 kw of additional standby demand per outage scenario.

[6] Based on UPPCO Tariff Cp-U, Primary Voltage, assuming 23 monthly peak days. Customer is a full requirements customer taking 3,000 kw of normal customer demand in addition to 2,000 kw of additional standby demand per outage scenario.

TABLE 9
Unscheduled Outage 8 Hours On-Peak, 8 Hours Off-Peak

| | Consumers | DTE | UMERC[7] | UPPCO[8] |
|---|---|---|---|---|
| Service Charge | 200 | 275 | 0 | 0 |
| Delivery Capacity/Distribution Charge | 8,100 | 6,760 | 0 | 0 |
| Reservation Fee | 0 | 0 | 0 | 0 |
| Demand Charges | 1,116 | 9,340 | 29,060 | 29,340 |
| Energy Charges | 1,775 | 1,170 | 1476 | 2291 |
| TOTAL | 11,191 | 17,545 | 30,536 | 31,631 |

For both UMERC and UPPCO, the difference between total charges for a scheduled outage versus an unscheduled outage is dramatic. This extreme difference between scheduled and unscheduled outage stems from the fact that these utilities do not offer customers a pro-rated standby billing option for unscheduled outages. Instead, they effectively "ratchet" the charges for any unscheduled outage – whether it lasts a few hours or a few days -- over the full month.

Additionally, as discussed above, Consumers Energy does not differentiate between scheduled and unscheduled outages. This raises questions as to when and to what extent a utility actually incurs additional costs for unscheduled versus scheduled outages. This is an area where increased transparency could assist regulators, customers and other stakeholders to better understand the cost justification behind charges for scheduled and unscheduled outages on their standby bills.

## RECOMMENDATIONS

We have three recommendations for additional review and reform of Michigan utility standby tariffs to ensure that they are just, cost-based, and transparent to all parties and do not act as an unwarranted barrier to the deployment of energy efficient CHP technologies in Michigan.

- **COST OF SERVICE**

  - **RECOMMENDATION:**

[7] Based on UMERC Tariff Cp-1M, Primary Voltage, assuming 250 annual peak days. Customer is a full requirements customer taking 3,000 kw of normal customer demand in addition to 2,000 kw of additional standby demand per outage scenario.
[8] Based on UPPCO Tariff Cp-U, Primary Voltage, assuming 23 monthly peak days. Customer is a full requirements customer taking 3,000 kw of normal customer demand in addition to 2,000 kw of additional standby demand per outage scenario.

**The Commission should require each utility to perform a cost of service study of CHP customers as a separate class.**

- **PRINCIPLE: COST DRIVEN ALLOCATION**

  - Cost of Service allocations should be correlated to the costs imposed by the Customer Class.[9]

  - CHP customers are unique: They are "partial use" customers who only use grid service approximately 5% of time for "Forced Outages" – 2 ½% during peak hours – and for scheduled maintenance.

  - Cost of Service allocation to the CHP Customers should reflect the costs imposed by the CHP Customer Class and be proportionate to their "partial use."[10]

- **SUPPORT**

  - **PURPA REQUIRES COST ALLOCATION**

The "cost driver" principle is incorporated in PURPA (Public Utilities Regulatory Policy Act of 1978, amended in 2005 by the Energy Policy Act) and the Federal Energy Regulatory Commission's (FERC) implementing regulations for utility sales to qualifying cogeneration facilities:

> **18 CFR 292.305 Rates for sales.**
> **(a)General rules**.
>
> (1) Rates for sales:
>
> (i) Shall be just and reasonable and in the public interest; and

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[9] See discussion of "Cost Based Standby Rates" in the Energy Resources Center (ERC) Report prepared for the Minnesota Department of Commerce Energy Division, April 2014, titled "Analysis of Standby Rates and Net Metering Policy Effects on Combined Heat and Power (CHP) Opportunities in Minnesota,", pp. 18-21; http://mn.gov/commerce-stat/pdfs/card-report-anal-standby-rates-net-metering.pdf

[10] As noted in the ERC Minnesota Report, at p. 20, cost-based standby tariffs should "be based on the actual costs of providing backup generation and grid capacity for distributed generators during their occasional outages, spread across the year and following random patterns." Citing Oregon Public Utility Commission, Distributed Generation in Oregon: Overview Regulatory Barriers and Recommendations, Prepared by Lisa Schwartz, Oregon Public Utility Commission (2005).

(ii) Shall not discriminate against any qualifying facility in comparison to rates for sales to other customers served by the electric utility.

(2) Rates for sales which are based on **accurate data** and consistent **systemwide costing principles** shall not be considered to discriminate against any qualifying facility to the extent that such rates apply to the utility's other **customers with similar load or other cost-related characteristics**. [emphasis added]

Specifically, FERC regulations state that rates for "backup and maintenance power" may not be based on unrealistic assumptions regarding forced outages and should take into account opportunities for beneficial coordination of scheduled maintenance:

**18 CFR 292.305 Rates for sales. …**

**(c) Rates for sales of back-up and maintenance power**.

The rate for sales of back-up power or maintenance power:

(1) Shall not be based upon an assumption (unless supported by factual data) that forced outages or other reductions in electric output by all qualifying facilities on an electric utility's system will occur simultaneously, or during the system peak, or both; and

(2) Shall take into account the extent to which scheduled outages of the qualifying facilities can be usefully coordinated with scheduled outages of the utility's facilities.

- **ANALYSIS OF COST DRIVERS FOR CHP STANDBY SERVICE**

In its In its April 2014 Report "Analysis of Standby Rates and Net Metering Policy Effects on Combined Heat and Power (CHP) Opportunities in Minnesota," ERC explained that CHP System "Forced Outage Rates" (FOR) should be the basis of utility reserve capacity and infrastructure planning for CHP Systems:

"…reliable standby customers with high availability rates impose their full demand on the grid far less frequently and in shorter durations than a standard full-requirements customer (i.e. some only requiring backup service a handful of days a year). The effect is that a utility supplying standby power will not have to plan as much reserve capacity to serve self-generating customers as it does for full requirements customers. This is because needed reserve capacity decreases as generator reliability increases such that those generators with lower than average forced outage rates (FOR) require less reserved capacity." *Id.* at 20-21

Scheduled maintenance Standby Service, on the other hand, is not a "cost driver" for additional capacity or other infrastructure:

> "Furthermore, since properly scheduled maintenance service falls largely in the off-peak period the amount of reserve capacity held for scheduled maintenance should be far less, if not zero, than that of backup service. As the Oregon PUC noted, an outage during off-peak periods does not impose the same cost on the utility system as an outage during peak demand and should therefore be priced differently." *Id.* at 21

Reflecting "cost-based" principles, utility "cost allocation" for the CHP Customer Class should focus on the incidence of "Forced Outages" during peak hours or the utility's "coincident peak" hours when the utility's capacity and infrastructure load from all customers is at its maximum.

As is discussed below, the extent to which CHP Customer Class Forced Outages contribute to a utility's "coincident peak load" is quite low and may be largely, if not entirely, offset by the diversity of standby service load within the utility's customer base and the load reductions provided by those self-generators.[11] As noted above, FERC regulations do not allow the utility to assume that all partial use customers will experience Forced Outages at the same time. Establishing the actual cost-impact of CHP System customers as a class requires a factual analysis which Michigan utilities should provide in a rate proceeding.

- **DATA ON CHP FORCED OUTAGES AND IMPACTS**

While the utilities were reluctant to provide the Working Group with customer data on actual standby service use, MCA and GPI provided the Working Group with the following two studies of CHP system operating reliability which demonstrate the limited impact of CHP Forced Outages on utility resources:

- **Oak Ridge National Labs "Distributed Generation Operational Reliability and Availability Database," 2004**

In 2004 Oak Ridge National Labs (ORNL) performed a study of the "forced outage rate" (FOR) of over 120 CHP units utilizing different types of CHP technologies, from large to

[11] Where there is a capacity shortage or delivery system facing upgrades, CHP Customer on-site capacity may allow deferral of new construction or maintenance rendering net costs to the utility negligible or even negative. "Designing Standby Rates Well," C. Linvill, The Regulatory Assistance Project, presentation to the Minnesota Dept. of Commerce, Sept. 11, 2014.

small and turbines to reciprocating engines and a study performed by 5 Lakes Energy based on 2- years of continuous CHP system operating data for nineteen facilities in the New York State Energy Resource Development Agency's database. The ORNL study found an average Forced Outage Rate of less than 2% for reciprocating engines and less than 3 % for both steam and gas turbines. If approximately half of these outages are assumed to have occurred during off-peak hours, the FOR during peak hours is in the range of only 1to 1½ %. Notably, the eighty-one (81) baseload CHP units in the ORNL study had an average availability of 93.39% with 3.69% Forced Outages and 3.18% Scheduled Outages and a mean time between Forced Outages of 3,457.13 hours.
https://www1.eere.energy.gov/manufacturing/distributedenergy/pdfs/dg_operational_final_report.pdf

- **5 Lakes Energy NYSERDA CHP Database Study, Douglas Jester, 2016**

In the Working Group proceedings, Douglas Jester of 5 Lakes Energy presented a study based on actual continuous operating data from nineteen (19) New York CHP self-generating facilities over a two year period. (See attached Mr. Jester's Power Point presentation. (Attachment B)) The CHP operating data plotted against the utility's overall load shows that CHP outages occur at diverse times and do not result in increased peak loads or peak load occurrences. See Jester Presentation, Slide 3, "CHP Facility Load Profile." *(Attachment B)* Indeed, CHP Systems reduce load that would otherwise be placed on the utility system. Mr. Jester also performed a statistical regression analysis of that data which demonstrates that the most accurate billing determinant for standby service for those nineteen CHP self-generating facilities would be on-peak "time of use" billing during the summer months. In contrast, demand charges, were poorly correlated to peak occurrences driving utility costs.

- **DIFFERENCES IDENTIFIED IN UTILITY STANDBY CHARGES MAY BE DUE TO IMPROPER COST ALLOCATION**

As discussed above, the Working Group discovered substantial differences in the charges imposed on standby customers by DTE and CE, which may, in part, be based on different methods and inaccuracy in cost allocation to the class of CHP customers. Indeed, DTE explained to the Working Group that its standby charges for CHP facilities were based on an historical allocation of revenue requirements to the larger class of customers in which CHP partial use customers were included. Thus, it appears that DTE's Standby Tariff charges are not based on the costs imposed on the utility by CHP customers. DTE's revenue-based allocation to CHP customers, rather than cost-based allocation, is inconsistent with costing principles and requires review by the Commission.

## ❖ RATE DESIGN

- **RECOMMENDATION:**
  - **The Commission should require each utility to revise their Standby Tariff to reflect “best practices” for standby rate design.**

- **Best Practices Principles:** Standby Tariffs should be designed to achieve fair rates, accurate cost recovery, reductions in peak load, and customer and public transparency.

- **Conceptual Model Standby Tariff**

In the Working Group proceedings, MCA and GPI offered a framework for designing and assessing utility standby tariffs that attempts to translate “best practice” principles into the types of charges found in typical utility standby tariffs. See attached Conceptual Model for Standby Tariffs. *(Attachment C)* This “conceptual model tariff” provides alternative approaches to achieving the best practice goals based on the following:

- Either: All “time of use” charges <u>or</u> a mix of “time of use” charges and fixed charges based on a reasonable proxy for “time of use;”
- Where fixed charges are employed they should be based on the CHP system’s actual FOR or a good approximation of that rate (e.g. equipment class outage rate);
- Cost-based price differentials for peak/off-peak energy and demand; and
- Additional reasonable price differentials to encourage scheduled maintenance which reduces unscheduled outages

- **Design Considerations**
  - **Time of Use Billing Determinants**

A “time of use” approach, often applied to energy consumption, most accurately reflects the costs imposed by diverse partial users on the utility infrastructure. It reflects both the quantum of utility capacity and transmission resources used by an individual customer (hours per day or days per month) and the impact of the individual customer’s load on utility resources (peak vs. off-peak). See D. Jester analysis. Therefore, “time of use” proportionality should be reflected in demand charges as well as energy charges.

