Solar Energy Industries Association®

COMMENTS OF THE SOLAR ENERGY INDUSTRIES ASSOCIATION ON STANDBY RATE DESIGN AND TARIFF ISSUES RE: EDC FILINGS TO ADDRESS N.J.S.A. 48:2-21 et seq AND CRITERIA IN JULY 18, 2012 BOARD ORDER

May 8, 2013

The Solar Energy Industries Association (SEIA) respectfully submits the following comments in the Standby Rates Proceeding. Our comments fall under two categories: 1) as the legislative intent clearly excludes solar technologies, SEIA urges the BPU to clarify its interpretation of the term 'distributed generation' as such; and 2) in response to questions h. and j., as put forward by Board Staff in their notice of the May 17, 2013 Working Group meeting and call for comments, SEIA submits that there are significant benefits to EDCs and ratepayers from distributed solar technologies.

SEIA has previously participated in meetings of the Standby Working Group convened by Board Staff. Our primary interest has been to advocate for a more narrow interpretation of N.J.S.A. 48:2-21 (the "Standby Law"), consistent with legislative intent, to exclude intermittent, low-capacity factor renewable resources. Since the Board has yet to definitively rule on the scope of the Standby Law, we reiterate our views herein.

SEIA is the national trade association for the U.S. solar industry and is a broad-based voice of the solar industry in New Jersey. SEIA member companies have installed over 60% of all MWs currently under operation in New Jersey and work in all market segments – residential, commercial, and utility-scale. In addition, SEIA member companies provide solar panels and equipment, financing and other services to a large portion of New Jersey solar projects. When establishing its policy positions, SEIA must balance diverse needs of its membership.

Per legislative intent, SEIA urges the BPU to clarify that the instant definition of 'Distributed Generation', and therefore this proceeding on implementing standby rates, does not apply to solar technologies

The Standby Rate Working Group has yet to establish which technologies are covered under the definition of "distributed generation", as set forth in legislation. The Standby Law applies to "distributed generation", defined as follows:

"Distributed generation" means energy generated from a district energy system or a combined heat and power facility as that term is defined in section 3 of P.L.1999, c.23 (C.48:3-51), the simultaneous production in one facility of electric power and other forms of useful energy such as heating or process steam, *and energy generated from other forms of clean energy efficient electric generation systems.* (italics added)

The question before the Board is whether the italicized language applies broadly to intermittent renewable resources, such as solar PV. It is SEIA's view that it does not.

SEIA Solar Energy Industries Association®

In a letter to President Hanna dated August 15, 2012, the primary legislative sponsors Senator Smith and Assemblyman Chivukula, clearly outlined their legislative intent to exclude these lower capacity factor resources, stating that they *specifically avoided* the use of the words "renewable energy resources".

Based on this stated scope, Senator Smith and Assemblyman Chivukula, counsel the Board to either amend the Board's June 2012 Order "to reflect the intent of Chapter 219, or that staff refocus their study efforts to exclude renewable technologies."

We concur. As the chairmen of the Senate and Assembly committees having jurisdiction, and as the primary sponsors of the underlying legislation, their statement of intent should be accorded significant weight.

Moreover, the legislative intent is borne out by the structure and overall context of the Standby Law. First, given the broader definitional context, the reference to "energy efficient" electric generation is clearly intended to focus on generation technologies that efficiently convert input energy (such as natural gas or other fossil fuels) into useful electrical or thermal energy. Second, a more limited scope is borne out by the legislation's concern that standby charges may discourage the dispatch of distributed generation during the hours when it is needed most; insofar as solar PV is an intermittent resource, once deployed output is primarily a function of weather conditions. Lastly, the overarching purpose of the legislation is to determine whether distributed generation should be offered relief from already existing standby charges; it would not make sense to analyze whether PV should be offered a discount from a charge it is not currently subjected to.

In light of author's clear intent, SEIA urges the BPU to respond to the August 15, 2012 letter with a declaration that solar technologies are not included in the instant standby rate design proceeding. Please see the attached letter from Senator Smith and Assemblyman Chivukula, as reference.

In response to questions h. and j. as put forward by Board Staff, distributed solar technologies supply significant benefits, both to the EDCs and to ratepayers more broadly.

As noted above, we believe that the issue of efficient and equitable standby rate design for solar PV is moot given the clear legislative intent to exempt solar PV from the reach of the Standby Law. Nonetheless, we wish to make the broader point that a properly structured study would reveal that the benefits of solar PV clearly outweigh the cost of deployment to the utilities and other ratepayers.

In 2012, there were 5,700 New Jerseyans employed by the solar industry.[1] This clear economic development benefit is in addition to the stable and reduced energy bills enjoyed by companies

[1] http://thesolarfoundation.org/solarstates

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and homeowners who deploy solar, a dual economic development benefit clearly highlighted in the 2011 Energy Master Plan.[2]

Additionally, the Mid-Atlantic Solar Energy Industry Association (MSEIA), commissioned a study to review the benefits of solar to both ratepayers and EDCs. This study included the following: fuel cost savings (including impacts of T&D losses), O&M cost savings, generation capacity value, T&D capacity value, fuel price hedge value, wholesale market price reduction, economic development value, environmental value, security enhancement value, long-term societal value

In Arizona, SEIA will release a report this week that shows the net positive impact of solar technologies on the Arizona ratepayer, using data from Arizona Public Services' own integrated resource plan along with other data either provided by the utility or the regional gas and electric markets.

In California, a study commissioned by SEIA suggests that the cost-effectiveness of net metering has improved significantly in the past few years, and that on average over all customer classes, net metering may indeed be cost effective throughout the investor-owned utilities' territories.

Austin Energy, a community-owned electric utility, has a unique method for valuing electricity generated by solar. They include the following benefits: loss savings, energy savings, generation capacity savings, fuel price hedge value, T&D capacity savings, environmental benefits.

At a April 26, 2013 roundtable discussion hosted by Princeton University and Columbia University on the Value of Distributed Generation, which was attended by several utility executives and representatives, there was overall agreement that there were *benefits to utilities* brought about by distributed generation that needed to be considered. A white paper from this event is forthcoming.

Although the inputs, assumptions, methodologies, and therefore outcomes vary by study and by perspective, distributed solar technologies clearly bring significant benefits to both the EDCs and ratepayers.

Respectfully submitted,

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[2] See pgs 106-107 of the 2011 EMP

NEW JERSEY SENATE

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August 15, 2012

Mr. Robert M. Hanna, President
New Jersey Board of Public Utilities
44 South Clinton Avenue
9th Floor
Trenton, NJ 08625-0350

RE: A-2872 / S-2971 Chapter 219 Laws of 2011

Dear President Hanna:

As prime legislative sponsors of the above referenced legislation and new law, we wanted to offer some comments to assist your offices in appropriately focusing on the narrower issues that this law was intended.

As you know, our state's electric public utilities all offer standby tariffs that serve to allow for their fair recovery of infrastructure costs associated with supplying "standby" or "backup service" for self generation facilities whose capacity factor is sufficiently high enough that more typical demand measured charges would lack the ability to reasonably recover. These tariffs have been approved typically during utility specific base rate cases and are all based upon different rate designs.

The New Jersey State Energy Master Plan calls for the development of some 1500 MWs of combined heat and power facilities by 2020. While the state and its Economic Development Authority continue to provide financial support to spur this development, it has become apparent that the statewide development of this important energy efficiency and job retention technology required a more consistent statewide tariff design that would appropriately factor overall system costs and benefits as well as consider the operational impacts of rate design upon combined heat and power facilities. It was never our intention to seek any cost shifting or create additional incentives. Our purpose was to create a study to view the system costs and benefits in a holistic way and to then create a consistent rate design methodology that could be applied consistently and fairly across all of our state's EDC's.

We understand that the definitional language in the law has created an expectation that all energy generation resources including low capacity factor renewables be included in the study framework. Please be assured that we specifically avoided the use of the words "renewable energy resources" to exclude these technologies in as much as all of the current utility standby tariffs have set capacity factor thresholds of 50% and higher to exempt these resources as well. Clearly, system infrastructure costs are recovered by utilities for renewable resources through traditional demand charges.

The definition of "Distributed Generation" in the law:
"Distributed generation" means energy generated from a district energy system or a combined heat and power facility as that term is defined in section 3 of P.L.1999, c.23 (C.48:3-51), the simultaneous production in one facility of electric power and other forms of useful energy such as heating or process steam, **and energy generated from other forms of clean energy efficient electric generation systems.**

Clearly, in addition to combined heat and power facilities and CHP based district energy systems, the section in bold was added to include other forms of distributed generation with a high capacity factor such as biomass based self generation facilities or other clean fuels requiring a standby tariff by virtue of their high capacity factor.

Therefore, in recognition of the most significant workload that you and Board staff will need to undertake in the next 270 days to create the fabric of rules and regulations required by the newly minted solar law among other vital areas of regulatory concern, we would hope that your order could either be amended to reflect the legislative intent of Chapter 219, or that staff refocus their study efforts to exclude renewable technologies.

Sincerely,

Bob Smith

Senator Bob Smith
Chairman, Senate Energy and Environment Committee

Upendra Chivukula

Assemblyman Upendra Chivukula
Chairman, Telecommunications and Utilities Committee

VEOLIA
ENERGY
320 S. Warren Street - Trenton NJ 08608

May 3, 2013

Board of Public Utilities
State of New Jersey
44 South Clinton Avenue, 9th Floor
Trenton, NJ 08625

Re: Docket No. GO12070600; In the matter of the Act Concerning the Imposition of Standby Charges Upon the Distributed Generation Customers Pursuant to N.J.S.A. 48:2-21 et seq. (the "Standby Act")

Dear Secretary Izzo:

Veolia Energy North America, Inc. ("Veolia"), in accordance with the recent notice from the Board Staff in this Docket, hereby submits its comments on the filings of the Electric Distribution Companies (the "EDC") on whether such filings address the concerns raised by N.J.S.A. 48:2-21 et seq. or satisfy the criteria set forth in the Board's July 18, 2012 Order in this Docket (the "Order").

Introduction

Veolia Energy, with its parent company Veolia Environnement, is a world class leading energy, water and environmental services company. The company focuses on district energy, building energy services, and operations and maintenance of energy assets for industrial, commercial and institutional customers. As part of this focus, the company owns and/or operates almost 5000 MW of Combined Heating and Power ("CHP") facilities around the world. In New Jersey, our Trenton district energy network (established in the 1980s), which has CHP as part of its generating assets, provides year-round heating and cooling for buildings in the State Capitol Complex and surrounding areas. Additionally, Veolia Energy has been active in the development and operation of CHP and other energy assets throughout New Jersey for many years.

Discussion

Veolia over the years has been opposed to discriminatory electric utility standby rates for customer owned distributed generation ("DG"). We are looking forward to the time when the backup rates faced by combined heat and power ("CHP") facilities fully recognize the broad range of benefits these facilities provide both for on-site customer facilities and the larger community. Load centric CHP reduces energy costs for the user, reduces electric grid disruptions, reduces peak loads, decreases the need for grid level capacity, provides a form of storm-proofing and can provide price stability for utility customers. Further, it is energy efficient, reduces greenhouse gas emissions, decreases line losses and helps avoid possible system failure during peak usage. The EDC existing standby rates, as viewed by Veolia and others, are a financial barrier for customers who are interested in installing and expanding CHP facilities. As such, Veolia applauds the Board's interest in exploring ways that these rates can be improved upon in the best interests of CHP and all EDC ratepayers.

Comments

Veolia applauds the New Jersey Legislature in its enactment of N.S.S.A. 48:2-21 et seq. (the "Standby Act") and its requirements that the Board: (i) conduct a study to determine the effects of distributed generation upon energy supply and demand and determine whether distributed generation contributes to any cost savings for electric public utilities; (ii) establish criteria for fixing rates associated with the assessment and imposition of standby charges; (iii) in establishing such criteria, ensure equity between distributed generation customers and other electric public utility customers with regard to the imposition of standby charges; (iv) consider, among other factors, the economic and environmental benefits the board finds are associated with distributed generation.

The Board in its July 18, 2012, Order, issued in response to the Standby Act, reported on its limited preliminary study of the standby issues required by the Standby Act - but recognized the need for a more thorough investigation. The first step in that further investigation was to invite the EDC to file their own views and responses to the Standby Act. Predictably, the responses were less than satisfactory to the CHP community. In particular, almost without exception, the EDC either chose to make no changes to their existing Standby Tariffs or to adopt new tariffs that sought to perpetuate the very demand ratchet provisions that have been one of the primary regulatory obstacles to greater CHP deployment in New Jersey to date.

Veolia submits that modernizing and optimizing standby rates for CHP is a necessary condition to achieving the CHP goals set forth in the Governor's Energy Master Plan. It is arguable that the driving force behind the

Standby Act was the general sense that the existing standby rates are burdensome on and discriminatory against CHP and other DG customers. The Board investigation should have as its ultimate goal the phasing out of the discriminatory demand ratchets and replacing them with just and reasonable standby rates for CHP.

The EDC proposals unfortunately fail to address the major concerns that Veolia believes drove the Legislature to enact the Standby Act. Veolia urges the Board to conduct a full review of the EDC Standby Rate Tariffs for the following reasons:

a. There is no cost of service study performed to support the contention that the existing and proposed Standby Tariffs are just and reasonable for CHP standby service.

b. There is no analysis of the range of different standby customers and their varying operating/load/generation profiles and how the Standby Tariffs have impacted and would impact this range of potential CHP customers. A full and fair analysis would evaluate a range of CHP operational scenarios, including those that do and do not have unplanned outages on seasonal peaks, off peaks, etc. The assumption that the entire fleet of CHP facilities will have simultaneous outages, coincident with the utility's system peak load is unfounded and needs to be evaluated.

c. Consideration should be given to the possibility that a new, more enlightened partial requirements tariff for CHP could be designed to be more cost based and less punitive.

d. As the Board is aware, the principal objection that CHP facilities have had with the current EDC Standby Rate Tariffs concerns the embedded contract demand ratchet provisions. The problems with this type of demand ratchet have been noted by the U.S. Environmental Protection Agency[1], the U.S. Department of Energy[2] and others.

e. In particular, the Executive Summary of the EPA Standby Study in Dec., 2009, concluded:

- "The review of selected rate tariffs suggests that the better rate designs share common and central characteristics: they are designed to give customers a strong incentive to use electric service most efficiently, to minimize the costs they impose on the system, and to avoid charges when service is not taken. This means that they reward customers for maintaining and operating their onsite generation. Specifically, these tariffs are marked by some or all of the following features:

[1] *Standby Rates for Customer-Sited Resources, Issues, Considerations, and the Elements of Model Tariffs*. December, 2009.
[2] L. Johnston, K. Takahashi, F. Weston and C. Murray, *Rate Structures for Customers With Onsite Generation: Practice and Innovation*. U.S. DOE, National Renewable Energy Laboratory. December, 2005.

