Standby/Capacity Reservation Charge Best Practices and Review:

Prepared for Pennsylvania Public Utility Commission CHP Working Group

April 16, 2019

By:

EXERGY
Partners Corp.

entropy
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Acknowledgments

We greatly appreciate the assistance of the following individuals in preparing and/or reviewing this report:

- Joseph M. Sherrick Supervisor Technical Utility Services, Policy & Planning, Pennsylvania Public Utility Commission
- Dr. James Freihaut, Director of DOE's Mid-Atlantic CHP Technology Assistance Partnership
- Vestal Tutterow, Laurence Berkley National Laboratory

We also acknowledge the rate review guidance provided by PECO, Duquesne Light and PPL.

Background

The Pennsylvania Public Utility Commission issued its Final Policy Statement on Combined Heat and Power April 5, 2018. The opening of the statement reads:

> *In light of the potential benefits to the public of Combined Heat and Power (CHP), the Commission is interested in considering ways to advance the development of CHP in Pennsylvania. The Commission recognizes that CHP is an efficient means of generating electric power and thermal energy from a single fuel source, providing cost effective energy services to commercial businesses like hotels, universities and hospitals. CHP systems capture the waste heat energy that is typically lost through power generation, using it to provide heating and cooling for manufacturing and business. In addition to improving manufacturing competitiveness and reducing greenhouse gas emissions, CHP benefits businesses by reducing energy costs and enhancing reliability for the user.*
>
> *The Commission observes that there are several areas where electric and natural gas distribution companies (EDCs and NGDCs) may be able to implement policies and practices that reduce barriers to such development. With this Order, the Commission establishes a biennial reporting requirement for EDCs and NGDCs regarding their efforts to eliminate obstacles to the development of CHP in the Commonwealth.*

National Association of Regulatory Utility Commissioners Board of Directors issued the following resolution actions February 13, 2019:

> *Now therefore be it resolved that the Board of Directors of the National Association of Regulatory Utility Commissioners, convened at its 2019 Winter Meeting in Washington, D.C., supports further discussion relating to the setting of standby rates for partial requirements customers that affect market entry and continued competitiveness of distributed generation; encourages regulators to consider whether the cost of standby rates discourages further deployment of CHP and WHP, and could harm CHP and WHP facility competitiveness; and encourages Commissioners to assure that standby rates for partial requirements customers acknowledge that: (a) effectively coordinating CHP and WHP with grid system operations reduces demand and costs; and (b) CHP and WHP have the potential to improve system reliability and resiliency.*

Purpose of this Analysis

Standby tariffs and rates can affect the economic feasibility of CHP projects. Customers who receive all of their electricity from the utility are known as "full requirements" customers. Their electricity is provided under rates that are primarily some mix of fixed customer charges - a recurring charge (monthly or daily) intended to cover the constant costs of metering, billing, and service drop facilities; energy charges - the charges for consumption of the electricity commodity applied on a per-kWh basis; and demand charges – charges based on the peak electricity demand (kW) during a given period and used to recover the capital costs of the capacity necessary to meet the customer's peak loads. Customers with onsite generation typically require a different set of services, which includes continuing electricity service for the portion of usage that is not provided by the onsite generator, as well as service for periods of scheduled or unscheduled outages. "Partial requirements" is the more precise name for *standby* or *backup* service: the set of retail electric products that customers with onsite, non-emergency generation typically need. This service could be provided under a tariff that replaces the standard full requirements tariff, or an additional tariff that applies on top of the standard tariff for certain special types of services. Common components of service for partial requirements customers can include:

(1) *Supplemental Service*. Supplemental service for customers whose on-site generation does not meet all of the customer's needs. In many cases, it is provided under the otherwise applicable full requirements tariff.
(2) *Back-up Service*. Back-up, or stand-by, serves a customer's load that would otherwise be served by DG, during unscheduled outages of the on-site generation.
(3) *Scheduled Maintenance Service*. Scheduled maintenance service is taken when the customer's generator is due to be out of service for routine maintenance and repairs.
(4) *A capacity reservation charge* to compensate the utility for the capacity that the utility must have available to serve a customer during an unscheduled outage of the customers own generation unit.

This analysis was undertaken to support the PA PUC's CHP working group to better understand the nature of standby, reservation charge and supplemental charges in Pennsylvania and the impact of these charges on CHP project economics. 5-Lakes Energy was initially engaged to gather the relevant rate data from three EDCs - PECO, PPL and Duquesne - and develop a model to assess the annual electricity costs for three CHP use cases detailed later in this report. 5-Lakes later became involved in an ongoing EDC rate case and did not participate in subsequent direct EDC contact or further analysis based on feedback from the EDCs. Exergy Partners Corp. and Entropy Research LLC worked with PECO, PPL and Duquesne to improve the accuracy of the modeling within current time constraints to be sure the relative comparisons are as accurate as possible. It should be noted that the three EDCs were cooperative in preparing this report to aid in discussion during the PA PUC CHP Working Group.

At this time, we have analysis of the impact PECO's standby Capacity Reserve Rider "CRR" and Duquesne's standby Rider 16. Time did not permit the same level of analysis regarding PPL's standby Rider 6.

Standby/Reservation Charges

To better understand the nature and structure of Electric Distribution Companies (EDCs) standby, Penn State University contracted with 5-Lakes Energy to initially examine standby charges impacting three typical CHP systems types and applications[1]:

1. 8 MW combustion turbine CHP system used in a high load factor production facility - 24/7 operation

