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Proposed Language for Discussion at the November 16, 2016 Commissioner Workshop

Title 20 Data Collection Regulations

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OVERVIEW

The proceeding will consider amending the California Energy Commission's regulations specifying data collection and disclosure for load-serving entities, which are found in California Code of Regulations, Title 20, sections 1301 et seq. and 2501 through 2511. The amendments will help the Commission implement provisions within Senate Bill 350 (de León, Chapter 547, Statutes of 2015) and Assembly Bill 802 (Williams, Chapter 590, Statutes of 2015) and may clarify existing provisions in the regulations.

The proceeding may look at policies related to the Commission's implementation of electricity, natural gas, and transportation energy demand forecasting under Senate Bill 350 and existing law. Data collection needs for efficiency programs and policy assessments may be part of the proceeding in order to track realized energy use reductions over time from efforts across California and to support energy efficiency markets.

The proceeding may also look at whether the Commission will adopt guidelines governing the submission of information, data, and reports needed to support the review of or recommendations for integrated resource plans that the publicly owned utilities will submit. Publicly owned utilities with annual demand exceeding 700 gigawatt hours averaged over 3 years will be filing these plans with the Commission.

Background

Order Instituting Rulemaking Developing Regulations, Guidelines and Policies for Implementing Senate Bill 350 and Assembly Bill 802

On January 13, 2016, the California Energy Commission instituted a rulemaking proceeding to implement regulations supporting California's energy efficiency, renewable energy, and greenhouse gas reduction goals and policies that combat climate change. The following draft language has been drafted as a means to discuss potential changes to Title 20 data collection regulations.

Throughout this document new or proposed language is identified by an underlined format and deleted language is noted with a strikethrough format.

Administrative Regulatory Changes and Deletions

Section 1302 Rules of Construction and Definitions

(a) Rules of Construction.

(1) Where the context requires, the singular includes the plural and the plural includes the singular.

(2) The use of "and" in a conjunctive position means that all elements in the provision must be complied with, or must exist to make the provision applicable. Where compliance with one or more elements suffices, or where existence of one or more elements make the provision applicable, "or" (rather than "and/or") is used.

(b) Definitions. In this Article, the following definitions apply unless the context clearly requires otherwise:

(1) "California offshore lands" means all lands under California state jurisdiction pursuant to subdivision (a)(2) of 43 U.S.C. Section 1301.

(2) "Cogenerator" means a power plant that produces (1) electricity; and (2) useful thermal energy for industrial, commercial, heating, or cooling purposes.

(3) "Company" means any person, firm, association, organization, partnership, business trust, corporation, or public entity, or any subsidiary, parent, affiliate, department, or agency thereof.

(4) "Control area" means an electric system or systems, bounded by interconnection metering and telemetry, capable of controlling generation to maintain its interchange schedule with other Control Areas and contributing to frequency regulation of the Western Electricity Coordinating Council.

(5) "Core customer" means a natural gas customer that consumes less than 20,800 therms of natural gas per month.

(6) "Customer" means an active billed account, of a UDC, an LSE, or a gas utility.

(A) "Bundled customer" means an end-user who receives generation services from the same LSE from which it receives distribution services.

(B) "Unbundled customer" means an end-user who receives generation services from one LSE and distribution services from a UDC that is a separate entity from that LSE.

(7) "Customer Classification Code" means NAICS codes and the following codes:

(A) RE0000 for residential service;

(B) 925190 for streetlighting service;

(B) 221311 for water supply service;

(D) 221312 for irrigation system service; and

(E) 999999 for unclassified service.

(8) "Customer sector" means the following:

(A) residential customer sector: private households, including single and multiple family dwellings, plus NAICS code 81411;

(B) commercial building customer sector: NAICS codes 115, ~~2372,~~ 326212, 42, 44-45, ~~48841,~~ 493, 512, 516, 518, 519, 52-55, 561, 61, 62 ~~(excluding 62191),~~ 71, 72, 81 (excluding 81411), and 92 (excluding 92811);

(C) ~~other commercial~~ transportation, communications, and utilities customer sector: NAICS codes 221 (excluding 22131), 48~~ (excluding 48841)~~, 49 (excluding 493), 515, 517, 562~~, 62191,~~ and 92811;

(D) industry customer sector: NAICS codes 1133~~1~~, 31-33, and 511~~, and 54171~~;

(E) other industry customer sector: NAICS codes 21 and 23~~ (excluding 2372)~~;

(F) agriculture customer sector: NAICS codes 111, 112, 113 (excluding 1133~~1~~), and 114;

(G) water pumping customer sector: NAICS code 22131;

(H) street lighting customer sector: lighting of streets, highways, other public thoroughfares, other outdoor area lighting, and traffic control lighting.

(9) "Customer group" means the following:

(A) residential: customers consuming electricity for residential purposes;

(B) commercial: customers consuming electricity for commercial purposes;

(C) industrial: customers consuming electricity for industrial purposes; and

(D) other: customers consuming electricity for other purposes.

(10) "Demand" means the rate at which electricity is delivered by generation, transmission, and distribution systems, measured in units of watts or standard multiples thereof, (e.g., 1,000 Watts = 1 kilowatt, 1000 kilowatt = 1 megawatt) or the rate at which natural gas, measured as million cubic feet per day, is consumed by the customer.

(11) "Distribution service" means those services provided by a UDC when it constructs, maintains, and utilizes power lines and substations to transmit electrical energy within its distribution service area to end-users.

(12) "Distribution service area" or "UDC service area" means the geographic area where a UDC distributes, or has distributed during an applicable reporting period, electricity to consumers.

(13) "EIA" means the Energy Information Administration of the United States Department of Energy.

(14) "Electric generator" means a machine that converts mechanical energy into electrical energy; or a device that converts non-mechanical energy to electricity directly, including without limitation photovoltaic solar cells and fuel cells.

(15) "Electric transmission system owner" means an entity, or where there is more than one owner, the majority of plurality owners or the managing partner, that owns an interconnected group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems.

(16) "Electric utility" means any company engaged in, or authorized to engage in, generating, transmitting, or distributing electric power by any facilities, including, but not limited to, any such company subject to regulation of the Public Utilities Commission.

(17) "End user" means any company that consumes electricity or natural gas for its own use and not for resale.

(18) "Executive Director" means the Executive Director of the Commission, or his or her designee.

(19) "Fuel cost" means the delivered cost of fuel consumed by an electric generator, expressed in dollars.

(20) "Fuel use" means the amount of fuel, expressed in both physical units such as cubic foot, barrel, or ton, and in heat content such as Btus, used for gross generation, or for any other purpose related to the operation of an electric generator including without limitation providing spinning reserve, start-up, or flame stabilization.

(21) "Gas processor" means any company that extracts, in California, natural gas liquids from natural gas produced from California reservoirs.

(22) "Gas retailer" means any company that (a) sells natural gas to end users or customers located in California, (b) produces and consumes natural gas on-site in California (except for gas consumed for gathering, processing, or compressing purposes), or (c) produces natural gas at one site and consumes natural gas at another site that is in California and that is owned or controlled by the company.

(23) "Gas service area" means the geographic area where a gas utility distributes, or has distributed during an applicable reporting period, natural gas to customers.

(24) "Gas utility" means any company that is (a) engaged in, or authorized to engage in, distributing or transporting natural gas or natural gas liquids, and that is (b) either owned or operated by a governmental public entity or regulated by the California Public Utilities Commission.

(25) "Generation service" means those services provided by an LSE when it procures electrical energy for consumption by its end-user customers.

(26) "Gross generation" means the total amount of electricity produced by an electric generator.

(27) "Hourly demand" means demand integrated over a single clock hour, measured in megawatt hours.

(28) "Hourly load" means the chronological sequence of hourly demands for a specified subset of, or for all customers of, an LSE for a specified interval of time.

(29) "Hourly sector load" means the hourly load of customer sectors measured at customer meters. Hourly sector data does not include losses.

(30) “Hourly system load” means the hourly load of a UDC or a control area, measured at power plants and at interconnections. Hourly system load includes losses.

(31) “Interchange” means electric power or energy that flows from one control area to another control area.

(32) “Interstate pipeline” means any pipeline that crosses a state border and that is under the regulatory authority of the Federal Energy Regulatory Commission or its successors.

(33) “Interstate pipeline company” means a company that owns or operates an interstate pipeline that delivers natural gas to California at the state's border or inside California's borders.

(34) “Load-serving entity” or “LSE” means any company that (a) sells or provides electricity to end users located in California, or (b) generates electricity at one site and consumes electricity at another site that is in California and that is owned or controlled by the company. LSE does not include the owner or operator of a cogenerator.

(35) “Local publicly-owned electric utility” or “local publicly owned electric utility” has the same definition as provided in Public Utilities Code section 9604.

(36) “Losses” means electricity that is lost, primarily as waste heat, as a natural part of the process of transmitting electricity from power plants to end-users.

(37) “Major customer sector” means the following:

(A) “residential major customer sector,” which means residential customer sector;

(B) “commercial major customer sector,” which means commercial building customer sector;

(C) “industrial major customer sector”, which means the sum of industry customer sector, and other industry customer sector; and

(D) “other major customer sector”, which means the sum of agriculture customer sector, other commercial customer sector, street lighting customer sector, and water pumping customer sector.

(38) “Monthly system peak demand” means the highest system hourly demand in a calendar month.

(39) “Nameplate capacity” means the full-load continuous rating of an electric generator or a power plant under specific conditions as designated by the manufacturer.

(40) “Natural gas liquids” means liquid products that are produced at natural gas processing facilities and that are gaseous at reservoir temperatures and pressures but are recoverable by condensation or absorption.

(41) “Natural gas sales” means the amount of natural gas sold by a Gas Retailer to a customer.

(42) “Net generation” means gross generation less plant use by an electric generator for auxiliary equipment.

(43) “Noncore customer” means a natural gas customer that is not a core customer.

(44) “North American Industry Classification System” or “NAICS” means the system of classification for business establishments set forth in the North American Industry Classification System United States Manual of 2002 (Executive Office of the President, Office of Management and Budget, Washington, D.C.), and as revised for 2007 pursuant to 71 Fed. Reg. 28532 (May 16, 2006).

(45) “NAICS Code” means the applicable 6-digit (unless otherwise specified) code in the NAICS for the entity being classified.

(46) “Outer continental shelf” means all submerged lands lying seaward and outside of the area of lands beneath navigable waters, as defined in 43 U.S.C. Section 1301, and of which the subsoil and seabed appertain to the United States and are subject to its jurisdiction and control.

(47) “Peak demand” means the highest hourly integrated net energy for load within a certain period (e.g., in a month, a season, or a year).

(A) For a UDC, peak demand is the sum of all net energy for load, within a specific operating hour, for all LSEs providing generation services within a UDC's service area.

(B) For each LSE, peak demand is the sum of all net energy for load, including assignable losses, within a specific operating hour for the specific customers to which the LSE provides generation services.

(C) “Net energy for load” means generation energy injected into a specific electrical system, plus energy received from other systems less energy delivered to other systems through interchange. It includes losses, but excludes energy required to operate storage facilities or plant use by a generator.

