NEW JERSEY BOARD OF PUBLIC UTILITIES

Docket No. QO2106094

New Jersey Electric Vehicle Infrastructure Ecosystem 2021 In the Matter of Medium and Heavy-Duty Electric Vehicle Charging Ecosystem

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Prepared on Behalf of NJR Clean Energy Ventures Corporation

In Response to the September 15, 2021 Panel Discussion: How to Determine Rates

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Attachments

Introduction

On behalf of NJR Clean Energy Ventures Corporation, I Paul Chernick, President of Resource Insight, Inc. hereby submit this expert report with respect to the New Jersey Board of Public Utilities' ("NJBPU") September 15, 2021 panel in Docket No. QO2106094, *New Jersey Electric Vehicle Infrastructure Ecosystem 2021 In the Matter of Medium and Heavy-Duty Electric Vehicle Charging Ecosystem* regarding how to determine rates for medium and heavy-duty electric vehicles ("EV"). This report directly responds to the topics discussed during the September 15, 2021 panel, including the initial presentations, and following question and answer discussions, and includes my conclusions regarding the topics presented and the conclusions reached by the panelists.

Panelists for the September 15th panel were:

- Kurt S. Lewandowski, Esq., Assistant Deputy Ratepayer Counsel, New Jersey Division of Rate Counsel
- Bill Ehrlich, Senior Policy Advisor, Charging Policy & Rates, Tesla, Inc.
- Phil B. Jones, Alliance for Transportation Electrification
- Brian Picariello, Section Manager, Electrification Orange and Rockland Utilities
- Jigar J. Shah, Manager, Distributed Energy and Grid Services, Electrify America
- Erick Ford, Executive Director, NJ Energy Coalition
- Elizabeth Stein, Lead Counsel, Energy Transition Strategy, Environmental Defense Fund

As I outline below, in my view, existing rate structures that rely upon demand charges are insufficient to appropriately allocate costs and properly incentivize the penetration of EVs into the New Jersey marketplace. Particularly with medium and heavy-duty fleet vehicles ("MHD"), the NJBPU should adopt a new rate class that relies upon time of use ("TOU") rates, as this rate structure will more adequately allow New Jersey to meet its EV and decarbonization goals, all while maximizing benefits to ratepayers and the grid. The presentations and discussion at the BPU's electric-vehicle virtual stakeholder meeting held on September 15, 2021 raised a number of issues, but the controversies clustered around two issues: the role of demand charges in EV rate design and the structure of energy charges.

In addition to developing baseline time-varying rates for MHD and fleet EV charging, the BPU should also consider rate-design incentives that will encourage the colocation of MHD and fleet charging with distributed energy resources such as solar photovoltaic and energy storage, to facilitate decarbonization and reduce the costs of integrating both solar and renewables into the distribution system. Time-varying energy rates can encourage the addition and beneficial use of behind-the-meter storage, but stronger mechanisms will be required to maximize the colocation of EV charging with renewable energy and storage. If the BPU allows the utilities to continue using non-coincident demand charges to dilute and distort the price signals, even stronger direct incentives will be necessary to appropriately promote and compensate colocation for the benefit of the grid.

My qualifications are attached as Attachment PLC-1.

Underlying Principles

As presented by Mr. Lewandowski in his summary of the Bonbright Ratemaking Principles, the "criteria of a sound rate structure" include:

> Efficiency of the rate classes and rate blocks in discouraging wasteful use of service while promoting all justified types and amounts of use:
>
> (a) in the control of the total amounts of service supplied by the company;
>
> (b) in the control of the relative uses of alternative types of service (on-peak versus off-peak electricity, …)[1]

Mr. Jones, in his presentation also cites Bonbright for the propositions that rates should reflect "supply and demand" and "get the price signals right" (presentation p. 2) and lists the following goals (presentation p. 3):

- Provide customer benefits—fuel savings and incentives for off-peak use.
- System benefits for all—reliability, integration, data, resiliency, lower rates.
- Positive environmental and public health benefits.

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[1] Bonbright, James C, Principles of Public Utility Rates, 2nd ed., Columbia University Press, New York NY, 1988, p. 291.

- Retain cost-reflective rates

As summarized by Ms. Stein (presentation p. 1), "Electric rates serve two distinct functions: Cost recovery for utilities [and] price signals for consumers. Therefore, rapid electrification of truck and bus sector requires balancing bill manageability (for truck and bus charging customers) with system cost containment."

