STATE OF CALIFORNIA

Public Utilities Commission
San Francisco

M e m o r a n d u m

Date: August 11, 2015

To: The Commission
(Meeting of August 13, 2015)

From: Lynn Sadler, Director
Office of Governmental Affairs (OGA) – Sacramento

Subject: **SB 286 (Hertzberg) – Electricity: direct transactions.**
As amended: August 17, 2015 (Amendments Pending)

RECOMMENDED POSITION: OPPOSE UNLESS AMENDED

SUMMARY OF BILL

As written, SB 286 (Hertzberg) would raise the cap on the amount of electricity transactions can be serviced by Direct Access (DA) by 8,000 gigawatthours (GWh) (from 24,792 GWh to 32,792 GWh). This would amount to total potential DA load reaching approximately 17% of total utility load in the state. The bill also requires that at least 100 percent of the new direct transactions must be for electricity products from eligible renewable energy resources meeting the requirements of subdivisions (b) and (c) of PU Code Section 399.16.

DA transactions (or "direct transactions") occur when a customer opts to purchase the generation component of its electricity from an Electric Service Provider (ESP), instead of the incumbent investor-owned utility (IOU). Currently, DA transactions are capped at 24,792 GWh, or approximately 13% of total utility load in the state. This bill would require the California Public Utilities Commission ("CPUC" or "the Commission") to adopt and implement a reopening of DA availability that commences January 1, 2016, and phases in new direct transactions for individual retail nonresidential end-use customers over a period of not more than three years.

The bill further requires the commission to ensure that retail sales associated with direct transactions do not contribute to resource curtailment or over-generation.

Additionally, forthcoming amendments to this bill that have not been placed in print but have been widely circulated in RN 15 23436 state that IOUs shall continue to own and operate all equipment on the distribution grid and provide DA customers with support functions, including, *but not limited to*, billing, customer service, call centers, support services, and line clearance tree trimming, through its own employees, except that construction of distribution system equipment and line clearance tree trimming may be performed pursuant to contracts between the electrical corporation and another entity.

CURRENT LAW

AB 1890 (1996) authorized DA transactions. AB 1X (2000) suspended DA in the aftermath of the 2000-'01 Energy Crisis. SB 695 (2009) partially reopened DA on a phased-in basis, up to the historical maximum level of DA.

To implement this, in 2010, the Commission issued Decision D.10-03-022 in Rulemaking R.07-05-025, modifying some of its effective rules governing DA and raising and resetting the cap on DA for each IOUs' service territory, up to historical limits and pursuant to a four-year phase-in schedule. Once those new caps were reached, the amount of new DA available through the program was once again capped.

AUTHOR'S PURPOSE

According to a fact sheet from the author's office: "Senate Bill 286 allows commercial and industrial customers to choose alternative electricity service, including options to buy 100% renewable energy, and sign contracts for delivery of electricity separate from the local utility company. The bill will encourage competition and reduce prices for electricity. This, in turn, will give California businesses the necessary tools to make cost-effective energy decisions and make California more business friendly, while providing new flexible options for meeting the state's renewable energy and greenhouse gas reduction goals."

EXPLANATION OF BILL'S IMPACT ON CPUC PROGRAMS, PRACTICE & POLICY

Following enactment of SB 695 in 2009, the Commission adopted and implemented a reopening schedule for DA starting April 11, 2010, to phase in authorized increases in the allowable direct transactions over a period of not less than three years, and not more than five years. 2014 was the fifth year in that phase-in period.

Since SB 695 capped DA at the historical maximum level of DA (24,792 GWh), the CPUC does not currently have the authority to authorize additional DA.

This bill would require the CPUC to reopen the DA program and implement a new schedule, increasing the numerical limit. If this bill passes, nonresidential customers will be allowed to purchase electricity from an Electric Service Provider (ESP), up to a new higher level raising the current DA cap by approximately 33% of total utility demand (from 24,792 GWh to approximately 32,792 GWh).

<u>Impact on Renewables Portfolio Standard (RPS)</u>

Incremental DA transactions authorized by this bill would be subject to the requirement that 100% of the incremental direct transactions would have to be provided by 100%

RPS-eligible energy. At present, all DA transactions are subject to the 33% RPS requirement. The bill does not explicitly state that these incremental renewable transactions would need to be subject to all RPS program rules. While the bill would impose the 100% requirement on incremental DA authorized by this bill, it is silent on whether this incremental DA would be subject to most other RPS requirements.