(48) “Person” means an individual human being.

(49) “Plant use” means the electricity used in the operation of an electric generator, or the electricity used for pumping at pumped storage power plants.

(50) “Power plant” means a plant located in California or a California control area that contains one or more prime movers, one or more electric generators, and appropriate auxiliary equipment.

(51) “Power plant owner” means any company that owns a power plant, or, where there is more than one owner, the majority or plurality owner or the managing partner.

(52) “Prime mover” means the engine, gas turbine, steam turbine, water wheel, or other machine that produces the mechanical energy that drives an electric generator; or a device that converts non-mechanical energy to electricity directly, including without limitation photovoltaic solar cells and fuel cells.

(53) “Stocks” means quantities of oil, natural gas, or natural gas liquids representing actual measured inventories corrected to 60 degrees Fahrenheit less basic sediment

and water where an actual physical measurement is possible. Stocks include domestic and foreign quantities held at facility and in transit thereto, except those in transit by a pipeline.

(54) “Submitted” means, with regard to data, a report, or an application that must be submitted by a specified date, that the data is received at the Commission by that date and that the data, report, or application is complete, accurate, and in compliance with the applicable requirements of this Article and with the forms and instructions specified under Section 1303 and 1342.

(55) “Tolling Agreement” means a contractual arrangement whereby the buyer of electricity agrees to provide specified amounts of natural gas to a power plant for conversion to specified amounts of electric energy over a specified period of time.

(56) “Utility distribution company” or “UDC” means an electric utility, or a business unit of an electric utility, that distributes electricity to customers.

(57) “Customer Class Code” means the designated NAICS for the sector or customers identified for the section.

(58) “Community Choice Aggregator” means any group of customers within a utility who have organized to secure alternative energy supply contracts on a community-wide basis.

Removed duplicative reference to term “losses” as existing definition captures both transmission and distribution losses.

(59) “Useful thermal output” means the thermal energy made available in a cogeneration system for use in any industrial or commercial process, heating or cooling application, or delivered to other end users, i.e., total thermal energy made available for processes and applications other than electrical generation.

(60) “Energy storage system” means technology that meets the definitions provided in Public Utility Code section 2835.

Removed duplicative detailed definition and referenced appropriate Public Utility Code section.

(61) “Therm” means a unit of heat equal to 100,000 British thermal units (1.054 x 108 joules).

(62) “Thermal energy” means the thermal output produced by a combustion source used directly as part of a manufacturing process, industrial/commercial process, or heating/cooling application, but not used to produce electricity.

(63) “Balancing authority” means the entity identified in Public Utilities Code section 399.12 (b).

Replaced using the term “balancing authority” in definition with “entity identified” which clarifies the definition.

(64) “PV” means flat-plate non-concentrating photovoltaic modules.

(65) “PEV” means a plug-in electric vehicle and includes both fully electric vehicles and plug-in hybrid vehicles.

(66) "EVSE" means electric vehicle service equipment and refers to equipment associated with charging electric drive vehicles. It encompasses all of the conductors, plugs, fittings, and other hardware purposed to deliver energy from the electric grid to the vehicle.

(67) "Networked EVSE provider" means any individual, company, or entity who supports the charging of a plug-in electric vehicle through a networked device which collects charging information.

Added new definitions for networked EVSE provider.

Note: Authority cited: Sections 25213, 25218(e) and 25320, Public Resources Code. Reference: Sections 25005.5, 25100-25141, 25216, 25216.5, 25300, 25301, 25302, 25302.5, 25303, 25324, 25330 et seq., 25401, 25401.2, 25403, 25403.5, 25602 and 25604, Public Resources Code; and Sections 9615 and 9620, Public Utilities Code.

Section 1305 Control Area Operator Reports

Each control area operator with California end users inside its control area, including without limitation the California Independent System operator, shall submit the following data:
~~(a) Monthly Reports on Monthly System Peak Demand: monthly system peak demand in the control area, and the date and hour of the monthly system peak demand.~~
~~(b) Quarterly Reports on Interconnections:~~
~~(1) the names of all other control areas with which the control area is interconnected;~~
~~(2) the names of all interconnections with other control areas; and~~
~~(3) the operating voltages of all such interconnections expressed in kilovolts.~~
(a~~c~~) Quarterly Reports on Interchanges:
(1) the name of each control area with which the control area operator scheduled interchanges;
(2) for each month, electricity, expressed in megawatt hours that was scheduled to be delivered from each control area identified in Section 1305(b)(1) into the control area operator's control area;
(3) for each month, electricity, expressed in megawatt hours that was scheduled to be delivered from the control area operator's control area to each control area identified in Section 1305(b)(1);
(4) for each month, electricity, expressed in megawatt hours that was delivered from each control area identified in Section 1305(b)(1) into the control area operator's control area; and
(5) for each month, electricity, expressed in megawatt hours that was delivered from the control area operator's control area to each control area identified in Section 1305(b)(1).
~~(d) UDCs Operating within a Control Area. Each year, each control area operator shall provide the following information for the prior calendar year:~~
~~(1) a list of the UDCs providing distribution services within the control area as of the December 31 of the prior calendar year;~~
~~(2) mail and e-mail address for each UDC identified in subdivision (d)(1) of this section;~~

~~(3) a list of the UDCs that began or ceased providing distribution services within the control area, and the date on which those changes occurred; and~~

~~(4) for each control area that reported changes pursuant to subdivision (d)(3) of this section, the following information shall be provided:~~

~~(A) updates to data series reported by the control area operator to the commission pursuant to Article 1 and Article 2 of this Chapter that are necessary to ensure that the Commission possesses a continuous series for that data for the three previous calendar years for the control area as defined at the close of the prior calendar year, and~~

~~(B) copies of all data submitted by the control area operator to WECC as part of WECC's Control Area Certification Procedure, adopted December 5, 2003.~~

~~(e) Annual Reports:~~

~~(1) hourly loads for all of the electricity consumption and losses in the control area; and~~

~~(2) if the definition of control area changed during the previous year, provide the date of the change, describe the nature of the change, and explain how this change affected the identification of hourly loads in subdivision (e)(1) of this section.~~

Note: Authority cited: Sections 25213, 25218(e) and 25320, Public Resources Code. Reference: Sections 25005.5, 25216, 25216.5, 25300-25303, 25401, 25401.2, 25403, 25403.5, 25602 and 25604, Public Resources Code.

Section 1395 Scope

~~The regulations in this Article implement the California Energy Commission (Commission) role in providing assessments and forecast of energy related matters within the state. The regulations set forth the mechanism and process for reporting of information by Departing Load customers requesting Cost Responsibility Surcharge (CRS) exemptions. The regulations set forth the mechanism and process for the Commission to assess and track eligibility of Departing Load customers for CRS Exemptions. The information obtained under these regulations will be incorporated into the Integrated Energy Policy Report (IEPR) in order to assess and forecast the impacts of CRS and CRS exemptions on the deployment of distributed generation.~~

~~Note: Authority cited: Sections 25213 and 25218(e), Public Resources Code. Reference: Sections 25216, 25216.5, 25301 and 25320, Public Resources Code.~~

Section 1395.1 Rules of Construction and Definitions

~~The rules of construction and definitions in Section 1302 of Article 1 of this Chapter, and the definitions set forth in this Section, apply to this Article.~~

~~(a) "Backup Generation" means electricity generated by a Customer on a temporary basis in order to replace the generation lost from that Customer's normal supply source, usually the Electric Utility where the customer resides.~~

~~(b) "Best Available Control Technology" or "BACT" means the maximum degree of emissions reduction achievable after taking into account energy, economic, and environmental~~

~~impacts, as set forth in Health and Safety Code Section 40405. The local air district where the generation is located usually makes the BACT determination.~~

~~(c) “Bonds” means the California Department of Water Resources (CDWR) Power Supply Revenue Bonds, Series 2002A-2002E, issued by the State of California on October 23, 2002, and November 7, 2002. The Bonds were issued for the purpose of repaying the State's General Fund for procuring electricity on behalf of Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas and Electric Company from January 17, 2001 to December 31, 2002.~~

~~(d) “CARB” means the California Air Resources Board.~~

~~(e) “CPUC” means the California Public Utilities Commission.~~

~~(f) “Cogeneration” means the sequential use of energy for the production of electrical and useful thermal energy, as set forth in Public Utilities Code section 218.5.~~

~~(g) “Cost Responsibility Surcharge” or “CRS” means energy cost obligations consistent with CPUC Decision 03-04-030 and subsequent CPUC decisions. CRS-related costs are recoverable from eligible customers on a cents-per-kilowatt-hour basis and include the following components:~~

> ~~(1) Costs associated with Southern California Edison Company's Historical Procurement Charge;~~
>
> ~~(2) Costs associated with repayment of bonds for the procurement of power by the CDWR for purchases made between January 17, 2001 and December 31, 2002;~~
>
> ~~(3) Costs associated with the power contracts entered into by the CDWR on behalf of Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas and Electric Company for procurement beginning January 1, 2003; and~~
>
> ~~(4) Cost associated with the Tail Competition Transition Charge, as defined in Public Utilities Code section 367(a).~~

~~(h) “CRS Exemption” means the avoidance of the payment of one or more of the CRS components, as defined in subsection (g) of this section, if a customer is eligible.~~

~~(i) “CRS Exemption Queue” or “Queue” means the list of CRS Exemption requests either placed or pending placement in order of receipt, for approval of a CRS Exemption within the appropriate Megawatt Cap.~~

~~(j) “Commission” means the California Energy Resources Conservation and Development Commission.~~

~~(k) "Customer" means an electric utility customer that has any portion of load qualifying as Departing Load, and is seeking a CRS Exemption or placement in the Queue to receive a future CRS Exemption.~~

~~(l) "Customer Generation" means any type of generation that (1) is dedicated wholly or in part to serve a specific customer's load; and (2) relies on non-utility or dedicated utility distribution wires rather than the utility grid, to serve the customer, the customer's affiliates and/or tenant's, and not more than two other persons or corporations. Those two persons or corporations must be located on site or adjacent to the real property on which the generator is located.~~

~~(m) "Departing Load" means those portions of the utility customer's electric load for which the customer: discontinues or reduces its purchase of bundled or direct access service from the utility; purchases or consumes electricity supplied and delivered by Customer Generation to replace the utility or direct access (DA) purchases; and remains physically located at the same location or elsewhere within the utility's service territory as of April 3, 2003. Reduction in load qualifies as Departing Load only to the extent that such load is subsequently served with electricity from a source other than a utility. This definition of departing load does not include the following:~~

