SENATE COMMITTEE ON ENERGY, UTILITIES AND COMMUNICATIONS
Senator Josh Becker, Chair
2025 - 2026 Regular

Bill No:	AB 1117	**Hearing Date:**	7/15/2025
Author:	Schultz		
Version:	7/2/2025 Amended		
Urgency:	No	**Fiscal:**	Yes
Consultant:	Nidia Bautista		

SUBJECT: Electricity: rates: optional dynamic rate tariffs

DIGEST: This bill requires the California Public Utilities Commission (CPUC), through a new or existing proceeding, to develop optional dynamic rate tariffs applicable to each large electrical corporation for their customers, specifically by July 1, 2028 for medium and large commercial and industrial customers, and by July 1, 2030 for residential and small commercial customers. Additionally, this bill authorizes medium and large commercial and industrial customers to receive generation service through the Direct Access (DA) program, thereby, opening the current statutory cap on this third party service.

ANALYSIS:

Existing law:

1) Establishes and vests the CPUC with regulatory authority over public utilities, including electrical corporations, also referred to as electric investor-owned utilities (IOUs). (Article XII of the California Constitution)

2) Authorizes the CPUC to fix the rates and charges for every public utility and requires that those rates and charges be just and reasonable. (Public Utilities Code §451)

3) Requires each electric IOU customer with distributed energy resources (DERs), as specified, to participate in real-time metering and pricing programs; and requires the CPUC to adopt a real-time pricing tariff by December 31, 2001, to serve these customers. (Public Utilities Code §353.3)

4) Requires the CPUC to ensure that rates are sufficient to enable electric IOUs to recover a just and reasonable amount of revenue from residential customers as a class, while observing the principle that electricity and gas services are necessities, for which a low affordable rate is desirable and while observing the

principle that conservation is desirable in order to maintain an affordable bill. (Public Utilities Code §739)

5) Requires the CPUC to establish rates using cost allocation principles that fairly and reasonably assign to different customer classes the costs of providing service to those customer classes, consistent with the policies of affordability and conservation. (Public Utilities Code §739.6)

6) Authorizes the CPUC to adopt new, or expand existing, fixed charges for the purpose of collecting a reasonable portion of the fixed costs of providing electrical service to residential customers. Requires the CPUC to structure the fixed charge on an income-graduated basis with no fewer than three income tiers. (Public Utilities Code §739.9)

7) Permits electrical corporations, with approval of the CPUC, to offer residential customers the option of receiving electric service pursuant to "time-variant pricing," which includes time-of-use rates (TOU), critical peak-pricing, and real-time pricing. Beginning in 2018, an IOU can employ default TOU pricing as long as the customer is provided with a rate comparison for one year of all billing options (commonly referred to as shadow-billing) and associated customer education. Subsequently, the customer must be guaranteed for one year that the total amount paid for electric service will not exceed the amount that would have been due under the customer's previous rate schedule (commonly referred to as bill protection). (Public Utilities Code §745)

8) Suspends the ability of retail end-use customers of the IOU to receive electrical service from an entity other than an electrical corporation unless authorized by the Legislature. This arrangement is commonly referred to as DA. (Public Utilities Code §365.1(a))

9) Allows a limited enrollment into DA for new nonresidential customers based on historical enrollment volumes. (Public Utilities Code §365.1(b))

10) Requires DA providers to meet the same requirements as the electrical corporations for resource adequacy (RA), the Renewables Portfolio Standard (RPS) Program, and the requirements for the electricity sector adopted by the California Air Resources Board (CARB) pursuant to the California Global Warming Solutions Act of 2006. (Public Utilities Code §365.1(c))

11) Requires the CPUC, by June 1, 2019, to issue an order that increases the maximum allowable total kilowatt-hours (kWh) annual limit for direct

transactions by 4,000 gigawatt-hours (GWh) and apportion among the service territories of the electrical corporations. (Public Utilities Code §365.1(e))

12) States the intent of the Legislature to prevent any shifting of recoverable costs among electrical corporation customers. (Public Utilities Code §366.1(d)(1))

13) Defines "direct transaction" as a contract between any one or more electric generators, marketers, or brokers of electric power and one or more retail customers providing for the purchase and sale of electric power or any ancillary services. (Public Utilities Code §331)

14) Defines an electric service provider (ESP) as a non-utility entity that offers electric service to customers within the service territory of an electric utility and requires each ESP to register with the CPUC. (Public Utilities Code §394(a))

This bill:

1) Makes several findings and declarations concerning dynamic rates and state the intent of the Legislature to establish optional dynamic rate tariffs for electricity customers.