If creating a new RPS for a sub-set of direct transactions is what the statute intends, it would require the Commission to create new rules to reconciling the different requirements for different DA customers. Additionally, Energy Division staff will need to develop a new element of the RPS reporting system and coordinate with the California Energy Commission (CEC), which is responsible for verifying claims of RPS-eligible procurement (see P.U. Code Section 399.25). On an ongoing basis, CPUC staff will need to monitor to ensure that the right RPS-eligible procurement is counted in the right ESP procurement obligation (i.e., that procurement up to the mandated-RPS percentage is counted for RPS compliance, and that additional procurement for the "new direct transactions" is counted for the new P.U. Code Section 365.1(b)(2) obligation).

Impact on RA

Furthermore, tracking compliance with the 100% RPS standard would require additional resources and reporting requirements to the CPUC to effectively implement this bill. Load Serving Entities (LSEs, some of which are ESPs) will have to provide the data necessary for the CPUC to ensure compliance with the provisions of this section. This new data may include customer-specific data in order for the CPUC to track the differential RPS obligations for new DA customers. Both in tracking RA and RPS obligations, staff would need to track this 8000 GW of load as it migrates between LSEs.

Currently, RPS compliance is verified after the fact, at the LSE level, based on total retail sales. In effect, each MWh provided has an equal RPS compliance obligation. If certain DA customers were required to have a higher RPS obligation (100%) than other customers in California, the CPUC would need to track RPS compliance on a customer-specific level. DA customers sign short-term contracts (usually 1 year or less) and their load moves around from LSE to LSE. With this movement of load, CPUC compliance monitoring will require the CPUC to gather data on individual customer accounts and which LSE is currently serving them. Tracking these customers as they move from LSE to LSE would require a database and additional staff to manage the database.

As discussed in detail below, the CPUC does not have jurisdiction to review or approve the resource procurement of the DA providers. The more DA that departs from CPUC-jurisdictional utilities, the greater the chance that grid reliability could be negatively affected.

Impact on Distributed Resource Plans, customer-owned generation and storage

The forthcoming amendments appear to undermine several key programs the CPUC is developing under specific statutory directions. This includes the Distribution Resource Plans, customer-owned generation using the Net Energy Metering Tariff, and storage.

Distributed Resource Plan Concerns

The forthcoming new Section 769.1 in RN 15 23436 could undermine a prime object of the Distributed Energy Resource Plans that are being developed per Public Utilities Code 769 limiting the ability of third-parties to own, construct, and operate Distributed Energy Resources (DERs) that meet the “distribution system equipment” or provide “distribution system support functions.” The DERs are aimed at developing “non-wires” solutions that substitute for traditional distribution system upgrades. Non-wire upgrades could include generation located on the distribution grid, customer generation and third party owned technologies such as storage and smart inverters that help manage the distribution grid. The limitations in the forthcoming amendments could be interpreted to mean that both ownership and operation of DER that provides system functions is reserved solely for utility-owned assets. This is contrary to both the intent and the direction of the Distribution Resource Plan (DRP).

Commission Rulemaking, pursuant to Section 769 (R. 14-08-013) and the Assigned Commissioner’s Ruling issued on February 6, 2015, all contemplate significant involvement of both customers and third-parties in developing de-centralized, two-way power flows in the distribution system that are based on the provision of services such as voltage regulation, reactive power management and other functions that have been traditionally reserved to the utility. Reserve these functions solely to the utility would defeat at least one of the major objectives of the rulemaking.

Impact on Customer-Owned Generation and NEM

The forthcoming Section 769.1 appears to further undermine the current retail renewable energy market construct eligible under Net Energy Metering (NEM) or the Virtual NEM (VNEM) tariff rules.

While the amendments attempt to exclude equipment on the customer side of the meter from the utility ownership requirements, recent advancements in inverter technology mean that distribution customers who produce their own electricity can also now provide “distribution system support functions” such as voltage support. Under Rule 21, advanced distribution energy technologies, such as rooftop solar and energy storage systems equipped with smart inverters can interconnect with the IOUs’ distribution system and provide voltage support and ancillary service functions that are necessary to stabilize the local distribution grid. If the forthcoming Section 769.1 is adopted it could be read to invalidate NEM customer installations, because (a) under NEM and VNEM tariff rules the distributed energy resource system, such as rooftop solar with a smart inverter, is owned by the customer and not the electrical corporation; and (b) NEM-eligible generation facilities can be deployed by third-parties who also support installations and other functions on these distribution systems.

Impact on storage projects

The forthcoming Section 769.1 could also negatively affect Energy Storage projects currently, or soon-to-be, interconnected to the distribution grid in contradiction to the goals of AB 2514 (Skinner)(2010).