Having reviewed these presentations, I largely agree with the presenters that the purpose of EV rate design is to encourage customers to use electricity wisely and charge at lower-cost times, to reduce system costs and keep transportation electrification affordable. As I explain below, however, a rate structure that relies upon non-coincident demand charges and fails to send adequate price signals to customers will not achieve these mutual objectives. To achieve these outcomes the BPU must employ a new TOU based rate structure, as the modern grid tackles challenges for which demand charges are no longer appropriate.

Problems with Demand Charges

By demand charges, we refer to charges that are assessed on the customer's highest usage in a short period, typically for the customer's highest load within the month. The short period may be instantaneous,[2] 15 minutes,[3] or 30 minutes.[4]

As pointed out by Mr. Ehrlich during the panel, "Demand charges can account for up to 90% of a station's monthly electric bill, resulting in prohibitively high operating costs and costs well above average rates." These are important components of the bills for EV charging and should be scrutinized.

[2] Suggested by Philip Jones in his presentation, p. 4.

[3] E.g., PSEG LPL primary rate, Tariff for Electric Service, Sheet No. 145.

[4] E.g., PSEG LPL secondary rate, ibid.

The History of Demand Charges

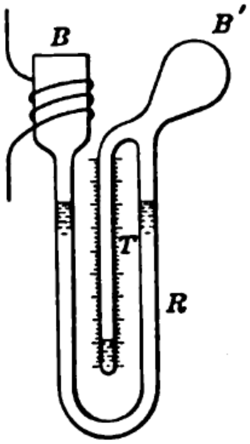

Fig. 79.—Diagram, Wright demand meter.

Demand charges were invented in the 19th century, to differentiate between high-load-factor and low-load-factor customers.

The original demand meter allowed the amperage flowing through a wire to heat air, which expanded and forced mercury over a lip into a collecting well; the higher the load over an hour or so, the higher the level of mercury in the well. The diagram to the left is from the Standard Handbook for Electrical Engineers, Frank F. Fowle, Editor-in-Chief, Fourth Edition, January 1917, p. 170.

For many decades, utilities had no practical way to measure energy usage by time. By the time that electronic recording of hourly loads became available in the 1980s or so, demand charges were strongly embedded in utility practice and culture.

Even though demand charges are no longer needed in an era of comprehensive data collection and rapid remote communication, they hang on as vehicles for ensuring utility revenue recovery and frustrating customer attempts to reduce their bills. Indeed, the original purpose of the demand charge may have been to undercut the cost of self-generation based on the customer's load factor, rather than to reflect the utility's costs:

> The usefulness of demand-charge rate structures as an instrument of price discrimination in the face of competition from isolated plants [self-generation] was known within the industry and was accepted by early regulatory commissions as a justification for their use. Historical evidence shows the role of the demand-charge rate structure as an instrument of price discrimination was more important to its widespread adoption than was its role as an imperfect form of peak-load pricing…[5]

Neufeld shows from the historical record that utilities designed rates for large customers with high demand charges and low energy charges to offer the lowest rates to customers with high non-coincident load factors, who would be the best

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[5] John Neufeld, Price Discrimination and the Adoption of the Electricity Demand Charge, The Journal of Economic History, 1987, p. 697

prospects for self-generation. Demand charges did not reflect the utility's cost structure so much as the cost structure of its distributed competitors.

Utility Preferences for Demand Charges

Electric utilities generally support demand charges, while other parties prefer that the demand charges be reduced or eliminated, with the revenues collected through time-differentiated energy charges that encourage energy conservation and shifting load from high-cost to low-cost hours.

Specifically, the utilities prefer non-coincident demand charges, which charge each customer for its load at the hour at which its own load is highest in each month. The demand charge is imposed even if the customer peaks at the lowest-load hour of the month on the feeder, substation, transmission region, or ISO. From the utility perspective, the advantages are that demand charges reduce the uncertainty and volatility of the utility's revenues, because:

- Demand charges are difficult to avoid.
- Demand charges are less dynamic, meaning that they do not respond to system conditions at any level of the system. Since demand charges do not reflect cost causation, they can provide more revenue stability than energy charges.
- Demand charges discount rates for customers with high non-coincident load factors, discouraging them from installing distributed generation, which was long the greatest competitive threat to utilities' revenues

Demand Charges and Price Signals

The costs of generation, transmission and most of the distribution system are not affected by customer maximum demand. The only costs that vary with customer maximum demand, as opposed to customer contribution to a diversified demand, are those associated with facilities dedicated to that customer (meters, service drops, sometimes transformers) and—for very large customers—local facilities that experience their peak loads whenever the customer peaks.