> ~~(1) Changes in usage occurring in the normal course of business resulting from changes in business cycles, termination of operations, departure from the utility service territory, weather, reduced production, modifications to production equipment or operations, changes in production or manufacturing processes, fuel switching, enhancement or increased efficiency of equipment or performance of existing Customer Generation equipment, replacement of existing Customer Generation equipment with new power generation equipment of similar size, installation of demand-side management equipment or facilities, energy conservation efforts, or other similar factors.~~
>
> ~~(2) New customer load or incremental load of an existing customer where the load is being met through a direct transaction with Customer Generation and the transaction does not otherwise require the use of transmission or distribution facilities owned by the utility.~~
>
> ~~(3) Load temporarily taking service from a Back-up Generation unit during emergency conditions called by the utility, the California Independent System Operator, or any successor system operator.~~
>
> ~~(4) Municipally-owned utilities or irrigation districts.~~
>
> ~~(5) Changes in the distribution of load among accounts at a customer site with multiple accounts, load resulting from the reconfiguration of distribution on the customer side of the site, provided that the customer changes do not result in a discontinuance or reduction of service from the Electric Utility at that location.~~

~~(6) Load that physically disconnects from the grid. This definition is intended to be consistent with CPUC utility tariffs and related subsequent CPUC decisions.~~

~~(n) "Departing Load CRS Information Form" or "Form" means the document containing pertinent information from the Customer necessary for the Commission to determine whether or not a Customer is eligible for a CRS Exemption.~~

~~(o) "Development Plan" or "Plan" means a detailed schedule for anticipated construction and interconnection activities. The Plan shall include a list of all permits and approvals that the Customer will need to obtain before interconnection will occur, and the anticipated time it will take for the Customer to obtain each of the permits and approvals.~~

~~(p) "Electric Utility" means an investor owned utility. In this case, Electric Utility refers to Pacific Gas and Electric Company, Southern California Edison Company, or San Diego Gas and Electric Company, depending on the service territory where the Customer Generation is located.~~

~~(q) "IEPR" means the Commission's Integrated Energy Policy Report.~~

~~(r) "Full CRS Exemption" means that a Customer is exempt from paying surcharges associated with the CRS defined in subsection (g) of this section.~~

~~(s) "Megawatt Cap" means the total amount of Departing Load, expressed in megawatts, eligible for a CRS Exemption, consistent with the Cap levels determined by the CPUC.~~

~~(t) "Net Energy Metering" shall have the same definition as set forth in Public Utilities Code section 2827(b)(3).~~

~~(u) "Partial CRS Exemption" means that a Customer is exempt from paying certain components of the CRS as defined in subsection (g) of this section, but do not qualify for a Full CRS Exemption. The extent that a Customer may be eligible for an exemption is based on the criteria set forth in Section 1395.3(d) of this Article.~~

~~(v) "Ultra Clean and Low-Emissions Distributed Generation" shall have the same definition as set forth in Public Utilities Code Section 353.2.~~

~~Note: Authority cited: Sections 25213 and 25218(e), Public Resources Code. Reference: Sections 25216, 25216.5, 25301 and 25320, Public Resources Code.~~

Section 1395.2 Departing Load CRS Information Form or Form

~~(a) (1) The Commission shall prepare, and make available to Customers, in conjunction with each Electric Utility a Departing Load CRS Information Form (Form). The Form shall provide information necessary to assess eligibility for a CRS exemption.~~

~~(2) The Form shall include, but not be limited to, the following information:~~

~~(A) Customer name;~~

~~(B) Contact information, such as phone number and email address;~~

~~(C) Address (including street number, street name, city, and zip code);~~

~~(D) Capacity of Customer Generation unit;~~

~~(E) Estimated annual Departing Load~~

~~(F) Type of technology;~~

~~(G) Anticipated interconnection date; and~~

~~(H) Proposed Project Development Plan and any anticipated activities that may delay the project beyond 12 months from submission of the Customer's application.~~

~~(b) Each Electric Utility may develop forms that substantially meet the criteria set forth in section (a)(2) of this section, and make such forms available to customers within its service territory for purposes of providing the information necessary to include a Customer in the CRS Exemption Queue. The Commission shall approve any Electric Utility forms and modifications to such forms at least 30 days prior to any formal use of the forms by the Electric Utility.~~

~~Note: Authority cited: Sections 25213 and 25218(e), Public Resources Code. Reference: Sections 25216, 25216.5, 25301 and 25320, Public Resources Code.~~

Section 1395.3 Process for Assessing Eligibility for CRS Exemptions, and Reporting Requirements

~~(a) The Customer shall submit a Form to the Electric Utility and the Commission.~~

~~(b) The Electric Utility shall:~~

~~(1) Conduct an initial review and determine whether the Form is complete.~~

~~(A) If the Form is incomplete, the Electric Utility shall notify the Customer within 10 calendar days after receipt of the Form that additional information is needed to process the request for a CRS Exemption. The notification shall indicate which portion(s) of the Form require supplemental information.~~

~~(B) If the Form is complete, then the Electric Utility shall within 10 calendar days after receipt of the Form:~~

~~1. Provisionally categorize each project;~~

~~2. Identify the conditions that must be met to receive final project categorization; and~~

~~3. Transmit the completed Form with provisional project categorization to the Commission, with a copy to the Customer serving as official notification.~~

~~(2) Automatically grant Full CRS Exemptions, if the Customer is:~~

~~(A) Eligible for participation in the CPUC's Self Generation Incentive Program up to 1 megawatt;~~

~~(B) Eligible for participation in the Commission's Renewable Energy Program up to 1 megawatt; or~~

~~(C) A Net Energy Metering Customer.~~

~~(3) Send the Commission and the Customer confirmation in writing of the Full CRS Exemption granted within 10 calendar days from issuance of the automatic exemption. The Commission shall incorporate the CRS Exemption into the queuing process for purposes of tracking the appropriate megawatt cap.~~

~~(c) Upon receipt of a completed Form with provisional project categorization from the Electric Utility, the Commission shall:~~

~~(1) Review the completed Form and assess whether the Customer is eligible for a CRS Exemption and if there is space available under the appropriate Megawatt Cap.~~

~~(2) Make the initial assessment of eligibility based on the information provided. This initial assessment shall be designated to the appropriate Commission Committee assigned to matters concerning distributed generation or departing load.~~

~~(3) Not include in the Queue any CRS Exemption request that is considered Backup Generation or diesel-fired Customer Generation, as these forms of generation do not qualify for a CRS Exemption.~~

~~(4) Not include in the queue a CRS Exemption request if the Customer does not meet the criteria outlined in section (d) of this section. If the Commission does not include a CRS Exemption request in the Queue it shall provide written notification to the Customer and the Electric Utility within 10 calendar days of rejecting the request.~~

~~(5) Place all qualifying Customers within the Queue. Customers that qualify for an exemption are those placed in the Queue within the appropriate Megawatt Cap as determined by the CPUC.~~

~~(d) The Commission shall place all Customers in the Queue based on technology categorization, and date of Form submittal. The Commission shall assess whether a Partial~~

~~CRS Exemption for each Customer submitting a Form should be in included in the Queue based on either the nameplate rating or estimated annual Departing Load. The amount of Departing Load and categorization will be utilized in maintaining an accurate account of available Megawatts in the Queue. The categorization of technology type is as follows:~~

~~(1) Ultra Clean and Low-Emissions Distributed Generation Over One Megawatt.~~

~~(2) Other Customer Generation not qualifying under (d)(1) of this section, subject to meeting air district BACT standards and the following megawatt caps:~~

~~(A) 600 megawatts by the end of 2004, of which 10 megawatts are reserved for University of California or the California State University System;~~

~~(B) 500 additional megawatts by July of 2008, of which 80 megawatts are reserved for University of California or the California State University System; and~~

~~(C) 400 additional megawatts thereafter, of which 75 megawatts are reserved for University of California or the California State University.~~

~~Note: Authority cited: Sections 25213 and 25218(e), Public Resources Code. Reference: Sections 25216, 25216.5, 25301 and 25320, Public Resources Code.~~

Section 1395.4 CRS Exemption Queue and Procedures for Updating the Queue

~~(a) A CRS Exemption Queue (Queue) shall be established by the Commission and be based on a first-come, first-served basis, utilizing the criteria outlined in Section 1395.3 and the information provided in the Form. Forms shall be date-stamped upon receipt by the Commission.~~

~~(b) The Commission shall maintain the Queue in electronic format with aggregated totals posted on the Commission website. The Commission website will list general information about each request including the size of the exemption, technology type and general location. The identification and specific location of a Customer applying for a CRS Exemption shall be deemed confidential.~~

~~(c) The Commission shall track all Forms and assess Customer eligibility for a CRS Exemption. Once eligibility is established, the Commission shall place the Customer request in the CRS Exemption Queue, subject to the applicable Megawatt Cap.~~

~~(1) If the Customer request falls within the Megawatt Cap:~~

~~(A) The Commission will notify the Electric Utility and the Customer within 10 calendar days of placing the Customer in the Queue.~~

~~(B) The Commission will notify the Customer of rank within the Queue and whether the Customer will receive a Partial CRS Exemption.~~

~~(C) The Customer will have 12 months from the date of placement in the Queue to interconnect with the grid. If the Customer does not believe it will be able to connect within the 12-month timeframe, then it must submit a Development Plan (Plan) to the Commission in order to demonstrate that the Customer is actively progressing in the permitting and/or construction of the project. The Commission may request additional information after the initial 12-month period to ensure continuing active progress by the Customer in conformance with the Development Plan.~~

~~(2) If the Customer request does not fall within the Megawatt Cap, the Commission will:~~

~~(A) Notify the Electric Utility and Customer that the request does not fall within the Megawatt Cap; and~~

~~(B) Place the Customer request in the Queue ranked in order of receipt.~~

~~(d) The Commission will update the Queue weekly in order to ensure timely and efficient Customer access to CRS Exemption information. In doing so the Commission shall:~~

~~(1) Remove CRS Exemption requests if a Customer does not commence operation within 12 months from the date a CRS Exemption request is placed in the Queue, if the Customer does not demonstrate sufficient compliance with a Plan submitted to the Commission at the time the exemption is listed in the Queue, or if the Customer otherwise ceases to meet the requirements for a CRS Exemption.~~

~~(2) Incorporate any changes to the Megawatt Cap as deemed appropriate.~~

~~(e) The Electric Utility shall notify the Commission when an eligible Customer commences operation of its generating facilities.~~

~~Note: Authority cited: Sections 25213 and 25218(e), Public Resources Code. Reference: Sections 25216, 25216.5, 25301 and 25320, Public Resources Code.~~

Section 1395.5 Extension Requests, Other Substantive Changes, and Requests to Evaluate Additional Information

~~(a) Substantive changes require prior notice to the appropriate Commission Committee and will be considered if requested in writing. Each request must describe the need for the change or extension of time, and must document the following:~~

~~(1) Circumstances beyond the control of the Customer that prevent the system from commencing operation as described in the Form.~~

~~(2) The Customer had no knowledge or reason to know that the commencement of operation would not occur until after the requested date stated in the Form.~~

~~(3) There are no other known obstacles in the way of completing the project within the requested extension period.~~

~~(b) Any request for extension of time must be based on good cause and demonstrate circumstances beyond the control of the Customer, unless the Customer provided a Plan to the Commission at the time the Departing Load was listed in the Queue.~~