- Contract demand or reservation charges are small in relation to the variable charges for peak demand and energy.
- Peak demand charges are not ratcheted or, at worst, have 30-day ratchets (that is, there are no more than monthly as-used demand charges).
- Energy-based charges to collect capacity costs would seem to offer the greatest promise in this regard, but utilities and their regulators do not appear to be prepared to entirely abandon some form of peak demand charge. As such, daily as-used demand charges are the next best solution, but how a particular rate is structured along these lines will depend on the levels of the various rate elements."

f. As required by the Standby Act and the Order, a fair determination of just and reasonable cost-based standby rates should take into account the many benefits that CHP provides to the grid. These include lower line losses, lower transmission, distribution and generation costs, lower grid installed capacity requirements, greater reliability, greater regional and national security, and perhaps most significantly, given the State's recent experience with Super Storm Sandy, greater storm proofing resiliency. Finally, compared to typical central station generating stations, CHP facilities produce roughly half the emissions per MWH generated, supporting the environmental goals of the State of New Jersey as set forth in the "Global Warming Response Act", N.J.S.A. 26:2C-37 et seq., and other State environmental laws. Why not recognize the myriad benefits provided by CHP and design a new cost-based tariff that is designed to fairly incentivize new CHP? The submittals made by the EDC failed to address these many benefits.

We recommend that the Board conduct a full review of the EDC Standby Rate Tariffs, in compliance with the Standby Act. If such a review requires EDC to conduct full cost of service (COS) studies of the cost impacts and benefits of CHP partial requirements service on the EDC system, such COS studies should be ordered. Such an investigation should be completed within the next twelve months. To delay such an investigation until the next filed rate cases of the EDC – potentially several years from now - would unfairly delay, and thus effectively deny, the promise of the Standby Act and result in a truly lost opportunity.

Veolia appreciates the opportunity to submit its comments on this docket.

Respectfully submitted,

Lawrence W. Plitch, Director

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CHRIS CHRISTIE
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May 3, 2013

VIA HAND DELIVERY AND ELECTRONIC MAIL
Kristi Izzo, Secretary
New Jersey Board of Public Utilities
44 South Clinton Avenue, 9th Floor
P.O. Box 350
Trenton, NJ 08625-0350

Re: I/M/O the Act Concerning the Imposition of Standby Charges Upon Distributed Generation Customers Pursuant to N.J.S.A. 48:2-21 et seq. BPU Docket No. GO12070600

Dear Secretary Izzo:

Please accept for filing an original and ten copies of the comments of the Division of Rate Counsel ("Rate Counsel") concerning the compliance filings submitted in this matter by the four New Jersey electric distribution companies ("EDCs") pursuant to the Board's July 18, 2012 order in this proceedings and the Board Staff's recent request for comments. A copy of these comments is being electronically sent to rule.comments@bpu.state.nj.us pursuant to the Board's Notice issued in this matter. We are enclosing one additional copy. Please date stamp the copy as "filed" and return it to the courier. Thank you for your consideration and attention to this matter.

BACKGROUND

On January 17, 2012, Governor Christie signed a bill into law that has been codified as N.J.S.A. 48:2-21.37 – 48:2-21.40, which has become known as the "Standby Charge Law." As the name implies, the Standby Charge Law concerns the imposition by an EDC of "standby charges" on "distributed generators." Standby service for a distributed generation customer, as defined by the Standby Charge Law, is an EDC making "energy available to the distributed generation facility during a [customer-owned] facility power outage."[1] That is, a distributed generation customer does not normally rely on its local EDC for all of its service, except during periods when the distributed generation customer's facilities are not able to meet all of the customer's own electric needs. During such times, the local EDC provides electric service to the customer. Thus, the EDC "stands by" with sufficient transmission and distribution capacity ready to serve the electric needs of its distributed generation customers.

The Standby Charge Law defines "distributed generation" as "energy generated from a district energy system or a combined head and power facility as that term is defined in [N.J.S.A. 48:3-51], the simultaneous production in one facility of electric power and other forms of useful energy such as heating or process steam, and energy generated from other forms of clean energy efficient electric generation systems."[2]

The Standby Charge Law requires two things of the Board: (1) Within 120 days of the effective date of the law, the Board shall "conduct a study to determine the effects of distributed generation upon energy supply and demand and determine whether distributed generation contributes to any cost savings for electric public utilities";[3] and (2) within 180 days of the effective date, the Board shall "establish criteria for fixing rates associated with the assessment and imposition of standby charges, and shall require electric public utilities to file tariff rates with the board in accordance with such criteria."[4]

In its order dated July 18, 2012, the Board referenced a "limited study" that was conducted pursuant to the Standby Charge Law. That Order recites that Board Staff previously had conducted a limited study by sending discovery requests to each of the four EDCs on April 13, 2012, requesting each "to provide its analysis with respect to the effects of distributed generation upon energy supply and demand, and whether distributed generation contributes to any cost savings for the EDC that would support establishing discounted standby charges for distributed generators."[5] Rate Counsel has not yet seen the EDCs' responses to those or

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[1] N.J.S.A. 48:2-21.37.
[2] N.J.S.A. 48:2-21.37.
[3] N.J.S.A. 48:2-21.38.
[4] N.J.S.A. 48:2-21.39(a).
[5] In the Matter of the Act Concerning the Imposition of Standby Charges Upon Distributed Generation Customers Pursuant to N.J.S.A. 48:2-21 et seq., BPU Docket No. GO12070600, Board Order dated July 18, 2012, page 2.

subsequent Board Staff discovery requests; nor has Rate Counsel seen a report on that limited study conducted by Board Staff. Ultimately, however, the Board concluded from the limited study by Board Staff that more information is needed and that the process should be opened to distributed generators and other interested parties, including Rate Counsel.[6] Accordingly, the Board directed each of the four EDCs, by November 1, 2012:

> to make a filing with all supporting documentation either proposing to continue the current standby service/tariff and rate design structure but extending it to include Distributed Generators as defined in the Standby Charge or to modify such standby service/tariff and rate design structure by proposing a new standby service for Distributed Generators as defined in the Standby Charge Law.[7]

Specifically, the Board directed each EDC to address and provide supporting analyses and documentation concerning the following five issues:

(1) Proposed standby service or provisions with rates that are available to Distributed Generators as defined in the Standby Charge Law.

(2) Standby service, rates and rate design shall consider the operating performance of the Distributor (sic) Generators as defined in the Standby Charge Law during peak electric demand periods, as well as the design of demand charges that could provide incentives to Distributed Generators to shift usage away from peak electric demand periods.

(3) Standby rates and rate design for Distributed Generators must be based on cost causation principles that address both the incremental costs and the overall costs to provide distribution service to these Distributed Generators.

(4) Standby service, rates and rate design shall ensure equity between Distributed Generators and other public utility customers.

(5) Standby service for Distributed Generators shall consider cost savings to EDCs resulting from distributed generation, and any other benefits associated with distributed generation, including, but not limited to, any increase in energy efficiency and any associated decrease in demand for electric power from the electric grid.[8]

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[6] Id. page 4.
[7] Id. page 4.
[8] Id. pages 4-5.

RESPONSES FROM THE EDCs

On or about November 1, 2012, each EDC filed a response to the requests contained in the Board's July 18, 2012 order in this matter. Following is a brief summary of the EDCs' responses.

Atlantic City Electric Company ("ACE")

ACE's comments contend that "the current terms and conditions and rate structure in Rider STB are appropriate for application to distributed generation ("DG") facilities. The Company therefore proposes no changes to existing Tariff Rider STB are necessary at this time in order to accommodate DG facilities."[9] No further analyses or documentation were provided.

Jersey Central Power & Light Company ("JCP&L")

JCP&L's comments included a proposed standby rate for DG customers, which it labeled, "Rider STB-DG." This rate, if accepted, would be available to DG customers with DG output capability of 250 kW or greater. JCP&L's comments also provided a brief response to each of the five issues that the Board requested each utility to address in its comments, summarized by Rate Counsel as follows:

Issue (1): Proposed Rider STB-DG specifies the eligibility requirements for standby service under the rider.

Issues (2): The proposed charge under Rider STB-DG is based on billing demand. This rate design, according to JCP&L, would incorporate existing incentives for customers to shift usage away from peak periods.

Issues (3),(4): Proposed charges under Rider STB-DG would be the same as demand and energy charges for all other customers, ensuring that cost causation principles are maintained and to prevent cross-subsidization of DG customers by other customers.

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[9] Letter from ACE to Board Secretary Izzo signed by Philip J. Passanante, dated November 5, 2012.

Issue (5): JCP&L maintains that DG will not contribute to any cost savings for JCP&L. In fact, JCP&L commented that certain types of DG facilities can increase costs because additional infrastructure may be needed to support the DG's facilities.[10]

JCP&L also commented that stakeholder meetings may be useful to clear up issues surrounding DG and standby rates that the Company believes are "vague and subject to different interpretations."[11]

Rockland Electric Company

Rockland submitted proposed revisions to its SC No. 2 and No. 7 tariff schedules to provide standby service to its DG customers under both these tariffs. Rockland's current rate schedule SC No. 7 contains a $1.55 per kW standby charge, based on its past cost of service and load studies. Prospectively, if approved, standby service will also be provided under SC No. 2 and will be made available to DG customers under either SC No. 2 or SC No. 7, using the same $1.55 per kW billing demand rate. Rockland's comments describe how standby billing demands will be determined. Like ACE, Rockland did not specifically comment on the five issues identified in the Board's July 18, 2012 order.

Public Service Electric & Gas ("PSE&G")

PSE&G's comments proposed new tariff provisions within its existing Rate Schedules GLP (General Lighting and Power Service), LPL (Large Power and Lighting Service), and HTS (High Tension Service) that apply to customers with self-generation units. PSE&G's comments specifically addressed each of the five issues identified in the Board's July 18, 2012 order, summarized by Rate Counsel as follows:

Issue (1): Standby service provisions have been added to Rate Schedules GLP, LPL, and HTS for self-generation customers with a combined net kW output rating equal to or greater than 50% of the customer's annual peak demand.

Issue (2): PSE&G comments that its proposed demand charges provide incentives to DG customers to minimize charges by minimizing or eliminating consumption of

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[10] Letter from JCP&L to Board Secretary Izzo signed by Gregory Eisenstark, dated November 1, 2012.
[11] Id. page 3.

electricity purchased from the Company. PSE&G comments that its cost of serving standby customers is the same as that for full service customers.

Issue (3): PSE&G maintains that its standby charges are cost-based and that those charges treat DG customers no differently than the other customers on the respective rate schedules in terms of recovering costs associated while serving them at their full peak loads.

Issue (4): PSE&G comments that the "correct" rate design should make the EDC's (and ratepayers) indifferent to whether the customer used DG or the electric grid as the source of its energy. PSE&G contends that its proposed standby demand charges accomplish this function.

Issue (5): Similar to JCP&L's comments, PSE&G contends that distributed generation service will not result in meaningful distribution and transmission cost savings for EDCs and that such service may increase connection fees to distributed generation customers. Moreover, the intermittent nature of service provided to DG customers may create a variety of operational challenges to the EDCs.

Subsequent to the EDCs' November 2012 filings, the Board Staff issued a "Notice of Working Group Meeting on Standby Rates Proceeding" ("Notice") wherein the Board Staff invited Rate Counsel and other interested parties to participate in a working group meeting on May 17, 2013 to discuss various issues surrounding standby rates for DG customers. The Notice also invited input in the form of comments on the EDCs' November 2012 standby rate filings. Following are Rate Counsel's limited comments on the EDCs' filings and on the working group process in general.

RATE COUNSEL'S ANALYSIS

Rate Counsel is pleased to participate in the Standby Rates Working Group. We understand the goal of the Working Group is to arrive at a clear policy so that the Board can implement fair, non-discriminatory and logical standby rates for DG customers. Rate Counsel believes that in order to achieve this goal all stakeholders must exchange their views. Thus, Rate Counsel supports Board Staff's efforts to reach out to other interested parties, including DG customers themselves, to receive their input in formulating an important Board policy.

Rate Counsel was not asked to participate in Board Staff's "limited study" that formed the basis for the Board's July 18, 2012 Order. Nor has Rate Counsel seen the results of that study or been afforded the opportunity to review the EDCs' responses to Board Staff's earlier data requests. Thus, Rate Counsel cannot comment on Board Staff's conclusions as set forth in the July 18, 2012 order or the adequacy of the EDCs' discovery and informal responses to Staff. Based on the EDCs' November 2012 filings, however, it is clear that more information and analyses are necessary before the Board can accept and implement the EDCs' proposed tariff provisions and proposed rates.

The Standby Charge Law, at N.J.S.A. 48:2-21.39, requires the Board to establish criteria for fixing rates for standby charges applicable to DG customers. Once again, the EDCs' November 2012 filings do not squarely address this requirement. PSE&G and JCP&L at least attempted to address the five issues that were identified in the Board's July 18, 2012 order relating to this section of the Standby Charge Law. But none of the EDCs clearly identified specific criteria for the Board to follow when establishing standby charges for DG customers. For example, ACE's filing consisted solely of a conclusory statement that its current terms and conditions and rate structure for standby service are appropriate for DG customers without ever explaining what those terms, conditions, and rates are or how they were originally derived, or addressing any of the factors set forth at N.J.S.A. 48:2-21.39. Without a complete understanding of what went into the development of ACE's existing standby service rates, and their interaction with the factors listed in the Standby Charge Law, the Board cannot fairly conclude that such terms, conditions, and charges are appropriate for DG customers. Similarly, Rockland concluded, in summary fashion, that its existing $1.55 per kW charge for standby service is appropriate for DG customers as well. Rockland claims that the rate was "based on past cost of service and load study indications."[12] Again, without knowledge of past cost of service and load study indications that Rockland references, but does not provide, the Board cannot fairly determine the reasonableness of the $1.55 per kW rate that Rockland proposed for standby service to DG customers. The definition of "distributed generation," at N.J.S.A. 48:2-21.37, is potentially quite broad and requires clarification; for example, whether it includes solar photovoltaic systems. Staff also should consider whether to limit the applicability of standby

[12] Rockland Electric Company's letter to Board Secretary Izzo signed by William A. Atzl, Jr. dated November 1, 2012, page 2.

charges by the potential output of a DG system. JCP&L, for example, would limit its standby rates to DG customers with DG output capability of 250 kW or greater.

It appears to Rate Counsel that the EDCs are "putting the cart in front of the horse" in an attempt to obtain swift Board approval for their proposed standby charges. Rather, Board Staff should proceed in a more logical, step-wise fashion that follows the directives of the Standby Charge Law. First, the study required in N.J.S.A. 48:2-21.37 must be completed. Thereafter, the Board must establish specific criteria for fixing rates for standby service, pursuant to N.J.S.A. 48:2-21.38. In establishing the criteria, the Board will require more information from the EDCs and from DG customers along the lines of the questions set forth in Board Staff's Working Group Meeting Notice in this matter. Once the data and information have been gathered and analyzed, specific criteria for fixing standby rates can be established. Following that, the individual tariff proposals by each EDC can be analyzed to determine if they meet the Board's established criteria, as required by the Standby Change Law. The Board may wish to consider whether uniformity in service offering and rate treatment between the is necessary or desirable in order to place standby charges for DG customers on a level playing field across the entire State.