Pub. Util. Code Section 2835(a)(2), pursuant to AB 2514, clearly states that an “energy storage system” may have any of the following characteristics:

> (A) Be either centralized or distributed.
> (B) Be either owned by a load-serving entity or local publicly owned electric utility, customer of a load-serving entity or local publicly owned electric utility, **or a third party**, or is jointly owned by two or more of the above.

This guiding principle was further adopted in CPUC Decision (D.)13-10-040, in which the CPUC stated that it is premature to allow 100% utility ownership in transmission and distribution-connected storage until it is determined what narrow applications are best-suited for utility ownership versus third-party ownership. The CPUC allowed third-party ownership, which is applicable to all energy storage connecting at the distribution level by stating that it is reasonable to limit utility ownership of storage systems to 50% across grid domains.

Implementation of the forthcoming Section 769.1 could derail the efforts to deploy emerging, preferred energy resources, such as storage systems at the distribution level. The forthcoming Section 769.1 has been very narrowly written without considering a broader and far-reaching impact on the current status of the energy market and deployments that meet California’s energy goals.

SAFETY IMPACT

No particular safety impact is identified. The ESPs and IOUs remain subject to all applicable state and federal safety rules and regulations.

RELIABILITY IMPACT

ESPs remain subject to RA requirements and the Cost Allocation Mechanism (CAM) implemented by the CPUC. When the CPUC requires IOUs to invest in new power plants for system reliability in the Long-Term Procurement Planning and RA-related proceedings, the departing DA customer (as well as all other utility distribution customers) pays for a fair share of these system and local reliability investments through the CAM. ESPs have historically opposed the adoption of charges such as CAM. These CAM and RA charges are designed to ensure that all IOU distribution customers, including DA customers, pay for costs for new generation needed to maintain reliability.

Further, there is a concern that since ESPs are historically hesitant to invest in physical generation, due to the potential for customers to shift to other ESPs, CCAs or to incumbent utilities, even if the ESPs comply with RPS and RA requirements, the resources they procure (logically, they would buy the cheapest they could get) may not help, and may actually hinder short and long-term grid reliability.

The bill seems to presume that whatever RPS-compliant resources the DA providers procure (likely the cheapest available) will be feasible to integrate in the CAISO grid. Given that current CAISO forecasts show operation challenges as the grid moved beyond 40% renewable, the CAISO has some legitimate operational challenges, this may not be a fair presumption.

The CPUC does not have the authority necessary to assure that DA providers buy portfolios of resources that are operational. The CPUC does not have the broad scope of review of DA procurement that it does over the IOUs. Thus, the legislation may still inadvertently exacerbate operational issues arising from renewables integration that the CPUC and CAISO are trying to address because it does not specify that the DA RPS portfolios must meet some yet-to-be-defined standard or approval process.

The bill also requires the CPUC to ensure that retail sales associated with direct transactions do not contribute to resource curtailment or over-generation. While it may be advisable to amend the bill to give the CPUC some authority to review of the DA providers' resource procurement, as written to the extent that the ESPs contract with RPS resources, it would help if these were curtailable. However, the CPUC doesn't approve contracts for ESPs or direct terms of the contracts, so even with the new mandate on the CPUC the CPUC would have limited authority to ensure that direction transactions do not contribute to curtailment or over-generation. It is not clear how the CPUC could ensure that increased DA, with higher RPS requirements, would not exacerbate potential over-generation.

RATEPAYER IMPACT

As long as DA customers continue to be responsible for paying the Cost Allocation Mechanism (CAM) and all applicable departing load charges, including, but not limited to the Public Purpose Program (PPP) charges, Nuclear Decommissioning charges and the Power Charge Indifference Adjustment (PCIA) charges, bundled ratepayers should remain financially "indifferent" or neutral to expanded DA.

As per D.11-12-018, DA customers are required to give 6-months' notice if they wish to return to bundled service. They are free to serve out those 6 months with DA or return immediately to IOU service. If they choose to return immediately to IOU service, they are placed on Transitional Bundled Service (TBS), which is generation procured at spot-market rates, which could be more or less than bundled service rates at any given moment. After this 6-month period, the DA customer returns on Bundled Service, but must remain there a minimum of 18 months before having the option to once again return to DA.

Under the current system, since the DA cap has been reached, if a customer left DA they would have to get back in line and hope to win the DA lottery.

FISCAL IMPACT

With the bill as written, Energy Division will require two (2) permanent, full-time Public Utilities Regulatory Analysts (at least a PURA III and a PURA V) to staff the Rulemaking this bill requires, and on an ongoing basis, manage the database, ensure compliance and monitoring of this increased DA program.