~~(c) Customers that disagree with the Commission's assessment of categorization may request a re-evaluation of the information provided in the Form, or submit additional information to supplement or clarify information provided in the Form for purposes of requesting a re-categorization of the Customer's placement in the Queue.~~

~~(d) Any request for extension of time or re-evaluation of categorization must be filed at least 30 days prior to the expiration of the Customer's place in the Queue, or 30 days from notification of the Customer's categorization within the Queue.~~

~~(e) The Commission shall notify the Customer of its final assessment in writing within 30 days from the receipt of the request for an extension of time or re-categorization. The Customer will not be removed from the Queue until a final assessment by the Commission has been made pursuant to this section.~~

~~Note: Authority cited: Sections 25213 and 25128(e), Public Resources Code. Reference: Sections 25216, 25216.5, 25301 and 25320, Public Resources Code.~~

Section 1395.6 Incorporation of Information and Impacts of CRS and CRS Exemptions into IEPR

~~(a) The Commission shall utilize information received by Customers, the Electric Utilities, and the Queue to assess impacts of CRS on deployment of Customer Generation, grid reliability, air quality, and the environment.~~

~~(b) The assessments and forecasts made pursuant to subsection (a) of this section shall be incorporated into the Commission's IEPR along with any recommendations as to the benefits or detriments of CRS and CRS Exemptions to statewide energy resource planning, including progress or implementation of the Distributed Generation Strategic Plan adopted by the Commission in June 2002.~~

~~Note: Authority cited: Sections 25213 and 25218(e), Public Resources Code. Reference: Sections 25216, 25216.5, 25301 and 25320, Public Resources Code.~~

Draft Generation Regulatory Language

Section 1304 Power Plant Reports

(a) Reports by Power Plant Owners. Each power plant owner shall submit all of the data and reports required by this subsection for each power plant that has a nameplate capacity of one megawatt or more, and that it owns or owned during the reporting period. For the purposes of this subsection, all of the wind turbines in an power plant shall be collectively considered as one single electric generator.

(1) Each Report: Power Plant Identification. The following data shall be submitted for each power plant with every quarterly, or annual report:

(A) name of the power plant;

(B) identification number of the power plant assigned by the Commission;

(C) facility code of the power plant assigned by the EIA;

(D) address where the power plant is physically located: street address, city, county, state and zip code;

(E) if the power plant operator is not the power plant owner, the power plant operator's full legal name and address of principal place of business including the street address, city, state, and zip code;

(F) nameplate capacity of the power plant;

(G) if the power plant is a cogenerator, the Customer Classification code of the entity to which the power plant supplies ~~waste heat~~ useful thermal energy;

(H) if the power plant supplies electricity directly to an entity on site, the Customer Classification code of the entity;

(I) if the power plant was sold during the reporting period;

1. the settlement date of the power plant sale;

2. the buyer's and the seller's full legal names and addresses including street address, city, state, and zip code; and

3. the name, address including street address, city state, and zip code, and telephone number of the contact persons for the buyer and seller; and

(J) for each electric generator in the power plant:

1. the identification number assigned by the power plant owner;

2. nameplate capacity of the electric generator and, if the prime mover is a wind turbine, the total number of the turbines reflected in the nameplate capacity;

3. the date electricity was first commercially generated by the electric generator;

4. the operating status of the electric generator during the reporting period, such as operating, standby, cold standby, on test, maintenance, out of service, indefinite shutdown, or retired;

5. if the electric generator was retired during the reporting period, the retirement date;

6. an identification of the prime mover that drives the electric generator; and

7. an indication whether the prime~~r~~ mover is part of a combined-cycle unit.

(2) Generation and Fuel Use Data.

(A) For power plants with nameplate capacity of one megawatt or more and less than ten megawatts, the following data shall be submitted annually:

1. gross generation of each electric generator, in megawatt hours;

2. net generation of each electric generator, in megawatt hours;

3. fuel use, by fuel type, of each electric generator;

4. fuel use, by fuel type, for useful thermal energy production and electricity generation of each cogenerator;

5. electricity in megawatt hours, consumed on site by the power plant owner, other than for plant use, classified by Customer Classification Code;

6. sales for resale, in megawatt hours; and

7. for cogenerators providing thermal energy to commercial end users or industrial end-users, sales of electricity to those end users, classified by Customer Classification Code, in megawatt hours, excluding sales to the wholesale market or LSEs.

<u>8. for cogenerators providing thermal energy to an entity on site, monthly useful thermal energy production of each cogenerator, in million British thermal units; and</u>

<u>9. for cogenerators providing thermal energy to commercial end users or industrial end-users, sales of useful thermal energy to those end users, classified by Customer Classification Code, in million British thermal units, excluding sales to the wholesale market or LSEs.</u>

(B) For power plants with nameplate capacity of ten megawatts or more and less than fifty megawatts, the following data shall be submitted quarterly:

1. monthly gross generation of each electric generator, in megawatt hours;

2. monthly net generation of each electric generator, in megawatt hours;

3. monthly fuel use, by fuel type, of each electric generator;

4. monthly fuel use, by fuel type, for useful thermal energy production and electricity generation of each cogenerator;

5. monthly electricity in megawatt hours, consumed on site by the power plant owner, other than for plant use, classified by Customer Classification Code;

6. monthly sales for resale, in megawatt hours; and

7. for cogenerators providing thermal energy to commercial end users or industrial end-users, monthly sales of electricity to those end users, classified by Customer Classification Code, in megawatt hours, excluding sales to the wholesale market or LSEs.

<u>8. for cogenerators providing thermal energy to an entity on site, monthly useful thermal energy production of each cogenerator, in million British thermal units; and</u>

<u>9. for cogenerators providing thermal energy to commercial end users or industrial end-users, sales of useful thermal energy to those end users, classified by Customer Classification Code, in million British thermal units, excluding sales to the wholesale market or LSEs.</u>

(C) For power plants with nameplate capacity of fifty megawatts or more, the following data shall be submitted quarterly:

1. monthly gross generation of each electric generator, in megawatt hours;

2. monthly net generation of each electric generator, in megawatt hours;

3. monthly fuel use, by fuel type, of each electric generator;

4. monthly fuel use, by fuel type, for useful thermal energy production and electricity generation of each cogenerator;

5. monthly electricity in megawatt hours, consumed on site by the power plant owner, other than for plant use, classified by Customer Classification Code;

6. monthly sales for resale, in megawatt hours;

7. for cogenerators providing thermal energy to commercial end users or industrial end-users, monthly sales of electricity to those end users, classified by Customer Classification Code, in megawatt hours, excluding sales to the wholesale market or LSEs~~.~~;

8. for cogenerators providing thermal energy to an entity on site, monthly useful thermal energy production of each cogenerator, in million British thermal units;

9. for cogenerators providing thermal energy to commercial end users or industrial end-users, sales of useful thermal energy to those end users, classified by Customer Classification Code, in million British thermal units, excluding sales to the wholesale market or LSEs; and

10~~8~~. monthly fuel cost by fuel type of each electric generator, except for the cost of fuel provided to the generator through a tolling agreement. If fuel is provided to the generator through a tolling agreement, indicate the portion of the fuel use identified in subdivision (a)(2)(C)(4) that is provided to the generator through the tolling agreement.

(3) The following environmental information related to power plant operations shall be reported annually for all types of power plants, except power plants that generate electricity solely from wind or hydroelectric processes:

(A) Environmental information related to water supply, and water use, and ~~/~~ wastewater discharge. All water and wastewater volume data shall be reported in gallons.

1. Water Supplies: Owners of power plants with a generating capacity of 20 megawatts and greater shall ~~submit copies of reports or filings required by regulations, permit, or contract conditions that identify any of the following information~~ provide for the previous calendar year:

a. a description of the type of primary and backup water supply sources used at the power plant, such as groundwater, surface water, recycled water, or potable water provided by another entity~~cooling technology being used for each unit within a power plant~~;

b. the name of the primary and backup water supplier(s) that provides water to the power plant, if applicable; ~~under contract to provide water to the power plant, if applicable, or the name of the water source as assigned by the U.S. Geological Survey on its 7.5-minute map series. Or, if well water is used, provide the well identification number and location as specified in the California Department of Water Resources, Water Facts, Issue No. 7, "Numbering Water Wells in California", June 2000.~~

c. if well water is used, provide the well identification number and location using the State Well Numbering system as specified in the current version of the California Water Code section 13751;

d. a description of the physical and chemical characteristics of the water supply(s);

e. if available, include any information obtained using the approved test methodology and detection limits specified by the U.S. Environmental Protection Agency in 40 CFR § 141 for analyzing the constituents in a water supply;

f. a description of all consumptive and non-consumptive water use processes at the power plant such as steam cycle cooling, 'once through cooling', lubricant and ancillary equipment cooling, inlet air cooling, injection for intercoolers and emissions control, dust control, mirror washing, water injected into and extracted from geothermal resources and oil field facilities, and drinking and sanitation;

g~~c~~. the ~~daily average and~~ daily maximum water use volumes in gallons for all power plant purposes;

h~~d~~. the monthly and annual consumptive and non-consumptive use of each water supply ~~amounts of water used~~ for all power plant purposes ~~in acre-feet~~; and

i~~e~~. the metering technology used to measure and track water use at the power plant and the frequency at which meter readings are recorded (hourly, daily, weekly, monthly or annually).

2. Wastewater Discharges: Owners of power plants with a gross generating capacity of 20 megawatts and greater shall ~~submit copies of reports or filings required by regulations, permit, or contract conditions that identify any of~~ provide the following information for the previous calendar year:

a. a description of the physical and chemical characteristics of ~~the source water or~~ the industrial wastewater discharge~~, including any information prepared with the approved test methodology and detection limits specified by the U.S. Environmental Protection Agency in 40 CFR §136.3 for analyzing the constituents in wastewater.~~;

b. a description of the power plant industrial wastewater treatment and ~~the wastewater~~ disposal system(s) ~~used at the power plant for discharges related to power plant cooling and operations~~ and, if applicable, the manufacturer(s), and the year of installation;

c. the name of the entity receiving the industrial wastewater discharge, if applicable, or a description of the industrial wastewater disposal method. If wastewater is discharged to a water body, identify the receiving water as assigned by the appropriate California Regional Water Quality Control Board;

d~~c~~. the measures taken, and the devices installed on the wastewater disposal system's outfall, if any, to control pollution discharges to municipal systems, receiving waters or land;

~~d. the name of the utility or organization receiving the wastewater discharge, if applicable, or the name of the receiving water as assigned by the U.S. Geological Survey on its 7.5-minute map series;~~

e. the monthly and annual totals ~~of~~ industrial wastewater ~~that are created from power plant operations in acre-feet~~; ~~and~~

f. the ~~daily average and~~ daily maximum industrial wastewater ~~waste water~~ discharge ~~volumes in gallons.~~; and

g. if available, include any information prepared with the approved test methodology and detection limits specified with the approved test methodology and detection limits specified by the U.S. Environmental Protection Agency in 40 CFR §136.3 for analyzing the constituents in the industrial wastewater discharge.