Once again, the Division of Rate Counsel if pleased to participate in the Working Group and stands ready to assist in the process. We look forward to working with the EDCs, the Board Staff, distributed generation customers, and all other interested parties in establishing fair rates for standby service to distributed generation customers.

Respectfully submitted,

STEFANIE A. BRAND
DIRECTOR, DIVISION OF RATE COUNSEL

By: *s/ James W. Glassen*
James W. Glassen
Asst. Deputy Rate Counsel

c: Jerome May, Director, Energy-BPU (via electronic mail and hand delivery)
Alice Bator,BPU Energy

State of New Jersey
Board of Public Utilities

In the Matter of the Act Concerning the Imposition of Standby Charges Upon Distributed Generation Customers Pursuant to N.J.S.A. 48:2-21 et seq.	**Docket No. GO12070600**

Comments of Bloom Energy Corporation Regarding Standby Rate Design and Tariff Issues

INTRODUCTION

Bloom Energy Corporation ("Bloom Energy") respectfully submits these comments ("Comments") in response to the request of Board of Public Utilities ("Board") Staff for information regarding: (1) whether the current Standby Tariffs and Rate Designs of the New Jersey Electric Distribution Companies ("EDCs") appropriately address the provisions set forth in N.J.S.A. 48:2-21 *et seq.* and the criteria set forth in the Board's Order dated July 18, 2012 ("Standby Order") in the above-referenced proceeding; and (2) whether the four EDCs' responsive filings address concerns raised by N.J.S.A. 48:2-21 *et seq.* and the criteria set forth in the Standby Order.

Bloom Energy is a provider of breakthrough all-electric solid oxide fuel cell technology that generates clean, reliable, and highly efficient onsite power using an environmentally superior non-combustion process. Bloom Energy currently has over 75 megawatts ("MW") of operating systems at over 100 locations across the United States. In New Jersey, Bloom Energy is seeing growing demand from customers, including telecommunications providers, data centers, office buildings, nursing homes, supermarkets, and others who desire a highly reliable distributed power generation solution, but may not have the thermal requirements necessary to support a traditional Combined Heat & Power ("CHP") solution.

As discussed in more detail below, Bloom Energy has significant concerns with the EDCs' current patchwork of Standby Tariffs and Rate Designs, as well as the proposals contained in the EDCs' responsive filings, which provide no improvement to the status quo.

I. In Order to Foster Regulatory Certainty, the Board Should Define which Types of On-Site Generation Technologies Are Subject to Demand Charges, Including Standby Charges.

First, as a threshold matter, Bloom Energy urges the Board to use this proceeding as an opportunity to provide regulatory certainty regarding which types of on-site generation technologies are subject to, or exempt from, any type of demand charges, including standby charges. Currently, the EDCs have no uniform standard regarding which customers must pay full demand charges or standby demand charges. For example, as described in the Standby Order, Atlantic City Electric Company ("ACE"), Jersey Central Power and Light Company ("JCP&L") and Rockland Electric Company ("RECO") only apply standby rates to qualifying facilities ("QFs") as defined under Section 201 and Section 210 of the Public Utilities, and then those standby rates are only applicable "when the customer's self-generation is either at least or exceeds 50% of the generation availability."[1] Under the JCP&L, ACE and RECO tariffs, a customer's generator that operates at less than 50% of the generation availability does not qualify for the discounted standby rate and must pay the full demand charges they would otherwise pay under their regularly applicable rate schedules.[2]

Public Service Electric & Gas ("PSE&G"), on the other hand, applies standby rates to "all types of generation, including CHPs, turbine generation, solar arrays, and Exempt Wholesale Generators as defined by PURPA" and its Standby Provision is applicable for customers whose self generation units: 1) have a net kW output rating equal to or greater than 50% of their annual peak demand or 2) was served on former Standby Service on 7/31/2003, or 3) were granted air permits for a QF by August 1, 2004.[3] Under the PSE&G tariff, these standby customers can avoid incurring a summer demand charge on top of their annual demand charges if they effectively reduce their load in the peak summer season and can shift their hourly load away from PSE&G's monthly system peak.[4]

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[1] *See* Standby Order, p. 3.

[2] *Id.*

[3] *Id.*

[4] *Id.* at 4.

{00030991.2 }

The statute requiring this Board proceeding does little to clarify which types of on-site generation technologies should be subject to, or exempt from, demand charges, including standby charges. Instead, it states that the Board should consider revising standby charges on "distributed generation," which is vaguely defined as:

> energy generated from a district energy system or a combined heat and power facility as that term is defined in section 3 of P.L. 1999, c. 23 (C-48:3-51), the simultaneous production in one facility of electric power and other forms of useful energy such as heating or process steam, and other forms of clean energy efficient electric generation systems.

Bloom Energy Servers are the cleanest and most efficient form of on-site electric generation systems commercially available and therefore clearly qualify as one of the "other forms of clean energy efficient electric generation systems." However, it is unclear from the above definition of "distributed generation," which other forms of generation also qualify. Bloom Energy consequently agrees with the assessment of JCP&L in its responsive filing that this definition is "vague and subject to different interpretations" and that the parties to this proceeding should "clarify the intended scope" of what technologies are covered by this definition. By developing uniform and concrete classes of customers who are subject to either demand charges or standby charges, Board Staff would enable companies, like Bloom Energy, and its customers to obtain a clearer picture of the cost of doing business in New Jersey.

In contrast to the vagaries regarding which technologies are subject to demand charges in New Jersey, several other states have clearly exempted fuel cells from all demand charges, including standby charges. In fact, Pennsylvania, New York, California and Connecticut prohibit electric utilities from imposing any demand or standby charges on fuel cell technologies.[5] The Board should eliminate any type of demand charges, including standby charges, for customers using fuel cell generation technologies so that New Jersey promotes more resilient forms of on-site clean energy, and is on a level playing field with the other major states in the region.

[5] *See* 52 Pa. Code § 75.13(j); NY CLS Pub Ser § 66-j(3)(d); Cal Pub Util Code § 2827.10(d)(1); Conn. Gen. Stat. § 16-245cc.

II. The Board Should Reject the EDCs' Argument that Distributive Generation Does Not Contribute to Cost Savings on their Electric Systems and Reduce Standby Charges Accordingly.

Despite what the EDCs have represented in their filings, the availability of distributed generation provides well-documented cost savings and other benefits to ratepayers. For instance, the development of distributed generation allows EDCs to avoid making certain generation, transmission and distribution investments that they would otherwise pass through to ratepayers. In addition, distributed generation provides a more reliable and resilient source of power than traditional sources of power that can help keep certain critical facilities or even the grid functional during widespread power outages. Finally, non-combustion distributed generation emits significantly less CO_2 than a typical coal-fired power plant and virtually no SOx, NOx, or other harmful air forming particulate emissions. These benefits suggest that New Jersey's standby rates should be eliminated, particularly for clean and highly resilient non-intermittent technologies like all-electric fuel cells.

Although there is ample documentation extolling the economic and environmental benefits of distributed generation, Bloom Energy suggests that the Board consider the February, 2011 Final Report of the New York State Energy Research and Development Authority ("NYSERDA") entitled, "Deployment of Distributed Generation for Grid Support and Distribution System Infrastructure: A Summary Analysis of DG Benefits and Case Studies." The report, which is available on the NYSERDA website includes detailed analyses of, among others, the following categories of benefits:

- Avoided transmission and distribution investments
- Avoided electricity generation
- Avoided and deferred generation capacity
- Wholesale price impact or Demand Reduction Induced Price Effect (DRIPE)
- Ancillary services
- Reliability value
- CO_2 and Criteria Pollutant Emissions

III. The Board Should Proceed Toward a Timely Decision or Rulemaking.

Rather than move the issues raised by the Standby Order into pending rate cases, Bloom believes that the Board should use this proceeding as an opportunity to establish uniform and meaningful changes to the demand charge and standby charge to bring New Jersey into general alignment with the other major states in the Region. The current patchwork of EDC standby tariffs and rate designs make it difficult for customers to predict the cost of installing on-site generation in New Jersey, and this unpredictability has the effect of chilling investment in the State.

There are many improvements to be made to the current standby charges and rate design and there are multiple examples of simple and effective approaches that are in place in other states. Thus, Board Staff should develop a record through evidentiary hearings, discovery and position papers which give stakeholders an adequate opportunity to contest the EDC proposals. After settlement meetings, Board Staff should decide whether to pursue a formal Board order or develop proposals through a rulemaking proceeding. To do any less than develop a full record would deprive distributed generation developers, their customers, and the ratepayers of New Jersey the opportunity to vet the issues and provide much needed changes to the status quo.

Respectfully submitted,

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Dated: May 3, 2013

STAND-BY RATE DESIGN FOR CHP

Prepared for:

New Jersey, Board of Public Utilities
Office of Clean Energy

Prepared by:

US DOE Mid-Atlantic Clean Energy Application Center

May 2, 2013

Rate Design Comments

U.S. Department of Energy
Mid-Atlantic Clean Energy Application Center
Promoting CHP, District Energy, and Waste Heat Recovery

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Confidentiality: This filing is considered public information

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Purpose: The purpose of this filing is to provide comments on Stand-By Rate design for CHP and to support the adoption of combined heat and power (CHP) systems in New Jersey.

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COMMENTS

The comments here are derived from our work relating to the implementation of combined heat and power, district energy and waste heat recovery both in NJ as well as throughout the Mid-Atlantic region.

General

With increased interest in efficient, clean, customer-sited resources comes increased interest in the regulatory policies that affect their deployment. The economic viability of clean, distributed generation (DG) and, in particular, combined heat and power (CHP) facilities, heavily depends on the regulatory policies that determine how they are treated by the electricity network. Standby rates are an important aspect of regulatory policies that must ensure that the utility is not punished for supporting CHP on its system while also ensuring that costs related to these charges are not such that they prevent CHP from being implemented. Standby rates should also recognize the societal benefits offered by CHP and take into account aggregation of multiple CHP plants on the utility's service line.

With the installation of onsite generation, a customer will rarely go entirely "off grid." Grid-supplied power retains value in a number of ways. For example, in a typical installation, the DG system is sized to serve less than the peak load at the customer site. A facility with a peak load of 1,000 kW that installs a 500-kW DG system to provide on site generation will require 500 kW from the grid during peak demand in addition to the power generated on site. Even a facility with onsite capacity sufficient to meet all of its demand may want or need to take power from the grid at times.

This may be done to:

• Serve needs in excess of that supplied by the DG system on average, to meet short-term or seasonal peaks, or, in certain cases, to serve the momentary need for increased power associated with DG start-up

• Supply power during scheduled outages of the DG system, most often for maintenance

• Supply power during unscheduled outages because of equipment failure, loss of fuel supplies, or other problems

• Purchase power at prices below the operating cost of the DG system, typically during off-peak periods when the local system is in surplus.

The term *"standby rate"* is often used as shorthand for the set of retail products that 'partial requirement' customers with onsite, non-emergency generation typically desire. Reasonable and nondiscriminatory standby rates for certain customers were first required under the Public Utilities Regulatory Policy Act of 1978. Many states distinguish among three types of service in their stand-by tariffs: supplemental, backup, and maintenance while some differentiate only between standby and supplemental. The following lists the most common components of service for partial requirements customers:

Supplemental Service. Supplemental service provides additional electricity supply for customers whose onsite generation does not meet all of their needs. In many cases it is provided under the otherwise applicable full requirements tariff.

Backup Service. Backup or standby service supports a customer's load that would otherwise be served by DG, during unscheduled outages of the onsite generation system.

Scheduled Maintenance Service. Scheduled maintenance service is taken when the customer's DG is due to be out of service for routine maintenance and repairs. In general, because this service can be scheduled for non-peak times, it is considered to create few additional or marginal costs to the utility's system, and tariffs are typically structured to exempt the customer from capacity-related costs (e.g., reservation charges or ratchets, for either generation or delivery).

Economic Replacement Power. Some utilities offer economic replacement power—electricity at times when the cost of producing and delivering it is below that of the onsite source.

Electric industry restructuring and the unbundling of the electric system's components (generation, distribution, transmission, etc.) has, in some states, added complexity to rate design whereas the electricity prices of vertically integrated utilities that have not been unbundled often include generation, transmission, and distribution charges. The separation of these functions in restructured states has also led to a separation of the charges for them. This can cause some confusion when comparing different rate elements and, in particular, their ratchets and exemptions. In general, in a restructured state the question of partial requirements service is limited to the remaining monopoly services that are only provided by the local incumbent utility—distribution and, in certain cases, transmission—but there might also be default service offerings for energy charges.

In response to your request for information please note the following:

The submissions from the Electric Distribution Companies (EDC) in response to the Board Order dated July 18, 2012 do not distinguish between CHP and other forms of distributed generation including intermittent sources such as PV and wind. It is not feasible to design an appropriate and fair standby rate for both dispatchable and non-dispatchable distributed generation. If the Board Order is intended to address CHP, then the EDC's need to be asked to submit proposals for CHP only.

The responses form the various EDC's do not provide sufficient detail in terms of modeling the impact of their standby rates on the various C&I customer classes. Modeling of the proposed standby rates and their impact on customer bills needs to be conducted in order to properly understand the EDC's interpretation of the proposed standby tariffs.

On the subject of the contribution of DG to EDC cost savings, please see attached the following publications that deal in some depth this issue:

SEEAction Guide to the Successful Implementation of State Combined Heat and Power Policies, Chapter 2 on Standby rate Design. The full report is available at:
http://www1.eere.energy.gov/seeaction/chp_policies_guide.html

Regulatory Assistance Project and ICF International 2009 report on Standby Rates for Customer-Sited Resources.

FOLLOW UP

I and my colleagues are available to discuss any of the above issues and will continue to support New Jersey in its efforts to develop a clean, cost effective and reliable power market through effective utilization of CHP in line with the NJ Board of Public Utility and Department of Energy's goals.

Chapter 2. Design of Standby Rates

2.1 Overview

A primary motivation for industrial and commercial customers to install CHP systems is to meet electricity and thermal energy needs at a lower cost. One potential impediment to the adoption of CHP[36] is standby rates, or partial requirements service, which the utility charges to compensate for providing certain services and which can affect CHP customer cost savings.[37] Utility rates should optimally allocate the total cost of service for a utility to recover costs from customer classes, reflecting each class's use of the system. This principle of "cost causation" is implemented through rate designs that fairly allocate costs based on measureable customer characteristics.

Utility standby rates cover some or all of the following services:

- *Backup power* during an unplanned generator outage
- *Maintenance power* during scheduled generator service for routine maintenance and repair
- *Supplemental power* for customers whose on-site generation under normal operation does not meet all of their energy needs, typically provided under the full requirements tariff for the customer's rate class
- *Economic replacement power* when it costs less than on-site generation
- *Delivery* associated with these energy services.

In the rate design process, utility costs are allocated to various components of customer services, including charges for billing and metering, energy, distribution, and transmission. Costs for each of these components are based on an average user profile for each customer rate class, such as large nonresidential customers, rather than customized for individual users.

