BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE

STATE OF CALIFORNIA

Order Instituting Rulemaking on the Commission's Own Motion to Conduct a Comprehensive Examination of Investor Owned Electric Utilities' Residential Rate Structures, the Transition to Time Varying and Dynamic Rates, and Other Statutory Obligations.	**Rulemaking 12-06-013** **(Filed June 21, 2012)**

INFORMAL COMMENTS OF THE CALIFORNIA LARGE ENERGY CONSUMERS ASSOCIATION ON MAY 25, 2021 DER WORKSHOP PRESENTATION FORWARD LOOKING VISION: ADVANCED DERS & DEMAND FLEXIBILITY MANAGEMENT

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The California Large Energy Consumers Association (CLECA)[1] submits these informal comments on the May 25, 2021 DER Workshop Presentation Forward Looking Vision: Advanced DERS & Demand Flexibility Management.

[1] CLECA is an organization of large, high load factor industrial customers located throughout the state; the members are in the cement, steel, industrial gas, pipeline, beverage, cold storage, and mining industries, and share the fact that electricity costs comprise a significant portion of their costs of production. Some members are bundled customers, others are Direct Access (DA) customers, and some are served by Community Choice Aggregators (CCAs); a few members have onsite renewable generation. CLECA has been an active participant in Commission regulatory proceedings since the mid-1980s, and all CLECA members engage in Demand Response (DR) programs to both promote grid reliability and help mitigate the impact of the high cost of electricity in California on the competitiveness of manufacturing. CLECA members have participated in the Base Interruptible Program (BIP) and its predecessor interruptible and non-firm programs since the early 1980s.

I. STANDARDIZED RATE DESIGN

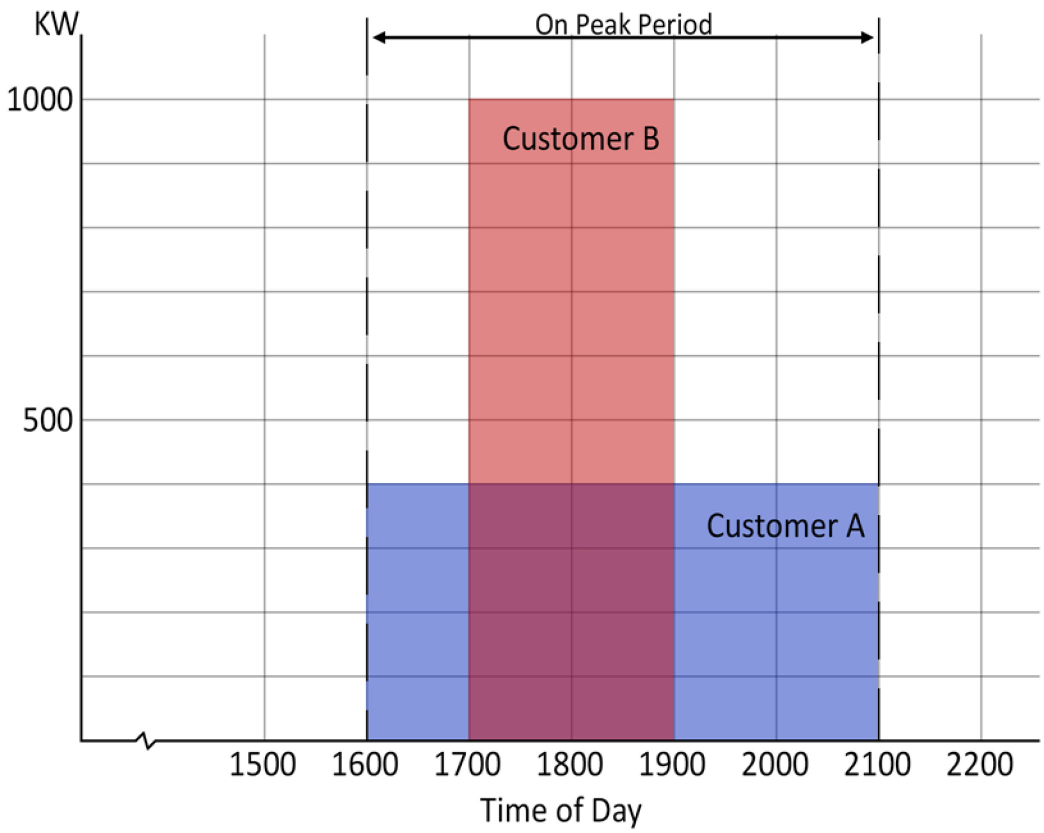
The Gupta presentation proposes to prepare a “standardized, universal access” to electricity prices for consumers and devices, and strongly implies that that standardized rate would be volumetric. A purely volumetric rate—even on a time-of-use basis—would provide inaccurate pricing signals to customers, because it would not fully reflect the significant costs of capacity that the utility system incurs in order to meet demand. This is as true for residential and small commercial/agricultural customers as it is for medium and large commercial/ industrial/agricultural customers.