Modifications to subsection 1304 (a)(3)(A) are new since the September 26 workshop. Modifications clarify the data being collected, make them consistent with state policy, remove data no longer needed, and insert additional data to support current Energy Commission analyses.

(B) Environmental information related to biological resources: Owners of power plants with a generating capacity of one megawatt or greater shall submit copies of reports or filings required by regulations, permit, or contract conditions that identify any of the following information for the previous calendar year:

1. documentation of the "take" and mortality and/or injury of terrestrial, avian and aquatic wildlife subject to legal protection under California Fish & G. Code § 2050 et seq., § 3511, § 4700, § 5050, § 5515, 16 U.S.C.A. § 1371 et seq., 16 U.S.C.A. § 1531 et seq., and 16 U.S.C. A. § 668 et seq., and the Migratory Bird Treaty Act 16 U.S.C.A. § 703-712 that occurred as a result of operation of the power plant.

2. documentation and identification of the biomass (by weight) and species composition of fishes and marine mammals killed by impingement on the intake screens of each once-through cooling system;

(C) Copies of any written notification provided by any state or federal regulatory agency to the owner of a power plant with a generating capacity of one megawatt or more that operation of the power plant has created a violation of an applicable statute, regulation, or permit condition related to environmental quality or public health during the previous calendar year, or that there is an ongoing investigation regarding a potential violation at the time that the data identified in this subdivision is required to be filed with the commission.

(b) Reports by UDCs. Each UDC shall report the following data for each power plant including energy storage systems ~~that has a generating capacity of 100 kilowatts or more,~~ located in the UDC's service area. The report shall be submitted on January 31 and July 31 each year, but if information for an existing plant has already been provided pursuant to this section, and is unchanged, the filing need only identify the date on which the information was previously provided.

(1) name;

(2) facility code assigned by the EIA;

(3) nameplate capacity in ~~mega~~kilowatts;

(4) voltage at which the power plant is interconnected with the UDC system or transmission grid;

(5) address where the power plant is physically located, including the street address, city, state, and zip code;

(6) power plant owner's full legal name and address of principal place of business, including the street address, city, state, and zip code;

(7) longitude and latitude, expressed to the nearest degree, if available;

~~(8) operating mode (e.g., independent power producer, cogeneration, dispatched as part of a demand side management program, parallel operation with utility deliveries in order to achieve premium power reliability, customer-dispatched to reduce delivered energy charges, peak shaving, emergency/backup/interruptible);~~

(8~~9~~) technology type (e.g., combined cycle, combustion turbine, microturbine, internal combustion engine, photovoltaic, wind turbine, fuel cell);

(9~~10~~) interconnection agreement type (e.g., interconnection agreements required by interconnection standards adopted in California Public Utilities Commission D.00-12-037 and in modifications to that decision, net energy metering agreement); ~~and~~

Staff has evaluated the continued need for interconnection agreement types and has decided to keep the previously stricken interconnection agreement subsection.

(10~~11~~) fuel type (e.g., natural gas, biogas, diesel, solar, wind.);

(11) customer-side installation (a value of "Yes" or "No" indicating if the power plant or storage system is installed behind the customers UDC owned meter);

(12) Name of electric tariff associated with the interconnection application;

Detailed information regarding the electric tariff is needed for each interconnection application to support forecasting.

(13) Date of interconnection approval;

(14) System removed (a value of "Yes" or "No" indicating if the power plant was removed during reporting period and is no longer interconnected to the utility distribution system); and

(15) Date the power plant or energy storage system was removed and is no longer interconnected to the utility distribution system.

Additional information and details about system removals have been inserted to better characterize the time frame systems are in operation.

(c) Reports by balancing authorities. Each balancing authority shall report the following data for each generation unit or storage facility interconnected to or dynamically scheduled into its balancing authority area. The report shall be submitted within 60 days of the end of each calendar quarter, but if information for an existing plant or facility has already been provided pursuant to this section, and is unchanged, the filing need only identify the date on which the information was previously provided.

(1) name;

(2) owner;

(3) identification string for the plant/unit used by the balancing authority (text string that links net output data to unit or facility);

(4)) identification number of the power plant assigned by the Energy Commission;

(5) facility code for the power plant assigned by the EIA; and

(6) hourly net output in megawatts (averaged over the hour)

Note: Authority cited: Sections 25213, 25218(e) and 25320, Public Resources Code. Reference: Sections 25005.5, 25216, 25216.5, 25300-25303, 25401, 25401.2, 25403, 25403.5, 25602 and 25604, Public Resources Code.

Section 1308 Quarterly Gas Utility and Electric Generator Tolling Agreement Reports

(a) Monthly natural gas receipts. Each gas utility shall report quarterly all natural gas received by the gas utility for each of the previous three months, expressed in thousand cubic feet or therms; and the average heat content of the natural gas received, expressed in Btu per cubic feet; each classified by all of the following:

(1) How received: purchased, transported for others, or withdrawn from storage;

(2) Where and from whom the natural gas was received, according to the following entities and locations:

(A) Pipeline locations at the California Border

1. El Paso Natural Gas at Topock

2. El Paso Natural Gas at Blythe

3. Transwestern Pipeline at Needles

4. PG&E Gas Transmission - Northwest at Malin

5. Other California Border Receipt Points (Designate)

(B) Instate locations

1. Kern River Gas Transmission/Mojave Pipeline at Kern River Station

2. Kern River Gas Transmission /Mojave Pipeline at Wheeler Ridge

3. Kern River Gas Transmission/Mojave Pipeline at Hector Road

4. PG&E at Wheeler Ridge

5. California Production at Wheeler Ridge

6. Kern River Gas Transmission at Daggett

7. Rainbow compression station

8. Dana Point compression station

9. Other interconnect points

(C) California Production

1. California onshore production received into the gas utility system

2. California offshore lands production received into the gas utility system

3. California outer continental shelf production received into the gas utility system.

(b) Monthly Natural Gas Sendout. Each gas utility shall report all natural gas delivered by the gas utility for each of the previous three months, expressed in thousand cubic feet or therms; and the average heat content of the natural gas delivered, expressed in Btu per cubic feet; each classified by all of the following:

(1) Core Customer Deliveries.

(A) Each Major Customer Sector (designate)

(B) Natural gas used to generate electricity when waste heat is used for industrial or commercial processes.

(C) Natural gas used to generate electricity when waste heat is used for industrial or commercial processes other than enhanced oil recovery.

(D) Natural gas used to generate electricity when waste heat is not used for industrial or commercial processes.

(E) Other (designate by Customer Classification code)

(2) Noncore Customer Deliveries

(A) Each Major Customer Sector (designate)

(B) Natural gas used to generate electricity when waste heat is used for industrial or commercial processes.

(C) Natural gas used to generate electricity when waste heat is used for industrial or commercial processes other than enhanced oil recovery.

(D) Natural gas used to generate electricity when waste heat is not used for industrial or commercial processes.

(E) Other (designate by Customer Classification code)

(3) Delivery to other utilities through the following delivery points:

(A) Kern River Station

(B) Wheeler Ridge

(C) Rainbow compression station

(D) Dana Point compression station

(E) Other points (designate)

(4) Delivery to Interstate Pipelines through the following delivery points:

(A) Kern River Station

(B) Wheeler Ridge

(C) Hector Road

(D) Daggett

(E) Other points (Designate)

(5) Delivery to International Pipelines

(A) Otay Mesa into Mexico

(B) Calexico into Mexico

(C) Other points (designate)

(6) For Storage Injection

(A) Gas utility-owned storage

(B) Non-gas utility-owned storage

(7) Losses and Unaccounted for

(c) Monthly Natural Gas Delivery.

(1) Each gas utility <u>with annual natural gas deliveries of less than 200 million therms in both of the two calendar years preceding the required data filing</u> shall report the number of customers, delivery revenue expressed in dollars, volume expressed in therms, ~~and natural gas average heat content expressed in Btu per cubic feet,~~ for all natural gas sold or transported by the gas utility during each of the previous three months as follows:

(A) sales to core customers, excluding cogeneration customers, by county and NAICS code;

(B) sales to core cogeneration customers by county and NAICS code;

(C) sales to noncore customers, excluding cogeneration customers, by county and NAICS code;

(D) sales to noncore cogeneration customers by county and NAICS code;

(E) transport to core customers, excluding cogeneration, by county and NAICS code;

(F) transport to core customers for cogeneration, by county and NAICS code;

(G) transport to noncore customers, excluding cogeneration, by county and NAICS code, and

(H) transport to noncore customers for cogeneration by county and NAICS code.

(2) For purposes of subdivision (c)(1) of Section 1308, revenue for both sales and transport shall be expressed in dollars, in aggregate, and shall include commodity costs and all non-commodity components of the utility's rates, including without limitation, costs of receiving, transporting, distributing, injecting to storage, recovering from storage, administration, regulatory, public purpose programs, energy market restructuring transition costs, and balancing accounts.

<u>(d) Monthly customer demand and billing data. Each gas utility with annual natural gas deliveries of 200 million therms or more in both of the two calendar years preceding the required data filing shall report delivery revenue expressed in dollars and volume expressed in therms, for all natural gas sold or transported by the gas utility during each of the previous three months as follows:</u>

<u>(1) sales to core customers, excluding cogeneration customers</u>

<u>(A) service address of account number, including the street address, city, state, and zip code;</u>

<u>(B) premise identification number</u>

<u>(C) meter identification number</u>

<u>(D) volume of natural gas delivered in therms</u>

<u>(E) monthly bill total (dollars);</u>

<u>(F) customer classification code;</u>

<u>(G) energy efficiency program participation identification; and</u>

<u>(H) building meter code</u>

<u>(2) sales to core cogeneration customers</u>

(A) service address of account number, including the street address, city, state, and zip code;

(B) premise identification number

(C) meter identification number

(D) volume of natural gas delivered in therms

(E) monthly bill total (dollars);

(F) customer classification code;

(G) energy efficiency program participation identification; and

(H) building meter code

(3) sales to noncore customers, excluding cogeneration customers

(A) service address of account number, including the street address, city, state, and zip code;

(B) premise identification number

(C) meter identification number

(D) volume of natural gas delivered in therms

(E) monthly bill total (dollars);

(F) customer classification code;

(G) energy efficiency program participation identification; and

(H) building meter code

(4) sales to noncore cogeneration customers

(A) service address of account number, including the street address, city, state, and zip code;

(B) premise identification number

(C) meter identification number

(D) volume of natural gas delivered in therms

(E) monthly bill total (dollars);

(F) customer classification code;

(G) energy efficiency program participation identification; and

(H) building meter code

(5) transport to core customers, excluding cogeneration customers

(A) service address of account number, including the street address, city, state, and zip code;

(B) premise identification number

(C) meter identification number

(D) volume of natural gas delivered in therms

(E) monthly bill total (dollars);

(F) customer classification code;

(G) energy efficiency program participation identification; and

(H) building meter code

(6) transport to core cogeneration customers

(A) service address of account number, including the street address, city, state, and zip code;

(B) premise identification number

(C) meter identification number

(D) volume of natural gas delivered in therms

(E) monthly bill total (dollars);

(F) customer classification code;

(G) energy efficiency program participation identification; and

(H) building meter code

(7) transport to noncore customers, excluding cogeneration customers

(A) service address of account number, including the street address, city, state, and zip code;

(B) premise identification number

(C) meter identification number

(D) volume of natural gas delivered in therms

(E) monthly bill total (dollars);

(F) customer classification code;

(G) energy efficiency program participation identification; and

(H) building meter code

(8) transport to noncore cogeneration customers

(A) service address of account number, including the street address, city, state, and zip code;

(B) premise identification number

(C) meter identification number

(D) volume of natural gas delivered in therms

(E) monthly bill total (dollars);

(F) customer classification code;

(G) energy efficiency program participation identification; and

(H) building meter code

(9) For purposes of subdivision (d)(1)-(8) of Section 1308, revenue for both sales and transport shall be expressed in dollars, in aggregate, and shall include commodity costs and all non-commodity components of the utility's rates, including without limitation, costs of receiving, transporting, distributing, injecting to storage, recovering from storage, administration, regulatory, public purpose programs, energy market restructuring transition costs, and balancing accounts.