For large customers, costs of utility service are separated into customer, energy, and demand charges. Customer charges are designed to recover costs incurred to provide metering and billing services and service drop facilities. Energy charges recover the variable costs incurred to generate electricity (i.e., chiefly fuel cost).[38] Demand charges are designed to recover the utility investment cost incurred to provide generating, transmission, and distribution capacity and may vary by season and time of day.[39] Generation costs may also vary by season and time of day.

Commonly, demand charges in standby rates are "ratcheted," meaning the utility continues to apply some percentage (often as high as 100%) of the customer's highest peak demand in a single billing month up to a year after its occurrence. The use of ratchets can be controversial—some view them as increasing the equity of fixed cost allocation, while others view them as barriers to economic applications by CHP customers. Although demand ratchets may be appropriate for recovering the cost of delivery facilities closest to the customer-generator, they arguably do not reflect cost causation for *shared* distribution and transmission facilities, which are farther removed from the customer. Distribution and transmission facilities are designed to serve a pool of customers with diverse loads, not a single customer's needs, and coincident outages drive their costs. In addition, unplanned CHP system outages occur randomly; CHP systems will not all fail at the same time or during the utility system's peak. Further, the customer's use of standby service may not coincide with the peak demand of the utility facility providing the service.[40] Use of standby service by CHP customers with low forced outage[41] rates typically is significantly less likely to coincide with the utility's peak demand than peak use by a full requirements customer. Arguably, billings based

[36] U.S. EPA. *Standby Rates for Customer-Sited Resources—Issues, Considerations, and the Elements of Model Tariffs*. December 2009. www.epa.gov/chp/documents/standby_rates.pdf.

[37] In restructured states, the utility may provide only delivery services and provider-of-last-resort energy service.

[38] Some fixed costs may be recovered through variable energy charges.

[39] In restructured markets, generation-related costs are not recovered in regulated revenue requirements, but in market-based supply prices.

[40] See Regulatory Assistance Project. "Distribution System Cost Methodologies for Distributed Generation." 2001. www.raponline.org/docs/RAP_Shirley_DistributionCostMethodologiesforDistributedGeneration_2001_09.pdf.

[41] Forced outages are unplanned or unscheduled outages of the CHP system due to equipment failure.

on ratcheted demands fail to recognize the diversity in load among CHP customers and the cost savings associated with that diversity, particularly as regards shared T&D facilities. Requiring CHP customers to pay ratcheted demands may result in CHP customers overpaying for utility-supplied electricity relative to full requirements customers.

2.2 Improving Standby Rates

Standby rates were originally designed to reflect an environment in which a utility operated within a fairly closed system with a few inter-ties with other utilities for backup emergency purposes. Today, many utilities rely on and participate in regional markets where electricity and capacity are pooled and can be purchased with relative ease. The ability to more easily transact energy and capacity allows a utility to take account of the probability of various CHP loads needing standby service at the same time, which will lower ratcheted demand charges.

Working with utilities and other stakeholders, some state utility regulators have improved the nexus between standby tariffs and cost causation, provided customer-generators with options to avoid charges when they do not impose costs, and established a reasonable balance between variable charges versus contract demand or reservation charges.

For standby or "partial requirements" customers, the following service components are the most common:[42]

- **Backup Service.** Backup or standby service supports a customer's load that would otherwise be served by DG, during unscheduled outages of the on-site generation.
- **Scheduled Maintenance Service.** Scheduled maintenance service is taken when the customer's DG is due to be out of service for routine maintenance and repairs.
- **Supplemental Service.** Supplemental service provides additional electricity supply for customers whose on-site generation does not meet all of their needs. In many cases, it is provided under the otherwise applicable full requirements tariff.
- **Economic Replacement Power.** Some utilities offer economic replacement power—electricity at times when the cost of producing and delivering it is below that of the on-site source.

Together, the following features encourage customer-generators to use electric service most efficiently and minimize costs they impose on the electric system:[43]

- **Reflect load diversity of CHP customers in charges for shared delivery facilities.** Charges for transmission facilities and shared distribution facilities such as substations and primary feeders should reflect that they are designed to serve customers with diverse loads. Load diversity can be recognized by designing demand charges on a coincident peak demand basis as well as the customer's own peak demand and by allocating demand costs primarily or exclusively to usage during on-peak hours. Differentiating on-peak demand from off-peak demand provides standby customers with an incentive to shift their use of the utility's assets to off-peak hours, when the marginal cost of providing service is typically much lower.
- **Allow the customer to provide the utility with a load reduction plan.** The plan should demonstrate its ability to reduce load within a required timeframe and at a specified amount to mitigate all, or a portion of, backup demand charges for local facilities. This allows the standby customer to use demand response to meet all, or a portion of, its standby needs. The utility would approve the load reduction plan, evaluating whether it provides sufficiently timely load shedding to avoid reserve costs incurred by the utility. The utility would approve the load reduction plan after evaluating and determining that it provides sufficiently timely load shedding to avoid reserve costs incurred by the utility.

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[42] The four bulleted service components are not necessarily subject to a demand charge. It depends on the utility's rate structure. www.epa.gov/chp/documents/standby_rates.pdf.

[43] For more on alignment of standby rates with rate design principles, see *Standby Rates for Customer-Sited Resources: Issues, Considerations and the Elements of Model Tariffs*, prepared by Regulatory Assistance Project and ICF International for the U.S. Environmental Protection Agency. December 2009. www.epa.gov/chp/documents/standby_rates.pdf.

- **In states with retail competition, offer a self-supply option for reserves.** This can be in the context of the load reduction plan discussed above, through utility-controlled interruptible load, or some other means that can both save costs for the customer and avoid costs for the utility. The self-supply plan can be structured to reflect actual performance of the customer over time.
- **Offer daily, or at least monthly, as-used demand charges for backup power and shared transmission and distribution facilities.** Moving away from annual ratcheted charges gives the CHP customer a chance to recover from an unscheduled outage without eroding savings for an entire year. Daily charges encourage customers to get their generators back online as quickly as possible. Daily charges for backup power should be market-based to provide appropriate price signals to CHP customers.
- **In states with retail competition, allow customer-generators the option to buy all of their backup power at market prices.**[44] The customer can avoid any utility reservation charge for generation service because the utility is relieved of the obligation to acquire capacity to supply energy during unscheduled outages of the customer's CHP unit.
- **Schedule maintenance service at nonpeak times.** In general, because this service can be scheduled for nonpeak times, it is considered to create few additional or marginal costs to the utility's system, and tariffs are typically structured to exempt the customer from capacity-related costs (e.g., reservation charges or ratchets, for either generation or delivery).
- **Provide an opportunity to purchase economic replacement power.** During times of the year when energy prices are low, the utility can provide on-site generators energy at market-based prices at a cost that is less than it costs to operate their CHP systems, and at no harm to other ratepayers. Such arrangements must be compatible with the structure of retail access programs, which the CHP customer may otherwise be relying on, and should allocate any incremental utility costs of purchasing such power (including general and administrative fees) to the CHP customer.

These features can create a standby rate regime consistent with standard ratemaking principles, avoiding cost shifting from CHP customers to other customers, while providing appropriate incentives to operate CHP facilities in a manner most efficient for the utility system as a whole, by aligning the economics for the CHP facility with the cost to serve that customer.

2.3 Successful Implementation Approaches

Pacific Power—Oregon Partial Requirements Service

Pacific Power provides standby services in Oregon under four primary tariffs and riders.[45] Taken together, this set of tariffs provides many of the customer-generator benefits discussed above, while allowing recovery of actual costs incurred by the utility and protecting other customers.

- The utility assesses charges for shared distribution facilities such as substations and transmission facilities based on the customer's actual 15-minute net demand recorded for the month during on-peak hours, using the same rate and billing determinants as the full requirements tariff. There is no annual ratchet.
- Cost recovery for local distribution facilities—those designed solely to serve the customer as well as those closest to end-users, such as transformers and low voltage lines—is based on the average of the two highest non-zero monthly on-peak demands for the past 12 months, same as for full requirements customers. The starting point and minimum level for the charge is the "baseline"—the customer's peak demand on the utility system assuming normal operation of the customer's generator. However, the

[44] This guide does not explore the merits or problems with the development of standby rates; it identifies how standby rate policies can be successfully implemented to facilitate CHP.

[45] These four tariffs include Schedule 48: Large General Service Partial Requirements 1,000 kW and Over Delivery Service, Schedule 76R: Large General Service Partial Requirements Service Economic Replacement Power Rider Delivery Service, Schedule 247: Partial Requirements Supply Service, and Schedule 276R: Large General Service Partial Requirements Service Economic Replacement Power Rider Supply Service. "Oregon Regulatory Information." Pacific Power. www.pacificpower.net/about/rr/ori.html.

baseline can be adjusted with a load curtailment plan for generator outages, installation of energy efficiency measures, and to accommodate planned, long-term changes in loads or generator operations.

- The customer's baseline also sets charges for reserves the utility holds to maintain capability to serve loads during outages of the on-site generator. The tariff provides self-supply options for reserves, including through an approved load reduction plan for supplemental reserve requirements.
- Scheduled maintenance service must be scheduled 30 days in advance, in take-or-pay blocks at a forward market-based price. Pacific Power also offers partial requirements customers the option to buy replacement energy (usage above baseline) at market prices when beneficial for the customer. For a CHP customer, the determination of favorable conditions includes the total benefits derived from the CHP system (electricity plus heat) compared with advantageously priced replacement power and boiler fuel.
- Energy service for unscheduled outages is based on real-time market prices. Importantly, demand and transmission charges for scheduled maintenance, economic replacement power and unscheduled outage service are based on daily demands and do not affect charges for distribution and transmission services under the base standby tariff.

Consolidated Edison Partial Requirements Service

Consolidated Edison offers replacement or supplemental service for approved projects for self-generation customers whose generation capacity is greater than 15% of their potential load. Pricing for this service is based on a contract demand representing the highest demand the facility is likely to meet for the customer under any circumstances. The charge for the contract demand reflects both the customer's contribution to local facilities used on a regular basis for baseload demand, as well as customer-specific infrastructure necessary to meet the maximum potential demand with or without the customer's generation in service. The rate for the entire contract demand is generally lower than the otherwise applicable rate. If the customer selects a contract demand level, the utility applies penalties if the maximum demand exceeds the contract demand by more than 10% or 20%.[46] If the contract demand level is utility-determined there is no penalty for exceeding that level. In both cases, when the original contract demand is exceeded, contract demand is re-set to the new highest demand.

In addition, the company assesses a demand charge based on the actual demand recorded each day. The rate varies by season and time of day—peak versus off-peak.[47, 48] This variable charge recovers shared system (upstream) costs. It is calculated on a daily basis.

Georgia Power[49]

Georgia Power provides backup service under a tariff rider. The rider allows a customer to contract for firm or interruptible standby capacity, or both, to replace capacity from a customer's generation when it is not in service. Customers may designate the level of service they wish to purchase from the utility. For firm backup power, the customer must provide notification within 24 hours of taking such service. Interruptible backup power requires advance permission from the company, except in the case of an unplanned outage where a 30-minute notice is required after beginning service.

Maintenance power, supplied for outages, must be scheduled 14 days in advance. Maintenance power is available as firm service during the off-peak months and as interruptible service during peak months. Customers purchase supplemental power (power required during normal operation of the generator and normal demands by the facility) at normally applicable rates.

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[46] www.coned.com/documents/elecPSC10/GR1-23.pdf, leaf 164; No penalties are assessed if the utility determines the contract demand.

[47] www.coned.com/documents/elecPSC10/SCs.pdf, leaf 453.

[48] The charge is zero for off-peak hours.

[49] www.georgiapower.com/pricing/files/rates-and-schedules/12.30_BU-8.pdf.

The utility computes the level of standby power as the difference between the "maximum metered demand measured during the time standby service is being taken, less the maximum metered demand during the time in the billing period when standby service is not being taken." This demand determination can be made on a peak versus off-peak basis.

All billing determinants are based on monthly values, with no ratchets. However, demand charges are subject to a standby demand adjustment factor, which adjusts the billed standby demand once a customer uses backup service for more than 876 hours during the most recent 12-month period. This provides an incentive for a customer to use standby service as efficiently as possible.

How the Criteria Are Addressed

Policy Intent. The policy intent is to charge CHP customers only for costs they impose on the system consistent with ratemaking principles, encourage customer-generators to use electric service most efficiently to minimize costs they impose on the electric system, and ensure that costs for backing up CHP customers are not passed on to non-CHP customers. The customer and the utility can work together to schedule planned outages at times that are best for the utility system.

Market Signals. CHP users and potential CHP adopters are motivated by expected cost savings available from their systems. By shifting risk to CHP users and appropriately charging for services actually rendered, both utilities and customers can benefit through appropriate market signals.

Ratepayer Indifference. By more accurately balancing the charges for service actually rendered with appropriate market signals and incentives for operational efficiencies, all customers should benefit from appropriately structured standby tariffs.

2.4 Conclusions

Standby charges should be designed to most closely preserve the nexus between charges and cost of service. Standby rates were originally designed to reflect an environment in which a utility operated within a fairly closed system with a few interties with other utilities for backup emergency purposes. Today, many utilities rely on and participate in regional markets where electricity and capacity are pooled and can be purchased with relative ease. The ability to more easily transact energy and capacity allows a utility to take into account the probability of various CHP loads needing standby service at the same time. Together, the features listed below encourage customer-generators to use electric service most efficiently and minimize costs they impose on the electric system.

KEY IMPLEMENTATION APPROACHES: DESIGN OF STANDBY RATES

- Offer daily or monthly as-used demand charges for backup power and shared transmission and distribution facilities.
- Reflect load diversity of CHP customers in charges for shared delivery facilities.
- Provide an opportunity to purchase economic replacement power.
- Allow customer-generators the option to buy all of their backup power at market prices.
- Allow the customer to provide the utility with a load reduction plan.
- Offer a self-supply option for reserves.

STANDBY RATES FOR CUSTOMER-SITED RESOURCES

ISSUES, CONSIDERATIONS, AND THE ELEMENTS OF MODEL TARIFFS

U.S. Environmental Protection Agency
Office of Atmospheric Programs
Climate Protection Partnerships Division
1200 Pennsylvania Ave., NW
Washington, DC 20460

December 2009

Final Report

Developed by the Combined Heat and Power Partnership

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List of Acronyms and Abbreviations

CHP	combined heat and power
DG	distributed generation
FERC	Federal Energy Regulatory Commission
kW	kilowatt
kWh	kilowatt-hour
MW	megawatt

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1: Executive Summary

With increased interest in efficient, clean, customer-sited resources comes increased interest in the regulatory policies that affect their deployment. The economic viability of clean, distributed generation (DG) and, in particular, combined heat and power (CHP) facilities, heavily depends on the regulatory policies that determine how they are treated by the electricity network. This paper focuses on one of those policies: the structure of prices for standby service. The report identifies approaches that, given the costs and benefits of DG, provide appropriate savings to the clean, DG system owner and appropriate cost recovery to the utility.