2) Requires the CPUC, through a new or existing proceeding, to develop optional dynamic rate tariffs applicable to each large electrical corporation for the large electrical corporation's customers.

3) Requires at least one optional dynamic rate tariff for each segment of medium and large commercial and industrial customers no later than July 1, 2028, and at least one optional dynamic rate tariff for each segment of residential and small commercial customers no later than July 1, 2030.

4) Requires each optional dynamic rate tariff to include, at minimum, specified components, including time-varying transmission and distribution rates that reflect dynamic grid constraints and non-bypassable charges, as specified.

5) Requires the CPUC to ensure, among other things, any overcollection of transmission-, distribution-, and generation-related revenue requirements from participating bundled customers is returned to the participating bundled customers and any undercollection of those revenue requirements is borne by those same customers.

6) Requires that any overcollection of transmission- or distribution-related revenue requirements from unbundled customers be returned to the same unbundled customers, and any undercollection of those revenue requirements be borne by those same customers.

7) Requires that any customer of an electrical corporation with an installed smart meter who chooses to take service under an optional dynamic rate tariff be provided access to their own interval usage data directly from the smart meter as that data is generated.

8) Requires each large electrical corporation to allow medium and large commercial and industrial customers taking service under an optional dynamic rate tariff to also participate in supply-side resource demand response programs, as provided.

9) Requires that any new medium and large commercial and industrial customer energized on or after July 1, 2028, that opts to take service under an optional dynamic rate tariff be eligible to receive generation service from an ESP, if specified conditions are met. This provision would open the existing DA cap under these bill's specified conditions.

10) Requires the CPUC to consider rules or conditions on participation by vulnerable residential customers to ensure adequate protection for those customers, specifically those receiving income-based and medical necessity rate assistance.

11) Requires the CPUC to incorporate the load shift and load reduction effects of dynamic rate adoption in proceedings on revenue requirement cost recovery, as provided.

12) Requires the CPUC to ensure load-serving entities provide adequate electricity bill comparison information to residential and small business customers interested in taking service under an optional dynamic rate tariff.

Background

Electricity rates. The CPUC must approve all rates – and only those that are just and reasonable – that each electric IOU charges its customers for service. The design of the rates received much attention last year with the CPUC's adoption of an income-based graduated fixed charge for residential customers. Prior to this decision (and until its full implementation), the majority of all costs to serve residential electricity customers are collected via a volumetric, per kilowatt-hour, of consumption. In general, in the late 20th century through the beginning of this century, those charges were collected via block tiered rate structures where a certain baseline of allowance of electricity for the billing cycle was collected at a particular rate and any usage beyond that tier was collected at a higher amount with potentially several increasing block tiers for the total amount consumed during the billing cycle. Block tiered rate structures were intended to encourage conservation and reduce consumption to help reduce overall costs on the electric system.

Time-of-use (TOU) rates. With the passage of AB 327 (Perea, Chapter 611, Statutes of 2013) block tier rate structures were both collapsed (and uncapped) and new TOU rates were authorized. In 2015, the CPUC issued a decision (*D.15-07-001*) providing specific steps for the large electric IOUs to reform the residential rate structure with an envisioned end-state of default TOU rates for residential customers in 2019. TOU rates were intended to better reflect the costs of electricity during the day, with peak prices during the time of day with the highest demand and when additional resources are needed to serve load. TOU was seen as an improved design for more accurate price signals over the block tiered rate structures, particularly to better account for the changing conditions on the electric grid with the increasing amounts of intermittent renewable energy resources (such as solar and wind) and the need to continue to rely on natural gas plants for electricity during the peak load (and net peak load when solar and wind are not available). Ultimately, the CPUC authorized the large electric IOUs to implement default TOU rates, generally, with the highest rates during the 4pm-9pm hours of each day (including weekends), and with seasonal differences, with the highest rates in the summer months when demand is the highest (largely due to air conditioning needs) and supplies can be constrained (diminishing hydroelectric generation and late summer or storm effects on intermittent resources). Other times of the day would have lower rates with varying rates for the nighttime, morning, and midday. Given the significant change TOU rates meant for customers, the CPUC decision also required electric IOUs to provide extensive customer and public messaging, as well as, opportunities for customers to opt out and protections for the first year of default TOU rates that ensured residential customers would not experience an overall increase in their bill for the first year of implementation. The rollouts were also timed independently for each electric IOU, based on their systems. In the case of other customers, including commercial and industrial customers, in many instances they were already required to be served on TOU rates, in some cases since the 1980s.