(e) Monthly Pipeline Delivery Information. Each gas utility with annual natural gas deliveries of 200 million therms or more in both of the two calendar years preceding the required data filing shall, beginning March 18, 2018 report for each month during the previous quarter the following for all natural gas volumes delivered by such company to locations in California or at the California border on each distribution pipeline segment:

(1) Natural gas characteristics

(A) chemical composition

(B) specific gravity

(C) maximum mass/molar flow rate

(2) Pipeline segment characteristics

(A) monthly average and maximum inlet pressure

(B) monthly average and maximum outlet pressure

(C) monthly average and maximum flow volumes

(D) monthly any and all changes to the natural gas distribution system, including changes in length, maximum operating pressure, and pipeline characteristics.

(f~~d~~) Natural Gas Tolling Agreements. Each LSE that has entered into a tolling agreement to provide natural gas to the owner or operator of an electric generator with a capacity of 50 MW or more for the operation of that generator shall report the following for each of the previous three months and for each electric generator:

(1) amount of natural gas delivered expressed in therms;

(2) the price of the natural gas delivered pursuant to subdivision (d)(1) of this section; and

(3) the location of the delivery identified in subdivision (d)(1) of this section.

Note: Authority cited: Sections 25213, 25218(e) and 25320, Public Resources Code. Reference: Sections 25005.5, 25216, 25216.5, 25300-25303, 25401, 25401.2, 25403, 25403.5, 25602 and 25604, Public Resources Code.

Section 1382 Definitions

For the purposes of this article, the following definitions shall apply unless the Commission has clearly indicated otherwise in these regulations:

(a) “Contingency Costs”: the costs which may be paid by investors after the initial investment, but which are not paid out of project revenues. Contingency costs may include such costs as turbine repairs or annual insurance fees paid during the reporting year.

(b) “Cumulative Number of Turbines Installed”: the cumulative total number of turbines of a given model installed by the end of the reporting period.

(c) “Electricity Produced (kWh)”: the total kilowatt hours actually produced by all of the turbines of a particular turbine model contained within the wind project where the electricity is delivered to a wind power purchaser for sale during the reporting period.

(d) “Name of Wind Project”: the name used for the project in any prospectus, offering memorandum, or sales literature.

(e) “Number of Turbines Installed During Reporting Period”: the number of additional turbines installed during the calendar quarter of the reporting period.

(f) “Project Cost”: the total cost of the turbines installed during the reporting period Project cost includes all debt and equity investment in the project (including non-recourse notes) and should be comparable to the project cost shown in the offering memorandum, prospectus or sales literature published by the developer.

~~(g) “Projected Annual Production Per Turbine (kWh)”: the annual average kWh production, by model, predicted by the developer in its prospectus, offering memorandum, or sales literature. This figure may be updated periodically revised annually prior to the first reporting quarter of each year and shall be based upon actual average site specific wind distributions and the wind turbine power curves.~~

(~~h~~g) “~~Projected~~ Actual ~~Quarterly~~ Periodic Production Per Turbine (kWh)”: the ~~quarterly~~ periodic breakdown of the ~~Projected~~ Actual ~~Annual~~ Production Per Turbine, by group. The production shall be reported for each quarter for projects of nameplate capacity less than ten MW and for each month for projects of nameplate capacity ten MW or more.

Clarified required data by removing the word “Annual” for the Group Turbine production data required for reporting.

(~~i~~h) “Rotor (M^2)”: the rotor swept area in square meters for each turbine model.

(~~j~~i) “Size (kW)”: the turbine manufacturer's published kW rating and ~~at a~~ specific ~~miles per hour (mph) with~~ rated wind speed (in m/s). ~~shown in parentheses~~.

(j) “Turbine Group”: a group of turbines of the same capacity, make, and model.

(k~~j~~) “Turbine Model”: the common or manufacturer's name for the turbine if that is a commonly used term for the model of a specific rotor (M^2) and size (kW).

(l~~k~~) “Wind Power Purchaser”: any electricity utility or other entity which purchases electricity from a wind project, as defined in this section.

(m~~l~~) “Wind project”: one or more wind turbine generators installed in California with a combined rated capacity of 100 kW or more, the electricity from which is sold to another party.

(n~~m~~) “Wind Project Operator”: any developer or operator who directly receives payments for electricity from the wind power purchaser.

Note: Authority cited: Sections 25213 and 25218(e), Public Resources Code. Reference: Sections 25216.5(d), 25601(c) and 25605, Public Resources Code.

Section 1383 Reporting Period

For the purposes of this article, and unless otherwise indicated, the reporting period shall be each calendar quarter, beginning with the first quarter following the effective date of this article. Quarterly reports filed pursuant to this article shall be submitted not later than the forty-fifth day following the close of each reporting period. Reports shall be deemed submitted as of the date of postmark, emailing, or online completion, provided that the report is properly and legibly completed.

Note: Authority cited: Sections 25213 and 25218(e), Public Resources Code. Reference: Sections 25216.5(d, 25601(c) and 25605, Public Resources Code.

Section 1385 Information Requirements: Wind Project Operators

Each operator firm submitting information pursuant to the provisions of this article shall include the following:

(1) Name of wind project

(2) Name and address of operator

(3) Name and phone number of contact person at operator's firm

(4) Operator's name as shown on power purchase contract (if different than 2 above)

(5) If the operator is not at the project site, the site manager and his contact information

(~~5~~6) Name of wind power purchaser

(~~6~~7) Purchase contract number

(~~7~~8) Resource area and county

(~~8~~9) Dates of reporting period

(~~9~~10) Turbine model

(11~~0~~) Cumulative number of turbines installed

(12~~1~~) Number of turbines installed during reporting period

(13~~2~~) Rotor (M^2)

(14~~3~~) Size (kW) at stated wind speed

(15~~4~~) Project cost

(16~~5~~) Additional project contingency costs for which investors may be responsible

(17~~6~~) ~~Projected q~~Quarterly or monthly production per turbine (kWh), depending on project capacity.

(18~~7~~) ~~Projected a~~Annual production per turbine (kWh)

(19~~8~~) Electricity produced (kWh)

(20~~19~~) Turbine manufacturer's name and address

~~(20) Operator comments, if any.~~

(21) For each turbine group, whether turbine (yaw) direction is fixed in position or follows wind direction, and if fixed, direction it faces.

(22) For each turbine group, type of wind direction and wind speed sensors installed.

(23) Height above ground surface (in m) of the center of the blade hub for each turbine group. If turbines within one group are installed at different heights the heights and numbers of the turbines within each group shall be stated.

(24) Elevation of the ground surface above sea level (in m) at the geographic center of each turbine group.

(25) Average wind speed (in m/s) at the project site, along with the height above ground surface (in m) at which the speed is measured. The speed data shall be reported on the same time basis that the energy produced is reported.

(26) Statistical parameters which best characterize the wind speed distribution at the project site. For example, where the Weibull distribution fits the wind speeds at the site, the Weibull shape and scale parameters, along with the height where these apply, shall be stated. If the speed distribution parameters are not known, this shall be stated on the reporting form.

(27) Qualitative type of surface (vegetative) cover at the project site and numeric value of the parameter quantifying the surface cover (for example, the roughness length). If the value for the roughness parameter is not known, this shall be stated on the reporting form, and the qualitative type shall be stated.

(28) Operator comments, if any.

Note: Authority cited: Sections 25213 and 25218(e), Public Resources Code. Reference: Sections 25216.5(d), 25601(c) and 25605, Public Resources Code.

Corrected spelling error under item (23), "If turbines within on group…" was changed to "If turbines within one group….".

Removed Average from subdivision (23), "Average height…" was changed to "Height…."

Inserted missing text in item (26), "Statistical parameters which characterize…" was changed to "Statistical parameters which ***best*** *characterize…"*

Draft Forecasting Regulatory Language

Section 1306 LSE and UDC Reports, and Customer Classification Reports

(a) Quarterly UDC Reports.

(1) Each UDC that has experienced a peak electricity demand of less than 1000 MW in both of the two calendar years preceding the required data filing date shall report the number of customers, revenue expressed in dollars, volume expressed in kWh for all electricity sold or delivered by the UDC during each of the previous three months as follows:

(A) sales to bundled customers classified by county, retail rate class, and customer classification code; and

(B) deliveries to unbundled customers classified by county, retail rate class, and customer classification code.

(2) for purposes of complying with subdivision (a)(1) of Section 1306, the following requirements shall apply:

(A) revenue for bundled customers is the aggregation of generation and non-generation costs, and excludes city or local taxes;

(B) revenue for unbundled customers is the aggregation of all non-generation costs, and excludes city or local taxes; and

(C) retail rate class is the general level of rate class used by UDC. Any rate schedule excluded from retail rate classes shall be reported as an aggregated amount classified by county and customer classification code.

(3) each UDC shall provide an electronic file with a list of the retail rate classes provided in subdivision (a)(1) of this section, including a description of each retail rate class.

(4) Quarterly UDC Reports. Each UDC that provides distribution services for other LSEs shall report quarterly to the Commission the following information:

(A) name of each LSE;

(B) business address of each LSE; and

(C) sales of electricity, expressed in kilowatt hours, by each LSE in the UDC's service area for each month of the preceding quarter.