The review of selected rate tariffs suggests that the better rate designs share common and central characteristics: they are designed to give customers a strong incentive to use electric service most efficiently, to minimize the costs they impose on the system, and to avoid charges when service is not taken. This means that they reward customers for maintaining and operating their onsite generation. Specifically, these tariffs are marked by some or all of the following features:

- Contract demand or reservation charges are small in relation to the variable charges for peak demand and energy.

- Peak demand charges are not ratcheted or, at worst, have 30-day ratchets (that is, there are no more than monthly as-used demand charges).

- Energy-based charges to collect capacity costs would seem to offer the greatest promise in this regard, but utilities and their regulators do not appear to be prepared to entirely abandon some form of peak demand charge. As such, daily as-used demand charges are the next best solution, but how a particular rate is structured along these lines will depend on the levels of the various rate elements.

- The rate structure yields a significant retail rate savings per kilowatt-hour (kWh) produced on site instead of purchased from the grid. This depends not only on the standby tariff itself, but also on the level and structure of the otherwise applicable full requirements tariff (e.g., the tariff that would apply in the absence of DG).

These findings are consistent with the understanding that the economics of onsite generation are based on reduced electricity purchases, and these reduced purchases must benefit the customer to make DG viable. Importantly, they also serve to remind regulators of the need to pay close attention to ensure that the design of partial requirement rate structures captures the economic and environmental benefits of reduced energy consumption. These examples also suggest that such rates can apply to DG while also fairly compensating utilities for the services they provide to onsite generators.

2: Introduction

Interest in clean, customer-sited,[1] non-emergency generation, in particular CHP systems,[2] continues to grow as appreciation likewise grows for the value that these resources can provide. The many benefits accrue both to the owners of the onsite resources—through cost savings from avoided purchases of grid-supplied power, improved reliability, reduced thermal (e.g., boiler) energy consumption, and lower overall energy costs—and to the electric system as a whole—through reduced demands for power, avoided investments in generation and delivery capacity, improved operational efficiencies, increased system reliability, and lower total system energy consumption, costs, and emissions.

With these benefits in mind, policy-makers, utility representatives, and system operators have begun to address the challenges of integrating these systems into the electric transmission and distribution networks. Much work has been done at the state and federal levels to develop and standardize technical and regulatory rules for interconnection of the onsite generator to the electric grid. Today, if interconnection remains a barrier to onsite generation, it is likely the result of a state's failure to adopt appropriate rules, and not the consequence of unresolved technological or operational challenges.

Customers primarily install onsite generation in an attempt to reduce their overall energy costs. Onsite generation typically reduces the amount of electricity purchased while increasing onsite capital and fuel costs. The decision to generate one's own power balances additional capital, fuel, and maintenance expenses with a decrease in the amount and therefore the cost of purchased power. CHP further enhances the customer economics because of additional savings from combining thermal and electric generation into one process. In general, CHP is most efficient, and cost effective, when it is sized to match the thermal loads of the facility and operates an extended number of hours on an annual basis. Electric rate structures, particularly standby and backup rates, can have a significant impact on CHP economics by affecting the amount of actual savings resulting from reduced electricity purchases from the grid. As such, tariffs can affect prime mover selection, system sizing, and operating strategy. Not all tariffs result in the most efficient system design or operating strategy.

Although an increasing number of states have begun to address the question of whether the lack of appropriate statewide rules on retail tariffs might also present a barrier to onsite generation, there is little evidence of a standard approach. States are innovating, and there are now several approaches to the design of rate structures for DG that warrant closer analysis.

This paper identifies the elements of rate structures that will appropriately charge customers with DG for the services they take, without creating economic barriers to DG. The degree to which customers' charges are adjusted under a certain tariff by generating their own electricity from DG will determine whether or not this is the case. These rates should also fairly compensate the utility for the costs of serving customers with DG in order to protect other customers from being charged unfairly high rates. This avoidance of cross-subsidization cannot, in the absence of company-specific cost data, be directly judged. The analyses in this paper presume that rates that are in effect or proposed by utilities are meeting cost-recovery (or revenue-burden) goals.

3: Electric Rate Structures and Economics of Distributed Generation

This section provides a brief primer on the basics of electric service and rate design to provide a context for the later discussions of standby rates. While this discussion applies to rate design generally, this paper focuses on rate structures for customers that are most likely to be suited to onsite generation—that is, high-volume commercial and industrial users for whom DG capacity would be at least 200 kilowatts (kW), but more likely 500 kW and greater.[3] Appendix B provides a more detailed discussion of these topics.

3.1 Elements of Electricity Rates

Electricity rates have three main components: customer charges, demand charges, and energy charges. There could, of course, be other charges as well, such as taxes or special assessments, but for the purposes of this paper, these can be ignored.[4]

The **customer charge** is a fixed, recurring charge (monthly or daily), typically intended to cover the constant costs of metering, billing, and service drop facilities, which must be recovered by the utility even if no electric service is taken. In this sense, it can be seen as a flat fee that provides access to the grid.

Energy charges are the charges for consumption of the electricity commodity applied on a per-kWh basis. Customers purchase energy at the tariffed rates or from third-party suppliers at negotiated rates; they may be differentiated by time-of-use, by season, by consumption block, or by some other means.[5] In addition, there may be adders or surcharges to cover related costs and risks of operation. In some cases, there may be multiple commodity charges associated with different categories of usage charges. For example, higher energy charges might apply during on-peak time periods as opposed to off-peak time periods, or the energy charge might decrease as more energy is purchased, in a declining block structure. For residential and small commercial rates, energy charges may be the only category of rates. However, larger facility rates (e.g., commercial and industrial) typically include both energy and demand charges.

Demand charges are based on the peak electricity demand (kW) during a given period, typically 1 month. Demand charges are used to recover the capital costs of the capacity necessary to meet customers' peak loads. Capacity is measured in kW or megawatts (MW), and it represents the ability of a facility (or the grid in the aggregate) to deliver the service desired at any instant. Because the electric service is to be provided on demand, the system must be designed to meet a variety of peak loads: that of the system as a whole, those of customers served by individual parts of the network, and those of individual customers. The costs of capacity can be included in per-kWh energy charges, as they often are for lower volume residential and small commercial consumers. For larger volume users, standard practice is to separate the charges for capacity and energy.

Demand charges are a means of allocating and recovering the costs of the capacity, measured and priced in dollars per kW per time period, to serve those peaks. They are deemed to give the larger utility users stronger incentives to manage their peak demand most efficiently, thus minimizing the investment in physical infrastructure that the utility must make on the customers' behalf. This incentive is further promoted by the common use of ratchets, which apply a peak demand value to the bill for anywhere from several months to a year after its occurrence.[6] Ratchets turn a fee that would otherwise vary with changes in demand into something more like a fixed charge that locks a customer into a minimum monthly payment for the duration of the ratchet. Although there is a certain logic behind ratchets—i.e., they link customer charges to the longer term nature of the capacity obligations of the utility—they nevertheless can be a financial barrier for customers looking for more efficient means of meeting their energy needs (even as they have the effect of lowering the cost of off-peak power).[7]

Most large customer electric rates include both an energy and a demand component. The relative level of each is determined by the characteristics of the local grid, supply mix, and other local market factors. The significance of the two components for a customer depends heavily on the customer's load factor. The load factor is the total energy consumption divided by the peak demand multiplied by the number of hours in the month. If the customer always consumed the same amount of electricity every hour of the month, then the demand would never change and the load factor would be 100 percent. This is an advantageous situation for the utility because its facilities are always being fully utilized. In this case, there would be little need to apply a demand charge, because demand and energy charges are fully linked.

If the demand is highly variable, then the load factor can be much less than 100 percent. In this case, there can be brief periods when supply facilities are heavily used, and long periods when consumption is much lower. In this situation, a utility would want to apply a demand charge to recover the costs of supplying the peak capacity that is not recovered by the lower level of consumption during nonpeak times. Because this load profile is in some respect related to the underlying operations of the customer, it might be appropriate for the customer to provide payment in this structure or alternatively to be driven by this structure to modify their operation to improve their load factor.

3.2 Standby Service

Customers who receive all of their electricity from the utility or via the grid are known as "full requirements" customers. Their electricity is provided under rates that are primarily some mix of the components discussed above. 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 desire. This service could be 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 service. Many of the utilities that provide these services distinguish in their tariffs among three types of partial requirements service: supplemental, backup, and maintenance. Some differentiate only between standby and supplemental. In this report, we recognize the following as the most common components of service for partial requirements customers:

- **Supplemental Service.** Supplemental service provides additional electricity supply for customers whose onsite generation does not meet all of their needs. In many cases it is provided under the otherwise applicable full requirements tariff.

- **Backup Service.** Backup or standby service supports a customer's load that would otherwise be served by DG, during unscheduled outages of the onsite generation.[8]

- **Scheduled Maintenance Service.** Scheduled maintenance service is taken when the customer's DG is due to be out of service for routine maintenance and repairs. In general, because this service can be scheduled for nonpeak times, it is considered to create few additional or marginal costs to the utility's system, and tariffs are typically structured to exempt the customer from capacity-related costs (e.g., reservation charges or ratchets, for either generation or delivery).

- **Economic Replacement Power.** Some utilities offer economic replacement power—electricity at times when the cost of producing and delivering it is below that of the onsite source.

Electric industry restructuring and the unbundling of the electric system's components (generation, distribution, transmission, etc.) has, in some states, added complexity to rate design (i.e., the Federal Energy Regulatory Commission's [FERC's] no action policy on states if deregulated). Whereas the electricity prices of vertically integrated utilities that have not been unbundled often include generation, transmission, and distribution charges, the separation of these functions in restructured states has also led to a separation of the charges for them. This can cause some confusion when comparing different rate elements and, in particular, their ratchets and exemptions. In general, in a restructured state the question of partial requirements service is limited to the remaining monopoly services that are only provided by the local incumbent utility—distribution and, in certain cases, transmission—but there might also be default service offerings for energy charges.

3.3 The Economics of Distributed Generation

As noted above, the basic economic underpinning of a DG system is a tradeoff between reduced electricity purchases and the increased capital and operating costs for the DG system. The facility operator invests in capital equipment and must pay operating and fuel costs. These costs must be offset by reduced electricity purchases for the system to be economical. For a CHP system, there are also increased efficiency and operating cost savings because of the combined generation of thermal and electric energy. At this level, there is a simple economic tradeoff between savings from reduced electricity consumption and the cost of additional fuel for onsite generation and levelized cost of increased capital investment.

The complication with respect to electricity rates comes when reduced consumption does not result in reduced electricity bills. This can result depending on the structure of the tariff—electric rate demand versus energy charges. Because DG reduces the purchase of energy (kWh), a rate that includes only a commodity charge would provide the most direct recognition of the benefit of the DG system. An 80 percent reduction in energy purchased would result in an 80 percent reduction in electricity cost.

Although the reduced consumption theoretically translates into a commensurate reduction in demand, in reality, every system has some number of planned or unplanned outages during the year, during which facility demand can reach the non-DG level. Thus, if the rate has only a demand charge and no energy charge, an outage would cause the facility to reach its peak demand during the month for a brief period, causing the DG system to achieve no savings at all in that month. If the rate has an annual ratchet, the one outage would cause the system to forgo any savings for the entire year.

Under these circumstances, the profile and timing of outages can be a major determinant of DG cost and system economics. Unplanned outages might be extremely rare and might not coincide with other system outages. Planned outages can be scheduled for off-peak hours when they place minimum stress on grid facilities. Thus, determining the appropriate rate structure of DG facilities requires a different analysis than that applied to conventional facilities. The rates applied to DG facilities can be many different combinations of standard, supplemental service, standby, emergency, and economic replacement rates. One cannot identify a unique structure that fits all customer and market characteristics; however, the goal of this paper is to identify basic structures that provide appropriate savings to DG facilities and appropriate cost recovery to utilities, recognizing the costs and benefits of DG.

4: Tariff Designs, Supplemental Service, and Economics of Distributed Generation Systems

Evaluating the economic effect of rate design on DG systems requires a detailed assessment of the time-dependent effect of both components of the rate structure. This section employs such a detailed assessment to evaluate the effect of partial requirements charges on a prototype DG (CHP) facility and to identify beneficial rate structures. This section discusses three tariffs, and Appendix A describes two additional examples.

4.1 Analytical Approach

The subsections that follow identify and analyze several approaches to standby rates using actual tariffs. This analysis compares annual bills of a DG customer with specified usage and production characteristics against the bills that the customer would otherwise pay as a full requirements customer. In each example, it is assumed that customers are billed monthly. Because the purpose of these analyses is to determine only the annual electric bill savings that a DG system would yield under the various tariffs given specified load and operating characteristics, the economics of the DG system were not being evaluated, so no attempt to characterize its costs and its thermal energy benefits was made.

The tariffs were evaluated for a mid-sized (5 MW) CHP project with characteristics summarized in Table 1.

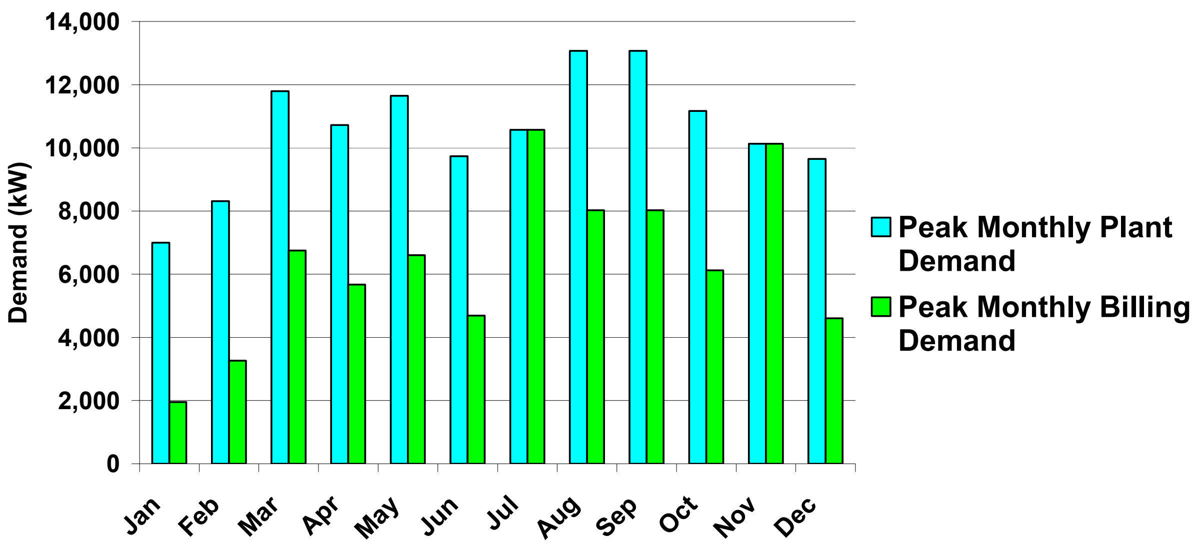
Table 1. Prototype CHP Facility

Plant Consumption Details		
Operating hours	8,760	
Annual power consumption, kWh	92,762,451	
Peak demand, kW	13,000	
CHP System		
Prime mover		Gas Turbine CHP
CHP electric capacity, kW		5,000
System availability, %		98%
System hours of operation		8,616
Electric Consumption	**Base System**	**Gas Turbine CHP**
Purchased power, kWh	92,762,451	49,273,191
Generated power, kWh		43,489,260

The modeled DG customer has a peak annual demand of 13,000 kW and annual consumption of 92,762,451 kWh. The peak demand is set in August. As shown in Figure 1, the 5,000 kW CHP system is baseloaded and provides about 47 percent of the customer's annual power needs.