Otherwise, demand charges are generally inappropriate because they do not reflect the way that customers impose costs on the system. This is particularly true when those demand charges are based on the customer's monthly non-coincident peak load, regardless of whether that load coincides with high-load, high-cost hours on the generation, transmission or distribution systems. Recovery of costs related to overall system demand through a non-coincident demand charge dampens price signals for conservation, promotes inefficient customer behavior, and undermines customers' ability to control electricity costs.

An EV charging facility is unlikely to reach its maximum demand at the same time as when the diversified peak on the distribution system occurs. Thus, a demand charge would provide an incentive to control load at the time that customer reaches its individual maximum demand, which does not necessarily correspond to the time of peak load on the distribution system. In fact, some customers might respond to a demand charge by shifting loads from their own peak to the peak hour on the local distribution system, thereby increasing their contribution to maximum or critical loads on the local distribution system and further stressing the system during peak periods.

Demand charges are a particularly ineffective means for giving price signals, for the following reasons:

- Demand charges do not "target peak demand reduction," since they apply to customer maximum demands, not to the times of system peaks or equipment maximum loads. Capacity costs are driven by coincident loads at the times of the peak loads, not by the non-coincident maximum demands of individual customers. The customer's individual peak hour is not likely to coincide with the peak hours of the other customers sharing a piece of equipment.
- At best, demand charges encourage flat load shapes through the billing month. From the perspective of the utility and ratepayers, the optimal load shape is not flat; loads should be concentrated in hours with low energy costs and low contributions to the high-load hours in which additional load reduce reliability and require increased investment.
- Demand charges do not provide appropriate incentives to conserve, even during high load hours. Once a customer has hit a particular billing demand level, the demand charge provides no incentive to reduce load in any hour later in the month in which its load is below that threshold.
- Non-coincident demand charges charge customers for usage in hours with low costs at every system level, from the line transformer to the generator.
- Not only are demand charges ineffective in shifting loads off high-cost hours, but they may also cause some customers to shift loads in ways that increase costs. For a customer who experiences its maximum summer demands at noon,

a demand charge encourages the shifting of load into the afternoon peaks on the generation, transmission, and distribution systems.

- A demand charge encourages Customer 1 (who is facing a maximum load in the hour ending 5 pm) to shift load to 6 pm or 8 pm, but also encourages Customer 2 (who is facing a maximum load in the hour ending 9 pm) to shift load to 4 pm or 6 pm. The customer demand shifts may just add to a coincident peak at 6 pm, or the sum of the customers' hourly loads may not change, as Customer 1 shifts load from HE 5 pm to HE 9 pm and Customer 2 shifts load from HE 9 pm to HE 5 pm.
    - This problem is illustrated in the Transit Bus slide of Elizabeth Stein's presentation, which shows a load that would peak just before 9 PM at about 9.5 MW, if measured on an instantaneous or 15-minute basis, or a little after 9 PM around 7 MW on an hourly basis. But the PJM peaks usually occur in the hour ending 5 PM or 6 PM (or occasionally as early as 3 PM) and the New Jersey utilities' peak summer loads occur in the hour ending 6 PM or less frequently at 5 PM (PSEG) or 7 PM (Atlantic City Electric). The zonal peak loads are distributed similarly. If the transit bus system reduced its demand charge by shifting load from around 9 PM to the late afternoon, e.g., at 5 PM, it would increase its contribution to utility and system peaks.
- Demand charges are difficult for any customer to mitigate. Even a single failure to control load results in the same monthly demand bill as if the same load had been reached in every day or every hour. Thus, one restart of the customer's systems after an outage, one failure of the energy management system, or one day with a confluence of charging requirements can undo a month's worth of careful load management.
- Demand charges provide little or no incentive to control or shift load from those times that are off the customers' peak hours but that are very much on the generation and T&D peak hours. Customers who can anticipate their maximum load can reduce demand charges merely by redistributing load within the peak period. Some of those customers will be shifting loads from their own peak hour to the peak hour of various parts of the distribution, transmission, and generation systems. This will cause customers to increase their contribution to maximum or critical loads on all those systems.
- To control monthly charges from a non-coincident demand charge, customers need to have detailed information regarding their load profiles for each day of the coming month as well as an in-depth understanding of which combination of appliance- or equipment-usage gives rise to monthly maximum demands.