- **Clear Price Signals**

- **Time of Use vs. Fixed Monthly Charges**

“<u>Time of use</u>” charges also send the strongest price signal encouraging efficient use of the utility’s standby service. In contrast, fixed charges multiply the cost imposed for a few hours of standby service into a higher monthly charge – and thereby provide no incentive for reducing load placed on the utility during that month-long period. While hourly demand charges are more strictly proportional, daily demand charges are a common, fairer, and more accurate means of recovering a utility's embedded costs and encouraging efficient use of standby service.

For the same reason, fixed reservation fees are a highly opaque and imperfect method of recovering utility embedded costs. At best they attempt to estimate the demand to be "reserved" and require a customer to pre-pay it every month regardless of actual use -- at worst they actually duplicate demand charges. Where a reservation fee is not duplicative of demand charges, but is based on an assumed FOR that is higher than a CHP system's actual outage rate, it acts as a *de facto* "grace period" and a disincentive to efficient CHP system operation. It hides the price signal for the CHP system operator. The function and basis for reservation fees should be examined and cost-justified in the Commission's review of Standby Tariffs.

- **Peak vs. Off-Peak Charges**

Differential peak/off-peak pricing sends a price signal for reducing load placed on system during system peak. While many tariffs reflect peak and off-peak pricing in energy charges, Standby Tariffs can further encourage reductions in load during peak periods by also reflecting the cost differential in variable peak and off-peak demand charges.

- **Scheduled vs. Unscheduled Charges**

While "Forced Outages" by nature are unpredictable and cannot be eliminated, maintenance outages can be scheduled to avoid peak periods. Also, more routine maintenance during off-peak periods can result in fewer peak period "Forced Outages."

Scheduling of CHP system maintenance with the utility at times that complement utility system operations and thereby provide an ancillary benefit to the utility system can be encouraged by a price reduction or credit that is reflective of the value of such scheduling to the utility. Scheduled outages should be inexpensive for the customer and easy to arrange.

Unscheduled outage charges should be based on a price differential reflecting the proportional actual costs imposed by the CHP customer's load. However, a Standby Tariff should not over-recover by assuming a "worst case scenario" (as the UP utilities appear to do). If a customer's unscheduled outage does not fall during a utility system peak and does not actually create extra costs for the utility, a standby customer should not be penalized with an unwarranted surcharge.

- **TRANSPARENCY**

  - **RECOMMENDATION: The Commission should require each utility to include in their Standby Tariff a summary of charges in a prescribed short form.**

- **Principle:** Standby Tariffs should be readily understandable and comparable to customers, the public and regulators.

- **Discussion:**

CHP System designers and operators routinely complain about the complexity and opaque nature of utility Standby Service Tariffs. These tariffs are often in the form of a lengthy Rider which references multiple other tariffs and which includes multiple types of charges and ambiguities. Further, Standby Tariffs are all different and have no uniform structure. Indeed, 5 Lakes Energy reported it was a challenge to their well-versed energy consultants to unpack the DTE and CE Standby Tariffs to create the "Apples-to Apples" comparison they provided to the Working Group.

CHP System designers and operators would favor the Commission requiring each utility to conform their Standby Tariffs to a prescribed template or form. However, recognizing that current utility Standby Tariff Riders have their roots in other underlying tariffs and prior rate proceedings, we suggest as an alternative that the Commission require that a prescribed one or two page summary table of charges be included in each Standby Tariff which clearly translates tariff differences into uniform categories of charges (e.g. facility charge; reservation fee; demand charges (peak/off-peak; scheduled/ unscheduled), and energy charges (peak/off-peak)); and states the utility's applicable rates in each category. Two examples of such a summary table, as are included in Ameren Missouri's Standby Tariff and Otter Tail Power's Standby Tariff, are attached. (*Attachments D and E*)

## CONCLUSION

The Five Lakes "Apples-to-Apples" comparison of DTE's and CE's Standby Tariffs, and new comparison of charges under two Upper Peninsula utilities' Standby Tariffs, has shed light on significant differences in how Michigan utilities' Standby Tariffs are designed and inequities in the charges they impose on CHP System Customers. Where these differences are not cost-justified they skew the marketplace for investments in energy efficient, cost-saving CHP technologies in Michigan and make Michigan businesses less competitive. Standby Tariffs appear to have received little attention from the utilities or the Commission in past rate cases and may be under-utilized because of some of the unjustified charges we discuss above. We believe these tariffs require greater Commission scrutiny.

As discussed above, MCA and GPI recommend that the Commission require that each Michigan utility take the following steps in their next rate proceedings:

1) Perform a "cost of service" study of existing and/or potential CHP Customers requirements as a separate class to justify the charges imposed in their Standby Tariffs;

2) Revise their Standby Tariffs to reflect “best practices” for standby rate design, as discussed herein; and

3) Make their Standby Tariffs more transparent by including a summary of charges in a prescribed short form.

MCA and GPI appreciate the Commission’s attention to these Standby Tariff issues and would again like to thank you and your staff for your leadership on this important issue.

Sincerely,

| | |
|---|---|
| Patricia F. Sharkey | Amanda Bilek |
| Policy Director | Government Affairs &<br>Communications Director |
| Midwest Cogeneration Association | Great Plains Institute |

**ATTACHMENT A**
**MCA & GPI FINAL COMMENTS**

5 Lakes Energy "Apples to Apples" Scenario Analyses

Consumers Energy

For the following calculations, we built off of Minnesota Power's billing simulations provided in their filing in Minnesota PUC Docket No. E-999/CI-15-115, and adapted each scenario for a General Service customer served at the Primary Distribution level (here, Customer Voltage Level 3).

We assumed a customer with 3,000 kW in standard service, 2,000 kW in reserved standby service, and that the customer was served at the primary distribution level.

For purposes of calculating the customer's Standby Demand, we will rely on the highest 15 minute kW demand, and will assume that there has been no Standby Demand usage for the previous 11 months. The Power Factor for all scenarios is assumed to be 0.90. It is further assumed that neither the Substation Ownership Credit nor the Transmission Interconnect Credit apply.

Rates for Power Supply Capacity, Power Supply Energy, and Delivery Capacity were revised to include explanations provided in Consumers Energy's comments received on 10/18/16 and 1/27/17.

*Note that a customer would not be able to reasonably estimate its Standby Bill without access to an estimate or forecast of the following:

1. The highest price of contracted capacity purchased by the Company in that month;
2. Costs related to Transmission and Ancillaries;
3. The MISO Real-Time Locational Market Price (LMP) for the Company's load node.

**Summary:**

No Outage = $8300

Scheduled Outage 16 hours off-peak: $9246

Scheduled Outage 16 hours on-peak: $11,645

Scheduled Outage 8 hours on-peak, 8 hours off-peak: $11,191

Scheduled Outage 32 hours on-peak: $14,833

Unscheduled Outage 8 hours on-peak, 8 hours off-peak: $11,191

***No Outage***

The Company defines "Standby Demand" as:

> *the greater of the (i) highest 15 minute kW demand the Company supplies the customer for Standby Service during the current month or (ii) highest Standby Demand from the previous 11 months. The Company shall determine the amount of monthly Standby Demand supplied to the customer based upon the total amount of power supplied to the customer, their contract Standby Capacity and generator output.*

In the case of no outage, the Minimum Charge would apply.

The Company defines the Minimum Charge as:

> *The System Access Charge included in this Rate Schedule in addition to the customer's contracted Standby Capacity multiplied by the net of any Substation Ownership Credit and Delivery Capacity Charges of this Rate Schedule.*

The Delivery Capacity Charges for Customer Voltage Level 3 would be calculated as:

2,000 * 4.05 = $8,100

The System Access Charge for a Generator that does not meet or exceed load is $100/month.

There is a $100/month charge for the generator meter.

There are no Power Supply Capacity or Energy Charges in a "no outage" scenario.

Total "No Outage" Standby Bill = **$8300.00**

***Scheduled Outage – 16 hours off-peak***

For this scheduled outage calculation, we assumed a complete 16-hour outage that took place during Consumer's Energy's off-peak window over two days in March.

The Delivery Capacity Charges for Customer Voltage Level 3 would be calculated as:

2,000 * 4.05 = $8,100

The System Access Charge for a Generator that does not meet or exceed load is $100/month.

There is a $100/month generator meter charge.

There are no Power Supply Capacity charges because the outage takes place during off-peak times.

Power Supply Energy Charges are based on the spreadsheet sent by Consumers Energy on 1/26/17:

Total Energy Charges = $946

Total Standby Charges = **$9246**

***Scheduled Outage – 16 hours on-peak***

Note: There is no difference between a Scheduled and Unscheduled outage under Consumers Energy's Standby Tariff.

For this scheduled outage calculation, we assumed a complete 16-hour outage that took place during Consumer's Energy's peak window over two days (11 am to 7 pm) in March, per comments received from the Company. The assumed peak load was 5,000 kW. We are still assuming 3,000 kW in standard nominated service and 2,000 kW in reserved standby capacity.

The Delivery Capacity Charges for Customer Voltage Level 3 would be calculated as:

2,000 * 4.05 = $8,100

The System Access Charge for a Generator that does not meet or exceed load is $100/month.

There is a $100/month generator meter charge.

Power Supply Capacity Charges are calculated as:

> On Peak Capacity x (1 + Voltage 1 losses) x Standby Power Capacity Charge for the month x (# on peak days/total on peak days)
>
> 2000*1.05448*11.64*(2/22) = 2231.66

Power Supply Energy Charges are based on the spreadsheet sent by Consumers Energy on 10/18:

> In general: Sum [On Peak Capacity x (1 + Voltage 1 losses) x (LMP / 1000 + Market Settlement Fee)]
>
> In this case: Sum [2,000 kW x (1 + Voltage 1 losses) x (LMP / 1000 + $0.002/kWh)]
>
> =1112.90

Total Standby Charges = **$11,644.56**

***Scheduled Outage – 8 hours on-peak, 8 hours off-peak***

Note: There is no difference between a Scheduled and Unscheduled outage under Consumers Energy's Standby Tariff.

The differences here would show up in Power Supply Capacity Charges and Power Supply Energy Charges.

Power Supply Capacity Charges are calculated as:

> On Peak Capacity x (1 + Voltage 1 losses) x Standby Power Capacity Charge for the month x (# on peak days/total on peak days)
>
> 2000*1.05448*11.64*(1/22) = 1116.00

Power Supply Energy Charges are based on the spreadsheet sent by Consumers Energy on 10/18:

> In general: Sum [On Peak Capacity x (1 + Voltage 1 losses) x (LMP / 1000 + Market Settlement Fee)]
>
> In this case: Sum [2,000 kW x (1 + Voltage 1 losses) x (LMP / 1000 + $0.002/kWh)]
>
> = 1775.00

Therefore, the total for a 16-hour scheduled outage in which 8 hours were on-peak and 8 hours were off-peak, would still be **$11,191.**

***<u>Scheduled Outage – 32 hours on-peak</u>***

Note: There is no difference between a Scheduled and Unscheduled outage under Consumers Energy's Standby Tariff.

For this scheduled outage calculation, we assumed a 32-hour outage that took place during Consumers Energy's peak window over four days in March. The assumed peak load was 5,000 kW. We are still assuming 3,000 kW in standard nominated service and 2,000 kW in reserved standby capacity.

The Delivery Capacity Charges for Customer Voltage Level 3 would be calculated as:

2,000 * 4.05 = $8,100

The System Access Charge for a Generator that does not meet or exceed load is $100/month.

Power Supply Capacity Charges are calculated as:

> On Peak Capacity x (1 + Voltage 1 losses) x Standby Power Capacity Charge for the month x (# on peak days/total on peak days)

2000*1.05448*11.64*(4/22) = 4463.00

Power Supply Energy Charges are based on the spreadsheet sent by Consumers Energy on 10/18:

In general: Sum [On Peak Capacity x (1 + Voltage 1 losses) x (LMP / 1000 + Market Settlement Fee)]

In this case: Sum [2,000 kW x (1 + Voltage 1 losses) x (LMP / 1000 + $0.002/kWh)]

=2070.00

Total Standby Charges = **$14,833**

***<u>Unscheduled Outage</u>***

Note: There is no difference between a Scheduled and Unscheduled outage under Consumers Energy's Standby Tariff.