In order to evaluate the impact of outages on savings under different tariff structures, the CHP system was assumed to experience unplanned outages during 2 months out of the year. As shown in Figure 1, the CHP system reduces the customer's monthly peak billing demand by 5,000 kW, except during July and November when the outages occurred. In these months, the peak billing demand is equal to the total demand of the facility.

Figure 1. Prototype Demand Profile



The rate impacts for the system for each tariff were calculated for each month of the year for the DG and non-DG cases. A spreadsheet tool was developed to calculate these monthly values and summarize them for the year. The tool calculated several annual average cost figures based on the total energy consumption. The first is the average cost per kWh for grid-supplied electricity under the full requirements tariff. This was calculated as the annual bill divided by the annual electricity consumption or purchases. The second is the average cost per kWh for grid-supplied electricity under the partial requirements tariff. This is the annual utility bill divided by the annual electricity purchases. Next, the tool calculated the value, per kWh, of the avoided grid-supplied electricity. This was calculated as the bill savings divided by the avoided consumption (or generation).

Last, the tool compared the value of the avoided purchases with the value of the full requirements electricity on a per-kWh basis. This avoided cost percentage is an important concept for evaluating the treatment of onsite generation by partial requirement tariff structures. One of the key economic values of onsite generation[9] is the displacement of purchased electricity and the avoidance of those costs. Ideally, the reduction in electricity price should be commensurate with the reduction in purchased electricity. If the onsite system reduces consumption by 80 percent, the cost of electricity purchases would also be reduced by 80 percent. The economics are severely impacted if partial requirements rates are structured so that only a small portion of the electricity price can be avoided. The higher the ratio of avoided costs to the full retail average price, the higher the user's savings. As an evaluation measure, partial requirement rate tariffs that result in avoided costs that are above 90 percent of the full service retail rate percentage generally provide adequate savings to support onsite generation.

4.2 Example 1—Portland General Electric

The first example is the Portland General Electric partial tariff 75, summarized in Table 2, as compared with the full requirements tariff 89. The rate is a fairly standard structure with customer, demand, and energy charges. A critical feature, however, is that this rate has monthly as-used on-peak demand charges (i.e., no ratchet). Thus, the assumed outages only affect the demand charge in that month and do not reduce the savings in other months.[10]

Table 2. Portland General Electric Tariff Provisions

Unbundled Service for Partial and Full Requirements Customers (>1 MW) With Monthly As-Used Demand Charges Portland General Electric		
	Full Requirements Rate 89	**Partial Requirements** Rate 75
Part 1: Customer charge		
Customer charge	$150/month	$150/month
Part 2: Transmission charges		
On-peak demand	$0.70/kW-month	$0.70/kW-month
Part 3: Distribution charges		
Sum of A + B		
A. Facility capacity		
First 1,000 MW	$1.90/kW-month	$1.90/kW-month
Over 1,000 MW	$0.57/kW-month	$0.57/kW-month
B. On-peak demand	$2.01/kW-month	$2.01/kW-month
Part 4: Generation charges		
Generation contingency reserves		
Sum of A + B		
A. Spinning (>2,000 kW)	N/A	$0.2340/kW-month
B. Supplemental (>2,000 kW)	N/A	$0.2340/kW-month
System usage charge	$0.0039/kWh	$0.0039/kWh
Energy charge	Wholesale market price/kWh	
Average on/off peak	$0.0626/kWh	$0.0626/kWh

Source: Portland General Electric, Rate 75 (partial requirements) and Rate 89 (full).

The partial requirements tariff is in most respects the same as the full requirements tariff. The primary difference is a contingency reserve and a spinning reserve charge applied to the onsite generator capacity. These contract demand charges are fixed, but their rates are low enough that they do not significantly change the electricity cost for the CHP system. Table 3 shows the breakdown of costs for the fuel requirements and partial requirements cases. There are three key elements:

- The first thing to notice is that the energy charges constitute more than 90 percent of the total cost in both cases. Because DG affects energy consumption, this is an initial indicator that these rates will be favorable for DG economics.
- Second, as mentioned above, this rate does not have a demand ratchet, so the outages do not have an exaggerated effect on the cost.
- Finally, the standby demand charges, though fixed, are only a $28,000 adder compared with the $3-million savings provided by the CHP systems.

Overall, the cost savings are more than 97 percent of the electricity savings, indicating that the tariff does a good job of recognizing the value of DG.[11]

Table 3. Portland General Electric Cost Comparison

Comparative Annual Bills	Full Requirements	Partial Requirements
Purchased electricity, kWh	92,762,451	49,273,191
Facilities charges	$1,800	$1,800
Distribution on-peak demand charges	$255,056	$153,601
Facility capacity demand charges	$105,404	$88,289
Transmission on-peak demand charges	$88,826	$53,493
Standby demand charges	$0	$28,347
Energy charges	$6,170,439	$3,277,589
Total electric charges	**$6,621,524**	**$3,603,120**
Average rate for purchased power	$0.0714	$0.0731
Average avoided rate	N/A	$0.0694
Average avoided rate as a percentage of average retail service rate	**97.2%**	

Source: EPA analysis using Portland General Electric tariff.

This rate structure illustrates a number of rate design features that could be appropriate for large users, whether full or partial requirements:

- Transmission, distribution, and generation charges are separated and, within these categories, the rates are further unbundled as justified by their cost characteristics.
- The customer charge, transmission rate, and distribution rates are the same for full and partial requirements customers.[12] This might also be true of the generation rates, but it could depend on the existence of competitive alternatives.
- The charges might differ, depending on the voltage level at which service is taken (i.e., secondary, primary, sub-transmission).
- The customer charge is typically a fixed, periodic (daily or monthly) charge. It should cover at most the costs of metering, billing, and customer service that do not vary with usage. It goes without saying that charges should not be duplicative—for example, a partial requirements customer should not pay a customer charge for standby service and a second one for supplemental service.
- The transmission charge is applied to kW of monthly on-peak demand (no ratchet).
- There are two categories of distribution charges, one for dedicated facilities and a second for shared facilities.

The facilities (or contract demand) charge is a per-kW fee applied to the customer's maximum noncoincident peak demand (or contractually agreed-on maximum) of required capacity for dedicated facilities, subject to an 11-month ratchet or similar mechanism.

The charge for shared facilities is also a per-kW fee, but applied to the customer's maximum monthly demand during the on-peak periods (e.g., 8 a.m. to 11 p.m.).

The generation charges cover the costs of generation capacity necessary to serve unplanned outages of the DG. These per-kW charges can be calculated in one of two ways, in recognition of the DG's diversity benefits (they should, theoretically at least, yield the same result):

1. As a function of the probability of the occurrence of an unplanned outage coinciding with a system peak or other times of capacity constraint (e.g., when other units are suffering unplanned outages). The ratchet will depend in part on the nature of wholesale capacity and energy markets and the obligations of participants. At most, a ratchet should reflect the timing and duration of capacity purchase requirements, but should also be reflective of the other uses to which that capacity can also be put (i.e., the diversity of the loads it will serve).
2. As a share of the contingency reserves required to serve load in the event of an unplanned outage.[13] Energy charges are rendered in dollars per kWh and can be differentiated by time (on-peak, off-peak, season, hourly) to reflect the variable costs of production or a market-based approach.

4.3 Example 2—Orange & Rockland

Orange & Rockland is an investor-owned utility in New York State. Table 4 summarizes Orange & Rockland's standby service tariff SC-25, as compared with its full requirements tariff SC-9. A unique feature of this standby service tariff is that all service—both that needed to serve the customer when its onsite generation is offline (i.e., standby) and that needed to serve the customer's demand in excess of the capacity of its onsite generation (i.e., supplemental)—is taken under the partial requirements tariff. This means that the contract demand charge applies to the customer's total maximum demand, not merely that portion necessary to backing up its generator. In this respect it differs from other tariffs with daily as-used demand charges (for instance, see Appendix A, which describes the Hawaiian Electric standby tariff). Note, however, that a customer has the option to segregate a portion of its load so it might indeed be billed under the applicable full requirements tariff.

As suggested earlier, a monthly demand charge is, in effect, a daily demand charge with a 30-day ratchet. An alternative to a monthly demand charge for shared facilities is a daily as-used, on-peak demand charge. It reduces the costs of partial requirements service for those customers whose need for backup is infrequent, providing incentive for increased onsite generation. In its other aspects, this type of rate design looks very much like the previous design.

Table 4. Orange & Rockland Tariff Summary

Unbundled Service for Full and Partial Requirements Customers (>1 MW) With Daily As-Used Demand Charges Orange & Rockland		
	Full Requirements SC-9	**Partial Requirements** SC-25
Part 1: Customer charge		
Customer charge	$450/month	$371/month
Part 2: Delivery charges, demand		
A. Period A	$9.89/kW-month	
B. Period B	$4.64/kW-month	
As-used demand charge		
Daily summer as-used		$0.4210/kW-month
Daily non-summer as-used		$0.2769/kW-month
Part 3: Delivery charges, energy		
Period A, all kWh	$0.01103/kWh	
Period B, all kWh	$0.01103/kWh	
Period C, all kWh	$0.0041/kWh	
Standby		
Contract demand charge		$3.09/kW-month
Part 4: Energy, commodity	Energy, ancillary service, capacity at wholesale market prices	
Commodity charge	$0.0795/kWh	$0.0795/kWh

Source: Orange & Rockland, general service Tariff SC-9 and standby service Tariff SC-25.

Table 5 shows the calculated cost for the conventional and CHP systems under Orange & Rockland's two tariffs. As in the previous example, the energy charges predominate, though not as much, accounting for slightly more than 80 percent of the total cost. The contract demand charges and delivery charges in the partial requirements tariff are much higher than in the previous example, accounting for almost $1 million. However, these charges are in lieu of higher demand and delivery charges included under the full requirements tariffs, so the result is a net savings. The reduction in cost is more than 95 percent of the reduction in consumption, again showing a good recognition of the value of DG in the tariff. The key factors again are a tariff dominated by energy charges, no demand ratchet, and, in this case, standby charges that replace rather than add to the demand and delivery charges in the full services tariff.

Table 5. Orange & Rockland Cost Comparison

Comparative Annual Bills	Full Requirements	Partial Requirements
Purchased electricity, kWh	92,762,451	49,273,191
Facilities charges	$5,398	$4,457
Delivery demand charges	$832,744	$0
Delivery energy (usage) charges	$667,311	$0
Contract demand charges	$0	$484,880
Daily as-used demand charges	$0	$489,961
Commodity energy charges	$7,374,615	$3,917,219
Total electric charges	**$8,880,068**	**$4,896,518**
Average rate for purchased power	$0.0957	$0.0994
Average avoided rate	N/A	$0.0916
Average avoided rate as a percentage of average retail service rate	**95.69%**	

Source: EPA analysis using Orange & Rockland tariff.

4.4 Example 3—NSTAR

NSTAR has a standby rate design that calls for contract demand charges only; there are no variable demand charges, either monthly or daily. Table 6 summarizes NSTAR’s partial requirements SB-T2 rate, as compared with its full requirements T2 tariff.

Table 6. NSTAR Tariff Summary

Unbundled Service for Full and Partial Requirements Customers (>14,000 Volts) Contract Demand Charges for Partial Requirements Monthly As-Used Demand Charges for Full Requirements NSTAR		
	Full Requirements Rate T2	**Partial Requirements** Rate SB-T2
Part 1: Customer charge		
Customer charge	$375/month	$375/month
Part 2: Distribution charges, demand		
Summer peak	$19.5/kW-month	$19.5/kW-month
Winter peak	$11.03/kW-month	$11.03/kW-month
Energy charge	$0.01371/kWh	$0.01371/kWh
Transmission charges, demand		
Summer	$4.50/kW-month	$4.50/kW-month
Part 3: Other charges, standby		
Summer contract demand		$14.67/kW-month
Winter contract demand		$8.75/kW-month
Part 4: Energy, commodity		
Default service, all kWh	$0.11678/kWh	$0.11678/kWh

Source: NSTAR, Rate SB-T2 for partial requirements customers and Rate T2 for full.

Table 7 summarizes the cost analysis for this NSTAR example. The energy charge is the largest cost component, but it represents only 70–75 percent of the total, which is lower than in the previous examples. This suggests a less favorable outcome for DG; however, there is no demand ratchet. The standby charge is a contract demand charge, and, as such, it cannot be reduced through the generation of more power. It therefore represents an unavoidable cost which is larger than in the previous examples, accounting for more than 7 percent of the total electricity cost in the DG case compared with $6 million in savings. This accounts for a large part of the difference between the average retail rate before DG and the average avoidable rate.

Table 7. NSTAR Cost Summary

Comparative Annual Bills	Full Requirements	Partial Requirements
Purchased electricity, kWh	92,762,451	49,273,191
Facilities charges	$4,500	$4,500
Distribution demand charges	$1,793,221	$954,125
Standby/contract demand charges	$0	$649,512
Transmission demand charges	$571,021	$298,456
Distribution energy charges	$1,271,773	$675,535
Commodity energy charges	$10,832,799	$5,754,123
Total electric charges	**$14,473,315**	**$8,336,252**
Average rate for purchased power	$0.1560	$0.1692
Average avoided rate	N/A	$0.1411
Average avoided rate as a percentage of average retail service rate	**90.44%**	

Source: EPA analysis using NSTAR tariff.

5: Conclusions

A host of factors will affect increased investment in efficient, clean DG. These factors include the costs of the onsite DG systems and the costs (e.g., the rates) for partial requirements electricity service. Rate designs that have a reasonable balance between energy and demand or reservation charges will naturally be more amenable to the broad policy goal of encouraging clean, efficient DG. Rate designs that reward reliable operation can encourage the development of a diversified, more reliable electric grid. The review of tariffs and operation on peak in this report suggests that the more favorable rate designs share common and central characteristics: they are designed to give customers a strong incentive to use electric service most efficiently, to minimize the costs they impose on the system, and to avoid charges when service is not taken. Put another way, they reward customers for maintaining and operating their onsite generation. Specifically, they are marked by some or all of the following features:

- Contract demand or reservation charges are small in relation to the variable charges for peak demand and energy.

- Peak demand charges are not ratcheted or, at worst, have 30-day ratchets (that is, there are no more than monthly as-used demand charges).