Even with such information and knowledge, it would be difficult for many small business customers to reduce non-coincident demand charges, since even a single failure to control load during the month would result in the same charge as if the customer had not attempted to control load at all.

- Rather than promoting conservation at high-cost times, or shifting of load from system peak periods, demand charges encourage customers to waste resources on the arbitrary tasks of flattening their personal maximum loads, even if those occur at low-cost times. For instance, to respond to demand charges effectively, a customer will need to install equipment to monitor its loads, interrupt discretionary load, schedule deferrable loads and dispatch storage, rather than using those efforts to shift load into the low-cost hours.[6] Moreover, lower energy charges will encourage increased electric use, some of which will likely occur in the peak period.
- Shifting recovery of demand-related costs from demand charges to TOU energy rates would send a better energy price signal. Retaining non-coincident demand charges keeps energy rates lower and thereby perversely encourage increased energy consumption. Some of the increased energy consumption might occur at times of peak load on the distribution system – when energy conservation is most needed. Maintaining excessive non-coincident demand charges could therefore increase distribution system costs

The deficiencies of the demand charge have been known for at least 80 years:

> This conclusion [demand charges] was hailed as a great discovery, and made the basis of many tariffs. Unfortunately, it was based on a simple confusion. It is true that it costs a station more to supply 1,000 units if they are all to be taken in one minute than if they are to be spread over a longer period; but this applies to the aggregate output of the station, and not to supplies to the individual consumer. What is true of the individual consumer is that the cost of selling to him is greater if he buys during peak periods than if he buys during slack periods (unless there is excess capacity even at the peak). If therefore he takes 24 units all in one minute during the slack period it may cost less to supply him than if he takes 24 units at the rate of one unit per hour, because in the latter case he adds to capital costs at the peak. The maximum rate at which the individual

[6] Mr. Lewandowski's slide on "Ratemaking Issues for Consideration: Demand Charges" lists energy storage and managed charging as mitigation options for demand charges. The BPU should be encouraging customers to use those tools to mitigate system costs, not to chase customer non-coincident charges that do not reflect real costs.

> consumer takes is irrelevant; what matters is how much he is taking at the time of the station's peak.[7]

Alfred Kahn also recognized the deficiencies of demand charges:

> [The] demand or capacity charge—is a charge for the utility's readiness to serve, on demand. This readiness to serve is made possible by the installation of capacity, the demand charge, therefore, distributes the costs of providing the capacity—the fixed, capital costs—on the basis of the respective causal responsibilities of various buyers for them. And the proper measure of that responsibility is the proportionate share of each customer in the total demand placed on the system at its peak…
>
> Unfortunately, the principle has usually been badly applied, in several important ways. First, if the demand charge were correctly to reflect peak responsibility it would impose on each customer a share of capacity costs equivalent to his share of total purchases at the time coinciding with the system's peak (a "coincident peak" demand charge). Instead, the typical two-part tariff bases that rate on each customer's own peak consumption over some measured time period, regardless of whether his peak coincides with that of the system (hence the designation "noncoincident" demand charge). That is, the peak (for example, half-hour) consumption of all customers, regardless of the time of day or year in which each falls, is added up, and each then is charged a share of total system capital costs equivalent to the percentage share that his peak consumption constitutes of that total. The noncoincident demand method does have some virtue: it encourages customers to level out their consumption over time, in order to minimize their peak taking, hence their share of capacity costs. This, in turn, tends to improve the system's load factor—the ratio of average sales over the year to capacity—that is, the degree of capacity utilization. But it is basically illogical. It is each user's proportion of consumption at the system's peak that measures the share of capacity costs for which each is causally responsible: it is consumption at that time that determines how much capacity the utility must have available. The system's load factor might well be improved by inducing individual customers to cut down their consumption to a deep trough at the system, peak and enormously

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[7] W. Arthur Lewis – The Two-Part Tariff, Economica, 1941, attached as PLC Attachment 3, p. 252, attached as Attachment PLC-2.

increase their peak utilization at the system's off-peak time: yet the noncoincident demand system would discourage them from doing so.[8].