The next frontier of rate design – dynamic rates. As the California Energy Commission (CEC) has noted, time-dependent rates are designed to reflect the time-dependent marginal cost of electricity more accurately, on a daily, hourly, or sub-hourly basis. The more closely retail prices are aligned with marginal costs in space and time, the better customers can manage flexible loads, enabling further development of carbon-free supply resources and improving system efficiency. Time-varying electricity rates are designed to mirror the variability in wholesale electricity prices, with the intended effect of discouraging electricity use during periods of high demand and encouraging use when supplies are plentiful. While TOU rates are a form of time-dependent rates, real-time (or dynamic) rates have been the focus of the next frontier of electricity rate design as they better reflect market conditions in near real-time. The concept is to allow the real-time supply and demand of wholesale electricity prices to be reflected at particular time intervals to customers and thereby allowing customers to adjust their consumption based on these prices. This is somewhat similar to the real-time pricing that had been prevalent for long-distance telephone service (though it is no longer a common feature) or as is experienced by surge pricing for ride-hailing services, such as Uber and Lyft, when prices rise with increased demand.

Opportunities for effective real-time pricing. Effective real-time pricing rests on customers having control over their consumption, accurate real-time visibility of prices that reflects the marginal cost of the service, and the ability of customers to quickly adapt to changing conditions, among other requirements. Dynamic rates have long been an area of interest and pursuit among some electricity regulators, customers, and stakeholders, going back 20+ years. The investments in advanced metering infrastructure (smart meters) by electric utilities a key component to deploying dynamic rates which ensure two-way communication between the customers' electric meter and the electric grid. Additionally, the increase in intermittent renewable energy resources on the electric grid, as well as the deployment of DERs (particularly solar, energy storage, thermostats, electric vehicles, and others), further supports the opportunities for dynamic pricing to help shift energy loads to times when prices are lower and supply is more abundant (known as load shifting and demand flexibility). This is particularly the case if customers are able to depend on automated programming afforded by these devices, thereby reducing the need for customers to manually monitor and adjust their load to account for changing prices.

State actively pursuing optional dynamic rates. California has been actively (but cautiously) studying and piloting dynamic rates, with particular concerns about potential impacts to electric grid reliability, overall costs on the system, impacts to customers (especially vulnerable customers), fairness in rate recovery among customers, and other concerns. The rapid growth of electric end uses – including electric vehicle charging, DERs, and building decarbonization – presents new challenges and opportunities for coordinating demand flexibility to meet system needs on a regular basis.

CPUC Proceeding on demand flexibility (R.22-07-005) Order Instituting Rulemaking to Advance Demand Flexibility through Electric Rates. In July 2022, the CPUC opened a rulemaking to establish demand flexibility policies and modify electric rates to advance the following objectives: (a) enhance the reliability of California's electric system; (b) make electric bills more affordable and equitable; (c) reduce the curtailment of renewable energy and greenhouse gas (GHG) emissions associated with meeting the state's future system load; (d) enable widespread electrification of buildings and transportation to meet the state's climate goals; (e) reduce long-term system costs through more efficient pricing of electricity; and (f) enable participation in demand flexibility by both bundled and unbundled customers. As an early basis of the proceeding, in June 2022, the CPUC's Energy Division released a whitepaper, *Advanced Strategies for Demand Flexibility Management and Customer DER Compensation*, a proposal for California Flexible Unified Signal for Energy (CalFUSE) that includes integrating real-time price signals in customer rates with better DER management. The whitepaper proposed strategies for advancing demand flexibility through a universally accessible, dynamic, and economic signal.