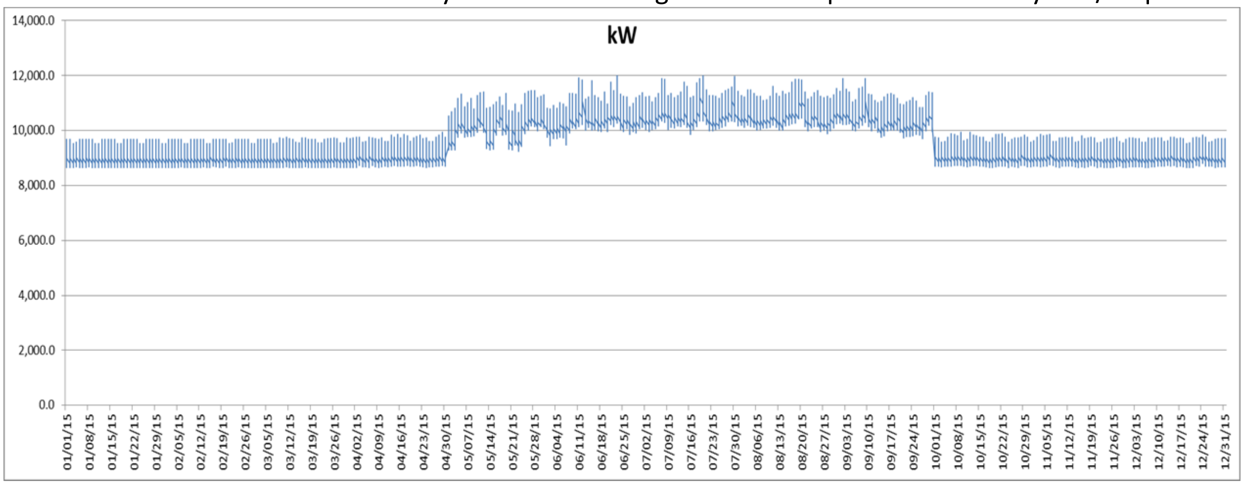


Figure 1: ***High Load Factor Production Load Profile***

Application: High Load Factor Production - 24/7 Oper							Base Voltage: 13,200						
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
Billing days per month	31	28	31	30	31	30	31	31	30	31	30	31	365
Hours	744	672	744	720	744	720	744	744	720	744	720	744	8760
Maximum Demand, kW	9,685	9,691	9,754	9,939	11,454	12,000	11,992	11,874	11,898	9,939	9,872	9,845	12,000
Average Demand, kW	8,988	8,978	8,976	9,017	10,173	10,363	10,556	10,512	10,411	9,034	9,015	9,011	9,590
Minimum Demand, kW	8,659	8,659	8,659	8,659	9,238	9,454	9,851	9,889	9,712	8,659	8,659	8,659	8,659
Consumption, kWh	6,687,328	6,033,316	6,678,317	6,492,359	7,568,346	7,461,397	7,853,748	7,821,226	7,496,206	6,721,619	6,490,696	6,704,248	84,008,805
CHP Generation, kWh	4,040,000	5,376,000	5,952,000	5,760,000	5,952,000	5,760,000	5,760,000	5,952,000	5,760,000	5,952,000	5,760,000	5,952,000	67,976,000
Standby Generation kWh	1,912,000	0	0	0	0	0	192,000	0	0	0	0	0	2,104,000
Supplemental Generation kWh	735,328	657,316	726,317	732,359	1,616,346	1,701,397	1,901,748	1,869,226	1,736,206	769,619	730,696	752,248	13,928,805
Max Supplemental Demand kW	1,685	1,691	1,754	1,939	3,454	4,000	3,992	3,874	3,898	1,939	1,872	1,845	4,000
Average Supplemental Demand kW	988	978	976	1017	2173	2363	2556	2512	2411	1034	1015	1011	1586
Load Factor													0.799

Figure 2: ***High Load Factor Production CHP Dataset Example***

CHP system assumptions:

CHP Capacity: 8 MW
CHP Electrical Efficiency: 29.2%
Useful Thermal: 4,848 Btu/kWh
CHP O&M cost: 0.012 $/kWh
Fuel Price, $/MMBtu: $5.00
CHP operation: 24 hours/day, 7 days/week
Scheduled Maintenance Outage: One 10-day outage in January
Unscheduled Forced Outage: One 24-hour outage in July

[1] For comparison purposes a natural gas price of $5 / MMBtu was used in all cases for CHP prime mover fuel and displaced boiler fuel costs

2. 1 MW reciprocating engine CHP system in an average load factor production facility - 2 shifts/5 days per week operation

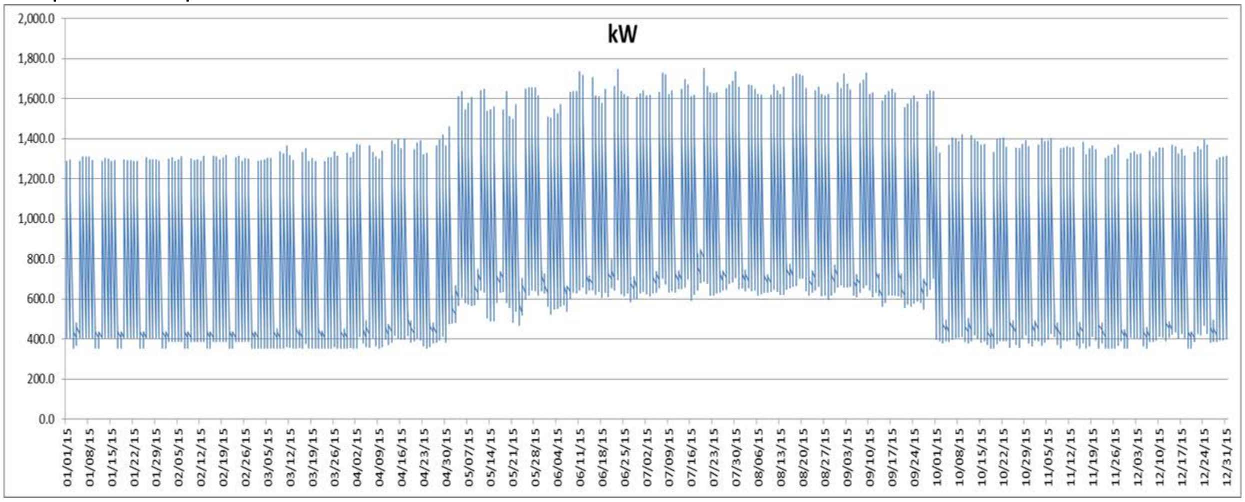


*Figure 3: **Average Load Factor Production Load Profile***

Application: Average Load Factor Production - 2 Shifts/5 Days per Week Oper								Base Voltage: 13,200/4,160					
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
Billing days per month	31	28	31	30	31	30	31	31	30	31	30	31	365
Hours	744	672	744	720	744	720	744	744	720	744	720	744	8,760
Maximum Demand, kW	1,311	1,318	1,363	1,418	1,656	1,747	1,750	1,723	1,726	1,418	1,401	1,394	1,750
Average Demand Op Hours, kW	1,079	1,080	1,075	1,162	1,384	1,450	1,474	1,399	1,456	1,160	1,126	1,152	1,250
Average Demand, kW	760	761	758	804	976	1,036	1,081	1,044	1,052	803	785	799	889
Minimum Demand, kW	357	357	357	357	471	524	593	598	551	357	357	357	357
Consumption, kWh	565,565	511,189	564,035	579,036	726,320	746,125	804,061	776,422	757,465	597,739	565,336	594,669	7,787,962
CHP Generation, kWh	361,479	341,014	397,479	384,658	397,479	384,658	379,479	397,479	384,658	397,479	384,658	397,479	4,608,000
Standby Generation kWh	36,000	18,000	0	0	0	0	18,000	0	0	0	0	0	72,000
Supplemental Generation kWh	168,085	152,175	166,556	194,378	328,840	361,467	406,582	378,943	372,808	200,260	180,678	197,190	3,107,962
Max Supplemental Demand kW	432	432	432	432	656	747	750	723	726	432	432	432	750
Average Supplemental Demand kW	226	226	224	270	442	502	546	509	518	269	251	265	354
Load Factor													0.508

*Figure 4: **Average Load Factor Production CHP Dataset Example***

CHP system assumptions:

CHP Capacity: 1 MW

CHP Electrical Efficiency: 37.6%

Useful Thermal: 3,909 Btu/kWh

CHP O&M cost: 0.011 $/kWh

Fuel Price, $/MMBtu: $5.00

CHP operation: 18 hours/day, 5 weekdays/week

Scheduled Maintenance Outage: One 36-hour weekend outage in January

Unscheduled Forced Outage: Two 18-hour weekday outages in February and July

3. 200 kW microturbine CHP system in an office building with normal business hour operation