- Energy-based charges to collect capacity costs would seem to offer the greatest promise in this regard, but utilities and their regulators do not appear to be prepared to entirely abandon some form of peak demand charge. As such, daily as-used demand charges are the next best solution, but how a particular rate is structured along these lines will depend (as the first bullet mentions) on the levels of the various rate elements.

- The rate structure yields a high value of retail rate savings per kWh produced on site instead of purchased from the grid. This depends not only on the standby tariff itself, but also on the level and structure of the otherwise applicable full requirements tariff.

These findings are consistent with the understanding that the economics of onsite generation are based on reduced electricity purchases, and these reduced purchases must benefit the customer to make DG viable. Importantly, they also serve to remind regulators of the need to pay close attention to ensuring that the design of partial requirement rate structures captures the economic and environmental benefits of reduced energy consumption. These examples also suggest that such rates can apply to DG while also fairly compensating utilities for the services they provide to onsite generators.

6: Notes

1 There are a variety of terms and associated acronyms for customer-sited generation, some of which are synonyms and some of which refer to subsets of others: for example, DG, onsite generation, and CHP systems. For simplicity's sake, we use the catch-all term "DG" here because our analyses are concerned only with utility rates and not with the costs and benefits of different kinds of onsite facilities. The generic system that we model in the analyses is a high-capacity factor CHP system slightly more than 5 MW in size.

2 EPA's Combined Heat and Power Partnership defines CHP as follows: "CHP, also known as cogeneration, is an efficient, clean, and reliable approach to generating power and thermal energy from a single fuel source."

3 Energy and Environmental Analysis, an ICF International Company, maintains a Combined Heat and Power Installation Database that contains data on CHP units in each state. The database can be accessed at <http://www.eea-inc.com/chpdata/States/MT.html>.

4 Of course, how these other charges are calculated (e.g., as a function of demand or energy or according to some other measure) will be relevant to whether they pose barriers to DG and can be avoided.

5 Some tariffs define their consumption blocks in terms of kWh per kW of demand, thus relating usage directly to levels of demand.

6 A typical ratchet calls for billing the customer, in each of the 11 months following their peak demand, for a share of that peak demand or the peak in that month, whichever is greater. If a higher peak occurs, that new demand forms the basis of a new ratchet, which then extends for the following 11 months, unless it too is surpassed. To the extent that generation and delivery charges are unbundled, the computation and application of the charges and ratchets can differ. In the case of generation, the demand charge should be a function of the customer's contribution to system (i.e., coincident) peak, whereas for delivery it will be a function of the customer's noncoincident peak and its contribution to the need for dedicated and shared facilities.

7 The tension with ratchets lies in precisely this circumstance. Onsite generation systems, particularly CHP systems with higher capacity factors, save energy, but depending on the nature of their outages, they might have less of an impact on the need for grid-supplied capacity (both generation and delivery). Whether this is the case depends on the probabilities and timing of outages and the overall load shapes of the relevant customer classes and the system as a whole. A relatively diverse system should have less of a need for longer-duration charges. Some standby tariffs allow for the conversion of the historical ratchet into the level of contract or reservation demand, which further exacerbates the challenges for the customer in making the case for DG work.

8 At least one utility—Detroit Edison—calls the service that it provides to customers with onsite generators "backup," even if the customer sheds load to compensate for the unplanned outage (see the discussion in Section III.C. on physical assurance). Similarly, all service taken by an Orange & Rockland DG customer is supplied under the partial requirements tariff; "standby" is not differentiated from "supplemental" service.

9 There are additional economic values provided by onsite generation, including increased reliability and, in the case of CHP applications, reduced fuel use for onsite thermal needs.

10 This example assumes that this customer is on a calendar month billing cycle. Other simplifying assumptions having to do with the market price for the energy commodity were also made.

11 This is the consequence of a simplifying assumption in which the generation energy charges that partial requirements customers pay are the same as those paid by the full requirements customer. This is not the case in practice. Whereas the partial requirements customer pays for its generation contingency reserves separately from the energy it uses, the full requirements customer pays an energy rate that already includes the cost of the contingency reserves. By using the same energy commodity charge for both customers, we have slightly

overstated the cost of partial requirements service, though not significantly enough to affect the central conclusions.

12 This assumes that the distribution- and transmission-level diversity benefits (or losses) provided by DG customers do not significantly differ from those of full requirements customers. If they do, regulators might want to set rates that better reflect those impacts.

13 Mathematically, the differences between the two methods are as follows. In the first instance, the amount of load to be served in the case of an outage is discounted by the probability of that outage occurring on peak. Then applied to that discounted demand is a price per kW for the generation needed to cover it. In the second case, it is the cost of the system's generation reserves that is discounted (that is, it is shared among all customer classes according to their contributions to system peak) and is then applied to the total kW that a customer is expected to incur during an unplanned outage.

Appendix A: Additional Analyses of Specific Standby Tariffs

A.1 Hawaiian Electric Company—Unbundled Rates and Daily Demand Charges

This is an additional example of a standby rate that makes use of daily as-used demand charges. Hawaiian Electric Company, serving an island, is faced with particularly high costs. Its rates are provided in Table 8.

Table 8. Hawaiian Electric Company Tariff Summary

Unbundled Service for Full and Partial Requirements Customers (>1 MW) With Daily As-Used Demand Charges Hawaiian Electric Company		
	Full Requirements Rate PS	**Partial Requirements** Rate SS
Part 1: Customer charge		
Customer charge	$230/month	$230/month
Part 2: Delivery charges, demand		
Sum of A + B		
A. Reservation demand charge*		$7.26/kW-month
B. As-used demand charge		$0.66/kW-day
First 500 kW of billing demand	$10.00/kW-month	
Next 1,000 kW of billing demand	$9.50/kW-month	
Over 1,500 kW of billing demand	$8.50/kW-month	
Part 3: Delivery charges, energy		
All kWh		$0.124/kWh
First 200 kWh/month per kW of billing demand**	$0.072087	
Next 200 kWh/month per kW of billing demand	$0.064104	
Over 400 kWh/month per kW of billing demand	$0.061010	
Part 4: Energy, commodity	$0.15/kWh	$0.15/kWh

Source: Hawaiian Electric Company, full requirements Rate PS and partial requirements Rate SS.

*Note that, unlike the Orange & Rockland contract demand charge, Hawaiian Electric Company's reservation demand charge applies only to the amount of demand associated with backup service (e.g., the nameplate capacity of the onsite generation or a contractually agreed-on demand). Any demand in excess of that amount is paid for under the otherwise applicable full requirements tariff.

**Energy charges in kWh/month per kW of billing demand denote a declining block structure where the number of kWh under each block rate is a function of the monthly kW billing demand.

The standby rate customer, as in the other examples discussed in this report, will avoid the purchase of 47 percent of its grid-supplied energy, and the customer will reduce its utility bill by 42 percent. The average cost of a grid-supplied kWh under the partial requirements tariff is approximately 5 percent greater than under full requirements. The value of the average avoided kWh is 94.3 percent of the average retail rate.

Of interest is the fairly high per-kWh charge ($0.124/kWh) for delivering energy to the partial requirements customer when the DG is offline. A similar charge is not imposed on full requirements customers, but they pay delivery demand charges that range from 17 percent to 37 percent higher than partial requirements customers. An energy-based delivery charge is, as a general matter, a preferred approach to standby rate design, in that it gives the customer a strong and direct incentive to ensure that their DG is properly maintained and operating. In this example, the delivery charge constitutes a relatively small portion of the total annual bill (approximately $90,000) because the onsite generation operates at a fairly high capacity factor. But, for a less well-performing DG system, this charge could be much larger. This tariff, in effect, shifts part of the revenue burden for partial requirements customers from an unavoidable delivery demand charge to a “pay as you go” energy charge. This, in combination with the daily as-used demand charge, enables the 42 percent reduction in the customer’s annual bill and results in the fairly high value of avoided retail purchases. Obviously, even a rate structure that makes use of avoidable charges might still impose relatively high bills on the customer with DG, if the recurring charges (customer and reservation or contract demand charges) are themselves set at disproportionately high levels. What matters are the relative shares of the total bill to which the various rate elements contribute.

A.2 Consolidated Edison—Daily As-Used Demand Charges

This analysis shows the full and partial requirements tariffs of an additional New York utility, Consolidated Edison. Table 9 compares this utility’s full and partial requirements tariffs.

Table 9. Consolidated Edison Tariff Summary

Unbundled Service for Full and Partial Requirements Customers (>1.5 MW) With Daily As-Used Demand Charges Consolidated Edison		
	Full Requirements Tariff SC-9, Rate II	**Partial Requirements** Tariff SC-14RA
Part 1: Customer charge		
Customer charge	$0	$908
Part 2: Delivery charges, demand		
June–September: sum of A + B + C		
A. M–F, 8 a.m.–6 p.m.	$5.86/kW-month	
B. M–F, 8 a.m.–10 p.m.	$11.09/kW-month	
C. All days, all hours	$10.94/kW-month	$5.41/kW-month
All other months: sum of B + C		
B. M–F, 8 a.m.–10 p.m.	$8.14/kW-month	
C. All days, all hours	$3.54/kW-month	
Part 3: Delivery charges, as-used demand		
8 a.m.–6 p.m., Jun–Sept		$0.3423/kW-day
8 a.m.–10 p.m., Jun–Sept		$0.6910/kW-day
8 a.m.–10 p.m., other months		$0.5200/kW-day
Part 4: Delivery charges, energy		
M–F, 8 a.m.–10 p.m.	$0.0058/kWh	
All other hours/days	$0.0058/kWh	
Part 5: System benefits charges, energy		
All hours/days	$0.0018/kWh	$0.0018/kWh
Part 6: Energy, commodity	Energy, ancillary service, capacity at wholesale market prices	

Source: Consolidated Edison, partial requirements tariff SC-14RA and full requirements tariff SC-9, Rate II.

The partial requirements customer, in keeping with the other examples, will avoid the purchase of 47 percent of its grid-supplied energy, and will reduce its utility bill by 43.7 percent. The average cost of a grid-supplied kWh under the partial requirements tariff is 6 percent greater than that under full requirements. The value of the average avoided kWh is 93.2 percent of the average retail rate.

Appendix B: Principles of Rate Design

B.1 Basic Principles of Rate Design

There are two broad, fundamental justifications for governmental oversight of the utility sector. The first is the widely held belief that this sector's outputs are essential to the well-being of society—its households and businesses. The second is that its technological and economic features are such that a single firm often can serve the overall demand for its output at a lower total cost than can any combination of more than one firm. Competition cannot thrive under these conditions and, eventually, all firms but one exit the market. This is called "natural monopoly," and, like monopoly power in general, it gives the surviving firm the power to restrict output and set prices at levels higher than are economically justified. Economic regulation is seen then as the necessary and explicit public or governmental intervention into a market to achieve a public policy or social objective that the market fails to accomplish on its own.

In light of the economic and public welfare characteristics of utilities, certain purposes for price regulation emerge. They can be generalized in the two goals of *economic efficiency* and *fairness* (or equity), which can then be further broken down as follows:

- **Economic efficiency**. Because electric utilities generally do not operate in competitive markets that would impose cost discipline on them, regulation must fulfill that function. To achieve this objective, regulation sets rates that reflect, to the greatest extent possible, the long-run marginal costs of production.[1]

- **Fair prices** for consumers and investors. Price regulation is intended to guard against the reaping of unjustifiably high profits (called economic "rents"), while still enabling the utility to generate enough revenue to cover necessary expenses and investment and to provide a reasonable return on that investment. Prices should also be fair to competitive providers or, more accurately, the competitive process. They should also minimize any distortional effects on the economy—changes in how the economy and customers would act if there were perfect competition with no regulation and no monopoly.

- **Non-discriminatory access** to service for all consumers.

- **Adequate quality and reliability**. Because electricity is an essential service, reliability is critically important.

- **Other stated public policy objectives** (e.g., environmental protection, universal service, low-income support, energy efficiency) (Bonbright, 1961, pp. 25–41; Pierce, 1999, p.11; Kahn, 1988, Vol. I, pp. 20–25, 69–70, and Vol. II, pp. 243–246).

For goods and services that competitive markets can provide, the markets by themselves will go a long way toward meeting these goals.[2] Thus, it can be said that economic regulation is intended to achieve outcomes that competition, if it were possible in the market for electricity, would otherwise achieve (Kahn, 1988, Vol. I, p. 17; Bonbright, 1961, p. 372; Pierce, 1999, pp. 2, 47–48, 94–95). Also, prices in regulated industries naturally affect prices in competitive ones, and vice versa, and therefore affect the overall efficiency of the economy—all the more reason to adopt utility rate designs that most closely resemble price structures in competitive markets and therefore do not create excessive distortionary effects on the economy.

The general goals of economic regulation inform the rate design process. More specifically, the object is to set economically efficient and fair prices, while simultaneously giving the regulated firm a reasonable opportunity to recover its legitimate costs of providing service—including return of, and on, its investment.

The particular problem faced by regulators in this exercise is that the legitimate historical (accounting or "embedded") costs that a utility incurs are to be recovered in rates, but these costs may only bear a passing resemblance to the marginal costs—what a customer must pay to receive one more unit of energy—that form the basis of economically efficient prices. The need to cover historical costs, set economically efficient prices, and then meet other objectives of regulation requires careful judgment. James Bonbright (1961) dedicated five chapters and 120 pages to the subject, beginning with a catalogue of the several and sometimes competing objectives of rate design. It remains today the comprehensive compilation on which regulators rely. Paraphrased, Bonbright's principles are (Bonbright, 1961, p. 291):

Revenue-Related Objectives:

- Rates should yield the total revenue requirement.
- Rates should provide predictable and stable revenues.
- Rates themselves should be stable and predictable.

Cost-Related Objectives:

- Rates should be set so as to promote economically efficient consumption, where the well-being of both the utilities and consumers is maximized, given the restraints (static efficiency).
- Rates should reflect the present and future private and social costs and benefits of providing service (i.e., all internalities and externalities).
- Rates should be apportioned fairly among customers and customer classes.
- Undue discrimination should be avoided.
- Rates should promote innovation in supply and demand (dynamic efficiency).

Practical Considerations:

- Rates should be simple, certain, payable conveniently, understandable, acceptable to the public, and easily administered.

- Rates should be, to the extent possible, free from controversies about proper interpretation

The tension among these sometimes competing and always challenging goals gives regulators a good deal of discretion in designing pricing structures. But because prices should, for the most part, reflect the long-run marginal costs of production, regulators are rightly limited to consumption-based prices, because it is demand for units of the good, electricity in this case, that, in the long run, drives its costs—and in the long run all costs are variable. In this way, consumers must pay to use the good, but they avoid costs when they do not use the good, and the costs to society of the resources allocated to that good (externalities) are fully covered.