Additionally, Energy Division will need to hire an outside firm to build, house, and maintain this database on an ongoing basis to ensure compliance with the provisions of this bill. Such data may include customer-specific data in order for the Commission to track the differential RPS obligations for new DA customers. Contract funding in the amount of $300,000 per year shall be authorized for such purpose.

Legal Division and Administrative Law Judge (ALJ) Divisions will also require additional staff to handle the three-year, phase-in period for incremental nonresidential DA. Because the intended increased volume of short and long-term energy resources combined with ESPs' organizational aversion to long-term investments in generation, an additional attorney will be needed to work with Energy Division staff to monitor and address short and long-term reliability impacts of increased DA volume in order to fulfill the Commissions duties to assure safe, reliable energy supplies at reasonable prices.

Legal Division will require a P.U. Counsel III, to conduct due diligence reviews of the proceeding and attend to ongoing issues with the implementation thereof. This will be a permanent full-time position.

Similarly, ALJ Division will require a limited-term ALJ II for a minimum of eighteen months to oversee the proceeding for which this legislation calls, beginning in 2016.

The source of the funding will be fund #0462. The total cost for one year of this bill will be $832,349.

ECONOMIC IMPACT

At present, DA customers are required to pay a variety of departing load charges or non-bypassable charges to ensure that their departure does not negatively affect bundled customers remaining with the utility. These charges are designed to leave customers staying with the utility financially indifferent to their departure. In addition to the public purpose program charges for low income customers and nuclear decommissioning charges, DA customers must pay for the above-market costs of the utility's portfolio of generating resources and the capacity cost of new power plants built or purchased by the utilities for system reliability and to meet the needs of customers which have departed.

The above-market costs of the utility's generating portfolio to be paid by DA customers are vintaged to reflect the costs of the utility's portfolio at the time of the departure. The above-market costs are recovered from departing DA customers through the Power Charge Indifference Adjustment (PCIA). The DA customer is assigned a "vintage," corresponding to the year it first departed bundled IOU service. The customer is responsible for PCIA charges from the date they departed. In other words, a customer who left in 2010 and a customer who left in 2011 would have different vintages, and thus, pay different PCIA amounts depending on market costs and conditions at the date of their respective departures.

Furthermore, when the CPUC requires IOUs to invest in new power plants for system reliability in the Long-Term Procurement Planning and RA-related proceedings, the departing DA customer pays for a fair share of these system and local reliability investments through the Cost Allocation Mechanism (CAM).

As long as the legislature retains the CPUC's authority to determine the departing load charges to keep IOU bundled load customers financially indifferent, there will be no negative economic impact on the remaining utility customers. In the absence of such authority, the bill could leave residential customers subsidizing the costs of investments the utility made to service non-residential customers who can leave as DA customers if the bill is passed.

LEGAL IMPACT

P.U. Code Section 365.1(c)(1) requires the CPUC to ensure that ESPs are subject to the "same requirements" that are applicable to the state's three largest IOUs under, among other things, the RPS program. This bill, as written, treats ESPs and IOUs differently, vis-à-vis their relative requirements under the RPS program (i.e. IOUs have a 33% RPS and ESPs will have a portion of their load subject to a 100% RPS). This violates this provision and therefore, either the bill or Section 365.1(c)(1) would need to be amended accordingly.

LEGISLATIVE HISTORY

SB 695 (2009) directed the Commission to reopen DA transactions on a limited basis over a three- to five-year period. Starting in 2010, the CPUC did so in D.10-03-022. The CPUC adopted a four-year period, which ended in 2014.

BACKGROUND INFORMATION ON IMPACTED PROGRAMS, PRACTICE OR POLICY

There are some questions and possible challenges that arise from this bill. In California, there is already a 33% RPS by 2020. Governor Brown has announced a 50% renewables goal by 2030. The current 22+% renewables procured by CPUC-jurisdictional utilities (IOUs) has already caused significant changes in electric load patterns on daily and seasonal bases. (e.g., the CAISO's well-known "Duck Curve.") In particular, the procurement of "least cost" renewable resources has caused various stresses on the grid (e.g., over-generation by wind at night in Northern California and other places, daily drop-off of solar power while load rises in the p.m.). Since DA providers can procure their electricity from sources of their choosing and are not CPUC-regulated, allowing more nonresidential customers to leave regulated utility system could exacerbate these problems.