Therefore, the total for a 16-hour unscheduled outage in which 8 hours were on-peak and 8 hours were off-peak, would still be **$11,191**

## <u>DTE Energy</u>

For the following calculations, we built off of Minnesota Power's billing simulations provided in their filing in Minnesota PUC Docket No. E-999/CI-15-115, and adapted each scenario for a General Service customer served at the Primary Distribution level.

For purposes of a comparable analysis of DTE Energy's Rider No. 3, we assumed a Primary Supply Rate (Schedule D11) customer with 3,000 kW in nominated standard service, 2,000 kW in reserved Standby Service.[1]

For each of the following scenarios, the Daily Demand Cap was calculated using the D11 Power Supply Demand Charge of 14.65 per kW of contracted standby capacity (2000 kW) for a total of $29,300. The Daily On-Peak Backup Demand Charges do not exceed this maximum, so this figure does not apply.

[1] For purposes of this analysis, we refer to "Standby Service" and not "Station Power Standby Service" as defined in Standard Contract Rider No. 3, Parallel Operation and Standby Service and Station Power Standby Service. "Standby Service" applies to customers with generation facilities that are located within retail service territory of DTE and are directly interconnected with DTE.

**Summary:**

No Outage = $10,535.00

Scheduled Outage 16 hours off-peak: $11,657.24

Scheduled Outage 16 hours on-peak: $18,653.24

Scheduled Outage 8 hours on-peak, 8 hours off-peak: $13,405.24

Scheduled Outage 32 hours on-peak: $30,271.48

Unscheduled Outage 8 hours on-peak, 8 hours off-peak: $17,545.24

***No Outage***

For the "no outage" calculation, we assumed an April peak load of 3,000 kW.

- With no outage and no standby service provided, the Reservation Fee would apply.
- DTE calculates the Reservation Fee as:

  Standby Reservation Rate * standby capacity reserved (kW)

  The Standby Reservation Rate is listed as $1.75. The Standby Capacity reserved is 2,000 kW.

  Therefore, the Reservation Fee is calculated as:

  1.75 * 2000 = $3,500

The Delivery Service Charge is $275/month and does not appear to be contingent on whether standby service is used.

The Distribution Charge is applied to total standby contract capacity, do does not appear to be contingent on whether standby service is used. Therefore, the Distribution Charge in this scenario would be calculated as:

3.38 * 2000 = 6760.00

Total "No Outage" Standby Bill = **$10,535.00**

***Scheduled Outage – 16 hours off-peak***

For this scheduled outage calculation, we assumed a complete 16-hour outage that took place during DTE's off-peak window over two days (7pm to 11 am) in April. The assumed peak load was 5,000 kW. We are still assuming 3,000 kW in standard nominated service and 2,000 kW in reserved standby capacity.

- As above, the Reservation Fee is calculated as:

  Standby Reservation Rate * standby capacity reserved (kW)

  The Standby Reservation Rate is listed as $1.75. The Standby Capacity reserved is 2,000 kW.

  Therefore, the Reservation Fee is calculated as:

  1.75 * 2000 = $3,500

- However, if total Daily On-Peak Back-Up Demand Charges are more than the Reservation Fee, the Reservation Fee is waived.
- There are no Daily On-Peak Back-Up Demand Charges because this outage takes place during off-peak times.
- Energy charges are calculated using the Schedule D11 On-Peak Energy Charge Rate of 3.507 cents/kWh of standby power used.
- The outage lasted 16 hours and used 2,000 kW of capacity. Therefore, 32,000 kWh were used.
- Energy charges for this outage scenario would be calculated as:

0.03507 * 32,000 = 1122.24

- In addition to demand and energy charges, there would be a Delivery Service Charge of $275/month.
- Also, there would be a Distribution Charge of $3.38/kW of standby capacity used.

3.38 * 2000 = 6,760

Total Standby Charges = $11,657.24

***<u>Scheduled Outage – 16 hours on-peak</u>***

For this scheduled outage calculation, we assumed a complete 16-hour outage that took place during DTE's peak window over two days (11 am to 7 pm) in April. The assumed peak load was 5,000 kW. We are still assuming 3,000 kW in standard nominated service and 2,000 kW in reserved standby capacity.

- As above, the Reservation Fee is calculated as:

  Standby Reservation Rate * standby capacity reserved (kW)

  The Standby Reservation Rate is listed as $1.75. The Standby Capacity reserved is 2,000 kW.

  Therefore, the Reservation Fee is calculated as:

1.75 * 2000 = $3,500

- However, if total Daily On-Peak Back-Up Demand Charges are more than the Reservation Fee, the Reservation Fee is waived.
- The "maintenance" or Scheduled rate for Daily On-Peak Back-Up Demand Charges is 2.60.
- Daily On-Peak Back-Up Demand Charges are calculated as:

Daily On-Peak Back-Up Demand Charges Maintenance Rate * kW of standby capacity used * number of days of outage

Therefore, the calculation would be:

2.60 * 2000 * 2 = 10,400

- Because Daily On-Peak Back-Up Demand Charges total more than the Reservation Fee, the Reservation Fee is waived.
- Energy charges are calculated using the Schedule D11 On-Peak Energy Charge Rate of 3.807 cents/kWh of standby power used.
- The outage lasted 16 hours and used 2,000 kW of capacity. Therefore, 32,000 kWh were used.
- Energy charges for this outage scenario would be calculated as:

0.03807 * 32,000 = 1,218

- In addition to demand and energy charges, there would be a Delivery Service Charge of $275/month.
- Also, there would be a Distribution Charge of $3.38/kW of standby capacity used.

3.38 * 2000 = 6,760

Total Standby Charges = $18,653.24

***<u>Scheduled Outage – 8 hours on-peak, 8 hours off-peak</u>***

For this scheduled outage calculation, we assumed a complete 16-hour outage, 8 hours of which took place during DTE's peak window (11 am to 7 pm) over one day in April. The assumed peak load was 5,000 kW. We are still assuming 3,000 kW in standard nominated service and 2,000 kW in reserved standby capacity.

- As above, the Reservation Fee is calculated as:

Standby Reservation Rate * standby capacity reserved (kW)

The Standby Reservation Rate is listed as $1.75. The Standby Capacity reserved is 2,000 kW.

Therefore, the Reservation Fee is calculated as:

1.75 * 2000 = $3,500

- However, if total Daily On-Peak Back-Up Demand Charges are more than the Reservation Fee, than the Reservation Fee is waived.
- The "maintenance" or Scheduled rate for Daily On-Peak Back-Up Demand Charges is 2.60.
- Daily On-Peak Back-Up Demand Charges are calculated as:

Daily On-Peak Back-Up Demand Charges Maintenance Rate * kW of standby capacity used * number of days of outage

Therefore, the calculation would be:

2.60 * 2000 * 1 = 5,200

- Because Daily On-Peak Back-Up Demand Charges total more than the Reservation Fee, the Reservation Fee is waived.
- Energy charges are calculated using the Schedule D11 On-Peak Energy Charge Rate of 3.807 cents/kWh and Off-Peak Energy Charge Rate of 3.507 cents/kWh of standby power used.
- The outage lasted 16 hours and used 2,000 kW of capacity; 8 hours were on-peak and 8 hours were off-peak. Therefore, 16,000 kWh were on-peak and 16,000 kWh were off-peak.
- Energy charges for this outage scenario would be calculated as:

0.03807 * 16,000 = 609.12

0.03507 * 16,000 = 561.12

Total Energy Charges = 1,170

- In addition to demand and energy charges, there would be a Delivery Service Charge of $275/month.
- Also, there would be a Distribution Charge of $3.38/kW of standby capacity used.

3.38 * 2000 = 6,760

Total Standby Charges = **$13,405.24**

***<u>Scheduled Outage – 32 hours on-peak</u>***

For this scheduled outage calculation, we assumed a complete 32-hour outage that took place during DTE's peak window over four days (11 am to 7 pm) in April. The assumed peak load was 5,000 kW. We are still assuming 3,000 kW in standard nominated service and 2,000 kW in reserved standby capacity.

- As above, the Reservation Fee is calculated as:

  Standby Reservation Rate * standby capacity reserved (kW)

  The Standby Reservation Rate is listed as $1.75. The Standby Capacity reserved is 2,000 kW.

  Therefore, the Reservation Fee is calculated as:

  1.75 * 2000 = $3,500

- However, if total Daily On-Peak Back-Up Demand Charges are more than the Reservation Fee, the Reservation Fee is waived.
- The "maintenance" or Scheduled rate for Daily On-Peak Back-Up Demand Charges is 2.60.
- Daily On-Peak Back-Up Demand Charges are calculated as:

Daily On-Peak Back-Up Demand Charges Maintenance Rate * kW of standby capacity used * number of days of outage

Therefore, the calculation would be:

2.60* 2000 * 4 = 20,800

- Because Daily On-Peak Back-Up Demand Charges total more than the Reservation Fee, the Reservation Fee is waived.
- Energy charges are calculated using the Schedule D11 On-Peak Energy Charge Rate of 3.807 cents/kWh of standby power used.
- The outage lasted 32 hours and used 2,000 kW of capacity. Therefore, 64,000 kWh were used.
- Energy charges for this outage scenario would be calculated as:

0.03807 * 64,000 = 2,436

- In addition to demand and energy charges, there would be a Delivery Service Charge of $275/month.
- Also, there would be a Distribution Charge of $3.38/kW of standby capacity used.

3.38 * 2000 = 6,760

Total Standby Charges = **$30,271.48**

***Unscheduled Outage***

For this unscheduled outage calculation, we assumed a complete 16-hour outage, 8 hours of which took place during DTE's peak window (11 am to 7 pm) over one day in April. The assumed peak load was 5,000 kW. We are still assuming 3,000 kW in standard nominated service and 2,000 kW in reserved standby capacity.

- As above, the Reservation Fee is calculated as:

  Standby Reservation Rate * standby capacity reserved (kW)

  The Standby Reservation Rate is listed as $1.75. The Standby Capacity reserved is 2,000 kW.

  Therefore, the Reservation Fee is calculated as:

  1.75 * 2000 = $3,500

- However, if total Daily On-Peak Back-Up Demand Charges are more than the Reservation Fee, the Reservation Fee is waived.
- The non-maintenance or Unscheduled rate for Daily On-Peak Back-Up Demand Charges is 4.67.
- Daily On-Peak Back-Up Demand Charges are calculated as:

Daily On-Peak Back-Up Demand Charges Non-Maintenance Rate * kW of standby capacity used * number of days of outage

Therefore, the calculation would be:

4.67 * 2000 * 1 = 9,340

- Because Daily On-Peak Back-Up Demand Charges total more than the Reservation Fee, the Reservation Fee is waived.
- Energy charges are calculated using the Schedule D11 On-Peak Energy Charge Rate of 3.807 cents/kWh of standby power used.
- The outage lasted 16 hours and used 2,000 kW of capacity; 8 hours were on-peak and 8 hours were off-peak. Therefore, 16,000 kWh were on-peak and 16,000 kWh were off-peak.
- Energy charges for this outage scenario would be calculated as:

0.03807 * 16,000 = 609.12

0.03507 * 16,000 = 561.12

Total Energy Charges = 1,170

- In addition to demand and energy charges, there would be a Delivery Service Charge of $275/month.
- Also, there would be a Distribution Charge of $3.38/kW of standby capacity used.