Replacing the traditional demand charge with a charge for the customer's maximum non-coincident load in the peak period, to a coincident-peak charge on the utility or PJM system peak, as Professor Kahn suggested, would be an improvement, from the perspective of 1970. However, while Kahn assumes that the need for capacity is created by one annual hour, the generation capacity requirements of PJM (as well as the zones and subzones covering New Jersey—MAAAS, EMAAC and PSEG) are driven by loads in many hours. PJM relies on probabilistic measures such as loss-of-load expectation (LOLE), which are descended from the loss-of-load probability (LOLP) concept introduced for planning in 1966, just four years before Kahn's opus was published.[9] PJM recognizes this reality to a limited extent by allocating capacity costs within a capacity zone in proportion to the load-serving entity's contribution to the five highest system hours, rather than a single hour.

Similarly, distribution costs are driven by the frequency and magnitude of high-load periods that overheat and gradually degrade equipment, especially overhead conductors and the insulation in transformers and underground lines.

Accordingly, well-designed time-of-use energy rates reflecting hourly contribution to capacity needs are better suited for collecting capacity-related costs than are demand charges.

Peak-Period Demand Charges

As a variant, utilities sometimes propose and impose "Maximum On-Peak" non-coincident demand charges, which charge the customer for its load at the hour at which its own load is highest during designated peak period in each month. In PSEG's LPL rate, the peak period is defined as five hours (8 AM to 10 AM and 4 PM to 7 PM) every weekday, or roughly 110 hours each month, June through September.

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[8] The Economics of Regulation, Alfred Kahn, Vol. I, 1970, pp. 95–96.

[9] L.L. Garver, "Effective Load Carrying Capability of Generating Units", Paper 31 TP 66-51 Power System Engineering Committee of the IEEE Power Group, IEEE Winter Power Meeting, New York, N.Y., January 30–February 4, 1966.

The demand charge is imposed even if the customer peaks at the lowest-load hour of the 110 hours.

Subscription Charges

Some utilities advocate for subscription charges (as suggested by Philip Jones at pp. 5 and 6 of his presentation) as an alternative to conventional demand charges. These charges represent a more onerous version of demand charges, imposed every month regardless of the customer's actual demand. These charges are not based on cost causation, would provide essentially no incentive for reducing costs to the utility, and would make it more difficult for customers to control their bills. The NJBPU should not consider subscription charges as an option for EV charging rates.

Temporary Demand-Charge Discounts

Some parties suggest that the problem with demand charges is primarily that they impose high costs on EV charging during the transition to electrified transportation:

- "At current rates of EV adoption, utilization of DCFC stations are low, and demand charges account for the majority of electric costs." (Tesla presentation).
- Of the ten Commercial EV Rate Examples compiled by Tesla, seven use some temporary discount or rebate of demand charges.
- Erick Ford proposes "Subsidy and incentives—demand charge credit to customer: incentive structures that provide temporary relief to charging stations, and which phase out as EV deployment grows and charger usage increases"
- Philip Jones suggests "transitional relief" as "a path to profitability by altering the demand charge component of rate structures on a temporary basis to help meet public policy objectives and better fit today's public charging business models. The goal is to get us past this period of low utilization." (p. 5) He also lists a several "examples of transitional relief of demand charges" (not all of which are transitional) that largely overlap those listed by Tesla.

The problems with the demand charges are not limited to a transition period. Some use cases will continue to have low non-coincident load factors indefinitely. Others will result in non-coincident load spikes, even when the hours of charge usage have increased. For customers that achieve desirable load shapes, shifting load into the overnight hours or (as solar comes to dominate the generation supply) the sunny midday hours, non-coincident demand charges would impose a penalty reducing the non-coincident demand by moving energy into the peak period. And customers with storage and flexible charging will need to decide whether to use those capabilities to reduce their demand charges or reduce their usage at high-cost hours.

The BPU should pursue EV rate designs that will make sense in the long term, even as rate levels and TOU periods change, rather than short-term solutions for permanent problems.

PJM Charges

In addition to charges developed by the utilities, some tariffs (and contracts with third-party suppliers) simply flow through PJM generation and transmission costs. One example is the PSE&G BGS-CIEP rate for customers over 500 kW. These rate designs are constrained by PJM's cost-allocation decisions, which may not necessarily reflect cost causation at the regional levels but do determine the allocation of costs to load-serving entities. PJM determines generation costs by utility zone three years in advance, using probabilistic risk of outages, but allocates generation costs among LSEs base on contributions to peak loads on the five days of the previous year with the highest PJM coincident loads. Transmission costs are allocated based on contribution to the utility's single coincident peak hour in the preceding year. Each utility is responsible for determining the coincident loads within its territory.