However, it is clear there is pent-up demand for DA. The below excerpt from the CPUC's Energy Division DA Annual Status Report On the Enrollment Process for 2013, dated May 26, 2014, illustrates the amount of potential pent-up demand for more DA.

	PG&E	SCE	SDG&E	Total
Number of customers that remained on the waiting list as of December 31, 2013	155	255	435	845
Associated annual GWh of customer loads that remained on the waiting list as of December 31, 2013	545.2	1,351	4,235	6,131

OTHER STATES' INFORMATION

Unknown.

SUMMARY OF SUPPORTING ARGUMENTS FOR RECOMMENDATION

The CPUC should oppose SB 286 unless amended for the following reasons:

(1) Reserving distribution systems equipment and distribution system support function operation, construction, and ownership functions to the utility in perpetuity would hamper competition, greenhouse gas emission reduction goals, and derail multiple CPUC proceedings already underway.

(2) The tracking of disparate RPS requirements for a sub-set of customers creates significant implementation and compliance issues for the CPUC.

(3) There is not a feasible way to implement 100% RPS for a subset of DA customers which does not exacerbate over-generation issues.

SUMMARY OF SUGGESTED AMENDMENTS

(1) The forthcoming addition of Section 769.1.(b) should be amended in the following way:

769.1(b): An electrical corporation*, either on its own, or in concert with eligible third-parties*, shall continue to construct, own, and operate distribution system equipment, and shall continue to provide distribution system support functions directly with their own employees, except that construction of distribution system equipment and line clearance tree trimming may be performed under a contract between the electrical corporation and another entity.

(2) One specific correction for consistency with RPS statute:

Procurement of eligible renewable energy resources in excess of the renewable portfolio standard shall be subject to the same ~~minimum product~~ portfolio content requirements specified in Section 399.16 for procurement credited toward each renewable portfolio standard compliance period.

(3) One crucial addition for successful implementation of this bill:

Load serving entities shall provide the data necessary for the commission to ensure compliance with the provisions of this section, and such data may include customer-specific data in order for the Commission to track the differential renewables portfolio standard obligations for new direct access customers. Funding in the amount of $300,000 annual shall be authorized for such purpose.

STATUS

SB 286 is pending consideration in the Assembly Appropriations Committee on August 26, 2015.

SUPPORT/OPPOSITION

The latest available committee analysis states support and opposition as follows:

Support
Alliance for Retail Energy Markets
Alta Deana Dairy, A Dean Foods Company
Boral Industries Inc.
Building Owners and Managers Association
California Business Properties Association

California Manufacturers and Technology Association
California Association of Sanitation Agencies
California State Universities
Commerce Energy, Inc.
COMPETE Coalition
Constellation (an Exelon Company)
Direct Energy Business, LLC
eBay Inc.
Energy Research Consulting Group
Just Energy Group, Inc.
Liberty Power Corp., LLC
Lineage Logistics
Noble Americas Energy Solutions LLC
Nordic Energy Services, LLC
Owen-Illinois
Owens Corning
Recurrent Energy
Retail Energy Supply Association
RockTenn
School Project for Utility Rate Reduction (SPURR)
San Diego County Water Authority
Solar City
Swisstex California
TechNet
Western States Petroleum Association
Wilmar Oils and Fats Stockton

Opposition
California State Association of Electrical Workers
California State Pipe Trades Council
Coalition of California Utility Workers
Natural Resources Defense Council
Pacific Gas and Electric Company
San Diego Gas and Electric
Southern California Edison
Western States Council of Sheet Metal Workers

VOTES

07/13/15 (PASS)	Asm Utilities and Commerce	10	1	4	Do pass as amended and be re-referred to the Committee on [Appropriations]

Ayes: Bonilla, Burke, Eggman, Cristina Garcia, Roger Hernández, Obernolte, Patterson, Rendon, Ting, Williams

Noes: Dahle

No Votes Recorded: Achadjian, Hadley, Quirk, Santiago

06/03/15 (PASS)	Senate Floor	34	2	4	Senate 3rd Reading SB286 Hertzberg

Ayes: Allen, Anderson, Beall, Berryhill, Block, Cannella, De León, Fuller, Gaines, Galgiani, Glazer, Hall, Hernandez, Hertzberg, Hill, Hueso, Huff, Jackson, Lara, Leno, Liu, McGuire, Mitchell, Monning, Moorlach, Morrell, Nielsen, Pan, Pavley, Roth, Stone, Vidak, Wieckowski, Wolk