3.38 * 2000 = 6,760

Total Standby Charges = **$17,545.24**

### Overview of Total Standby Bills

| | Consumers | DTE |
|---|---|---|
| No Outage | 8300 | 10,535 |
| Scheduled 16-hour on-peak | 9246 | 11,657.24 |
| Scheduled 16-hour off-peak | 11,645 | 18,653 |
| Scheduled 8-hour on peak, 8-hour off-peak | 11,191 | 13,405 |
| Scheduled 32-hour on-peak | 14,833 | 30,272 |
| Unscheduled 8-hour on-peak, 8-hour off-peak | 11,191 | 17,545 |

### No outage

| | Consumers | DTE |
|---|---|---|
| Service Charge | 200 | 275 |
| Delivery Capacity/Distribution Charge | 8100 | 6760 |
| Reservation Fee | 0 | 3500 |
| Demand Charges | 0 | 0 |
| Energy Charges | 0 | 0 |
| … | | |
| Subtotal of Monthly Delivery and Customer Charges | 8300 | 7035 |
| Subtotal of Monthly Reservation and Daily Demand | 0 | 3500 |
| Subtotal of Energy Charges | 0 | 0 |
| TOTAL | 8300 | 10,535 |

**Scheduled Outage 16 hours off-peak**

| | Consumers | DTE |
|---|---|---|
| Service Charge | 200 | 275 |
| Delivery Capacity/Distribution Charge | 8100 | 6760 |
| Reservation Fee | 0 | 3500 |
| Demand Charges | 0 | 0 |
| Energy Charges[2] | 946 | 1122.24 |
| … | | |
| Subtotal of Monthly Delivery and Customer Charges | 8300 | 7035 |
| Subtotal of Monthly Reservation and Daily Demand | 0 | 3500 |
| Subtotal of Energy Charges | 946 | 1122.24 |
| TOTAL | 9246 | 11,657.24 |

**Scheduled Outage 16 hours on-peak**

| | Consumers | DTE |
|---|---|---|
| Service Charge | 200 | 275 |
| Delivery Capacity/Distribution Charge | 8100 | 6760 |
| Reservation Fee | 0 | 0 |
| Demand Charges | 2232 | 10,400 |
| Energy Charges | 1113 | 1218 |
| … | | |
| Subtotal of Monthly Delivery and Customer Charges | 8300 | 7035 |
| Subtotal of Monthly Reservation and Daily Demand | 2232 | 0 |
| Subtotal of Energy Charges | 1113 | 1218 |
| TOTAL | 11,645 | 18,653 |

**Scheduled Outage 8 hours on-peak, 8 hours off-peak**

[2] Energy charges calculations for Consumers Energy provided by Consumers Energy.

| | Consumers | DTE |
|---|---|---|
| Service Charge | 200 | 275 |
| Delivery Capacity/Distribution Charge | 8100 | 6760 |
| Reservation Fee | 0 | 0 |
| Demand Charges | 1116 | 5200 |
| Energy Charges | 1775 | 1170 |
| … | | |
| Subtotal of Monthly Delivery and Customer Charges | 8300 | 7035 |
| Subtotal of Monthly Reservation and Daily Demand | 1116 | 5200 |
| Subtotal of Energy Charges | 1775 | 1170 |
| TOTAL | 11,191 | 13,405 |

**Scheduled Outage 32 hours on-peak**

| | Consumers | DTE |
|---|---|---|
| Service Charge | 200 | 275 |
| Delivery Capacity/Distribution Charge | 8100 | 6760 |
| Reservation Fee | 0 | 0 |
| Demand Charges | 4463 | 20,800 |
| Energy Charges | 2070 | 2436 |
| … | | |
| Subtotal of Monthly Delivery and Customer Charges | 8300 | 7035 |
| Subtotal of Monthly Reservation and Daily Demand | 4463 | 20,800 |
| Subtotal of Energy Charges | 2070 | 2436 |
| TOTAL | 14,833 | 30,272 |

**Unscheduled Outage 8 hours on-peak, 8 hours off-peak**

| | Consumers | DTE |
|---|---|---|
| Service Charge | 200 | 275 |
| Delivery Capacity/Distribution Charge | 8100 | 6760 |
| Reservation Fee | 0 | 0 |
| Demand Charges | 1116 | 9,340 |
| Energy Charges | 1775 | 1170 |
| … | | |
| Subtotal of Monthly Delivery and Customer Charges | 8300 | 7035 |
| Subtotal of Monthly Reservation and Daily Demand | 1116 | 9340 |
| Subtotal of Energy Charges | 1775 | 1170 |
| TOTAL | 11,191 | 17,545 |

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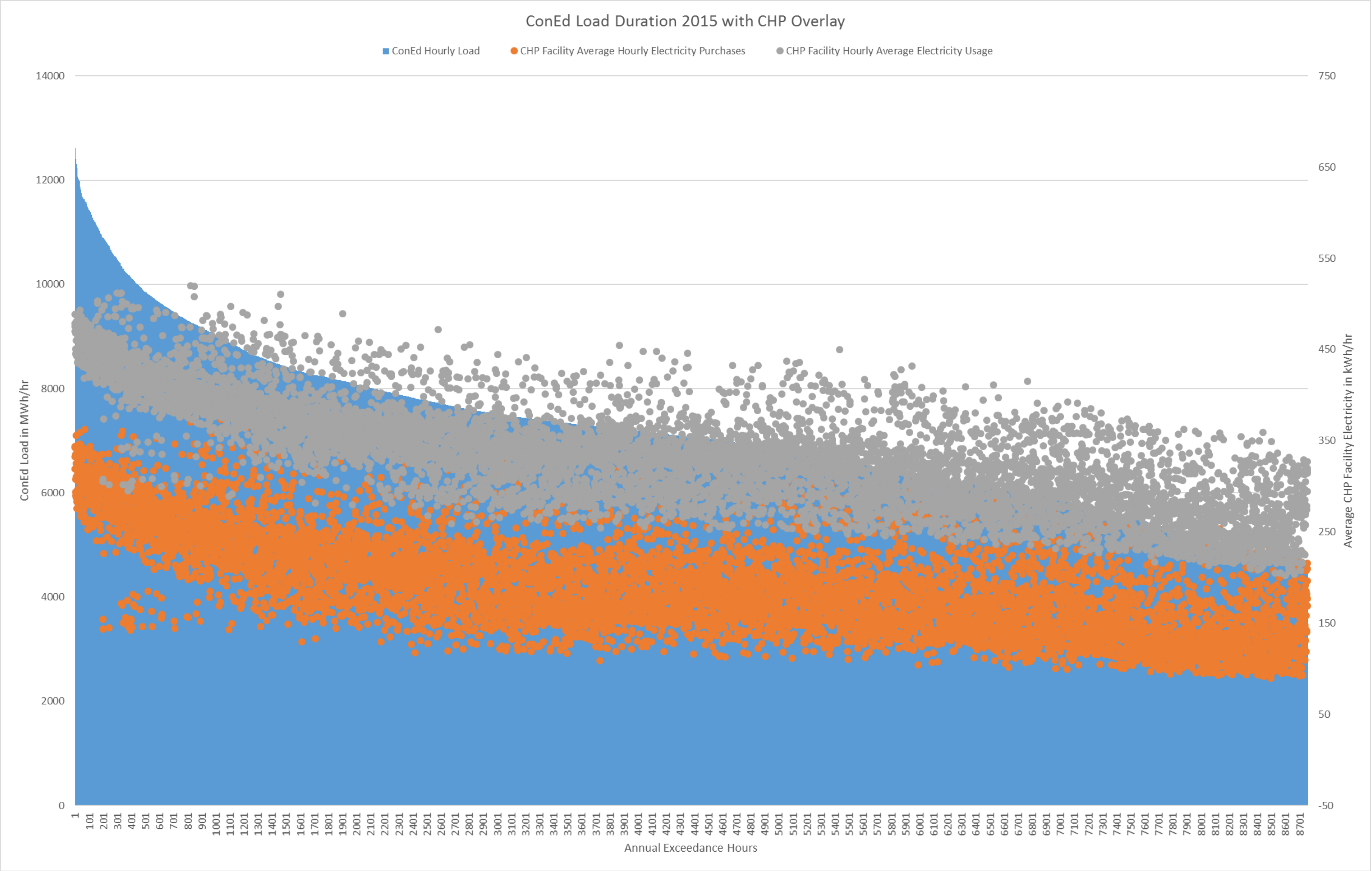
# NYSERDA Data

- Distributed generation data set accumulated over 10 years.
- Submitted by distributed generation hosts, with varying quality.
- Selected ALL CHP generators in ConEd territory with reasonably complete hourly generation and utility purchase data for 2014 and 2015.
- 19 ConEd customers, including health care, industrial, multi-family residential, retail, educational

# CHP Facilities Load Profile



# CHP Facility Purchased Electricity

| Facility | 121 | 133 | 166 | 185 | 203 | 211 | 227 | 236 | 252 | 312 | 166 | 181 | 185 | 203 | 211 | 227 | 252 | 312 | 345 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | 2014 | 2014 | 2014 | 2014 | 2014 | 2014 | 2014 | 2014 | 2014 | 2014 | 2015 | 2015 | 2015 | 2015 | 2015 | 2015 | 2015 | 2015 | 2015 |
| 1CP | 6033 | 472 | 263 | 304 | 0 | 1910 | 201 | 414 | 546 | 22 | 65 | 202 | 245 | 369 | 1056 | 235 | 605 | 25 | 276 |
| 4CP | 6096 | 453 | 149 | 215 | 151 | 1253 | 177 | 258 | 483 | 23 | 138 | 206 | 213 | 346 | 904 | 186 | 616 | 25 | 263 |
| 12CP | 3991 | 406 | 107 | 111 | 135 | 819 | 150 | 214 | 419 | 28 | 82 | 163 | 150 | 221 | 752 | 120 | 465 | 23 | 179 |
| Energy | 2312 | 189 | 78 | 106 | 117 | 650 | 109 | 160 | 300 | 25 | 62 | 101 | 107 | 153 | 655 | 91 | 351 | 25 | 158 |
| Peak Energy | 2847 | 324 | 83 | 117 | 148 | 691 | 118 | 196 | 337 | 25 | 63 | 130 | 120 | 188 | 698 | 101 | 382 | 26 | 161 |
| Off-peak Energy | 2146 | 146 | 77 | 102 | 108 | 637 | 106 | 149 | 289 | 25 | 61 | 92 | 103 | 142 | 641 | 87 | 341 | 25 | 157 |
| Winter Peak Energy | 1921 | 304 | 79 | 79 | 118 | 566 | 96 | 181 | 298 | 27 | 51 | 115 | 100 | 150 | 661 | 78 | 311 | 27 | 134 |
| Summer Peak Energy | 4769 | 363 | 89 | 195 | 209 | 941 | 162 | 228 | 414 | 23 | 85 | 158 | 156 | 263 | 770 | 147 | 522 | 23 | 214 |
| Demand | 11269 | 945 | 460 | 355 | 534 | 2018 | 314 | 655 | 627 | 77 | 467 | 454 | 310 | 546 | 1636 | 316 | 721 | 80 | 335 |
| CPP Energy | 6217 | 474 | 151 | 182 | 210 | 939 | 187 | 391 | 510 | 22 | 93 | 202 | 232 | 360 | 889 | 173 | 609 | 25 | 248 |

# CHP Facility Total Electricity

| Facility | 121 | 133 | 166 | 185 | 203 | 211 | 227 | 236 | 252 | 312 | 166 | 181 | 185 | 203 | 211 | 227 | 252 | 312 | 345 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | 2014 | 2014 | 2014 | 2014 | 2014 | 2014 | 2014 | 2014 | 2014 | 2014 | 2015 | 2015 | 2015 | 2015 | 2015 | 2015 | 2015 | 2015 | 2015 |
| 1CP | 12738 | 1018 | 553 | 367 | 238 | 1908 | 299 | 648 | 655 | 53 | 516 | 330 | 382 | 614 | 1118 | 283 | 643 | 60 | 276 |
| 4CP | 12897 | 1008 | 509 | 352 | 377 | 1322 | 290 | 492 | 598 | 55 | 476 | 446 | 352 | 592 | 1037 | 284 | 646 | 59 | 272 |
| 12CP | 9722 | 858 | 476 | 250 | 370 | 943 | 245 | 430 | 510 | 63 | 427 | 413 | 253 | 462 | 913 | 225 | 504 | 60 | 222 |
| Energy | 8150 | 681 | 405 | 195 | 349 | 774 | 205 | 309 | 395 | 53 | 384 | 333 | 204 | 394 | 830 | 198 | 390 | 52 | 199 |
| Peak Energy | 8990 | 836 | 430 | 220 | 379 | 819 | 218 | 360 | 431 | 58 | 400 | 394 | 224 | 428 | 875 | 210 | 422 | 58 | 202 |
| Off-peak Energy | 7888 | 633 | 397 | 187 | 340 | 759 | 201 | 293 | 383 | 52 | 379 | 313 | 198 | 383 | 816 | 195 | 380 | 51 | 198 |
| Winter Peak Energy | 7751 | 801 | 410 | 190 | 352 | 714 | 192 | 337 | 387 | 62 | 377 | 373 | 192 | 388 | 846 | 187 | 353 | 60 | 179 |
| Summer Peak Energy | 11559 | 905 | 468 | 282 | 435 | 1029 | 269 | 406 | 520 | 52 | 443 | 436 | 284 | 508 | 933 | 256 | 556 | 52 | 246 |
| Demand | 14503 | 1154 | 571 | 390 | 586 | 2018 | 317 | 680 | 737 | 79 | 588 | 614 | 392 | 645 | 1635 | 322 | 748 | 79 | 337 |
| CPP Energy | 13004 | 1025 | 509 | 342 | 431 | 1089 | 293 | 602 | 626 | 55 | 487 | 464 | 345 | 584 | 1017 | 279 | 645 | 58 | 271 |