Subscription charges may be more acceptable to smaller customers than demand charges, so it may make sense to fashion standardized rates for smaller customers around subscription charges. Subscription charges would produce appropriate price signals for customers reflecting the cost of capacity, provided that the subscription levels (and associated charges) increase as the customer’s demand increases, as discussed in D.19-10-056.

Standardized prices should not eliminate demand charges for larger customers. However, it would be appropriate for these demand charges to be charged largely on a coincident basis. It is impossible to price fairly across various types of large customers without reflecting customer demands in that equation. Capacity, whether it is generation capacity or distribution capacity, creates fixed costs – and those costs should be borne in proportion to the loads that cause the system to incur the costs. Variable rates alone will not appropriately address the fixed costs.

Figure 1 below demonstrates how two customers with different demands could use the same amount of energy but impose very different costs on the system:

Figure 1



In Figure 1, Customer B imposes 2.5 times as much demand on the system as Customer A, and yet under an all-volumetric rate design Customer B won't pay any more for its service than Customer A. This is unfair pricing.

Demand charges are very appropriate because they charge for capacity—which is a fixed, not variable, cost. <u>If all costs are reduced to energy charges, low load factor customers who can impose exactly the same fixed capacity cost on the utility system as high load factor customers can basically get a free ride, because they don't pay enough through their energy charges to pay the system back for the capacity costs that they impose</u>.

II. OPTIONAL REAL TIME PRICING RATE

The Gupta presentation also proposes an optional real time rate design based on CAISO wholesale energy costs. In addition, the proposal seems to base the cost of capacity on the scarcity prices in the CAISO market. However, the scarcity prices would show up in only a very few hours (if any) during the year. During the remaining hours, the wholesale energy cost would not reflect any capacity value. Furthermore, there may not be a large variation in day-ahead market (DAM) prices from hour to hour. Thus the effect of relying entirely on the DAM prices might be to flatten out prices, even during hours where there may be need for additional system capacity, as measured by higher load levels or hours a Loss of Load Expectation (LOLE) study has identified as being at higher risk of service interruption.

Relying on DAM prices for the hourly rate would leave a very large gap between the proposed rate and the price signal that needs to be sent to customers. Furthermore, the rate would fail to collect the required generation revenue requirement by a substantial factor. Thus, this proposal would not be acceptable. Instead, in addition to the DAM hourly price, the hourly rate should be based on an allocation of capacity costs to those hours that drive the need for capacity, such as loads over a certain pre-determined threshold, or hours that an LOLE study has identified as being at higher risk of interruption.

Moreover, the distribution portion of the rate would need to be based on a more traditional ratemaking approach. Customers would still need to see a price signal that reflects the costs that they impose on the distribution system, and that includes their maximum demand for the most local parts of the distribution system. Coincident demand charges would be a good choice here or, alternatively, subscription rates would be acceptable – provided the subscription rates increase as the customer's demand increases. The Commission could consider a penalty rate that gets paid by customers exceeding their subscription demand level, and impose a limit on the number of exceptions that are allowed in a year before the customer is pushed to the next higher subscription demand level.

The Commission would still have to grapple with revenue undercollection or overcollection for various rate elements. While the energy portion of the generation rate should match the LSE's costs more closely because the hourly rate would track the CAISO DAM rate, the capacity portion of the generation rate would still be based on a forecast. Furthermore, the various portions of the distribution rates would be based on a forecast.

III. THERE ARE LESSONS TO BE LEARNED FROM ONGOING RATE PROCEEDINGS

The ED should consider the types of mechanisms for allocating that capacity cost to hours that are being considered on an experimental basis for RTP rates for nonresidential customers in the PG&E Commercial Electric Vehicle (CEV) proceeding (A.20-10-011) and the PG&E Phase 2 proceeding (A.19-11-019). Similar issues have emerged in the two proceedings: (1) While there is general consensus that CAISO wholesale energy prices are the appropriate basis for the energy component of the RTP rate, there is some controversy regarding the use of day-ahead or day-of prices; (2) There is significant controversy about how to reflect generation capacity costs in the hourly RTP rates. Some parties have proposed to allocate generation capacity costs to each hour based on a load-based mechanism that assigns zero to each hour below 80 percent of peak demand and an increasing fraction above that threshold, depending upon how high each hour's load is relative to the projected system peak figure. Depending upon how the hourly assignment is structured, there can be large swings in generation capacity-related revenue collection from year to year. Some parties have also proposed to include a critical peak pricing (CPP)-type element to recover capacity revenues in some hours; (3) There is debate among parties regarding how best to collect the difference between the generation marginal cost revenues and the generation revenue requirement – through an equal charge to each hour, or a charge that varies on a TOU basis; (4) Some parties have proposed using an "otherwise applicable tariff (OAT)" structure for collecting the distribution portion of the revenue requirement—that is only the generation portion of the revenue requirement would be collected through the RTP rate, while others propose to collect the distribution revenue requirement through subscription charges.

CLECA appreciates this opportunity to provide informal comments.

Respectfully submitted,

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