(b) Monthly customer demand and billing data. Each UDC that has experienced a peak electricity demand of 1000 MW or more in both of the two calendar years preceding the required data filing date, shall on a quarterly basis provide monthly electricity sold or delivered by the UDC during each of the previous three months as follows:

(1) monthly sales and bill to each bundled customer including:

(A) service address of account, including the street address, city, state, and zip code;

(B) premise identification number

(C) meter identification number

(D) volume of electricity sold in kWhs;

(E) tariff;

(F) monthly bill total (dollars);

(G) number of days in billing cycle;

(G) customer classification code;

(I) energy efficiency program participation identification;

(J) identifier for PV;

(K) identifier for PEV (registered to address, owned or leased);

(L) identifier for EVSE;

(M) date EVSE installation;

(N) identifier for ES ownership or leasing and date of installation;

(O) building meter code ; and

(P) monthly peak load (kW, day, and hour)

(2) monthly deliverables and bill to each unbundled customer including:

(A) service address of account, including the street address, city, state, and zip code;

(B) premise identification number

(C) meter identification number

(D) volume of electricity delivered in kWhs;

(E) tariff;

(F) monthly bill total (dollars);

(G) customer classification code;

(I) energy efficiency program participation identification;

(J) identifier for PV;

(K) identifier for PEV (registered to address, owned or leased);

(L) identifier for EVSE;

(M) date EVSE installation;

(N) identifier for ES ownership or leasing and date of installation;

(O) building meter code ; and

(P) monthly peak load (kW, day, and hour)

(~~b~~c) Quarterly LSE Reports. LSEs not reporting under 1306(a) or (b), shall report the following:

(1) number of customers during each of the previous three months, classified by UDC, county, and major customer sector or customer group;

(2) revenue, defined as the aggregation of all costs plus profits, received by an LSE from its end-use customers in providing generation services, and expressed in dollars during each of the previous three months, classified by UDC, county, and major customer sector or customer group; and

(3) volume expressed in kWh, for all electricity sold by the LSE during each of the previous three months, classified by UDC, county, and major customer sector or customer group.

Note: Authority cited: Sections 25213, 25218(e) and 25320, Public Resources Code. Reference: Sections 25005.5, 25216, 25216.5, 25300-25303, 25401, 25401.2, 25403, 25403.5, 25602 and 25604, Public Resources Code.

Section 1307 Gas Utility and Gas Retailer Reports and Customer Classification Reports

(a) Quarterly Gas Retailer Reports. Each gas retailer that does not report pursuant to 1308(c), shall report quarterly the following:

(1) Natural Gas Sales.

(A) monthly natural gas sales expressed in millions of therms;

(B) monthly number of customers; and

(C) monthly revenue expressed in dollars, including commodity charges, adjustments, and any other charges billed for gas sold.

(2) The information provided in subdivisions (a)(1)(A), (B), and(C) above shall be classified by county, month, and major customer sector or customer group.

(b) Gas Retailer Information to the Commission. For each gas retailer that sells natural gas to customers in the gas utility's gas service area, the gas utility shall report quarterly to the Commission:

(1) name of the gas retailer;

(2) business address of the gas retailer; and

(3) sales of natural gas, expressed in thousand cubic feet or therms, to customers in the gas utility's service area;

(c) Monthly customer demand and billing data. Each gas utility with an annual natural gas demand of 200 million therms or more in both of the two calendar years preceding the required data filing data shall on a quarterly basis provide the calendar monthly natural gas sold or transported by the utility during each of the previous three months as follows:

The intent for this section is that information will be reported by each large gas utility; therefore, the term "gas retailer" is corrected to "gas utility."

(1) Monthly sales and revenue for each customer including:

(A) service address of account, including the street address, city, state, and zip code;

(B) premise identification number

(C) meter identification number

(D) volume of natural gas sold in therms

Makes units consistent with information reported in Section 1308(c).

(E) billing rate class;

(F) monthly bill total (dollars);

Clarifies monthly bill information

Removed (G) customer classification code since it is duplicative of the NAICS information.

(G) NAICS;

(H) energy efficiency program participation identification; and

(I) building meter code

Note: Authority cited: Sections 25213, 25218(e) and 25320, Public Resources Code. Reference: Sections 25005.5, 25216, 25216.5, 25300-25303, 25401, 25401.2, 25403, 25403.5, 25602 and 25604, Public Resources Code.

Section 1343 Energy End User Data: Survey Plans, Surveys, and Reports

(a) Sector Survey Implementation Support. Each UDC that has experienced a peak electricity demand of 1000 MW or more in both the two calendar years preceding the survey implementation date, and each natural gas utility that has delivered 100 billion cubic feet of gas per year in both of the two calendar years preceding the survey implementation date shall provide energy related data and other required resources to support implementation of Commission survey data collection.

(1) The Commission shall notify utilities or UDCs of survey implementation project, including the applicable customer sector, schedule and participation requirements for the project consistent with Section 1343.

(2) UDCs shall provide supporting data and resources to the Commission, including, but not limited to, accounting records and geographic identifiers required for designing, selecting, and properly weighting the sample, 24 months of individual energy consumption for all utility accounts, load metering data as required for a given project pursuant to Public Resources Code Section 25216.5, staff resources to cooperate and coordinate recruitment and implementation of survey for identified customers, and funding in the amount determined by the Commission to be reasonably necessary to fulfill the data collection objectives of this Section.

(3) A utility or UDC shall be in compliance with this Section for the customer sector identified by the Commission if it meets the following conditions:

(A) the utility or UDC responds in writing to the Commission's notification of a survey implementation project within 60 days, agreeing to comply with the Commission's participation requirements;

(B) the utility or UDC submits to the Commission, according to the schedule described in this Section, the information and data for conducting surveys and performing subsequent analyses identified by the Executive Director as necessary to conduct the survey;

(C) the utility provides staff resources, cooperation, and coordinates with the Commission to recruit survey participants and implement survey; and

(D) the utility or UDC funds the survey in the amount determined by the Commission to be reasonably necessary to fulfill the data collection objectives of this Section.

(b~~a~~) Data Collection and Analyses Compliance Option. ~~Each UDC that has experienced a peak electricity demand of 1000 MW or more in both the two calendar years preceding the required data filing date, and each natural gas utility that has delivered 100 billion cubic feet of gas per year in both of the two calendar years preceding the required data filing date shall may complete the survey plans, surveys, and reports described in this Sections~~ ~~(c) through (f), unless exempt as described under the Compliance Option described under subsection (f).~~ In lieu of the requirements contained in subsection (a), a utility or UDC shall respond in writing to the Commission within 60 days of a survey implementation project notification. The written response shall include:

(1) a detailed alternative survey project plan in compliance with and discussing all elements identified in Section 1343 (b), (c), (d), (e), and (f).

(2) a data transfer plan detailing how all data utilized for the survey will be transferred the Commission; and

(3) a signed agreement that once submitted, the utility will work with the Commission to ensure the data is of the proper format, detail, and veracity to be integrated with the Commission survey data collection.

(4) The Commission shall approve the utility's or UDC's request to use the alternative compliance option or recommend modifications to submitted request within 30 days of its submission.

(A) the utility or UDC shall provide an updated request within 30 days of the date of delivery of the Commission's recommended modifications.

(c~~b~~) Survey Plans and Plan Approval.

(1) Submittal of Survey Plans. For each survey a utility or UDC is ~~required~~ approved to independently perform under this Section, the utility or UDC must complete and submit to the Commission a plan for conducting the survey that is consistent with subsections (c~~b~~) through (f~~e~~) of this Section. This plan is due ~~one year~~ 18 months before survey data is due under subsection (e~~d~~) and shall describe, at a minimum:

(A) the purpose, scope, and design of the survey project;

(B) the data to be collected, including all data required by subsection (c~~b~~);

(C) the methods and schedules to be followed;

(D) the format for presenting the results;

(E) the use of contractors to assist in the project;

(F) the estimated cost of the project, nature of funding source, and regulatory authority to complete the study;

(G) what confidential data will be used in the study; how confidentiality will be maintained during the conduct of the survey; any special confidentiality protection needed for types of data not explicitly addressed by Chapter 7, Article 2 of this Division;

(H) the methods, processes, and strategies the utility will use to guarantee data will be consistent with the Commission's survey implementation, enabling data integration with the larger statewide data upon delivery to the Commission; and

(I~~H~~) the means for ensuring that the data are representative of the entire end user population located within the utility distribution company service area, Commission forecasting zone, and subareas defined by the Commission. The Commission shall presume that the results are representative if the design satisfies all of the following requirements:

1. The survey is designed to achieve end-use saturation estimates accurate to within plus or minus 5 percent at a 95 percent confidence level;

2. The survey design includes methods to reduce non-response bias, including repeated contacts of non-respondents;

3. The survey design includes methods to ensure and verify that results are representative of the end user population; and

4. Survey methods (such as mail, telephone, or on-site data collection methods) are appropriate to the complexity and amount of data requested.

(2) Commission Approval of Plans. The Commission shall evaluate each survey plan in light of the requirements set forth in this Section, and shall approve any plan that meets the requirements of this Section. During this evaluation, the Commission staff may recommend improvements or amendments to enhance the value, reliability, or relevance of the survey results to energy demand forecasting and analysis. The Commission shall approve or disapprove a submitted plan, including a revised plan, within 60 days of its submission. If the Commission disapproves of a plan, it shall specify the plan's deficiencies in writing. Within 30 days of receiving survey plan disapproval, the utility or UDC shall submit to the Commission a revised plan correcting the specified deficiencies.

(3) The surveys shall be conducted in accordance with the approved survey plan. If changes to the survey plan become necessary, the utility or UDC shall notify the Commission in writing before those changes are implemented. If the Commission objects to the changes, it shall notify the utility or UDC within ten working days of its receipt of those changes. If the Commission does not respond, the amended plan will be accepted.

(d~~c~~) Data Collection Requirements. Each utility or UDC shall complete surveys of end-users in the residential, commercial, and industrial major customer sectors within its distribution service area every four years, carried out in accordance with the plan approved under subsection (c). Major customer sectors shall be defined pursuant to Section 1302 of this Chapter~~, except that NAICS code 324 may be excluded from the industrial customer sector~~. The data collected by the surveys shall include, without limitation, all of the following:

(1) For all customers:

(A) presence and characteristics of energy-using equipment;

(B) installed energy efficiency measures;

(C) building management controls, and measures designed to shift load;

(D) presence and type of any metering and telemetry equipment used to meter energy use;

(E) presence, type, and characteristics of any energy-producing equipment or fuel supply;

(F) electric and gas retailer identification or type of provider;

(G) location of the building surveyed, identified by ~~zip code~~ street address;

(H) patterns of behavior and appliance and equipment operation affecting energy use and load profiles; and

(I) building characteristics, including wall construction, foundation, number of stories, square footage of the building, and characteristics of windows.

(2) For the residential customer sector:

(A) building type (single family, multifamily, or mobile home) and vintage of building;~~,~~ and

(B) demographic characteristics of occupants, including income, primary language spoken in the home, level of educational attainment, number of persons by age group, and race or ethnic group.

(3) For the commercial building customer sector:

(A) type of business identified by industrial classification code, and

(B) occupancy profile, including number of employees and hours of operation.

(4) For the industrial major customer sector:

(A) type of industry identified by industrial classification code;

(B) number of employees;

(C) annual monetary value of shipments; and

(D) energy-using production processes used by the facility.

(5) Corollary data for all surveys:

(A) all accounting records, customer identifiers, and associated data that are necessary for analysis and development of weights to expand respondent data to the population;

(B) for interval metered accounts, ~~8760 hours of~~ interval meter energy consumption data for each sampled premise. For other accounts, twelve months of energy consumption data for each sampled premise; and

(C) for each survey where the survey plan includes a load metering element, load metering data for each metered, sampled account.