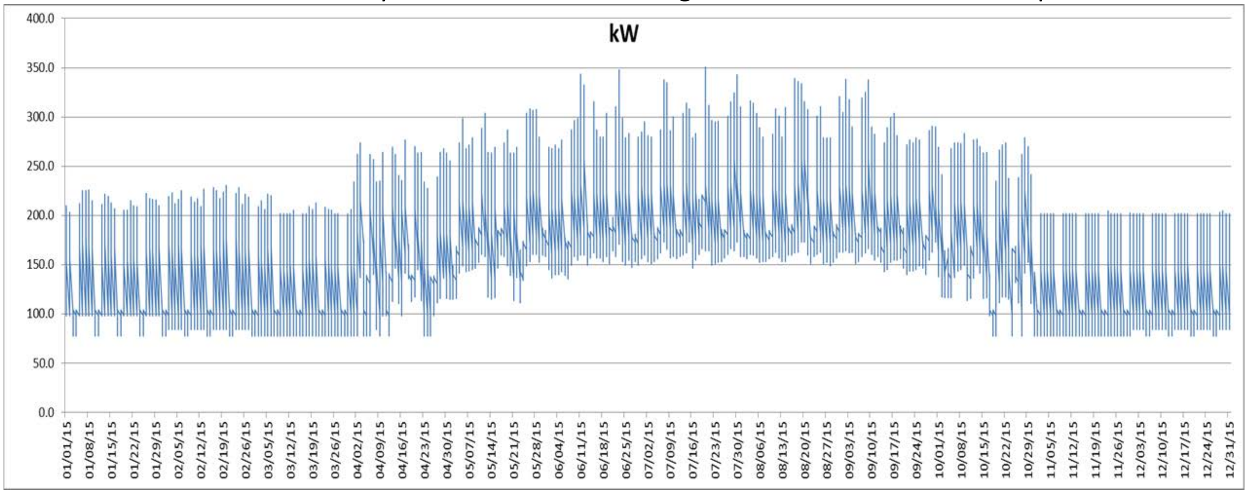


Figure 5: ***Office Building with Normal Business Hour Operation Load Profile***

Application: Office Building - Normal Business Hrs Oper							Base Voltage: 480						
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
Billing days per month	31	28	31	30	31	30	31	31	30	31	30	31	365
Hours	744	672	744	720	744	720	744	744	720	744	720	744	8,760
Maximum Demand, kW	226	231	221	276	308	348	350	339	338	283	204	204	350
Average Demand Op Hours, kW	216	219	198	256	287	301	308	290	305	244	190	198	251
Average Demand, kW	135	136	129	164	191	202	212	207	207	175	126	129	168
Minimum Demand, kW	78	78	78	100	125	136	146	149	140	125	78	78	78
Consumption, kWh	100,422	91,442	95,734	117,795	141,884	145,750	157,623	154,011	149,040	130,396	90,602	95,754	1,470,454
CHP Generation, kWh	40,997	47,868	52,997	51,288	52,997	51,288	50,597	52,997	51,288	52,997	51,288	52,997	609,600
Standby Generation kWh	12,000	0	0	0	0	0	0	2,400	0	0	0	0	14,400
Supplemental Generation kWh	47,424	43,574	42,736	66,508	88,887	94,463	107,026	98,614	97,753	77,398	39,314	42,757	846,454
Max Supplemental Demand kW	103	103	103	125	150	161	171	174	165	150	103	103	174
Average Supplemental Demand kW	64	65	57	92	119	131	144	133	136	104	55	57	96
Load Factor													0.479

Figure 6: ***Office Building with Normal Business Hour Operation CHP Dataset Example***

CHP system assumptions:

CHP Capacity: 200 kW
CHP Electrical Efficiency: 28.4%
Useful Thermal: 4,578 Btu/kWh
CHP O&M cost: 0.02 $/kWh
Fuel Price, $/MMBtu: $5.00
CHP operation: 12 hours/day, 5 weekdays/week
Scheduled Maintenance Outage: One 5 weekday outage in January
Unscheduled Forced Outage: One 12-hour weekday outage in July

Results

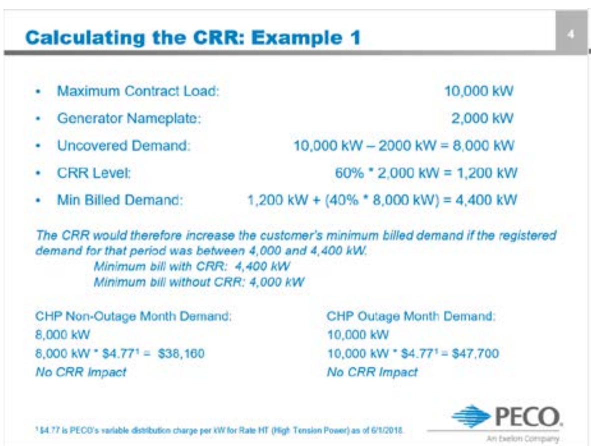
PECO

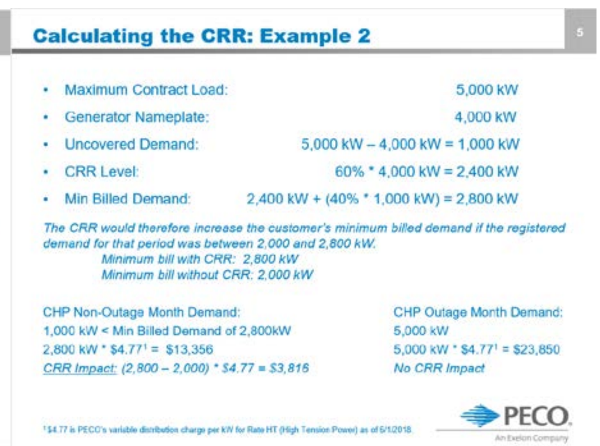
The CRR applies to parallel-generating customers to commercial and industrial customers placing generation facilities with over 100 kW nameplate capacity online on or after 1/1/2016. The CRR modifies customer's minimum billing demand.

Min Billing Demand Under CRR = Min Billing Demand Under Prevailing Tariff Rate (40% of uncovered demand[2]) + "CRR Level" applying to customer's generation nameplate as follows:

> 100 kW but <= 5,000 kW – 60% of generator nameplate rating
> 5,000 kW but <= 10,000 kW – 50% of generator nameplate rating
> 10,000 kW – Determined by negotiation (not < 40%)
Amount of reserved capacity reflects potential peak demand

For example:





Figures 7 to 9 show the calculated Transmission, Standby/Reservation Charges & Supplemental electric cost for the three case studies both with and without PECO's Capacity Reserve Rider. The model used 2018 PECO's High-Tension Rate Tariff for the 12,000 kW and 1,750 kW sites and PECO's General Service Rate Tariff for the 350 kW site. Note the CRR does not distinguish between planned maintenance outages or unplanned outages. Figures 7 through 9 show that for all three cases, using the CRR is more costly than the standard rate tariff for the three defined typical CHP cases.

Energy Supply Charge Rate	$0.030206	per kWh
Rate administrative adder	$0.004860	per kWh
Energy Capacity Charge Rate	$0.1537	per kW
Variable Distribution Service Charge Rate	$4.77	per kW

Table 1 PECO 2018 High Tension Rate Tariff Electricity Cost in the Model for the 12,000 kW and 1,750 kW Case Studies

[2] any load behind meter not covered by CRR e.g. annual peak load minus CHP unit electric capacity covered by the CRR

Energy Supply Charge Rate	$0.030206	per kWh
Rate administrative adder	$0.005060	per kWh
Energy Capacity Charge Rate	$0.1537	per kW
Variable Distribution Service Charge Rate	$7.98	per kW

Table 2 PECO 2018 General Service Rate Tariff Electricity Cost in the Model for the 350 kW Case Study

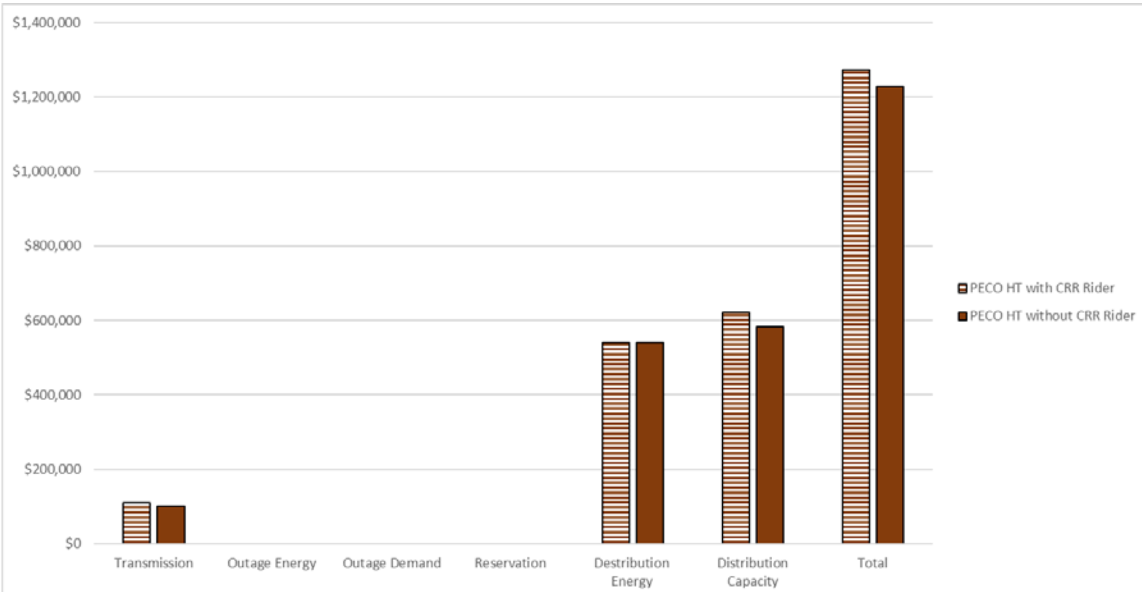


Figure 7: PECO Transmission, Standby/Reservation Charges & Supplemental 12 MW Site - 8 MW CHP