The Staff Whitepaper identified six strategies:

1) Provide universal access to the current electricity price through a statewide internet-based price portal that provides the current composite electricity price specific to each customer at any time.
2) Introduce dynamic energy prices based on real-time wholesale energy costs that reflect the localized marginal cost of energy.
3) Incorporate dynamic capacity prices based on real-time grid utilization.
4) Offer bi-directional electricity prices that allow customers to import and export energy based on the same dynamic, composite prices.
5) Offer a subscription option based on customer-specific load shapes.
6) Enable transactive features that allow customers to lock in electricity prices to import or export a pre-determined quantity of energy at some future time.

As part of the proceeding, in April 2023, the CPUC adopted a decision *(D. 23-04-040) Decision Adopting Electric Rate Design Principles and Demand Flexibility Design Principles*, which updated electric rate design principles for the assessment of the rate design proposals of three large electric IOUs. These principles were based on previously adopted versions, including those adopted in 2015, after the passage of AB 327 (Perea, 2013), which required changes to electricity rate designs which were also based on the 1961 Bonbright Principles which have guided electric utility ratemaking at the CPUC and across the country. The new electric ratemaking principles are intended to modernize the ratemaking approach and were informed by the Demand Flexibility Whitepaper. Within the proceeding, the CPUC has also directed pilots by the electric IOUs to assess the real life impacts of optional dynamic rates on customers and the electric grid. Learnings from these pilots are expected in 2027.

The adopted electric rate design principles are as follows:

a) All residential customers (including low-income customers and those who receive a medical baseline or discount) should have access to enough electricity to ensure that their essential needs are met at an affordable cost.
b) Rates should be based on marginal cost.
c) Rates should be based on cost causation.
d) Rates should encourage economically efficient (i) use of energy, (ii) reduction of greenhouse gas emissions, and (iii) electrification.
e) Rates should encourage customer behaviors that improve electric system reliability in an economically efficient manner.
f) Rates should encourage customer behaviors that optimize the use of existing grid infrastructure to reduce long-term electric system costs.
g) Customers should be able to understand their rates and rate incentives and should have options to manage their bills.
h) Rates should avoid cross-subsidies that do not transparently and appropriately support explicit state policy goals.
i) Rate design should not be technology-specific and should avoid creating unintended cost-shifts.
j) Transitions to new rate structures should (i) include customer education and outreach that enhances customer understanding and acceptance of new rates, and (ii) minimize or appropriately consider the bill impacts associated with such transitions.

Particularly relevant to this bill, the CPUC decision also adopted the following new *Demand Flexibility Design Principles* to guide the development of demand flexibility tariffs, systems, processes, and customer experiences of the state's three large electric IOUs:

a) Demand flexibility tariffs should be designed in accordance with all of the Commission's Electric Rate Design Principles.
b) Demand flexibility tariffs should provide a dynamic price signal in a standardized format that can be integrated into third-party DERs and demand management solutions.
c) Dynamic prices should, to the extent feasible, accurately incorporate the marginal costs of energy, generation capacity, distribution capacity, and transmission capacity based on grid conditions.

d) The systems and processes for calculating dynamic price signals should be able to include bundled and unbundled rate components so that any load serving entity can elect to participate.
e) Customers (including low-income customers and those who receive a medical baseline or discount) should have access to tools and mechanisms that enable them to plan and schedule their energy use while managing the monthly variability of their bills.
f) Demand flexibility tariffs should provide marginal cost-based compensation for exports to enable economically efficient grid integration of customer-sited electrification technologies and DERs.

CEC Load Management Standards. In addition to the CPUC proceeding, in 2022, the CEC made revisions to its Load Management Standards in Docket 21-OIR-03. The proposed amendments require the five largest electric utilities in California and the community choice aggregators located within their boundaries to: (i) develop retail electric rates that change at least hourly to reflect locational marginal costs; (ii) update the time dependent rates in the CEC's Market Informed Demand Automation Server database; (iii) implement a single statewide standard method for providing automation service providers with access to customers' rate information; and (iv) educate and enable customers to participate in load management through participation in hourly rates or load flexibility programs based on hourly rates. In January 2023, the Office of Administrative Law approved the CEC's revisions to the Load Management Standards which require all electric IOUs, Community Choice Aggregators (CCAs), and publicly owned utilities to provide optional hourly marginal based rates to all customer classes by January 1, 2027.