# CHP Effects on Facility Electricity

| Facility | 121 | 133 | 166 | 185 | 203 | 211 | 227 | 236 | 252 | 312 | 166 | 181 | 185 | 203 | 211 | 227 | 252 | 312 | 345 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | 2014 | 2014 | 2014 | 2014 | 2014 | 2014 | 2014 | 2014 | 2014 | 2014 | 2015 | 2015 | 2015 | 2015 | 2015 | 2015 | 2015 | 2015 | 2015 |
| 1CP | -6705 | -547 | -290 | -63 | -238 | 2 | -98 | -234 | -109 | -31 | -450 | -128 | -137 | -245 | -62 | -48 | -39 | -35 | -1 |
| 4CP | -6801 | -554 | -360 | -137 | -226 | -69 | -113 | -235 | -115 | -32 | -339 | -240 | -139 | -246 | -133 | -99 | -30 | -35 | -9 |
| 12CP | -5731 | -452 | -368 | -139 | -235 | -125 | -95 | -216 | -91 | -35 | -345 | -250 | -103 | -241 | -162 | -106 | -39 | -37 | -43 |
| Energy | -5837 | -493 | -327 | -89 | -232 | -124 | -97 | -149 | -95 | -28 | -323 | -232 | -97 | -241 | -175 | -108 | -39 | -28 | -41 |
| Peak Energy | -6142 | -512 | -347 | -103 | -231 | -129 | -100 | -163 | -94 | -33 | -337 | -265 | -104 | -240 | -177 | -109 | -40 | -32 | -41 |
| Off-peak Energy | -5742 | -487 | -320 | -85 | -232 | -122 | -96 | -144 | -95 | -27 | -318 | -222 | -95 | -241 | -174 | -107 | -39 | -26 | -41 |
| Winter Peak Energy | -5830 | -497 | -331 | -110 | -233 | -149 | -96 | -156 | -89 | -35 | -325 | -258 | -92 | -238 | -185 | -109 | -43 | -33 | -45 |
| Summer Peak Energy | -6790 | -541 | -379 | -88 | -226 | -88 | -107 | -178 | -106 | -29 | -359 | -278 | -128 | -244 | -163 | -110 | -34 | -29 | -32 |
| Demand | -3235 | -209 | -111 | -36 | -52 | 0 | -3 | -25 | -110 | -2 | -121 | -160 | -82 | -99 | 1 | -6 | -27 | 1 | -1 |
| CPP Energy | -6787 | -551 | -358 | -160 | -221 | -149 | -105 | -211 | -116 | -33 | -395 | -262 | -113 | -225 | -128 | -105 | -36 | -33 | -23 |

# Empirical Rate Design

- Assume cost drivers (e.g. 4CP, 12CP) are not usable as billing determinants
- Assume a set of usable billing determinants
- Assignment of costs to individual customers with least error can be found by regressing each cost driver (dependent variable) against the set of billing determinants
- Billing determinant coefficient * average value of billing determinant/average cost driver = % of cost driver to allocate to billing determinant

# Empirical Rate Design

- Stepwise regression to simplify
  - Remove insignificant billing determinants
    - Not predictive hence not fair
  - Remove billing determinants with small cost allocations
    - Not material, so simplify
  - PERHAPS remove billing determinants with ”wrong sign”
    - Indicates collinearity between billing determinants leading to perverse price signals

# Empirical Rate Design

- Can do regression within class or across classes, if same billing determinants available in all classes.
- Within class regression sensible if and only if classification variable adds information about cost causation.

# ConEd CHP
# 12CP of Purchased Electricity

| STEP 1 | Coefficients | Standard Error | t Stat | P-value | Lower 95% | Upper 95% | Average Contribution | % Cost Allocation |
|---|---|---|---|---|---|---|---|---|
| Intercept | 0 | #N/A | #N/A | #N/A | #N/A | #N/A | #N/A | #N/A |
| Off-peak Energy | -3.43815E-05 | 2.55568E-05 | -1.3453 | 0.199916 | -8.91954E-05 | 2.04324E-05 | -65.58624699 | -14.60% |
| Winter Peak Energy | 0.000401521 | 8.48318E-05 | 4.733145 | 0.00032 | 0.000219575 | 0.000583468 | 155.5500961 | 34.63% |
| Summer Peak Energy | 0.000794695 | 0.000249082 | 3.1905 | 0.006543 | 0.000260468 | 0.001328922 | 284.0876736 | 63.24% |
| Demand | -0.005446809 | 0.032537921 | -0.1674 | 0.86945 | -0.07523371 | 0.064340091 | -6.340734098 | -1.41% |
| CPP Energy | 0.002674333 | 0.00195625 | 1.367071 | 0.193154 | -0.001521407 | 0.006870073 | 85.26308816 | 18.98% |

| STEP 2 | Coefficients | Standard Error | t Stat | P-value | Lower 95% | Upper 95% | Average Contribution | % Cost Allocation |
|---|---|---|---|---|---|---|---|---|
| Intercept | 0 | #N/A | #N/A | #N/A | #N/A | #N/A | #N/A | #N/A |
| Off-peak Energy | -3.32297E-05 | 2.38023E-05 | -1.39607 | 0.183013 | -8.3963E-05 | 1.75037E-05 | -63.38897369 | -14.11% |
| Winter Peak Energy | 0.000399381 | 8.10997E-05 | 4.924561 | 0.000183 | 0.000226521 | 0.000572241 | 154.7207346 | 34.44% |
| Summer Peak Energy | 0.000778038 | 0.000220819 | 3.523416 | 0.003072 | 0.000307373 | 0.001248702 | 278.1328868 | 61.91% |
| CPP Energy | 0.002620476 | 0.001866048 | 1.404292 | 0.180599 | -0.001356911 | 0.006597863 | 83.5460217 | 18.60% |

| STEP 3 | Coefficients | Standard Error | t Stat | P-value | Lower 95% | Upper 95% | Average Contribution | % Cost Allocation |
|---|---|---|---|---|---|---|---|---|
| Intercept | 0 | #N/A | #N/A | #N/A | #N/A | #N/A | #N/A | #N/A |
| Winter Peak Energy | 0.000301631 | 4.21185E-05 | 7.161466 | 2.26E-06 | 0.000212343 | 0.000390918 | 116.8521731 | 26.01% |
| Summer Peak Energy | 0.000566537 | 0.00016535 | 3.426292 | 0.003463 | 0.000216011 | 0.000917063 | 202.5256261 | 45.08% |
| CPP Energy | 0.004189177 | 0.001533357 | 2.73203 | 0.014769 | 0.000938606 | 0.007439749 | 133.5593536 | 29.73% |

# ConEd CHP
# 4CP of Purchased Electricity

| STEP 1 | Coefficients | Standard Error | t Stat | P-value | Lower 95% | Upper 95% | Average Contribution | % Cost Allocation |
|---|---|---|---|---|---|---|---|---|
| Intercept | 0 | #N/A | #N/A | #N/A | #N/A | #N/A | #N/A | #N/A |
| Off-peak Energy | 2.16049E-05 | 4.774E-05 | 0.452552848 | 0.6578042 | -8.07873E-05 | 0.000124 | 41.21353464 | 6.44% |
| Winter Peak Energy | -0.000202998 | 0.000158466 | -1.281023499 | 0.22099947 | -0.000542873 | 0.0001369 | -78.64186344 | -12.29% |
| Summer Peak Energy | 0.001822518 | 0.000465284 | 3.917002484 | 0.001549055 | 0.000824584 | 0.0028205 | 651.5139153 | 101.85% |
| Demand | 0.097034208 | 0.060780752 | 1.596462771 | 0.132704514 | -0.03332754 | 0.227396 | 112.9593601 | 17.66% |
| CPP Energy | -0.002612171 | 0.003654271 | -0.714826897 | 0.486465859 | -0.010449802 | 0.0052255 | -83.28123332 | -13.02% |

| STEP 2 | Coefficients | Standard Error | t Stat | P-value | Lower 95% | Upper 95% | Average Contribution | % Cost Allocation |
|---|---|---|---|---|---|---|---|---|
| Intercept | 0 | #N/A | #N/A | #N/A | #N/A | #N/A | #N/A | #N/A |
| Winter Peak Energy | -0.00014114 | 7.80217E-05 | -1.808989241 | 0.090536976 | -0.00030744 | 2.516E-05 | -54.67801461 | -8.55% |
| Summer Peak Energy | 0.00197271 | 0.000317347 | 6.216255826 | 1.65132E-05 | 0.001296301 | 0.0026491 | 705.2044907 | 110.25% |
| Demand | 0.089628394 | 0.056963609 | 1.573432523 | 0.136470555 | -0.031786663 | 0.2110435 | 104.3381122 | 16.31% |
| CPP Energy | -0.003484931 | 0.003020551 | -1.153740191 | 0.266659321 | -0.009923082 | 0.0029532 | -111.1065672 | -17.37% |

| STEP 3 | Coefficients | Standard Error | t Stat | P-value | Lower 95% | Upper 95% | Average Contribution | % Cost Allocation |
|---|---|---|---|---|---|---|---|---|
| Intercept | 0 | #N/A | #N/A | #N/A | #N/A | #N/A | #N/A | #N/A |
| Winter Peak Energy | -9.93198E-05 | 6.98016E-05 | -1.422887403 | 0.173974017 | -0.000247293 | 4.865E-05 | -38.47667247 | -6.02% |
| Summer Peak Energy | 0.001697299 | 0.00021126 | 8.034168538 | 5.24691E-07 | 0.001249448 | 0.0021452 | 606.7505232 | 94.86% |
| Demand | 0.06500002 | 0.053356339 | 1.218224903 | 0.240798183 | -0.048110364 | 0.1781104 | 75.66775528 | 11.83% |

| STEP 4 | Coefficients | Standard Error | t Stat | P-value | Lower 95% | Upper 95% | Average Contribution | % Cost Allocation |
|---|---|---|---|---|---|---|---|---|
| Intercept | 0 | #N/A | #N/A | #N/A | #N/A | #N/A | #N/A | #N/A |
| Winter Peak Energy | -0.000134671 | 6.43811E-05 | -2.091786336 | 0.051775931 | -0.000270504 | 1.161E-06 | -52.17195112 | -8.16% |
| Summer Peak Energy | 0.00194553 | 5.65629E-05 | 34.39589292 | 3.70373E-17 | 0.001826193 | 0.0020649 | 695.4882194 | 108.73% |

| STEP 5 | Coefficients | Standard Error | t Stat | P-value | Lower 95% | Upper 95% | Average Contribution | % Cost Allocation |
|---|---|---|---|---|---|---|---|---|
| Intercept | 0 | #N/A | #N/A | #N/A | #N/A | #N/A | #N/A | #N/A |
| Summer Peak Energy | 0.001829753 | 1.27049E-05 | 144.0190388 | 5.13982E-29 | 0.001803061 | 0.0018564 | 654.1003313 | 102.26% |