As a principle, it can be easily agreed on by all, but its practical application is difficult. Debate focuses not only on the level of rates, but also on the use of fixed, recurring, and ratcheted charges. Proponents of DG make two fundamental arguments: (1) customers with onsite generation should be no more obligated to pay unavoidable charges than full requirements customers (in fact less so, given their asserted lower probabilities of needing service at times of peak); and (2) their charges should be discounted in relation to those of full requirements customers, because they provide diversity benefits to the system as a whole. Fixed and ratcheted charges might, arguably, be designed to satisfy this principle—they cover the long-run costs of service and can be avoided by taking no service at all—but as a practical matter, they look very much like access fees, to be paid regardless of whether, and the level at which, service is taken. Unavoidable charges are inconsistent with the objectives of economic efficiency.[3]

This logic might suggest that the economist's preferred price unit for electric service is the kWh charge (differentiated by time and, perhaps, geography).[4] It certainly has its appeal. But there are other objectives of rate design, which, if unmet, might threaten the financial integrity of the utility and the overall reliability of the grid. The succession of rate structures, measured by customers' ability to avoid paying charges, extends from the energy charges to the recurring customer charge, passing along the way from as-used demand charges to ratcheted ones. As pointed out earlier, the essential differences among them are their time denominations. The longer duration charges, though supposedly still avoidable, give the utility some greater measure of revenue predictability, and remind customers as well that their right to call on the system at any time depends in part on the availability of otherwise idle capacity. The justification for demand charges lies in this balancing act.

To the degree that the characteristics of demand for standby service and therefore its costs differ significantly from those of the rate class to which the DG customer would otherwise belong, its rate design should reflect these differences. Daily as-used demand charges are one example of this (although, arguably, there is no reason why they cannot be extended to full requirements customers as well). Price discounts or ratchet adjustments, to account for (or reward) high-capacity factors (reliability) of onsite generation, are another approach.[5] A customer's guarantee that demand for standby service will not exceed a specified level (accompanied by facilities or equipment to make good on the guarantee, known as "physical assurance") is another tariff feature that allows for alternative rate treatment of CHP.[6]

The degree of diversity that customers with onsite generation bring to a system appears to be most often the thorniest issue that regulators deal with. This diversity benefit obviously depends on the operating characteristics of the generation, which system operators and utilities argue is far less understood than proponents contend. One way to deal with this issue, at least in the early years of a new standby rate structure, is to make the tariff optional—that is, give customers the choice of taking service under the standby tariff or under the otherwise applicable full requirements tariff. Customers will choose the tariff that better serves their needs and reduces their costs more. While this may result in a lower aggregate level of revenues for the utility from these customers, it will reveal a good deal about the performance that customers expect from their machines and might indeed offer a better allocation of the risks between them.[7]

B.2 Pricing the Components of Electric Service

Rate designers differentiate the major components of the system according to the drivers of their costs—i.e., according to the functions of the system. Three broad categories of costs emerge from this approach—generation, transmission, and distribution—which can be separately priced as consumer understanding and administrative simplicity allow. Where the benefits of changes in usage caused by more complex rate designs are not enough to justify the added metering and billing costs to support such rates, the pricing elements are combined and aggregated into simpler energy-only or energy and demand charges.

We note here that the structure of the electric industry in a state might affect the nature of partial requirements service, like that of full requirements service. If multiple competitive suppliers provide generation services, distribution utilities will provide only delivery service and regulatory interest in standby will be, accordingly, restricted to that component of service. Restructuring accelerated the movement to unbundled pricing for the various components of service (i.e., separate prices for the differentiable elements of service—generation, transmission, and distribution), but nothing about vertically integrated industry structures prevents a similar unbundling of rates. Unbundling makes the nature of costs more transparent and, if done properly, greatly reduces or even eliminates the potential for the cross-subsidization of one service by another.

Generation consists of energy and capacity costs. Energy is the cost to actually produce kWh—that is, variable (or marginal) cost. Primarily this is the cost of fuel, but often there are variable operations and maintenance costs that are not incurred if the unit does not run. Capacity is the cost of the plant—or, more precisely, of the ability to generate power—for the period of the purchase (hour, day, month, year).[8] As described above, capacity is typically expressed in per-kW terms, but it can also be expressed in energy terms (per kWh) given assumptions about a plant's operating characteristics.

The amount of generation that a system needs is a function of its overall peak demand. Only that amount necessary to meet peak (and reserves—otherwise unused capacity to maintain reliability in case of unplanned outages) should be acquired; any more would be wasteful and any less would, without remedial action, jeopardize system reliability. This means that it is a customer's or, more accurately, a customer class's full or partial requirement, contribution to the system (or coincident) peak that determines its responsibility for the costs of the required generation capacity. Insofar as the load-serving entity (i.e., the utility or competitive service provider) knows generally when peaks will occur, time-differentiated pricing can be designed to reflect the expected costs of peak demand, and this will go a long way toward fairly allocating the costs of capacity among users, capturing the benefits of demand response, and capturing load diversity from the different power generation sources.[9]

Each customer class imposes unique demands on the system, and the tariffs drawn up to reflect those different characteristics provide, in effect, different services suited to the needs of the classes. To the extent that the usage characteristics of partial requirements customers, and the costs associated with that usage, are demonstrably different from those of related full requirements customers, such customers can be seen as constituting a different class. Whether, from the perspective of DG customers, being treated as a separate class is good or bad (that is, less or more costly) depends on, among other things, the average load factor (the ratio of average electric load to peak load) of the group and its contribution to system peak. If the load factors of DG customers are for the most part better than those of other customers in the relevant full requirements service class, then the non-DG customers are benefiting from the inclusion of DG owners in the class.[10] Or it might be the other way around. But either way, a detailed cost of service study—using reliable data on the operational characteristics of DG systems—will be needed to inform the regulators' decision about how to treat these customers.

A standard practice in the design of standby tariffs is to impose more than one type of demand charge. The first is the reservation or contract demand charge, which ostensibly covers the costs of the capacity that the utility must have access to in order to cover a call for unscheduled service, even if that call is never made. Typically, the reservation charge is applied against monthly billing demand (contract, maximum potential, or ratcheted), and therefore looks very much like an unavoidable, fixed, recurring fee that gives a customer the right to take standby service.[11] The contract demand is often based on the net capacity of the onsite generator or some negotiated or specified portion of that capacity. The next charge is a usage-related demand charge, which is applied against demand associated with standby service actually taken. This charge is often a monthly, or sometimes daily, price per kW used and, in the absence of a ratchet, is referred to as "as-used." This charge is generally linked to the costs of shared facilities, which can vary insofar as the plant can be redeployed (used to serve other demands).[12]

A variation on the reservation charge is a fee for contingency reserves, the amount of operating reserves that must be available to meet load in the event that the customer unexpectedly takes energy from the grid—that is, when its onsite generation suffers an unscheduled outage. Under this approach the customer has the same obligations that other load serving entities have: namely, entitlement to sufficient operating reserves to cover the load in cases of an unplanned outage of any of the resources serving that load. Because the probabilities of two or more generating facilities (whether central station or customer-sited) suffering an unplanned outage simultaneously and, in particular, at the time of a system peak, are less than 100 percent, the amount of resources to be held in reserve is correspondingly less than the full potential load that they might be called on to serve. This is the effect of diversity, and it greatly reduces the amount of excess capacity that the system must have to maintain a given level of reliability.

A combination of factors drives investment in the distribution system. For facilities dedicated to the customer, a customer's noncoincident peak demand (i.e., maximum demand, regardless of when it occurs) drives investment, and for facilities shared among distribution customers (e.g., substations, feeders, etc.), the driving force is coincident peak demand of the customers they serve. Though the costs are separable, they are typically combined within one demand charge (or set of charges) for distribution service, priced on a per-kW-month basis. Simplicity is one reason for this. Another is the lack of a metering and data management capability that measures both customer coincident and noncoincident peaks on discrete sections of the distribution system—although advances in metering technology are changing this.

The distribution demand charge is multiplied by the customer's billing demand, which is one of several quantities (or some variation on them): the customer's monthly noncoincident peak demand, its maximum potential demand, or an agreed-on contract demand. For partial requirements customers, the negotiated contract demand might be accompanied by the customer's promise not to exceed it (accompanied by special load-limiting facilities to make good the guarantee), a feature sometimes referred to as "physical assurance."[13] Not all utilities offer these options; each has its own approach.

If avoidability of charges is a key determinant of whether a rate structure is beneficial to DG, then the design of demand charges—specifically, their ratchets—becomes a focus of analysis. Ratchets are most painful to customers with relatively low load factors—i.e., low ratios of actual usage (in kWh in a period) to maximum potential usage (the product of peak demand and hours in the period). They require the customer to pay a fee related to a significant fraction of their peak demand in periods when their demand does not approach their peak. A customer with relatively high load factors is less affected by the ratchet the closer its periodic demands are to its peak, and so the fees it pays are not much different from those it would pay without the ratchet. Either way, of course, it is worth examining the justification for the ratchet to determine if it is related to the nature of the costs incurred and if the capacity whose costs it covers is indeed unable to be put to alternative uses. This is another way of looking at the question of diversity, the measure of the coincidence of customer demands. The more diverse a system (or part of a system) is, the less impact the peak demand of any one customer or set of customers has on the overall peak of the system. Conversely, the greater the degree of coincidence in customer demands, the less diverse the system's load.

A number of utilities have eliminated multi-month ratchets for distribution service. Portland General Electric assesses distribution demand charges on the basis of the customer's peak in the month; each month's costs are determined separately and are unrelated to any previous month's demand.[14] Rochester Gas & Electric, Orange & Rockland, and other New York utilities use daily on-peak only (as-used) demand charges.

Transmission costs tend to be less problematic than generation and distribution costs if only because they are typically a small portion of the bill. Transmission investments are shared facilities and, depending on the size of the facilities in question, are characterized by greater diversity than much of the distribution system. Because transmission, like distribution, is driven by the relevant peak demand, it is priced on a per-kW (or per-MW) basis. In many restructured states, transmission charges are typically included in the prices of competitive generation suppliers, not the prices of the distribution company.

B.3 Notes

[1] The economics literature in support of this statement is extensive. (See, for example, Kahn, 1998, Chapters 3 and 4, and Bonbright, 1961, p. 318.) This is not to say that it is not appropriate, in certain circumstances, to set prices at short-run marginal cost, for instance when variable costs (e.g., the price of fuel) exceed the long-run marginal cost. In that event, consumers undervalue the good and use more of it than is economically justified, and the utility loses money. Some regulatory economists argue that the converse is also true—that when capacity is surplus, it is economically inefficient to charge greater than variable operating cost. We would say, however, that this argument might have more appeal if all the costs of production, including the external costs (e.g., environmental damage costs), were included in the price.

[2] This is not to say that competitive markets will, by themselves, satisfy all, or fully any, of the welfare-enhancing objectives that a society embraces. Transaction costs, externalities, lack of information, and the preexisting distribution of wealth and income—to name a few factors—all affect the operations of markets in ways that often call for some form of governmental intervention into the market for the benefit of the public overall. Content labeling; performance requirements; health standards; labor, anti-trust and anti-discrimination laws; and financial requirements are all examples of government actions taken to assure that other highly valued outcomes (such as equity) are achieved.

[3] Moreover, they are virtually unknown in competitive markets. One does not pay a toll, for example, to enter a grocery store. The relatively few instances of such fees in nonregulated markets (e.g., cellular telephone service) can be seen as exercises of some degree of market power and, perhaps more importantly, as symptomatic of an industry in which capacity (bandwidth) is plentiful and inexpensive, and the marginal costs of usage (in both the short and long runs) are very low. This is not the case in the electric industry.

[4] Indeed, early designs for competitive wholesale markets called only for energy pricing.

[5] For example, Arizona Public Service Corporation sets a minimum number of hours per month at which standby service will be provided at base prices. Failure to stay at or below the minimum will result in penalty charges. In addition, the onsite generation must maintain a 75 percent capacity factor, based on a rolling 18-month average. The onsite generation is also subject to penalties for failure to do so. Tucson Electric Power’s standby tariff works in a similar fashion.

[6] California is one state where this option is available.

[7] New York and Hawaii have both taken this approach, although in New York the option was available only to customers who had onsite generation as of January 2003.

[8] As a matter of economic theory, price should equal the *marginal* cost of the good, because that describes the value to society of the resources that production of the good requires. As a matter of law, the rates of regulated monopolies must be sufficient to cover actual expenditures that are deemed prudent and used and useful. These are referred to as historical or embedded costs. The problem is that utilities are natural monopolies and the economics of their industries, unlike those of competitive markets, do not drive their embedded costs per unit to equal their marginal costs; in the long run, their embedded costs will exceed their marginal costs. Worse yet, as monopolies, the profit-maximization imperative would cause them to set prices at levels that exceed their embedded costs. Regulation is intended to prevent that outcome and to ensure only the recovery of their embedded costs. Rate design aims, to the extent possible, to set rates that reflect marginal costs, adjusted as appropriate to generate revenues sufficient to cover embedded costs.

[9] An individual customer’s contribution to coincident peak is not, given traditional metering technologies, easily measured, nor is it, for rate design generally, a practical necessity. Advances in metering infrastructure are enabling more dynamic rate structures, including real-time pricing, which reveal hourly (or even shorter duration) changes in wholesale market prices for power. Early experience with these new technologies and prices has demonstrated that customer demand response, especially where made possible by automated systems (e.g., the shutting down of one’s air conditioning when a specified price trigger is hit), can be predictable and

significant. Technologies of this sort and the dynamic rate designs they support can have the effect of allocating costs more directly to those who cause them and, conversely, can more directly reward those who are able to avoid them.

[10] This, of course, is true of all rate structures as a general matter: the nature of average-cost ratemaking is that customers with load factors that are below average pay less than what might be described as their "full share" of the class's total cost of service, and the customers with better-than-average load factors pay more than their share. And it is also true of pricing in competitive industries as well: the standard rate for delivery of a package by Federal Express doesn't vary by distance. The customers who cost less to serve than the average cover some part of the costs of those who cost more than the average to serve.

[11] What matters most under this scheme is the level of the per-kW reservation charge. If that level approximates the generation component of the otherwise applicable full requirements tariff and makes no provision for the probability that the service will be needed, it may result in total costs to the customer that will render most onsite generation projects uneconomic. Whether this will be the case depends on the relationship between (1) the capital and operating costs of the DG system and (2) the demand and energy costs of grid-supplied power.

[12] In this discussion, we haven't differentiated between the rates of vertically integrated utilities (those that are monopoly providers of generation, transmission, and distribution services) and delivery-only utilities. The general description of typical standby rate designs applies to both, but in the case of delivery-only service the charges would of course not include any generation costs.

[13] California is one state where this option is available. In Rulemaking 99-10-025 (1999), the state's public utilities commission defined physical assurance "as the application of devices and equipment that interrupt a DG customer's normal load when DG does not operate." The California Clean DG Coalition has since argued that a utility's ability to refuse service should not be unconditional, but should instead be limited to specified circumstances such as times of local distribution system peaks.

[14] This, in effect, is a demand charge with a maximum 31-day ratchet.

Appendix C: References

Bonbright, J.C. (1961). Principles of Public Utility Rates. Public Utilities Reports, Inc. New York: Columbia University Press.

Kahn, A.P. (1988). The Economics of Regulation, Vols. I and II. Cambridge, MA: MIT Press.

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