As pointed out by Jigar Shah for Electrify America, the utilities' methods for estimating those peak contributions for new EV charging loads can create a first-year billing problem. As explained in PSEG's tariffs (Sheet 26):

> The customer's Generation Obligation, in kilowatts, is determined by Public Service no less frequently than once a year. The Generation Obligation for existing customers or for new customers utilizing an existing building or premises is based upon the customer's share of the overall summer peak load assigned to Public Service by the Pennsylvania- New Jersey-Maryland Office of the Interconnection (PJM) as adjusted by PJM assigned capacity related factors. The Generation Obligation for customers taking service in a new facility, as determined by Public Service, is based upon the load requirements, as estimated by Public Service, of the customer's building or premises. More specifically the customer's Generation Obligation is established based upon the following: 1) an estimate of the customer's peak demand, based upon the load shape of a representative sample of customers served under the same rate schedule, in conjunction with the actual or estimated, as applicable, summer energy use of that customer, or on the customer's actual or estimated, as applicable, summer peak demand, depending upon the type of metering equipment installed by Public Service, and 2) the aforementioned PJM assigned capacity related factors which are established no less frequently than once a year.
>
> The customer's Transmission Obligation, in kilowatts, is determined in a similar manner to the Generation Obligation described above.

If the utility assumes that a new EV charging facility will have a load shape similar to commercial and industrial loads in the same rate schedule, it can substantially overestimate the facility's coincident peak contribution. As Mr. Shah says, "The BGS demand charge framework results in cost volatility and uncertainty for medium-duty and heavy-duty operators that inhibits investment in fleet electrification within New Jersey….Electrify America's initial assigned capacity tags across multiple NJ locations did not reflect cost-causation…no third- party supply options…would tolerate [this high level of] capacity tag risk at a reasonable cost/kWh" to the customer."(presentation p. 6).

While the generation and transmission costs are allocated to the utility zones by PJM, using rules that can only be changed through the PJM process with FERC approval, the estimation of the loads of new customers and other aspects of retail rate design are determined by the utilities. The BPU should require the utilities to solve the problem of overcharging in the first year by developing more realistic estimates of contribution to the PJM generation and transmission billing peak hours, for customers charged flow-through rates.

Time-Varying Energy Charges

Peak-period energy charges, not demand charges, best reflect costs that are driven by both peak demands and energy. Even Philip Jones, a proponent of demand charges, acknowledges that "Non-demand charge C&I rates below a certain demand level" … "have been shown to be based on cost of service at their core" and to be just and reasonable (Jones presentation, p. 5). Since the customer's non-coincident demand does not drive cost above the transformer level unless the customer's load dominates its feeder, that "certain demand level" would appear to be on the order of 10 MW.

Recovering costs through peak-period energy charges, rather than demand charges, will encourage customers to reduce usage in high-cost, high-load periods, when the system is heavily loaded, regardless of whether that is a high-load period for the customer. At this point, highest-cost periods are on summer afternoons, with the lowest costs overnight. As solar penetration increases, the high-cost periods will gradually shift later in the day, and the midday hours may become the lowest-cost period.

Whether for electric vehicles or most other applications, demand charges are inferior to energy charges in almost all circumstances. There may be exceptions for the costs of equipment that is actually sized by the maximum loads of a single customer, such as the feeder for a very large EV charging station, whose maximum demand essentially sets the peak load for the feeder, regardless of the time of day. Even in those cases, the sizing of the equipment may be driven by a combination of peak load and loads in other hours that contribute to the thermal overloads on the equipment. If one hour at a high load (e.g., 10 MW) is bad, loads near that level earlier in the day or on other days will also be bad, in terms of the thermal stress on the system. Basing a large share of the bill on load in one hour of the month does not reflect cost causation.

Philip Jones (presentation p.12) includes a description of a commercial electric vehicle rate with TOU energy rates and a critical-peak price of $1.50/kWh to recover demand-related costs at the time of the utility's highest stress (which may result from a combination of high load, high generation and transmission outages, and low renewable output). For New Jersey utilities, those CPP hours could include hours at high risk of affecting the forecast of peak loads three years hence (once PJM resumes its normal BRA schedule) or the allocation of capacity costs to LSEs for the following year. The BPU should explore development of similar rate designs for the New Jersey utilities.