# ConEd CHP
# 12CP of Combined Cases (Purchased and Total)

| STEP 1 | Coefficients | Standard Error | t Stat | P-value | Lower 95% | Upper 95% | Average Contribution | % Cost Allocation |
|---|---|---|---|---|---|---|---|---|
| Intercept | 0 | #N/A | #N/A | #N/A | #N/A | #N/A | #N/A | #N/A |
| Off-peak Energy | 4.32576E-06 | 1.84295E-05 | 0.234719 | 0.815877 | -3.3E-05 | 4.18E-05 | 14.79355996 | 2.17% |
| Winter Peak Energy | 0.000334525 | 5.9839E-05 | 5.590417 | 3.23E-06 | 0.000213 | 0.000456 | 237.9919709 | 34.94% |
| Summer Peak Energy | 0.000241529 | 0.000177965 | 1.357169 | 0.183938 | -0.00012 | 0.000604 | 130.2446151 | 19.12% |
| Demand | 0.078609996 | 0.010523584 | 7.469888 | 1.38E-08 | 0.0572 | 0.10002 | 100.3594991 | 14.74% |
| CPP Energy | 0.004325018 | 0.001576838 | 2.742842 | 0.009767 | 0.001117 | 0.007533 | 194.8619541 | 28.61% |

| STEP 2 | Coefficients | Standard Error | t Stat | P-value | Lower 95% | Upper 95% | Average Contribution | % Cost Allocation |
|---|---|---|---|---|---|---|---|---|
| Intercept | 0 | #N/A | #N/A | #N/A | #N/A | #N/A | #N/A | #N/A |
| Winter Peak Energy | 0.000346652 | 2.97632E-05 | 11.64701 | 2.05E-13 | 0.000286 | 0.000407 | 246.6197735 | 36.21% |
| Summer Peak Energy | 0.000270862 | 0.000124932 | 2.168075 | 0.037244 | 1.7E-05 | 0.000525 | 146.0623739 | 21.45% |
| Demand | 0.078336346 | 0.010312448 | 7.59629 | 7.97E-09 | 0.057379 | 0.099294 | 100.0101364 | 14.68% |
| CPP Energy | 0.004117095 | 0.001286242 | 3.200871 | 0.002967 | 0.001503 | 0.006731 | 185.4940713 | 27.23% |

| STEP 3 | Coefficients | Standard Error | t Stat | P-value | Lower 95% | Upper 95% | Average Contribution | % Cost Allocation |
|---|---|---|---|---|---|---|---|---|
| Intercept | 0 | #N/A | #N/A | #N/A | #N/A | #N/A | #N/A | #N/A |
| Winter Peak Energy | 0.000250514 | 4.36044E-05 | 5.745155 | 1.67E-06 | 0.000162 | 0.000339 | 178.2239347 | 26.17% |
| Summer Peak Energy | 0.00016044 | 0.00020085 | 0.798803 | 0.429792 | -0.00025 | 0.000568 | 86.51726816 | 12.70% |
| CPP Energy | 0.008886061 | 0.001817161 | 4.89008 | 2.24E-05 | 0.005197 | 0.012575 | 400.3579542 | 58.78% |

| | Coefficients | Standard Error | t Stat | P-value | Lower 95% | Upper 95% | Average Contribution | % Cost Allocation |
|---|---|---|---|---|---|---|---|---|
| Intercept | 0 | #N/A | #N/A | #N/A | #N/A | #N/A | #N/A | #N/A |
| Winter Peak Energy | 0.000283124 | 1.52449E-05 | 18.57173 | 5.01E-20 | 0.000252 | 0.000314 | 201.4238328 | 29.57% |
| CPP Energy | 0.010325014 | 0.000237707 | 43.43585 | 1.07E-32 | 0.009843 | 0.010807 | 465.1893802 | 68.30% |

# ConEd CHP
# 4CP of Combined Cases (Purchased and Total)

| STEP 1 | Coefficients | Standard Error | t Stat | P-value | Lower 95% | Upper 95% | Average Contribution | % Cost Allocation |
|---|---|---|---|---|---|---|---|---|
| Intercept | 0 | #N/A | #N/A | #N/A | #N/A | #N/A | #N/A | #N/A |
| Off-peak Energy | 2.65065E-05 | 3.26175E-05 | 0.812647 | 0.422245 | -3.99E-05 | 9.287E-05 | 90.64882844 | 10.07% |
| Winter Peak Energy | -0.00019144 | 0.000105906 | -1.80766 | 0.079783 | -0.000407 | 2.403E-05 | -136.1981736 | -15.12% |
| Summer Peak Energy | 0.001513049 | 0.000314972 | 4.803764 | 3.29E-05 | 0.000872 | 0.0021539 | 815.9130991 | 90.61% |
| Demand | 0.126264037 | 0.018625162 | 6.779218 | 9.93E-08 | 0.088371 | 0.1641572 | 161.1982719 | 17.90% |
| CPP Energy | -0.0006654 | 0.002790766 | -0.23843 | 0.813024 | -0.006343 | 0.0050125 | -29.97913895 | -3.33% |

| STEP 2 | Coefficients | Standard Error | t Stat | P-value | Lower 95% | Upper 95% | Average Contribution | % Cost Allocation |
|---|---|---|---|---|---|---|---|---|
| Intercept | 0 | #N/A | #N/A | #N/A | #N/A | #N/A | #N/A | #N/A |
| Off-peak Energy | 3.08754E-05 | 2.66071E-05 | 1.16042 | 0.253961 | -2.32E-05 | 8.495E-05 | 105.5899619 | 11.73% |
| Winter Peak Energy | -0.00019853 | 0.000100231 | -1.98071 | 0.05576 | -0.000402 | 5.165E-06 | -141.2393598 | -15.68% |
| Summer Peak Energy | 0.001442901 | 0.000110885 | 13.01256 | 9.25E-15 | 0.001218 | 0.0016682 | 778.0855697 | 86.41% |
| Demand | 0.124758322 | 0.01727711 | 7.221018 | 2.35E-08 | 0.089647 | 0.1598696 | 159.2759616 | 17.69% |

| STEP 3 | Coefficients | Standard Error | t Stat | P-value | Lower 95% | Upper 95% | Average Contribution | % Cost Allocation |
|---|---|---|---|---|---|---|---|---|
| Intercept | 0 | #N/A | #N/A | #N/A | #N/A | #N/A | #N/A | #N/A |
| Winter Peak Energy | -9.5145E-05 | 4.61504E-05 | -2.06163 | 0.046731 | -0.000189 | -1.45E-06 | -67.6892622 | -7.52% |
| Summer Peak Energy | 0.001520209 | 8.90785E-05 | 17.06594 | 1.53E-18 | 0.001339 | 0.001701 | 819.7741326 | 91.04% |
| Demand | 0.116997598 | 0.01600887 | 7.308298 | 1.54E-08 | 0.084498 | 0.1494973 | 149.3680315 | 16.59% |

| STEP 4 | Coefficients | Standard Error | t Stat | P-value | Lower 95% | Upper 95% | Average Contribution | % Cost Allocation |
|---|---|---|---|---|---|---|---|---|
| Intercept | 0 | #N/A | #N/A | #N/A | #N/A | #N/A | #N/A | #N/A |
| Summer Peak Energy | 0.001339791 | 1.73652E-05 | 77.15379 | 1.39E-41 | 0.001305 | 0.001375 | 722.4836186 | 80.23% |
| Demand | 0.145813826 | 0.008149592 | 17.89216 | 1.69E-19 | 0.129286 | 0.162342 | 186.1570202 | 20.67% |

# ConEd CHP
# Empirical Rate Design Conclusions

- CHP Class (Purchased Electricity)
  - 12CP Cost Factors should be allocated to (at most) winter peak energy (26%), summer peak energy (45%), and critical peak energy (29%)
  - 4CP Cost Factors should be allocated to summer peak energy (100%)
- Combined Classes (Purchased and Total Electricity)
  - 12CP Cost Factors should be allocated to winter peak energy (30%) and critical peak energy (70%)
  - 4CP Cost Factors should be allocated to summer peak energy (80%) and customer demand (20%)
- These can be further simplified without significant loss of cost allocation precision

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| | Conceptual Model Standby Rate Tariff (DRAFT 10/14/16) |
|---|---|
| **Monthly Customer Charge** | ●Zero, assuming this is already included in the customer's supplemental power tariff (Based on administrative costs)<br>AND<br>●Charge or Credit to reflect greater or lesser administrative costs associated with partial use customer. |
| **Monthly Reservation Fee** | ●Zero (instead recover in demand charge)<br>OR<br>●Fixed fee to recover utility's embedded costs for generation capacity (or capacity market purchases) and transmission based on FOR of best performing CHP systems |
| **On-Peak Daily, Daily or Hourly Demand Charge** | **Scheduled**<br>●Zero<br>OR<br>●Low variable demand charge proportionate to hours of planned usage reflecting utility's lower costs due to planning at times that impose zero or low cost to utility.<br>AND<br>●Reduced (or zero) variable demand charge for off-peak usage to reflect utility's lower costs during off-peak hours.<br>**Unscheduled**<br>●If no Reservation Fee, variable demand charge designed to recover proportion of utility's embedded costs for generation capacity (or capacity market purchases) and transmission based on CHP partial-use customer's hours of unscheduled use.<br>OR<br>●If a fixed Reservation Fee is also charged, variable demand charge designed to recover utility's embedded costs for |

| | |
|---|---|
| | generation capacity (or capacity market purchases) and transmission based on CHP partial use customer's proportionate use <u>above  FOR assumed in Reservation Fee</u><br><br>AND<br><br>●Reduced (or zero) variable demand charge for <u>off-peak usage</u> to reflect utility's lower costs during off-peak hours. |
| **Energy Charge** | ● If no Reservation Fee and Demand Charge, recover proportion of utility's embedded costs for generation capacity (or capacity market purchases) and transmission in energy charges based on CHP partial-use customer's hours of use.<br><br>●Pricing should reflect utility's lower costs for scheduled usage and off-peak usage.<br><br>OR<br><br>●If embedded generation capacity (or capacity market purchases) and transmission are recovered in Reservation Fee and/or Demand Charge, energy pricing should reflect utility' s average fuel and purchased energy costs (or utility's spot energy market purchases in the case of capacity market purchases).<br><br>AND<br><br>●Pricing should reflect peak and off-peak energy prices or real time energy prices. |

Notes:

1. On-Peak Daily, Daily and Hourly demand billing units should be calculated as the customer's demand in excess of its supplemental service demand billing units.  For example, assume a customer has a 50 MW generator and 50 MW of supplemental demand.  If the customer in a given hour has a 25 MW generation derate, but its supplemental demand is simultaneously down by 25 MW such that the customer's net demand is still below 50 MW, the standby demand for that customer for that hour should be zero.

2. Delivery (i.e., distribution) service charges for standby service should generally be the same for standby service as they are for supplemental service (including any credits for a customer ownership of their own substation).  However, where there are distribution networks whose costs are driven by the peak demand on that network rather than the non-coincident peak demand of individual customers, consideration should be given to the expected contribution of the standby service to the peak demand placed on that distribution network.

**RIDER SSR**

**STANDBY SERVICE RIDER**

**APPLICABILITY**

Applicable to each customer not currently served by Rider E, at a single premises with behind the meter on-site parallel distributed generation and/or storage system(s) with a capacity over 100 kilowatts (kW), as a modification to standard electric service supplied under either the tariffed rate schedules of Large General Service 3(M), Small Primary Service 4(M), or Large Primary Service 11(M). Customers with emergency backup, solar or wind generation that is not integrated with a storage system are excluded from this Rider.

**DEFINITIONS**

DISTRIBUTED GENERATION AND/OR STORAGE - Customer’s private on-site generation and/or storage that:

1. is located behind the meter on the customer’s premises,
2. has a rated capacity of 100 kW or more,
3. operates in parallel with the Company’s system, and
4. adheres to applicable interconnection agreement entered into with the Company.

SUPPLEMENTAL SERVICE - Electric service provided by the Company to customer to supplement normal operation of the customer’s on-site parallel distributed generation and/or storage in order to meet the customer’s full service requirements.