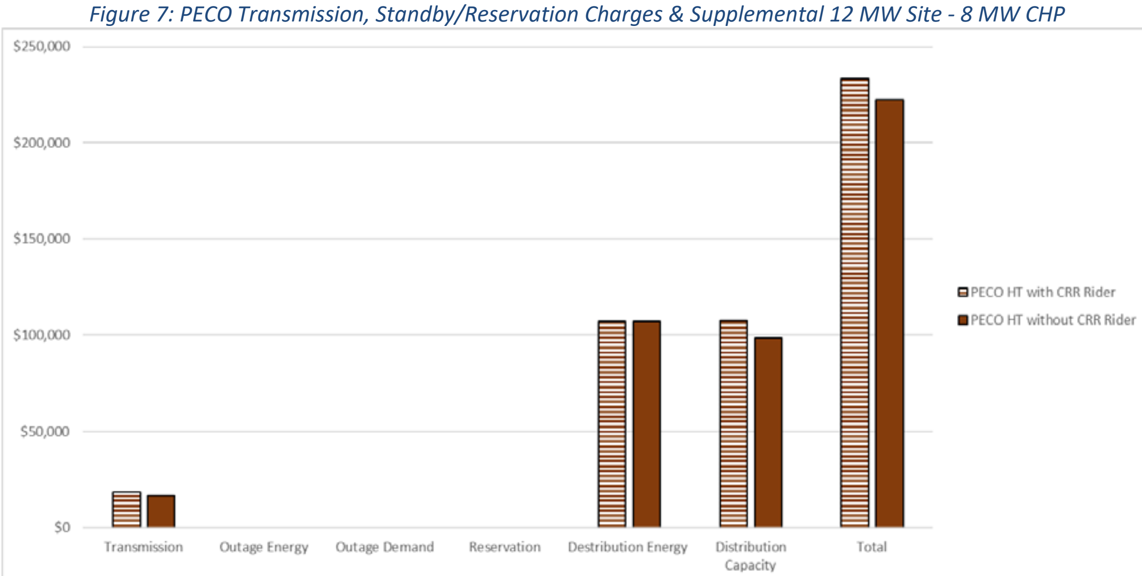


Figure 8: PECO Transmission, Standby/Reservation Charges & Supplemental 1.75 MW Site - 1 MW CHP

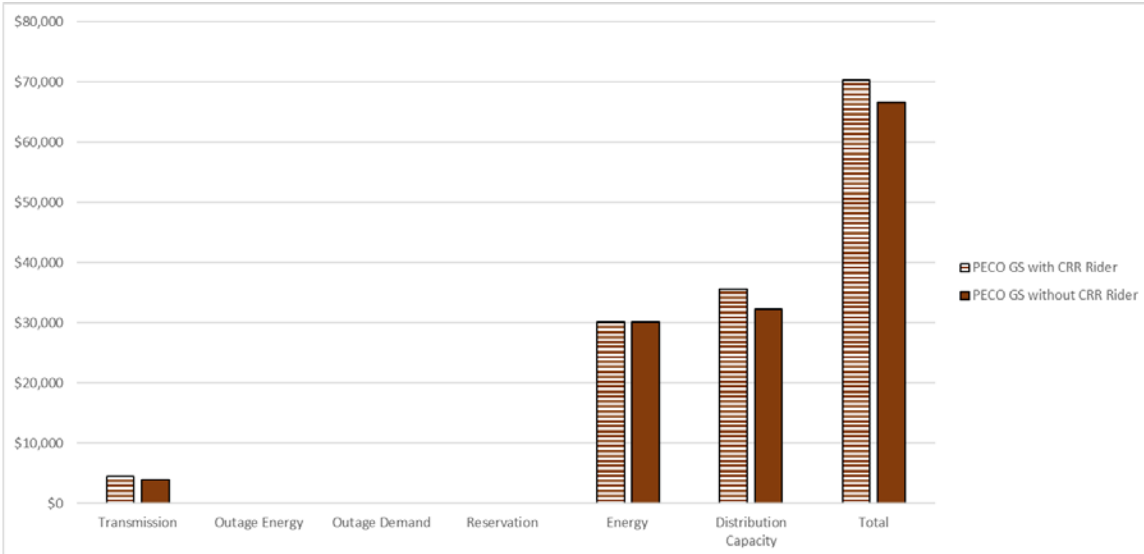


Figure 9: PECO Transmission, Standby/Reservation Charges & Supplemental 350 kW Site - 200 kW CHP

Understanding the impact of the base rate tariff versus the CRR rate tariff has on the three cases studies. The impact on purchased electricity costs switching between the two tariffs has on the CHP system operation can be seen in the second column of Table 3 Total Purchased Electricity.

The last column in Table 3 shows the impact of not using the CRR. In the case of the 8,000-kW CHP system, by not using the CRR you gain $45,431 in annual savings, in the case of the 1,000-kw system you gain $10,813 annually and the 200-kW system you gain $3,792 annually.

Note the largest percentage differential between the CRR rate and the base tariff is in the 200 kW CHP case.

	CHP Capacity Case	Total Purchased Electricity	CHP Fuel Cost	CHP O&M	Displaced Boiler Fuel	Total Operating Cost with CHP	Total Operating Cost without CHP	Operating Cost Savings with CHP	Savings without CRR
PECO HT with CRR	8,000 kW	$1,273,468	$3,971,475	$815,712	($2,059,673)	$4,000,982	$4,528,162	$527,180	
PECO HT without CRR	8,000 kW	$1,228,037	$3,971,475	$815,712	($2,059,673)	$3,955,551	$4,528,162	$572,611	$45,431
PECO HT with CRR	1,000 kW	$233,255	$209,076	$87,552	($112,579)	$417,304	$499,635	$82,331	
PECO HT without CRR	1,000 kW	$222,443	$209,076	$87,552	($112,579)	$406,491	$499,635	$93,143	$10,813
PECO GS with CRR	200 kW	$70,327	$36,619	$12,192	($17,442)	$101,696	$106,925	$5,229	
PECO GS without CRR	200 kW	$66,535	$36,619	$12,192	($17,442)	$97,904	$106,925	$9,021	$3,792

Table 3: PECO Operating Costs and CHP Savings with and without CRR

Duquesne Power and Light

Figures 10 to 12 show the calculated Transmission, Standby/Reservation Charges & Supplemental electric cost for the three case studies both with and without Duquesne's Rider 16.

Rider 16 states that a distribution charge of $2.50 per kW shall be applied to the Back-Up Power Billing Determinants for Back-Up Power. The distribution charges will be applied in each month based on the customer's Contract Demand without regard to whether or not back-up energy is supplied.

Note that Rider 16 does not distinguish between planned maintenance outages or unplanned outages. Figures 10 through 12 show that for all three cases, using the Rider 16 is less costly than the standard rate tariff. Rider 16 clearly shows that outage energy, demand and reservation charges combined with the reduced distribution capacity charge is less than the distribution capacity charge using the conventional rate tariff. In this case, Rider 16 performs as expected, reducing the cost for all three defined typical CHP cases. Table 4-6 show the base rates for the three cases used in the model.