Noes: Leyva, Nguyen

No Votes Recorded: Bates, Hancock, Mendoza, Runner

05/28/15 (PASS)	Sen Appropriations	5	1	1	Do pass as amended

Ayes: Bates, Beall, Hill, Lara, Leyva

Noes: Nielsen

No Votes Recorded: Mendoza

05/04/15 (PASS)	Sen Appropriations	7	0	0	Placed on suspense file

Ayes: Bates, Beall, Hill, Lara, Leyva, Mendoza, Nielsen

Noes:

No Votes Recorded:

04/21/15 (PASS)	Sen Energy, Utilities and Communications	11	0	0	Do pass as amended, but first amend, and re-refer to the Committee on [Appropriations]

Ayes: Cannella, Fuller, Hertzberg, Hill, Hueso, Lara, Leyva, McGuire, Morrell, Pavley, Wolk

Noes:

No Votes Recorded:

OTHER PERTINENT INFORMATION

Stay Requirements

Pursuant to Commission Decision, a customer who leaves Direct Access is required to stay on IOU Bundled Service for at least 18 months before returning to Direct Access once again. These stay requirements should help safeguard against any potential gaming, or arbitrage.

RPS Requirements

Currently most ESPs meet their California RPS compliance requirements through a combination of purchasing permissible amount of each RPS “bucket,” including bundled and un-bundled Renewable Energy Credits (RECs) as well as buying excess renewable generation on short-term contracts from existing renewable energy facilities. As to ESPs non-renewable generation, the CPUC does not have visibility on length or terms of those contracts. However, given the RPS compliance strategies employed by most

ESPs, the requirement that 100% of incremental direct transactions come from eligible renewable energy resources likely will not result in new renewable generation facilities getting built.

Furthermore, it is unclear from the language of the bill whether the additional 100% of direct transactions from “eligible renewable energy resources” subjects this incremental procurement to all the rules of California’s Renewable Portfolio Standard (RPS). For the sake of consistency and workability, it would be best to explicitly state that these additional renewable energy resource-based transactions shall be subject to all the rules of the RPS program, if in fact this language remains in the final version of the bill.

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BILL LANGUAGE

SECTION 1.

The Legislature finds and declares all of the following:
(a) As the state's electrical system evolves to include more electricity generated by eligible renewable energy resources and distributed generation, electrical corporations must continue to facilitate safe and reliable transactions for electricity. Whether it comes from efficient natural gas powerplants, large wind or solar facilities, or customer-owned generation, including rooftop photovoltaics, fuel cells, or combined heat and power systems, the role of electrical corporations will be to ensure that electricity moves from suppliers to customers. In effect, the electrical corporations will become transmission and distribution companies, connecting customers with the electrical mix they want when and where they need it.
(b) California already has a few examples for this business model, including community choice aggregation and direct access. Direct access allows a customer to receive electricity through a direct transaction with an electric service provider, rather than from the electrical corporation. The electricity is delivered over the electrical corporation's transmission and distribution grid and the direct access customer pays the utility for providing transmission and distribution service.
(c) Direct access was suspended in California in 2001, despite not being a contributing component to the market manipulation, blackouts, and price spikes that led to the energy crisis of 2000–01. In 2010, the right of individual retail nonresidential end-use customers to acquire electric service through a direct transaction was reopened, but subject to limitations on the amount of electricity that could be delivered through those transactions.
(d) Direct access customers currently pay charges for electrical grid maintenance and pay nonbypassable charges on the distribution of electricity to support public purpose programs, including the California Alternate Rates for Energy program, which supports affordable electric service for low-income customers, and energy efficiency programs. Other providers of electric service, including electric service providers and community choice aggregators, are required to follow the same laws, rules, and regulations as electrical corporations with respect to resource adequacy (Section 380 of the Public Utilities Code), procurement of electricity pursuant to the California Renewables Portfolio Standard Program (Article 16 (commencing with Section 399.11) of Chapter 2.3 of Part 1 of Division 1 of the Public Utilities Code), and for reducing emissions of greenhouse gases pursuant to the California Global Warming Solutions Act of 2006 (Division 25.5 (commencing with Section 38500) of the Health and Safety Code).
(e) The Public Utilities Commission is required to ensure local area reliability needs for the benefit of both bundled and unbundled electric service customers. If the commission determines that new resources are needed for reliability, the costs are to be shared equitably, on a fully nonbypassable basis, amongst all customers, whether the customer receives their electricity from the electrical corporation, a community choice aggregator, or an electric service provider. The cost allocation mechanism ensures that there is no cost shift to bundled customers of the electrical corporation.
(f) A growing number of businesses are recognizing the importance of managing their energy supplies and are seeking more control over their energy management decisions. Many of these businesses also want options to contract for electricity, with up to 100 percent of that electricity coming from eligible renewable energy resources. However, because of the statutory limitations placed upon direct transactions, most businesses lack the means and

necessary tools to make cost-effective energy decisions, which makes California less business friendly than other states with more direct access options.
(g) Given high demand for direct transactions, it is in the interest of the state to expand the right to direct access opportunities, especially to provide options for acquiring electricity from renewable sources of generation.