STANDBY SERVICE - Service supplied to the premises by the Company in the event of the customer exceeding its Supplemental Contract Capacity. Standby Service may be needed on either a scheduled or unscheduled basis. Standby Service comprises capacity and associated energy during the time it is used.

1. BACKUP SERVICE - Unscheduled Standby Service.
2. MAINTENANCE SERVICE - Scheduled Standby Service.

BACK-UP SERVICE - The portion of Standby Contract Capacity and associated energy used without advance permission from the Company. The customer must notify the Company within thirty (30) minutes of taking Back-up Service for amounts over five (5) megawatts (MW). For Back-up Service billed, the customer shall be charged the daily standby demand charge for back-up service and back-up energy charges associated with Standby Service. The rates for these charges as well as the monthly fixed charges are stated in this Rider. Back-up Service charges will be shown and calculated separately on the customer bill.

MAINTENANCE SERVICE - The portion of Standby Contract Capacity used with advance permission from the Company. The customer must schedule Maintenance Service with the Company not less than six (6) days prior to its use. Unless otherwise agreed to by the Company, Maintenance Service shall be limited to not more than six (6) occurrences and not more than sixty (60) total and partial days during twelve (12) consecutive billing periods (based on billing dates). Maintenance Service may be available during all months and shall not be greater than the seasonal Standby Contract Capacity. The scheduling of Maintenance Service may be restricted by the Company during times associated with system peaking conditions or other times as necessary. For Maintenance Service billed, the customer shall be charged the daily standby demand charge for maintenance service associated with Standby Service Demand.

## RIDER SSR

## STANDBY SERVICE RIDER (Cont'd.)

**DEFINITIONS (Cont'd.)**

MAINTENANCE SERVICE (Cont'd.) - The rates for these daily demand charges as well as the monthly fixed charges are stated in this Rider. Energy charges for Maintenance Service associated with the Standby Service will be billed as standard energy charges per the applicable tariffed rate schedule. Maintenance Service charges will be shown and calculated separately on the customer bill.

SUPPLEMENTAL CONTRACT CAPACITY - The customer must designate and contract by season the maximum amount of demand, in kW, taken at the premises through the billing meter that may be billed on the applicable standard tariffed rate and shall be mutually agreeable to customer and Company. The Supplemental Contract Capacity shall insofar as possible estimate ninety percent (90%) of the historic or probable loads of the facility as adjusted for customer generation.

STANDBY CONTRACT CAPACITY - The higher of:

1. The number of kilowatts mutually agreed upon by Company with customer as representing the customer's maximum service requirements under all conditions of use less Supplemental Contract Capacity, and such demand shall be specified in customer's Electric Service Agreement. Such amount shall be seasonally designated and shall not exceed the nameplate rating(s) of the customer's own generation. The amount of Standby Contract Capacity will generally consider the seasonal (summer or winter billing periods) capacity ratings and use of the generator(s), or may be selected based on a Company approved load shedding plan.

2. The maximum demand established by customer in use of Company's service less the product of Supplemental Contract Capacity and 110%.

Fixed monthly charges for generation and transmission access and facilities shall be levied upon a capacity not to exceed the nameplate rating(s) of the customer's generating unit(s).

SUPPLEMENTAL DEMAND - The lesser of:

1. Supplemental Contract Capacity or
2. The Total Billing Demand in this Rider.

STANDBY SERVICE DEMAND - The Total Billing Demand as determined in this Rider in excess of the Supplemental Contract Capacity.

TOTAL BILLING DEMAND - Total Billing Demand for purposes of this Rider during shall be the maximum 15 minute demand established during peak hours or 50% of the maximum 15 minute demand established during off-peak hours, whichever is greater, but in no event less than 100 kW for Large General Service or Small Primary Service, nor less than 5,000 kW for Large Primary Service.
Peak and off-peak hours are defined as follows:

Peak hours: 10:00 A.M. to 10:00 P.M.,
Monday through Friday

Off-peak hours: All other hours including the entire 24 hours of the tariffed holidays as defined in the base tariff. All times stated above apply to the local effective time.

**RIDER SSR**

**STANDBY SERVICE RIDER (Cont'd.)**

**GENERAL PROVISIONS**

The contract term shall be one (1) year, automatically renewable, unless usage, plant modifications or additional generation requires a change to Supplemental Contract Capacity or Standby Contract Capacity.

The Company will install and maintain the necessary suitable meters for measurement of service rendered hereunder. The Company may inspect generation logs or other evidence that the customer's generator is being used in accordance with the provisions this Rider.

Power production equipment at the customer site shall not commence parallel operation until after inspection by the Company and a written interconnection agreement is executed. The sale of excess energy to the Company may be included in the interconnection or other agreement.

If at any time customer desires to increase demand above the capacity of Company's facilities used in supplying said service due to plant modifications, customer will sign a new agreement for the full capacity of service required and in accordance with applicable rules governing extension of its distribution system.

In addition to the charges in the applicable rate schedule, customers taking service under this Rider will be subject to the applicable Administrative Charge, Generation and Transmission Access Charges, and the Facilities Charge each month contained herein. If customer chooses the Time-Of-Day (TOD) option under the applicable rate schedule such option will apply to this Rider SSR as well.

Those customers choosing to install more than one (1) generating unit on the same premises will have a twenty five percent (25%) discount applied to the monthly Generation and Transmission Access Charges and Facilities Charges applicable to each additional generator on the same premises.

In addition to the above specific rules and regulations, all of Company's General Rules and Regulations shall apply to the supply of service under this Rider.

In the event a customer adds distributed generation and/or storage after investments are made by the Company in accordance with the net revenue test described in the Company's line extension policy, the Company may require reimbursement by the customer. Such reimbursement shall be limited to that investment which was incurred within the previous five years and shall be based upon the change in load requirements on the Company's electric system.

Fuel and Purchased Power Adjustment (Rider FAC). Applicable to all billed kilowatt-hours (kWh) of energy under this Rider.

Energy Efficiency Investment Charge (Rider EEIC)and Energy Efficiency Program Charge. Applicable to all billed kilowatt-hours (kWh) of energy under this Rider excluding kWh of energy supplied to customers that have satisfied the opt-out provisions of Section 393.1075, RSMo.

**RIDER SSR**

**STANDBY SERVICE RIDER (Cont'd.)**

| STANDBY RATE | | | |
|---|---|---|---|
| | **Large General Service** | **Small Primary Service** | **Large Primary Service** |
| **Standby Fixed Charges** | | | |
| Administrative Charge | $199.00/month | $199.00/month | $199.00/month |
| Generation and Transmission Access Charge per month per kW of Contracted Standby Demand | $0.67/kW | $0.67/kW | $0.84/kW |
| Facilities Charge per month per kW of Contracted Standby Demand: | | | |
| Summer | $4.13/kW | $3.39/kW | $3.39/kW |
| Winter | $1.03/kW | $0.72/kW | $0.72/kW |
| **Daily Standby Demand Rate – Summer** | | | |
| Per kW of Daily Standby Service Demand: | | | |
| Back-Up | $0.04/kW | $0.04/kW | $1.12/kW |
| Maintenance | $0.02/kW | $0.02/kW | $0.56/kW |
| **Daily Standby Demand Rate - Winter** | | | |
| Per kW of Daily Standby Service Demand: | | | |
| Back-Up | $0.02/kW | $0.02/kW | $0.54/kW |
| Maintenance | $0.01/kW | $0.01/kW | $0.27/kW |
| **Back-Up Energy Charges – Summer** | | | |
| kWh in excess of Supplemental Contract Capacity | | | |
| Energy(1) | 10.58¢/kWh | 10.23¢/kWh | 3.54¢/kWh |
| On-Peak Energy(2) | 11.83¢/kWh | 11.14¢/kWh | 4.23¢/kWh |
| Off-Peak Energy(2) | 9.87¢/kWh | 9.72¢/kWh | 3.16¢/kWh |
| **Back-Up Energy Charges – Winter** | | | |
| kWh in excess of Supplemental Contract Capacity | | | |
| Energy(1) | 6.65¢/kWh | 6.44¢/kWh | 3.14¢/kWh |
| On-Peak Energy(2) | 7.03¢/kWh | 6.78¢/kWh | 3.45¢/kWh |
| Off-Peak Energy(2) | 6.44¢/kWh | 6.26¢/kWh | 2.96¢/kWh |
| **High Voltage Facilities Charge Discount** | | | |
| Facilities Charge Credit per month per kW of Contracted Standby Demand | | | |
| @ 34.5 or 69kV | N/A | $1.23/kW | $1.23/kW |
| @ 115kV or higher | N/A | $1.46/kW | $1.46/kW |

(1) Applicable to customers not on TOD rates.
(2) Applicable to customers on TOD rates for its non-back-up energy charges.

## STANDBY SERVICE

| | OPTION A: FIRM | | | OPTION B: NON-FIRM | | |
|---|---|---|---|---|---|---|
| | **On-Peak** | **Shoulder** | **Off-Peak** | **On-Peak** | **Shoulder** | **Off-Peak** |
| **Transmission Service** | 32-941 | 32-942 | 32-943 | 32-950 | 32-951 | 32-952 |
| **Primary Service** | 32-944 | 32-945 | 32-946 | 32-953 | 32-954 | 32-955 |
| **Secondary Service** | 32-947 | 32-948 | 32-949 | 32-956 | 32-957 | 32-958 |

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**RULES AND REGULATIONS:** Terms and conditions of this electric rate schedule and the General Rules and Regulations govern use of this service.

**AVAILABILITY:** This schedule, including Attachment 1 - Definitions and Useful Terms, provides **Backup**, **Scheduled Maintenance**, and **Supplemental Services**, is applicable to any Customer who has the following conditions:

1. Requests to become a **Standby Service Customer** of the Company. Otherwise, the Company views the Customer as a **Non-Standby Service Customer**. For information about the different categories of **Non-Standby Service Customers**, including exemptions from **Standby Service**, please see Attachment No. 1 – Definitions.

2. Utilizes **Extended Parallel Generation Systems** to meet all or a portion of electrical requirements, which is capable of greater than 100 kW. Customers with **Extended Parallel Generation Systems** used to meet all or a portion of electrical requirements that are capable of 100 kW or less are considered **Non-Standby Service Customers** and exempt from paying standby charges. Please see Attachment No. 1-Definitions for more information regarding **Non-Standby Service Customers**.

3. Enters into a contract for services related to its Generator. Contracts will be made for this service provided the Company has sufficient Capacity available in production, transmission and Distribution Facilities to provide such service at the location where the service is requested.

The Company delivers alternating current service at transmission, primary or secondary voltage under this rate schedule, supplied through one Meter.

Power production equipment at the Customer site shall not operate in parallel with the Company's system until the installation has been inspected by an authorized Company representative and final written approval is received from the Company to commence parallel operation.