Rate administrative adder	$0.001740	per kWh
Energy Capacity Charge Rate (per kW)	$0.15361	per kW
Variable Distribution Service Charge Rate	$13.12	per kW
Transmission Service Charge Rate	$4.10	per kW

Table 4 Duquesne Large Rate Tariff Electricity Cost in the Model for the 8,000 kW Case Study

Rate administrative adder	$0.001740	per kWh
Energy Capacity Charge Rate (per kW)	$0.15361	per kW
Variable Distribution Service Charge Rate	$8.41	per kW
Transmission Service Charge Rate	$3.95	per kW

Table 5 Duquesne General Service Large Rate Tariff Electricity Cost in the Model for the 1,000 kW Case Study

Rate administrative adder	$0.001740	per kWh
Energy Capacity Charge Rate (per kW)	$0.15361	per kW
Variable Distribution Service Charge Rate	$6.54	per kW
Transmission Service Charge Rate	$1.77	per kW

Table 6 Duquesne General Service Small and Medium Rate Tariff Electricity Cost in the Model for the 350 kW Case Study

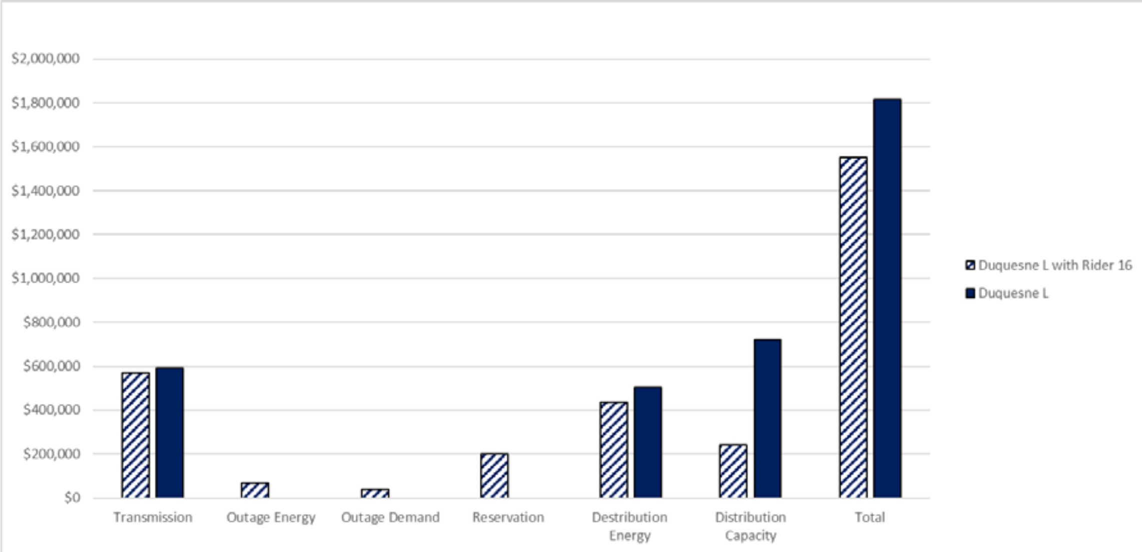


Figure 10: Duquesne Transmission, Standby/Reservation Charges & Supplemental 12 MW Site - 8 MW CHP

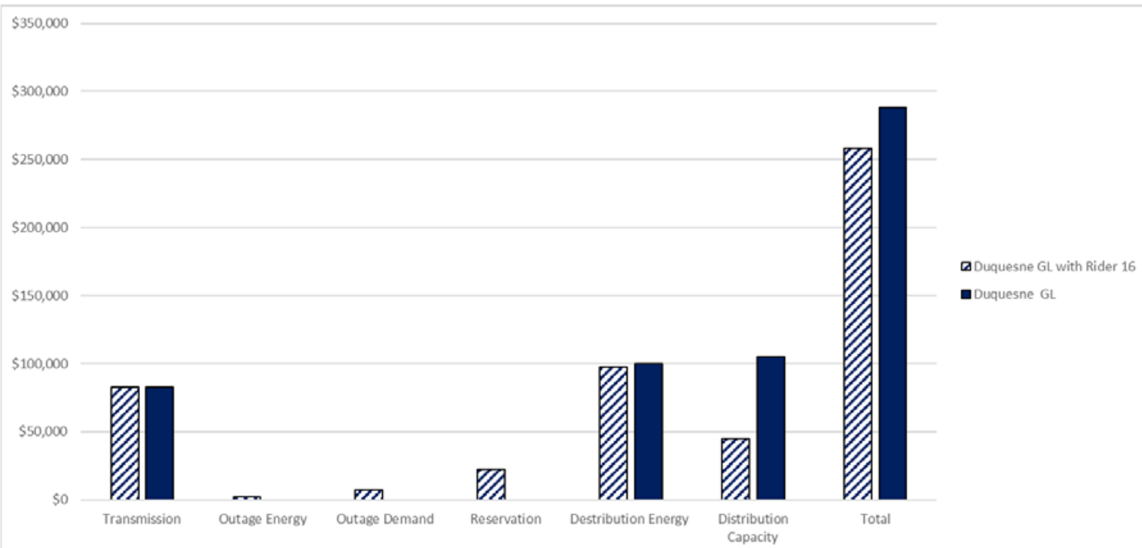


Figure 11: Duquesne Transmission, Standby/Reservation Charges & Supplemental 1.75 MW Site - 1 MW CHP

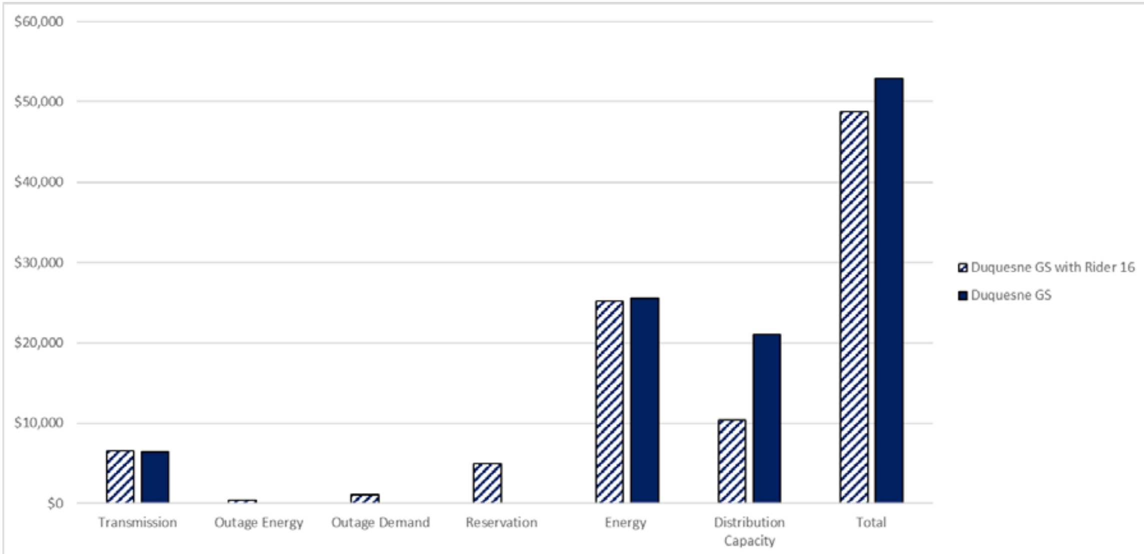


Figure 12: Duquesne Transmission, Standby/Reservation Charges & Supplemental 350 kW Site - 200 kW CHP

Table 8 shows the impact of the of Duquesne's rate tariffs on the three CHP cases. Understanding the impact of the base rate tariff versus the CRR rate tariff has on the three cases studies. The impact on purchased electricity costs switching between the two tariffs has on the CHP system operation can be seen in the second column of Table 3 Total Purchased Electricity.