SEC. 2.

Section 365.1 of the Public Utilities Code is amended to read:

365.1.

(a) Except as expressly authorized by this section, and subject to the limitations in subdivisions (b) and (c), the right of retail end-use customers pursuant to this chapter to acquire service from other providers is suspended until the Legislature, by statute, lifts the suspension or otherwise authorizes direct transactions. For purposes of this section, “other provider” means any person, corporation, or other entity that is authorized to provide electric service within the service territory of an electrical corporation pursuant to this chapter, and includes an aggregator, broker, or marketer, as defined in Section 331, and an electric service provider, as defined in Section 218.3. “Other provider” does not include a community choice aggregator, as defined in Section 331.1, and the limitations in this section do not apply to the sale of electricity by “other providers” to a community choice aggregator for resale to community choice aggregation electricity consumers pursuant to Section 366.2.
(b) ~~The~~ *(1) During the first phase-in period for expanding access to direct transactions, the* commission shall allow individual retail nonresidential end-use customers to acquire electric service from other providers in each electrical corporation’s distribution service territory, up to a maximum allowable total kilowatthours annual limit. ~~The~~ *During this first phase-in period for expanding access to direct transactions, the* maximum allowable annual limit shall be established by the commission for each electrical corporation at the maximum total kilowatthours supplied by all other providers to distribution customers of that electrical corporation during any sequential 12-month period between April 1, 1998, and the effective date of this section. Within six months of the effective date of this section, or by July 1, 2010, whichever is sooner, the commission shall adopt and implement a reopening schedule that commences immediately and will phase in the allowable amount of increased kilowatthours over a period of not less than three years, and not more than five years, raising the allowable limit of kilowatthours supplied by other providers in each electrical corporation’s distribution service territory from the number of kilowatthours provided by other providers as of the effective date of this section, to the maximum allowable annual limit for that electrical corporation’s distribution service territory. The commission shall review and, if appropriate, modify its currently effective rules governing direct transactions, but that review shall not delay the start of the phase-in schedule.
(2) The commission shall adopt and implement a second direct transactions reopening schedule that commences January 1, 2016, and phases in new direct transactions for individual retail nonresidential end-use customers over a period of not more than three years, raising the allowable limit of kilowatthours that can be supplied by other providers in each electrical corporation’s distribution service territory by that electrical corporation’s proportionate share of an aggregate of 8,000 gigawatthours, apportioned to each electrical corporation based upon its share of retail sales. For each electric service provider, 100

percent of retail sales associated with each direct transaction under this paragraph shall be procured from eligible renewable energy resources. Procurement of eligible renewable energy resources in excess of the renewable portfolio standard shall be subject to the same minimum product content requirements specified in Section 399.16 for procurement credited toward each renewable portfolio standard compliance period. The commission shall enforce the eligible renewable energy resource procurement requirements of this section as part of the California Renewables Portfolio Standard Program (Article 16 (commencing with Section 399.11)). The commission shall ensure that retail sales associated with direct transactions do not contribute to resource curtailment or over-generation.

(c) Once the commission has authorized additional direct transactions pursuant to subdivision (b), it shall do ~~both~~ *all* of the following:

(1) Ensure that other providers are subject to the same requirements that are applicable to the state's three largest electrical corporations under any programs or rules adopted by the commission to implement the resource adequacy provisions of Section 380, the renewables portfolio standard provisions of Article 16 (commencing with Section 399.11), and the requirements for the electricity sector adopted by the State Air Resources Board pursuant to the California Global Warming Solutions Act of 2006 (Division 25.5 (commencing with Section 38500) of the Health and Safety Code). This requirement applies notwithstanding any prior decision of the commission to the contrary.

(2) (A) Ensure that, in the event that the commission authorizes, in the situation of a contract with a third party, or orders, in the situation of utility-owned generation, an electrical corporation to obtain generation resources that the commission determines are needed to meet system or local area reliability needs for the benefit of all customers in the electrical corporation's distribution service territory, the net capacity costs of those generation resources are allocated on a fully nonbypassable basis consistent with departing load provisions as determined by the commission, to all of the following:

(i) Bundled service customers of the electrical corporation.