## STANDBY RATE OPTIONS - FIRM AND NON-FIRM

| **OPTION A: FIRM STANDBY** | **Transmission Service** | **Primary Service** | **Secondary Service** | |
|---|---|---|---|---|
| **Firm Standby Fixed Charges** | | | | |
| Customer Charge | $304.33/month | $304.33/month | $242.24/month | R |
| Minimum Monthly Bill | Customer + Reservation + Standby Facilities Charges | Customer + Reservation + Standby Facilities Charges | Customer + Reservation + Standby Facilities Charges | |
| Summer Reservation Generation Charge per **month** per kW of Contracted Backup Demand | 58.422 ¢/kW | 62.837 ¢/kW | 65.645 ¢/kW | N |
| Winter Reservation Generation Charge per month per kW of Contracted Backup Demand | 19.898 ¢/kW | 21.403 ¢/kW | 22.355 ¢/kW | R N |
| Standby Local Distribution Facilities Charge per month per kW of Contracted Backup Demand | Not Applicable | 45.00 ¢/kW | 55.00 ¢/kW | R N R |
| **Firm Standby On-Peak Demand Charge - Summer** | | | | |
| Metered Demand per **day** per kW On-Peak Backup Charge Transmission & Distribution Substation | 48.812 ¢/kW | 52.464 ¢/kW | 54.794 ¢/kW | R N N |
| **Firm Standby On-Peak Demand Charge - Winter** | | | | R |
| Metered Demand per **day** per kW On-Peak Backup Charge Transmission & Distribution Substation | 37.420 ¢/kW | 40.800 ¢/kW | 43.005 ¢/kW | NNR R |
| **Firm Standby Energy Charges - Summer** | | | | R |
| Energy Charges per kWh | | | | |
| On-Peak Charge | 7.840 ¢/kWh | 9.367 ¢/kWh | 9.672 ¢/kWh | |
| Shoulder Charge | 6.012 ¢/kWh | 7.147 ¢/kWh | 7.357 ¢/kWh | R |
| Off-Peak Charge | 3.429 ¢/kWh | 4.047 ¢/kWh | 4.146 ¢/kWh | R |
| **Firm Standby Energy Charges - Winter** | | | | R |
| Energy Charges per kWh | | | | |
| On-Peak Charge | 6.407 ¢/kWh | 7.752 ¢/kWh | 8.069 ¢/kWh | |
| Shoulder Charge | 5.937 ¢/kWh | 7.149 ¢/kWh | 7.419 ¢/kWh | |
| Off-Peak Charge | 4.005 ¢/kWh | 4.795 ¢/kWh | 4.958 ¢/kWh | |

| OPTION B: NON-FIRM STANDBY | | | | |
|---|---|---|---|---|
| | **Transmission Service** | **Primary Service** | **Secondary Service** | |
| **Non-Firm Standby Fixed Charges** | | | | |
| Customer Charge | $304.33/month | $304.33/month | $242.24/month | **R** |
| Minimum Monthly Bill | Customer + Reservation + Standby Facilities Charges | Customer + Reservation + Standby Facilities Charges | Customer + Reservation + Standby Facilities Charges | |
| Reservation Generation Charge per month per kW of Contracted Backup Demand | Not Available | Not Available | Not Available | **N** |
| Standby Local Distribution Facilities Charge per **month** per kW of Contracted Backup Demand | Not Applicable | 45.00 ¢/kW | 55.00 ¢/kW | **N** **R** |
| **Non-Firm Standby On-Peak Demand Charge - Summer** | | | | |
| Metered Demand per **day** per kW On-Peak Backup Charge Transmission & Distribution Substation | Not Available | Not Available | Not Available | **N** **N** |
| **Non-Firm Standby On-Peak Demand Charge - Winter** | | | | |
| Metered Demand per **day** per kW On-Peak Backup Charge Transmission & Distribution Substation | Not Available | Not Available | Not Available | **N** **N** |
| **Non-Firm Standby Energy Charges - Summer** | | | | |
| Energy Charges per kWh | | | | |
| On-Peak Charge | Not Available | Not Available | Not Available | **R** |
| Shoulder Charge | 6.012 ¢/kWh | 7.147 ¢/kWh | 7.357 ¢/kWh | **R** |
| Off-Peak Charge | 3.429 ¢/kWh | 4.047 ¢/kWh | 4.146 ¢/kWh | |
| **Non-Firm Standby Energy Charges - Winter** | | | | |
| Energy Charges per kWh | | | | |
| On-Peak Charge | Not Available | Not Available | Not Available | **R** |
| Shoulder Charge | 5.937 ¢/kWh | 7.149 ¢/kWh | 7.419 ¢/kWh | **R** |
| Off-Peak Charge | 4.005 ¢/kWh | 4.795 ¢/kWh | 4.958 ¢/kWh | |

**MANDATORY AND VOLUNTARY RIDERS:** The amount of a bill for service will be modified by any Mandatory Rate Riders that must apply and by any Voluntary Rate Riders selected by the Customer, unless otherwise noted in this schedule. See Sections 12.00, 13.00 and 14.00 of the Minnesota electric rates for the matrices of riders.

**DETERMINATION OF METERED DEMAND:** Metered **Demand** shall be based on the maximum kW registered over any period of one hour during the month in which the bill is rendered.

**TERMS AND CONDITIONS:**

1. Company's Meter will be detented to measure power and Energy from Company to Customer only. Any flow of power and Energy from Customer to Company will be separately metered under one of Company's Purchase Power Rate Schedules, Distributive Generation Rider, or by contract.

2. Option A - Firm Standby: Exclusive of any scheduled maintenance hours, if the number of hours on which **Backup Service** is supplied exceeds 120 On-Peak hours in the Summer season and 240 On-Peak hours in the Winter season, Customer may be required to take service under a standard, non-standby, rate schedule.

3. Option B – Non-Firm Standby: **Backup Service** is not available during any on-peak season. This service is only available in the **Summer Shoulder** and **Summer Off-Peak** and **Winter Shoulder** and **Winter Off-Peak** hours on a non-firm basis. The Company makes no guarantee that this service will be available, however, the Company will make reasonable efforts to provide **Backup Service** under Option B whenever possible.

4. One year (12 months) written notice to Company is required to convert from this standby service to regular firm service, unless authorized by the Company.

5. Any additional facilities, beyond normal transmission and Distribution Facilities, required to furnish service will be provided at Customer's expense.

6. Customer shall indemnify Company against all liability which may result from any and all claims for damages to property and injury or death to persons which may arise out of or be caused by the erection, maintenance, presence, or operation of the Customer generation facility or by any related act or omission of the Customer, its employees, agents, contractors or subcontractors.

7. During times of Customer generation, Customer will be expected to provide vars as needed to serve their load. Customer will provide equipment to maintain a unity power factor + or –

10% for **Supplemental Service**, and when Customer is taking **Backup Service** from Company.

**CONTRACT PERIOD:** Standby Service is applicable only by signed agreement, setting forth the location and conditions applicable to the electric service, such as the **Contracted Backup Demand**, type of standby service (Option A or B), excess facilities required for service and other applicable terms and conditions, and providing for an initial minimum contract period of one year, unless otherwise authorized by Company.

**ATTACHMENT NO. 1**
DEFINITIONS AND USEFUL TERMS

**Backup Demand** (a component of Backup Service) is the Demand taken when on-peak Demand provided by Company is used to make up for reduced output from Customer's generation.

**Backup Demand Charge** is the sum of the ten highest daily Backup Demands multiplied by the applicable Backup Demand Charge for that season.

**Backup Service** is the Energy and Demand supplied by the utility during unscheduled outages of the Customer's Generator.

**Billing Demand** is the Customer's Demand used by the Company for billing purposes.

**Capacity** is the ability to functionally serve a required load on a continuing basis.

**Contracted Backup Demand** is the amount of Capacity selected to backup the Customer's generation, not to exceed the capability of the Customer's Generator.

**Demand** is the rate at which electric Energy is delivered to or by a system, part of a system, or a piece of equipment and is expressed in Kilowatts ("kW") or Megawatts;

**Energy** is the Customer's electric consumption requirement, measured in Kilowatt-Hours ("kWh").

**Extended Parallel Generation Systems** are generation systems that are designed to remain connected in parallel to and in phase to the utility Distribution system for an extended period of time.

**Excess Distribution Facility Investment** are Distribution Facilities required to provide service to the distributed generation system that are not provided in the Company retail service schedules. The Customer is required to pay up-front for these facilities and pay maintenance costs as long as the facilities are required.

**MAPP** is the Mid-Continent Area Power Pool or any successor agency assuming or charged with similar responsibility.

**MISO** is the Midcontinent Independent System Operator, Inc. assures industry consumers of unbiased regional grid management and open access to the Transmission Facilities under Midwest ISO's functional supervision.

**Non-Standby Service Customer** is a Customer that a) does not request and receive approval of Standby Services from the Company or, b) is exempt from paying any standby charges as allowed by law or Commission Order, or, c) in lieu of service under this Tariff, may provide Physical Assurance, or d) will take service from any of the Company's other approved base Tariffs.

Customers with Extended Parallel Generation Systems used to meet all or a portion of electrical requirements that are capable of 100 kW or less are considered Non-Standby Service Customers and exempt from paying standby charges.

Standby Service for Customers with Extended Parallel Generation Systems used to meet all or a portion of electrical requirements that are capable of 100 kW or less is available under the Customer's base rate.

For more information regarding **Extended Parallel Generation Systems**, **Physical Assurance Customers**, and **Standby Service for Customers**, please see these terms under Definitions.

**Physical Assurance Customer** is a Customer who agrees not to require standby services and has an approved mechanical device, inspected and approved by a Company representative, to insure standby service is not taken. The cost of the mechanical device is to be paid by the Customer.

**Renewable Energy Attributes** refers to the benefits of the Energy from being generated by a renewable resource rather than a fossil-fueled resource.

**Renewable Energy Credit** is typically viewed as a certification that something was generated by a renewable resource.

**Renewable Resource Premium** referred to the extra payment received on top of the regular avoided costs. This extra payment is to reflect the value of the **Renewable Energy Credit**, which is a certification of the **Renewable Energy Attributes**.

***Reservation Charge (Unbundled).*** **N**

| Option A & B Where charges apply | Transmission Service | Primary Service | Secondary Service |
|---|---|---|---|
| Reservation Generation Charge | 100% is Generation | 100% is Generation | 100% is Generation |
| Local Distribution Facilities Charge Per Month per kW of Contracted Backup Demand | N/A | 100% is Local Distribution | 100% is Local Distribution |
| **Firm Standby On-Peak Demand Charge - Summer** | | | |
| Metered Demand per **day** per kW On-Peak Backup Charge Transmission & Distribution Substation | 100% is Trans. 0% is Dist. | 49% is Trans. 51% is Dist. | 49% is Trans. 51% is Dist. |
| **Firm Standby On-Peak Demand Charge - Winter** | | | |
| Metered Demand per **day** per kW On-Peak Backup Charge Transmission & Distribution Substation | 100% is Trans. 0% is Dist. | 100% is Trans. 0% is Dist. | 100% is Trans. 0% is Dist. |

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**Scheduled Maintenance Service** is defined as the Energy and Demand supplied by the utility during scheduled outages and is applicable to both Option A – Firm Standby and **N**
Option B – Non-Firm Standby services as defined herein. Where applicable the daily on-peak **N**
backup Demand charge under Variable Charges of the "Rate" section will be waived for a maximum continuous period of 30 days per calendar year to allow for maintenance of Customer generation source. Waiver is only valid during the months of April, May, October, and November, and with a minimum of five working days (excludes weekend and holidays) written notice to Company. In certain cases, such as very large

Customers, the Company and the Customer will mutually agree to different maintenance schedules as listed above.

**Standby Service Customer** is a Customer who receives the following services from the Company, Sections 11.01; backup power for non-Company generation, supplemental power, and scheduled maintenance power. These services are not applicable for resale, municipal outdoor lighting, or customers with emergency standby Generators.

**Summer Season** is the period from June 1 through September 30.

**Summer On-Peak**: For all kW and kWh used Monday through Friday between hours 1:00 p.m. to 7:00 p.m. **C C**

**Summer Shoulder**: For all kW and kWh used Monday through Friday between hours 11:00 a.m. to 1:00 p.m., 7:00 p.m. to 10:00 p.m., and on weekends between hours 11:00 a.m. to 10:00 p.m. **C C C**

**Summer Off-Peak**: For all kW and kWh used Monday through Friday between hours 10:00 p.m. to 11:00 a.m. and on weekends between hours 10:00 p.m. to 11:00 a.m. **C C**

**Supplemental Service** is the Energy and Demand supplied by the utility in addition to the capability of the on-site Generator. Except for determination of Demand, Supplemental Service shall be provided under Standard Rate Schedule 10.06.

**Supplemental Demand** (a component of Supplemental Service) is the metered Demand measured on Company Meter during on-peak and off-peak periods, less Contracted Backup Demand.

**Winter Season** is the period from October 1 through May 31.

**Winter On-Peak**: For all kW and kWh used Monday through Friday between hours 7:00 a.m. to11:00 a.m. **C C**

**Winter Shoulder:** For all kW and kWh used Monday through Friday between hours 6:00 a.m. to 7:00 a.m., hours 11:00 a.m. to 10:00 p.m. and, on weekends between hours 6:00 p.m. to 10:00 p.m. **C C C**

**Winter Off-Peak**: For all kW and kWh used Monday through Friday between hours 10:00 p.m. to 6:00 a.m. and on weekends between hours 10:00 p.m. to 6:00 p.m. **C C**