The last column in Table 3 shows the impact of using the Rider 16. In the case of the 8,000-kW CHP system, by using the Rider 16 you gain $974,860 in annual savings, in the case of the 1,000-kw system you gain $62,814 annually and the 200-kW system you gain $8,511 annually.

Note the largest percentage differential between Ricer 16 and the base tariff is in the 8,000 kW CHP case moving from a loss to a significant gain.

Note the large impact in the 8,000 kW CHP case.

	CHP Capacity Case	Total Purchased Electricity	CHP Fuel Cost	CHP O&M	Displaced Boiler Fuel	Total Operating Cost with CHP	Total Operating Cost without CHP	Operating Cost Savings with CHP	Savings with Rider 16
Duquesne Rider 16	8,000 kW	$1,857,126	$3,971,475	$815,712	($2,059,673)	$4,584,640	$5,284,991	$700,351	$974,860
Duquesne Rider GL	8,000 kW	$2,831,986	$3,971,475	$815,712	($2,059,673)	$5,559,500	$5,284,991	($274,508)	
Duquesne Rider 16	1,000 kW	$336,079	$209,076	$87,552	($112,579)	$520,127	$595,549	$75,422	$62,814
Duquesne Rider GL	1,000 kW	$398,893	$209,076	$87,552	($112,579)	$582,941	$595,549	$12,608	
Duquesne Rider 16	200 kW	$68,288	$36,619	$12,192	($17,442)	$99,657	$114,862	$15,205	$8,511
Duquesne Rider GS	200 kW	$74,240	$36,619	$12,192	($17,442)	$105,609	$112,303	$6,694	

Table 7: Duquesne Operating Costs and CHP Savings with and without Rider 16

Findings

The analysis raises a series of question regarding standby rate complexity, transparency and equity.

1. There appears to be little consistency between the EDCs with respect to standby charges.
2. Standby / Reservations charges and structure vary considerably between the three EDCs.
3. Descriptors vary widely for services, which fosters confusion.
4. PECO's CRR standby rate had a negative impact on the three CHP cases reviewed.
5. Duquesne's Rider 16 standby rate had a positive impact on the three CHP cases reviewed.
6. Tariffs descriptions were sometimes not clear – providing example calculations would help (one EDC had one example calculation).
7. Structures can be complex and difficult to properly apply without utility input. One example of utility assistance is from Ameren Missouri Rates group which has developed excel tools which customers can use to input projected load profiles and generation assumptions to estimate the impact of standby rider on their bill. https://www.ameren.com/missouri/business/rates/electric-rates/rider-ssr
8. There was no distinction between maintenance backup power (which can often be scheduled off-peak) demand and unscheduled downtime.

General Recommendation for Standby and Reservation Charges[3]

Summary of Best Practices in Standby

Rate Design

Based on the experience of RAP and BAI in the area of standby rate design, explained in Chapter 1, the following are best practices for consideration in the development of standby rates:

Allocation of Utility Costs

- Generation, transmission, and distribution charges should be unbundled in order to provide transparency to customers and enable appropriate and cost-based standby rate design.
- Supplemental power charges should be based on charges in the applicable full requirements tariff.
- Generation reservation demand charges should be based on the utility's cost and the forced outage rate of customers' generators on the utility's system.

Judgments Based on Statistical Method

- Standby rate design should not assume that all forced outages of on-site generators occur simultaneously, or at the time of the utility system peak.
- Transmission and higher-voltage distribution demand charges should be designed in a manner that recognizes load diversity.
- Standby rate design should assume that maintenance outages of on-site generators would be coordinated with the utility and scheduled during periods when system generation requirements are low.

Value of Customer Choice and Incentives

- Daily maintenance demand charges should be discounted relative to daily backup demand charges to recognize the scheduling of maintenance service during periods when the utility generation requirements are low.
- Customers should have the option to purchase all or some portion of their standby service on an interruptible basis and thereby avoid generation reservation demand charges.
- Pro-rated, daily, as-used demand charges for backup power and shared transmission and distribution facilities should be used to provide an incentive for generator reliability.
- Customers should be able to procure standby service from competitive power providers at prevailing market prices, where available.

[3] Standby Rates for Combined Heat and Power Systems Economic Analysis and Recommendations for Five States, James Selecky, Kathryn Iverson, and Ali Al-Jabir, Regulatory Assistance Project, February 2014

Why not use 2019 resolution?

Appendix A: NARUC Resolution on Standby Rates for Partial Requirements Customers

Whereas the National Association of Regulatory Utility Commissioners (“NARUC”) and its members have long focused on energy efficiency, electric system reliability and resiliency, and reduction of greenhouse gas emissions;

Whereas combined heat and power (“CHP”) can be a cost-effective way to produce two or more forms of useful energy from a single fuel source, often including both thermal energy and electricity;

Whereas waste heat to power (“WHP”) is the process of capturing heat discarded by an existing process and using that heat to generate power with no additional fuel, combustion or emissions;

Whereas CHP and WHP are forms of distributed generation that can provide benefits for consumers and to U.S. businesses in the form of reduced energy costs, reduced risk of electric grid disruption and enhanced energy reliability, stability, and resilience in the face of uncertain electricity prices and major disruptive events;

Whereas CHP and WHP can provide benefits for the nation by lowering the need for other, less efficient sources of new electric generation capacity, avoiding transmission and distribution costs, creating markets for domestic energy sources, developing and maintaining employment opportunities for skilled labor, optimizing the use of our nation’s abundant supply of natural gas, and reducing emissions;

Whereas CHP can provide services in a microgrid in ways that can help enable better use of other clean energy sources;

Whereas federal law recognizes these benefits by affording Qualifying Facility status to CHP and WHP systems and the executive branch in 2012 established a national goal of increasing CHP deployment by approximately 50% by 2020;

Whereas in 2008 NARUC passed a resolution explicitly urging commissions to “consider the adoption of regulatory policies that protect consumers while addressing barriers to increased use of CHP related to standby rate design;”

Whereas in 2012 NARUC passed a resolution encouraging State public service commissions to evaluate opportunities for CHP, encourage cost effective investment in CHP, and evaluate regulatory mechanisms to best deploy these technologies;

Whereas in 2013 NARUC passed a resolution supporting the inclusion of WHP technologies in State and federal clean energy policies and programs;

Whereas despite these resolutions and the widespread recognition of these benefits, the technical and economic potential for CHP and WHP far exceeds their deployment;

Whereas many utility companies have “standby” rates for customers taking “partial-requirements service” that may be confusing, might not be based on cost-of-service principles, and may fail to account for the benefits that these systems offer to the grid;

Whereas the NARUC Distributed Energy Resources Rate Design and Compensation manual provides that standby rates should reflect actual system costs and clarifies that charges should not discourage investment in CHP by potential customers;

Whereas encouraging or requiring CHP or WHP hosts to schedule maintenance during off-peak times and distinguishing between scheduled and unscheduled outages can reduce utility system demand and costs;

Whereas the rates for partial requirements service should be as simple, transparent, and consistent as practical;

Now therefore be it resolved that the Board of Directors of the National Association of Regulatory Utility Commissioners, convened at its 2019 Winter Meeting in Washington, D.C., supports further discussion relating to the setting of standby rates for partial requirements customers that affect market entry and continued competitiveness of distributed generation; encourages regulators to consider whether the cost of standby rates discourages further deployment of CHP and WHP, and could harm CHP and WHP facility competitiveness; and encourages Commissioners to assure that standby rates for partial requirements customers acknowledge that: (a) effectively coordinating CHP and WHP with grid system operations reduces demand and costs; and (b) CHP and WHP have the potential to improve system reliability and resiliency.