About Direct Access. DA service is retail electric service where customers purchase electricity directly from a competitive provider called an ESP, instead of from the electrical corporation (the electric IOU) or a CCA. The electrical corporation, as the utility, continues to deliver the electricity that the customer purchases from the ESP to the customer over its distribution system. An ESP is a non-utility entity that offers electric service to customers within the service territory of an electric IOU through bilateral contracts directly with the customer. Existing statute requires ESPs to comply with many, though not all, of the same requirements of other LSEs, including those pertaining to RPS and RA.

DA customers left without power during energy crisis. California's experiment with electricity deregulation was launched in 1996 when the Legislature passed AB 1890 (Brulte, Chapter 854, Statutes of 1996) to restructure the electric industry. Before the energy crisis in 2001, non-IOU providers under DA ESPs had enrolled customers but then failed to provide the power ordered. Those customers were abruptly returned to the electric IOUs for service at a time when the electric IOUs were themselves reeling from the market and policy conditions that limited their access to electricity supply. The abrupt return of DA customers exacerbated the emergency conditions as the utilities did not have the electric generation resources to serve those customers, contributing to the experienced supply-related service outages and need to purchase more generation at a time of immense price spikes in the whole sale electricity market (in part due to market manipulation by nefarious actors, including Enron). The ability to choose DA service was officially suspended on September 20, 2001 as an emergency measure to protect against further risks. However, CPUC rules allowed certain "eligible" customers to begin DA service after the suspension date and switch between bundled service and DA service.

DA service capped, then, reopened modestly. At the time of the energy crisis, enrollment was statutorily capped in the DA program out of concerns for reliability and also concerns regarding distributing sunk costs stemming from the energy crisis. If large electricity customers bypass purchasing electricity through a utility, then more of the sunk costs fall on the remaining customers. In 2010 the cap was revisited by the Legislature and expanded to approximately 13% of retail electric load with 41,975 enrolled customers comprising 0.3% of customer accounts in the state according the CPUC. Demand for DA service has remained high with requests for DA service outpacing availability. The vast majority of customers using DA are commercial businesses, including hospitals, grocery stores, schools, universities, and retailers.

SB 237(Hertzberg, Chapter 600, Statutes of 2018). More recently, SB 237 required a more modest opening of the DA cap and required the CPUC to make recommendations about further opening the cap to all medium and large commercial and industrial customers. Specifically, the bill increased the cap on DA service to 4,000 GWh and apportioned those costs to each of the electrical corporations. The 4,000 GWh increased the cap to about 15.4% of the total electric IOU territory load. In April 2020, the CPUC issued their recommendations in the SB 237 required report and recommended against lifting the DA cap. The recommendations specifically raised concerns about load migration that would leave LSEs uncertain about future load impacting the state's ability secure the necessary generation resources needed to ensure reliability and clean energy goals in the future.

Comments

Need for this bill. According to the author:

> AB 1117 would reward customers who can be flexible with their electricity usage to reduce electricity consumption during times of peak demand by shifting usage to times when renewable and carbon free resources are low cost and abundant in supply. By making these adjustments, customers on dynamic rates can reduce their own electricity bills and help all customers save money collectively by avoiding the high costs associated with meeting peak electricity demand and help avert grid reliability events. Dynamic pricing for electricity is not a new concept. California has deliberated on dynamic rates policies for over 20 years. It has been implemented and successful in the States of Illinois, Georgia, Pennsylvania, Alabama, and the European Union. AB 1117 would not force any customer to go onto dynamic rates. It would be an option that commercial, industrial, and residential customers can employ to save money on their electricity bills.

The potential of dynamic rates. Dynamic rates hold much promise, but there is also a need to be cautious. As noted above, optional dynamic rates can provide electric utility customer savings, make more efficient use of the electric grid, support greater integration of intermittent renewable energy, and support reliability. However, there are many considerations that must be addressed in designing and implementing dynamic rates, especially as they could result in high electricity bills for customers if they don't have the ability to manage their consumption, let alone on the time intervals (potentially in a five minute intervals) of the dynamic rate. This could include customers dependent on electricity for their medical needs, or who aren't able to shift uses at other times of the day (for example if they are working away from home and can only manage laundry or need air conditioning during times of the day when wholesale prices are highest). Additionally, the optional dynamic rates could result in unintended additional costs to nonparticipating customers. In many cases, these and other concerns are informing the CPUC's efforts to adopt the aforementioned principles, ensure learnings from current pilots, and generally address these and other issues within the proceeding. A February 2025 evaluation of a pilot by Southern California Edison (SCE) that utilized shadow billing to test hourly rate time-intervals over three years (2022-24) did not find evidence of consistent and/or large changes in hourly energy usage due to customer price response. The evaluation further noted that TOU rates seemed to provide a greater price signal to encourage load shifting compared to the dynamic rates.