(ii) Customers that purchase electricity through a direct transaction with other providers.

(iii) Customers of community choice aggregators.

(B) If the commission authorizes or orders an electrical corporation to obtain generation resources pursuant to subparagraph (A), the commission shall ensure that those resources meet a system or local reliability need in a manner that benefits all customers of the electrical corporation. The commission shall allocate the costs of those generation resources to ratepayers in a manner that is fair and equitable to all customers, whether they receive electric service from the electrical corporation, a community choice aggregator, or an electric service provider.

(C) The resource adequacy benefits of generation resources acquired by an electrical corporation pursuant to subparagraph (A) shall be allocated to all customers who pay their net capacity costs. Net capacity costs shall be determined by subtracting the energy and ancillary services value of the resource from the total costs paid by the electrical corporation pursuant to a contract with a third party or the annual revenue requirement for the resource if the electrical corporation directly owns the resource. An energy auction shall not be required as a condition for applying this allocation, but may be allowed as a means to establish the energy and ancillary services value of the resource for purposes of determining the net costs of capacity to be recovered from customers pursuant to this paragraph, and the allocation of the net capacity costs of contracts with third parties shall be allowed for the terms of those contracts.

(D) It is the intent of the Legislature, in enacting this paragraph, to provide additional guidance to the commission with respect to the implementation of subdivision (g) of Section

380, as well as to ensure that the customers to whom the net costs and benefits of capacity are allocated are not required to pay for the cost of electricity they do not consume.

(3) Ensure that customers of other providers are responsible for their proportionate share of the costs of programs authorized pursuant to Sections 379.5 and 381.

(d) (1) If the commission approves a centralized resource adequacy mechanism pursuant to subdivisions (h) and (i) of Section 380, upon the implementation of the centralized resource adequacy mechanism the requirements of paragraph (2) of subdivision (c) shall be suspended. If the commission later orders that electrical corporations cease procuring capacity through a centralized resource adequacy mechanism, the requirements of paragraph (2) of subdivision (c) shall again apply.

(2) If the use of a centralized resource adequacy mechanism is authorized by the commission and has been implemented as set forth in paragraph (1), the net capacity costs of generation resources that the commission determines are required to meet urgent system or urgent local grid reliability needs, and that the commission authorizes to be procured outside of the Section 380 or ~~Section~~ 454.5 processes, shall be recovered according to the provisions of paragraph (2) of subdivision (c).

(3) Nothing in this subdivision supplants the resource adequacy requirements of Section 380 or the resource procurement procedures established in Section 454.5.

(e) The commission may report to the Legislature on the efficacy of authorizing individual retail end-use residential customers to enter into direct transactions, including appropriate consumer protections.

~~*(f) An electrical corporation shall continue to provide direct access customers with support functions, including, but not limited to, billing, customer service, call centers, support services, and line clearance tree trimming, through its own employees, except that construction of distribution system equipment and line clearance tree trimming may be performed pursuant to contracts between the electrical corporation and another entity.*~~

SEC. 3.

Section 395.5 is added to the Public Utilities Code, to read:

395.5.

Beginning January 1, 2016, no electric service provider shall offer consolidated billing.

SEC. 4.

Section 769.1 is added to the Public Utilities Code, to read:

769.1.

(a) For purposes of this section, the following terms have the following meanings:

(1) "Distribution system equipment" means the portions of the electric delivery system beginning with equipment that operates at voltages lower than that controlled by the Independent System Operator up to and including a customer's electric meter.

(2) "Distribution system support functions" means the functions currently provided by an electrical corporation, including, but not limited to, billing, customer service, call centers, other support services, and line clearance tree trimming.

(b) An electrical corporation shall continue to construct, own, and operate distribution system equipment, and shall continue to provide distribution system support functions directly with their own employees, except that construction of distribution system equipment and line clearance tree trimming may be performed under a contract between the electrical corporation and another entity.
(c) Before January 1, 2021, the commission shall not adopt any decision inconsistent with subdivision (b).
(d) This section shall remain in effect only until January 1, 2021, and as of that date is repealed.

~~SEC. 4.~~SEC. 5.

No reimbursement is required by this act pursuant to Section 6 of Article XIII B of the California Constitution because the only costs that may be incurred by a local agency or school district will be incurred because this act creates a new crime or infraction, eliminates a crime or infraction, or changes the penalty for a crime or infraction, within the meaning of Section 17556 of the Government Code, or changes the definition of a crime within the meaning of Section 6 of Article XIII B of the California Constitution.