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Sponsored by the Committee on Energy Resources and the Environment
Adopted by the NARUC Board of Directors on February 13, 2019

Appendix B: PECO Capacity Reserve Rider

PILOT CAPACITY RESERVATION RIDER (CRR)

PURPOSE.
This Rider sets forth the eligibility, terms and conditions applicable to Customers who operate generation in parallel to the Company distribution system and who need to reserve electric capacity to serve their load when the customer generator is offline. The CRR shall not apply to customer generating facilities that are online prior to January 1, 2016.

This Rider also sets for the eligibility, terms and conditions applicable to Customers who want to reserve capacity in excess of their present demand from the PECO distribution system for new business growth or expansion.

APPLICABILITY/AVAILABILITY.
Applicable to customers, including but not limited to Qualifying Facilities or Small Power Producers and cogenerators as defined in the Public Utility Regulatory Policies Act, whose electrical requirements are partially or wholly provided by facilities not owned by the Company and when such facilities operate in parallel with the Company's distribution system. All such customers will be supplied under the provisions of this rider, the customer's applicable Base Rate, and other applicable riders.

Customers who wish to reserve available electrical capacity in excess of their present usage for new business growth or expansion may do so under this rider.

NOTICE BEFORE COMMENCEMENT OF CRR SERVICE.
The customer shall not commence initial operation of any other source of supply in parallel with the Company's distribution or transmission lines until written permission is given by the Company for such parallel operation. Such written permission shall include a statement of the amount of capacity reserved for the customer under this CRR. Before a customer is placed on the CRR, the Company must provide written notice to the customer informing the customer that, upon receiving service under the CRR, capacity beyond the amount of capacity reserved under the CRR may not be available to serve the customer. The Company shall have the right to inspect the customer's installation prior to providing such written permission, and at any reasonable time thereafter in accordance with Tariff Rule 9.3.

AMOUNT OF CAPACITY RESERVED.
The maximum firm capacity available to be reserved will be determined by the Company based upon its review of capacity available on its system at the time that a request for capacity reservation is made.

Batteries and other electrical storage shall not be deemed to be generators for purpose of the CRR, and the capacity or nameplate of storage or battery equipment shall not be used in calculating the CRR.

Any customer, regardless of size of load or generation, may initiate negotiation to set the CRR at a level other than the levels designated below.

For customers generating in parallel and who have generator capacity of greater than 100 kW and less than 5,000 kW, the amount of capacity reserved for that customer will be 60% of the generator nameplate rating.

For customers generating in parallel and who have generator capacity of greater than 5,000 kW and less than 10,000 kW, the amount of capacity reserved for that customer will be 50% of the generator nameplate rating.

For customers generating in parallel who have generator capacity in excess of 10,000 kW, the amount of capacity reserved for that customer will be determined by negotiation, with the amount of reserved capacity in an amount that the Company and customer agree accurately reflects the customer's peak potential demand on the Company's distribution system.

For customers who want to reserve capacity for new business growth or expansion, the amount of capacity reserved for that customer will be determined by negotiation.

In all cases, if the requested electric capacity is not available the customer shall pay all cost to the Company of any construction necessary to meet the customer's requested reserved capacity.

NEGOTIATIONS.

If the amount of reserved capacity is set through negotiations, the following will apply:
The customer and PECO will meet to discuss customer operations. After such discussions, the customer may designate a CRR level other than as set forth above, but not lower than 40% of the customer's peak demand for load behind its meter, based upon one or more of the following factors:

1. Parasitic Load: The power consumed by the equipment supporting the operation of a customer's generation shall be removed.
2. Operational Flexibility in Operation of Generation: The customer may state that it will operate its generation in a manner such that PECO will not need to keep capacity available to serve some portion of the customer's "covered" load.
3. Ability to Shed Load: The customer may state that, in the event that its generator goes offline or is not operating to full capacity, it will shed native load to offset some or all of the loss of generation.

If PECO accepts the customer's designated level of reserved capacity, then the amount of capacity reserved shall be the customer-designated level.

If PECO does not accept the customer's designated level of reserved capacity, then PECO may challenge the reasonableness of any such designation by filing a complaint with the PUC (to be referred to the Office of Mediation). Pending resolution of the complaint the CRR shall be set at:

- For customer designations based upon Parasitic Load, Operational Flexibility, or both, the CRR will be set at the customer-designated level, subject to retrospective revision upon completion of the mediation/litigation.

- For customer designations based in whole or part on Ability to Shed Load, the CRR will be set at a PECO-designated level, subject to retrospective revision upon completion of the mediation/litigation

PROCEDURES TO CONFIRM MODE OF CUSTOMER GENERATION OPERATION.

If a customer's CRR is set by negotiation based upon Parasitic Load or Operational Flexibility of Generation, or both, then:

- The customer shall inform PECO in writing if its generation operations differ materially from the mode of operations used to set the CRR limit;
- The customer shall verify to PECO once each calendar year that its generator operations in the prior year did not differ materially from the mode of operations used to set the CRR limit; and
- PECO shall have the right to conduct an audit of customer operations to determine whether generator operations differed materially from the mode of operations used to set the CRR limit.

NOTICE OF OPERATION CONTRARY TO A NEGOTIATED CRR LIMIT AND RESET PROVISION.

If, in its determination, PECO believes that a customer has operated its distributed generation units in a manner contrary to the mode of operations used to set the CRR limit, PECO may issue a written violation notice to the customer. PECO will rescind a violation notice if, within 30 calendar days of receiving the violation notice, a customer furnishes evidence showing that it operated its distributed generation units consistent with the mode of operations used to set the CRR during the period in question. If PECO is not satisfied that the information provided by the customer demonstrates that it operated its distributed generation units consistent with the mode operations used to set the CRR, PECO may file a complaint with the Commission and the Commission's determination shall prevail on whether the notice of violation will be deemed to be confirmed. If a customer does not furnish such evidence within 30 calendar days of receiving the violation notice, the violation notice is confirmed.

If a customer receives two confirmed violation notices within a 24-month period; the customer's going-forward CRR for the next 12 months shall be set at a level based upon the actual operations that led to the violation notice. Thereafter, the CRR may be reset to a lower level only upon the customer demonstrating that it has made material changes to its mode of operations to allow it to operate in the then-described manner.

PENALTY AND RESET FOR FAILURE TO SHED LOAD.

For customers with a CRR level that was set in whole or part based upon Ability to Shed Load, the following penalty and reset provisions shall apply:

- Penalty: If the customer's generator goes offline and the customer does not shed load as agreed upon the customer will be assessed a "burn-through penalty" calculated by determining the amount of load that the customer agreed to shed, but did not shed, and applying a penalty charge equal to 125% of the full demand charge in the prevailing rate to that amount of load on the first such occurrence, and 150% of the full demand charge in the prevailing rate to that amount of load for the second and subsequent occurrences, for the month in which the load shedding did not occur.

- Reset: The customer's going-forward CRR for the next 12 months shall be set at a level based upon the actual operations that occurred during the failure to shed load. Alternatively, the customer can opt to pay PECO for the actual cost of the required upgrades to PECO's distribution facilities to allow the customer to use delivery service at the higher operating level during outages in accordance with PECO's line extension policy. Thereafter, the CRR may be reset to a lower level only upon the customer demonstrating that it has made material changes to its mode of operations to allow it to operate in the then-described manner.

TEMPORARY DISCONNECTION OF CUSTOMER SERVICE.

PECO shall have the right to temporarily disconnect the customer on an emergency basis if, in PECO's opinion, the customer's failure to shed load as agreed creates a risk to PECO's distribution system or service to other customers.

BINDING LEGAL DUTY.

A CRR customer whose CRR is set at a negotiated level based in whole or part upon the customer's representation that it has an Ability to Shed Load will be deemed to have a binding legal duty to shed such load.

RATE AND BILLING.