Getting ahead of CPUC and CEC efforts. This bill requires specified dates by when large electric IOUs must develop optional dynamic rates, July 1, 2028 for medium and large commercial and industrial customers, and July 1, 2030 for small commercial and residential customers. In this regard, the author intends for these requirements to be included within the existing CPUC proceeding. Pacific Gas &

Electrict (PG&E), San Diego Gas & Electric (SDG&E), and Public Advocates Office oppose this bill expressing concerns that the bill is imposing arbitrary deadlines, bypassing the CPUC proceeding, and prescribing outcomes outside the participation of the other stakeholders in the proceeding. In general, they oppose this bill as they prefer the process continue within the CPUC proceeding, particularly once learnings from pilots and other actions inform future rate designs. They also express concerns that the proposed rates would include not only generation, but also distribution, and transmission components which they contend are unknown in other dynamic rates. The supporters of this bill, including many who are active participants in the proceeding, generally believe the efforts to implement optional dynamic rates is not moving at a pace necessary to more quickly capture the benefits optional dynamic rates can provide. They are generally frustrated by the current pace of action. Many of them are also market providers of these services and believe the state is falling behind many other states who have implemented dynamic rates.

Double counting of resources. Among many of the concerns raised by the opponents are the potential for double-counting of supply and demand side resources by this bill. There is concern that this could result in customers receiving double compensation through the dynamic rates and demand response payments for a single instance of load reduction. This could also implicate the accuracy of demand forecasts used for planning and to inform reliability planning. *In order to protect against these concerns, the author and committee may wish to amend this bill to require the CPUC to determine whether such an approach should be authorized and, if so, ensure that supply-side resource demand response baseline is adjusted to reflect the load shift from the effects of the dynamic rates.*

Incorporating distribution and transmission components. This bill would require the optional dynamic rate tariffs to incorporate generation, distribution, and transmission components. SDG&E has raised concerns that incorporating transmission components could raise that states cannot compel utilities to propose specific transmission rate structures to the Federal Energy Regulatory Commission (FERC) or mandate transmission rates without FERC approval. The supporters of the bill state that both SDG&E and SCE have proposed a plan or rate design based on FERC authorized approach of assigning transmission costs that inform dynamic rate design. *Given the need to ensure consistency with federal requirements, and to preserve more informed discussions and decisions at the CPUC considering whether, and how, to incorporate transmission components, the author and committee may wish to amend this bill to authorize, but not require, the various components in the optional dynamic rates as determined within the CPUC proceeding.*

DA cap opening unnecessary to policy in this bill. This bill would authorize an opening of the DA statutory cap that restricts the amount of electrical load that can be served by ESPs. As noted above, the opening of the DA cap was recently considered by the CPUC which recommended against its opening as reliability and clean energy procurement would likely be affected. This bill would require its opening by authorizing medium and large commercial customers who participate in the optional dynamic rate tariffs to have ESPs serve them. This bill attempts to include guardrails by requiring only ESPs that meet RA, RPS, and integrated resources plan (IRP) requirements. However, while these requirements provide some safeguards they do not remove the larger risks that could be created by injecting uncertainty into the market about the potential for additional load migration. Such uncertainty, particularly as the state has recently experienced supply-side reliability challenges and energy procurement is affected by federal policies and market conditions, contributing to additional uncertainty may undermine the state's efforts to achieve its clean energy, reliability, and affordability efforts. *To that end, the author and committee may wish to delete the language authorizing the opening of the DA cap, Section 2, Public Utilities Code Section 729.3(e)(2) of the bill.*

Clarifying language concerning protecting against costs shifts. As currently drafted, this bill attempts to incorporate sufficient protections against under- and over-collections. However, there is concern that the incorporated language will limit the CPUC's necessary discretion to ensure the rates are designed to best protect against cost shifts among participating and non-participating customers, including bundled and unbundled, if needed. *To that end, the author and committee may wish to delete this language and instead bolster the reporting requirement to provide the CPUC the necessary discretion to assess and modify tariffs to ensure they are aligned with the adopted rate-design principles.*

Prior/Related Legislation

SB 541 (Becker) of 2025, requires the CEC, as part of each integrated energy policy report, to identify incremental load shifting targets to meet the statewide load-shifting goal, including biennial adjustments to the goal. The bill is pending in the Assembly Utilities & Energy Committee.