The following billing provisions apply to this rider in conjunction with service under applicable Rate GS, HT, PD, and EP. Customers will be billed monthly the contracted reserved demand amount plus actual electric demand and usage. Demand and billing demand are defined in the tariff sections "Definition of Terms and Explanation of Abbreviations" and Section 15 of "Rules and Regulations".

No customer who reserves capacity due to parallel generation will pay more demand charges greater than the actual load behind its meter. Customers who reserve capacity for business growth or expansion will pay the reserved CRR amount even though it exceeds their current actual load behind the meter.

MINIMUM CHARGE.

The monthly minimum charge provisions apply to this rider in conjunction with service under applicable Rates GS, HT, PD, and EP.

The monthly minimum demand charge will be the greater of:

1. The demand as registered by the customer's meter;
2. An amount equal to the CRR level determined as set forth above, plus 40% of any load behind the meter that is not covered by the CRR; or
3. Any designated contract minimum.

The monthly minimum customer charge will be determined by reference to the underlying prevailing rate.

TERM OF CONTRACT.

The term of a CRR contract shall be three years for all non-negotiated CRR applications. For negotiated CRR levels, the contract term shall be negotiated. There is no right to automatic renewal of a CRR; upon the expiration of the contract term, the Company will review available capacity on its system and, if such capacity is available, the parties will enter into a new CRR using the procedures set forth above.

- ## Appendix C: Duquesne Rider 16

DUQUESNE LIGHT COMPANY

SUPPLEMENT NO. 91
TO ELECTRIC – PA. P.U.C. NO. 24
FIFTH REVISED PAGE NO. 101
CANCELLING FOURTH REVISED PAGE NO. 101

STANDARD CONTRACT RIDERS - (Continued)

RIDER NO. 16 - SERVICE TO NON-UTILITY GENERATING FACILITIES

(Applicable to all General Service Rates Except Non-Demand Metered GS/GM Customers) **(C)**

The following applies to non-utility generating facilities including, but not limited to cogeneration and small power production facilities that are qualified in accord with Part 292 of Chapter I, Title 18, Code of Federal Regulations (qualifying facility). Electric energy will be delivered to a non-utility generating facility in accord with the following:

A. DEFINITIONS

Supplementary Power is electric energy and capacity supplied by the Company or by an Electric Generation Supplier (EGS) to a non-utility generating facility and regularly used in addition to that electric energy which the non-utility generating facility generates itself. The Company's regular and appropriate General Service Rates will be utilized for billing for Supplementary Power. Customers purchasing Supplementary Power from an EGS will be billed for charges according to their applicable rate and billing arrangement with their EGS. **(C)**

Back-Up Power is electric energy and capacity supplied by the Company to a non-utility generating facility during any outage of the non-utility generating facility's electric generating equipment to replace electric energy ordinarily generated by the non-utility generating facility's generating equipment. **(C)**

Base Period is the twelve consecutive monthly billing periods applicable to the customer ending one month prior to the installation of new on-site generation or increase in capacity to existing on-site supply.

Contract Demand is the maximum electrical capacity in kilowatts that the Company shall be required by the contract to deliver to the customer for Back-Up Power. A Contract Demand may be established for Supplementary Power to the customer's facility. (C) (C)

Supplementary Power Billing Determinants are the monthly billing period billing demand in kilowatts (kW) and the energy usage in kilowatt-hours (kWh) for Supplementary Power during the current billing month under which the on-site generation is operable. The Supplementary Power kW shall not exceed the Contract Demand kW for Supplementary Power, if applicable. (C) (C) (C)

Back-Up Power Billing Determinants are the monthly billing period billing demand in kilowatts (kW) and energy usage (kWh) in excess of those provided as Supplementary Power. If a Contract Demand exists for Supplementary Power, the Back-Up Billing Determinants are the kW and kWh in excess of the Supplementary Power Contract Demand. (C)

Distribution Base Period Billing Determinants are the billing demand (kW) and the energy usage (kWh) for the month in the Base Period corresponding to the current billing month under which the on-site generation is operable. For new customers, the Company will use existing procedures to estimate Base Period Billing Determinants.

Supply Billing Determinants for customers on Rate Schedules GL, GLH, L and HVPS are the billing demand (kW) and energy usage (kWh) during the current billing month then in effect under Rider No. 9. Supply Billing Determinants for customers on Rate Schedule GS/GM and GMH shall be the same as those defined above for Distribution.

(C) – Indicates Change

ISSUED: APRIL 29, 2014 EFFECTIVE: MAY 1, 2014

STANDARD CONTRACT RIDERS - (Continued)

RIDER NO. 16 - SERVICE TO NON-UTILITY GENERATING FACILITIES - (Continued)

(Applicable to all General Service Rates)

B. BACK-UP POWER

The Company will supply such service each month at the following rates:

DISTRIBUTION

(C)
(C)

A distribution charge of $2.50 per kW shall be applied to the Back-Up Power Billing Determinants for Back-Up Power. (C)

The distribution charges will be applied in each month based on the customer's Contract Demand without regard to whether or not back-up energy is supplied.

SUPPLY

In any month that the Company provides energy to back up the customer's equipment, supply service shall be supplied and billed under Rider No. 9 for customers with Contract Demand of 300 kW or more. For customers having Contract Demand of less than 300 kW, the Company will bill the applicable supply demand and energy charges then in effect under Rate Schedule GS/GM.

The use of backup power at this price level will be limited to 15% usage for all hours in a year. Incremental usage above this limit will be billed on the applicable general service rates, including all ratchets applicable.

If a customer's actual kW demand at the time back-up is being supplied exceeds the customer's back-up Contract Demand by 5% or more, the actual kW demand as established will become the customer's new back-up Contract Demand for the remaining term of the back-up contract. If a customer's actual kW demand at the time back-up service is being supplied exceeds the customer's back-up Contract Demand by 10% or more, the customer will be assessed a fee determined by the difference between the actual demand established when back-up service is being supplied and the back-up Contract Demand multiplied by two times the applicable charge per kilowatt.

C. INTERCONNECTION

Each non-utility generating facility will be required to install at its expense or pay in advance to have the Company install interconnection equipment and facilities which are over and above that equipment and facilities required to provide electric service to the non-utility generating facility according to the Company's General Service Rates, except as noted below. Any such equipment to be installed by the non-utility generating facility must be reviewed and approved in writing by the Company prior to installation. Nothing in this Rider shall exempt a new customer from the application of Rule No. 7 and Rule No. 9 regarding Supply Line Extensions and Relocation of Facilities.

However, customers may elect to pay the cost of existing or newly required transformation equipment that is over and above that equipment necessary for the Company to supply the customer with its contracted Supplemental Power via a monthly charge rather than in total at the onset of the contract. The monthly charge for transformation equipment for customers with contract demand under this rider of 5,000 kW or more will be determined by the Company on a case-by-case basis. For all others, the rate of $0.2523 per kW per month will apply.

(C) – Indicates Change

Appendix D: Ameren Missouri Rider SSR - Standby Service Rider

Ameren MISSOURI

Back to Non-Residential Electric Rates

Rider SSR - Standby Service Rider

Rider SSR - Standby Service Rider (PDF)

The Ameren Missouri Rates group has developed excel tools which customers can use to input projected load profiles and generation assumptions to estimate the impact of Rider SSR on their bill. The bill impact tools are designed to utilize 15 minute usage data which is the same information currently used to determine how bills are calculated under Rider SSR. For customers who only have hourly data as an input, the Rates Group has also created a tool to convert this into 15 minute data for ease of use with the bill impact tools.

The SSR rate tools are provided to educate and inform how a customer's bill may be impacted given various usage and generation assumptions under Rider SSR. The decision to invest in cogeneration is complex, and involves numerous factors outside the scope of rate design and the bill impact tools provided on this page.

For questions or assistance with these tools, please contact:

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