SB 846 (Dodd, Chapter 239, Statutes of 2022) among its many provisions, required the CEC to adopt a load shifting goal to reduce net peak electrical demand.

SB 237 (Hertzberg, Chapter 600, Statutes of 2018) directed the CPUC to make changes to the existing DA service program, which authorizes direct energy transactions between electricity suppliers and retail end-use customers, including: (1) increasing the annual maximum allowable limit of the DA service program by

4,000 GWh for non-residential customers; and (2) require the CPUC to provide recommendations to the Legislature, with specified findings, on the adoption and implementation of a second direct service transactions reopening schedule.

AB 327 (Perea, Chapter 611, Statutes of 2013) among its many provisions, restructures the rate design for residential electric IOU customers. Status.

SB 695 (Kehoe, Chapter 337, Statutes of 2009) among the provisions, allowed the expansion of DA service to individual retail non-residential end-use customers up to the total annual kilowatt-hours supplied by electric service providers for any year after April 1, 1998 approximately doubling enrollment in the DA program.

AB 1X (Keely, Chapter 4, Statutes of 2001) suspended DA until the Department of Water Resources no longer provides power.

FISCAL EFFECT: Appropriation: No Fiscal Com.: Yes Local: Yes

SUPPORT:

Alliance for Retail Energy Markets
California Efficiency + Demand Management Council
California Large Energy Consumers Association
NRG Energy
Sierra Club of California

OPPOSITION:

Pacific Gas and Electric Company
Public Advocates Office
San Diego Gas and Electric Company

ARGUMENTS IN SUPPORT: NRG Energy states:

> Over half of our customers in California today opt to take service under a dynamic rate option. When customers reduce their peak time usage, the reduced peak demand lowers our resource adequacy compliance obligation, and thereby lowers our overall wholesale generation portfolio cost. This creates a virtuous cycle by which the lowered portfolio cost allows us to maintain our ability to offer competitive rate plans to DA-eligible customers to help them save money. AB 1117 would help make the California electricity market more affordable and resilient by broadening this benefit of dynamic rates to all investor-owned utility customers. With California's retail electricity prices soaring, this bill would empower consumers who can shift their consumption to lower cost hours

to pay a lower price that is reflective of the wholesale market price and general grid conditions. This, in turn, would lower the overall system cost for all customers by avoiding expensive peak power purchase.

ARGUMENTS IN OPPOSITION: Pacific Gas & Electric states:

> [AB 1117] …prejudges outcomes of regulatory processes, does not allow the needed flexibility to incorporate implementation feasibility and learnings from pilots, could result in cost shifting to non-participating customers and lacks needed guardrails prior to considering the potential for unlimited Direct Access.

> They contend the bill imposes arbitrary deadlines and prescriptive requirements that limit flexibility to incorporate learnings and limit the CPUC's discretion to implement dynamic electricity rates for all customer classes in a way that is understandable for participating customers, cost-effective for all ratepayers, and feasible for utilities. They further take issue

The Public Advocate's Office states:

> AB 1117 would bypass the CPUC current Demand Flexibility Rulemaking, which is focused on identifying approaches that will better position electric customers to shift their energy usage to off peak hours through dynamic pricing… …This bill would fast-forward to a course of action - requiring dynamic electric rates be offered to customers - without considering the input of numerous parties, including our Office, who are actively participating in this rulemaking to ensure the CPUC has an extensive record upon which to make informed decisions. Also, recent amendments to AB 1117 would allow certain customers to participate in optional dynamic rate tariffs and supply-side demand response programs. These amendments could lead to compensating resources twice for the same load reduction performance – potentially increasing customer's monthly bills. …Moving forward on dynamic rates without considering the information provided by diverse parties participating in the CPUC's rulemaking and the pilot programs may impact the state's ability to achieve its affordability and reliability goals.

-- END --