(e~~d~~) Delivery of Data and Documentation. Each utility or UDC shall provide to the Commission all data required by subsection (d~~c~~), and a Survey Methodology Report, according to the schedule below. The Survey Methodology Report shall describe the procedures that were followed for the survey, including the survey instrument, sample design, sample selection and implementation process, coding procedures, how the survey as implemented differs from the survey plan, and all other information needed for subsequent analyses of the data.

(1) Residential customer sector: on or before July 1, ~~2003~~2019, and on or before July 1 of every fourth year thereafter.

(2) Commercial building customer sector: on or before July 1, ~~2004~~2021, and on or before July 1 of every fourth year thereafter.

(3) Industrial major customer sector: On or before July 1, ~~2006~~2020, and on or before July 1 of every fourth year thereafter.

(f~~e~~) Data Analysis Reports

(1) Residential End Use and Saturation Reports. Each utility or UDC shall submit, within ~~six~~nine months after the residential sector survey data are due under subsection (e~~d~~), the following reports based on analysis of the survey data:

(A) the Residential End Use Report shall provide estimates of average energy consumption for each major end use by housing type and vintage. The estimates shall be derived from load metering, engineering or conditional demand analysis techniques, which shall be described in the report; and

(B) the Residential Saturation Report shall document the percentage of households using electricity, natural gas, or other type of energy for each appliance or end use, by housing type and vintage;

(2) Commercial Building Floor Space Stock and Saturation Reports. Each utility or UDC shall submit, within ~~six~~nine months after the commercial building sector survey data are due, the following reports based on an analysis of the survey data:

(A) the Floor Space Stock Report shall provide estimates of current year commercial building floor space stock, measured in square footage, by building type and vintage; and

(B) the Commercial Saturation Report shall document the percentage of commercial floor space using electricity, natural gas, or other type of energy for each end use, by commercial building type and vintage.

<u>(g) Utilities and UDCs in non-compliance with this Section will be subject to actions defined in Section 1353.</u>

~~(f) Data Collection and Analyses Compliance Option. In lieu of the requirements contained in subsection (b) through (e) of this Section, a utility or UDC may participate in projects identified by the Commission as satisfying the corresponding data collection and analyses elements of this Section.~~

~~(1) Participation requirements:~~

~~(A) may include a funding contribution from each utility or UDC in the amount determined by the Commission to be reasonably necessary to fulfill the data collection objectives of this Section; and~~

~~(B) shall require participating utilities or UDCs to provide certain data to the Commission, including, but not limited to, accounting records and geographic identifiers required for designing, selecting, and properly weighting the sample, individual energy consumption histories for sampled accounts, and load metering data that the Executive Director identifies as required for a given project pursuant to Public Resources Code Section 25216.5.~~

~~(2) The Commission shall notify utilities or UDCs of project participation opportunities, including the applicable customer sector, schedule and participation requirements for the project consistent with Section1343. This notification shall occur at least eighteen months before compliance is due.~~

~~(3) A utility or UDC shall be in compliance with the corresponding elements of subsections (b) through (e) of this Section for the customer sector identified by the Commission if it meets the following conditions:~~

~~(A) the utility or UDC responds in writing to the Commission's notification of a project participation opportunity within 60 days, requesting to use the compliance option. In its response, the utility or UDC shall agree to comply with the Commission's participation requirements;~~

~~(B) the utility or UDC submits to the Commission, according to the schedule described in this Section, the information and data for conducting surveys and performing subsequent analyses identified by the Executive Director as necessary to conduct the survey; and~~

~~(C) the utility or UDC transfers funding to the Commission in the amount determined by the Commission to be reasonably necessary to fulfill the data collection objectives of this Section.~~

~~(4) The Commission shall approve or disapprove the utility's or UDC's request to use the compliance option within 30 days of its submission.~~

Note: Authority cited: Sections 25213, 25218(e) and 25320, Public Resources Code. Reference: Sections 25005.5, 25216, 25216.5, 25300, 25301, 25302 and 25303, Public Resources Code.

Section 1344 Load Metering Reports

<u>(a) Hourly load data requirements specified in sections (b) – (h) shall be prepared using actual load metering data from the customer populations identified in each section. When an LSE believes submissions for any section's requirements using actual load metering data is infeasible, it shall submit a plan 180 days in advance of the due date for that section that identifies an alternative estimation technique for the forthcoming annual submission date and the process the LSE will follow to come into compliance for future submissions of the required data. An LSE's proposal to use an alternative estimation technique will be evaluated by the Commission and approval of such alternative estimation techniques shall be granted or denied within 90 days. A denial of an LSE's plan shall require that LSE to submit another plan which will be reviewed and either granted or denied within 30 days. In evaluating proposed plans the Commission may use the following criteria which each LSE's plan must include:</u>

<u>(1) LSE's metering infrastructure to support customer billing;</u>

<u>(2) feasibility of using special load research projects to overcome lack of customer interval metering systems to support customer billing;</u>

<u>(3) uncertainty introduced by use of proposed statistical or engineering methods;</u>

<u>(4) cost of implementation; and</u>

<u>(5) the preceding year's annual revenues reported to the United State's Energy Information Administration on Form 861.</u>

Added a new subsection (a) to define expectations of estimating and reporting load data for following subsections (b) through (h) in response to stakeholder comments.

(<u>b</u>~~a~~) Annual LSE Customer Load Data by Hour. Beginning March 15, ~~2008~~<u>2018</u>, and every year thereafter, each LSE that has experienced a peak electricity demand of ~~200~~<u>50</u> megawatts or more in both of the two calendar years preceding the filing date shall submit annual load data, including losses, for every hour of the previous calendar year for its customers to which it provides generation services, separated by UDC service area in accordance with the following:

~~(1) Hourly load data and analyses shall be developed and compiled from actual load metering, or using valid statistical estimating techniques when actual measurements are infeasible;~~

~~(2) Load metering shall be conducted in an accurate and reliable manner;~~

Removed subsections (1) and (2) since estimation requirements are now defined in Section 1344(a).

(1~~3~~) Hourly load data shall be delivered to the Commission in electronic form;

(c~~b~~) Annual Distribution System Load Data by Hour. Beginning March 15, ~~2008~~2018, and every year thereafter, each UDC that has experienced a peak electricity demand of ~~200~~50 megawatts or more in both of the two calendar years preceding the filing date shall submit its annual distribution system load data for every hour of the previous calendar year in accordance with the following:

~~(1) Hourly system load data and analyses shall be developed and compiled from actual load metering or from valid statistical estimating techniques when actual measurements are infeasible;~~

~~(2) Load metering shall be conducted in an accurate and reliable manner;~~

Removed subsections (1) and (2) since estimation requirements are now defined in Section 1344(a).

(1~~3~~) Hourly system load data shall be delivered to the Commission in electronic form;

(2~~4~~) Three sets of h~~H~~ourly loads shall be submitted~~ in two formats~~: (1) the aggregated hourly customer loads, (2) the composite of ~~the~~ aggregated customer hourly loads and ~~(the composite of customer loads plus~~hourly distribution losses~~)~~ for all LSEs supplying electricity in the UDC's distribution service area, and (3~~2~~) ~~format (1) expanded to include~~ hourly distribution system losses plus transmission losses for each hour.

Updated subsection (4)(1) to specify aggregated hourly customer loads and (4)(2) to specify aggregated customer hourly loads in order to clarify the level of hourly data needed as suggested in stakeholder discussions.

(d~~c~~) Hourly Load Estimates by Customer Sector as defined in Section 1302. Beginning ~~September 1, 2007~~March 15, 2018, and every year thereafter, each UDC that has experienced a peak electricity demand of ~~1000~~ 200 megawatts or more in both of the two calendar years preceding the filing date shall submit its hourly sector load estimates by customer sector for the previous calendar year in accordance with the following:

(1) The hourly sector load estimates shall, at a minimum, include identification of each of the following components:

(A) residential customer sector;

(B) commercial customer sector (including commercial building customer sector and ~~other commercial~~ transportation, communications, and utilities customer sector);

(C) industry customer sector and other industry customer sector~~)~~;

(D) agriculture customer sector;

(E) water pumping customer sector;

(F) street lighting customer sector;

(G) unclassified customer sector; and

(H) losses.

(2) The samples used to develop hourly load estimates for each sector shall be designed to insure that estimates are accurate to within +10 percent of the monthly sector load coincident with system peak, and with 90 percent confidence.

(3) The hourly sector load estimates shall be delivered to the Commission in electronic form.

Updated customer classification references to match with Section 1302 definitions as identified in stakeholder discussions.

(e~~d~~) Monthly Distribution System Load Data by Hour. Beginning March 15, ~~2008~~2018, and every month thereafter, each UDC that has experienced a peak electricity demand of 2000 megawatts or more in both of the two calendar years preceding the filing date shall submit its distribution system load data for every hour of the previous month in accordance with the following:

~~(1) Hourly system load data and analyses shall be developed and compiled from actual load metering or from valid statistical estimating techniques when actual measurements are infeasible;~~

~~(2) Load metering shall be conducted in an accurate and reliable manner;~~

Removed subsections (1) and (2) since estimation requirements are now defined in Section 1344(a).

(1~~3~~) Hourly system load data shall be delivered to the Commission in electronic form;

(2~~4~~) Hourly loads shall include all distribution and transmission system losses.

(f~~e~~) Annual Electric Transmission System ~~Peak~~ Load Data by hour and subarea. Beginning June 1, ~~2008~~2018, and every year thereafter, each Electric Transmission System Owner that has experienced a peak electricity demand of 2000 megawatts or more in both of the two calendar years immediately preceding the filing date shall submit its hourly load data by subarea for every hour of the previous calendar year, verifying the total load of the transmission owner is equal to the sum of all reported subareas and in accordance with the following:

~~(1) Hourly load data and analyses shall be developed and compiled from actual load metering or from valid statistical estimating techniques when actual measurements are infeasible;~~

~~(2) Load metering shall be conducted in an accurate and reliable manner;~~

Removed subsections (1) and (2) since estimation requirements are now defined in Section 1344(a).

(1~~3~~) Hourly load data shall be delivered to the Commission in electronic form;

(2~~4~~) An electronic file containing geographic identifiers of the subarea shall be included;

(3~~5~~) Subareas are climate zones or geographic subdivisions of the transmission system area, specified by the Commission ~~used by the transmission system owner for transmission system expansion plan studies, including studies of local deliverability of load, prepared for the control area operator or governing body~~.

(g) Hourly Load Estimates by Load Modifier and Subareas. Beginning March 15, 2018, and every year thereafter, each UDC that has experienced a peak electricity demand of 200 megawatts or more for any two sequential calendar years beginning with 2013 shall submit hourly load estimates by load modifier and subarea for the previous calendar year when the installed capacity of each load modifier as reported in Section 1304(b) exceeds one percent of the UDC's peak load for that year in accordance with the following:

Set a threshold for reporting of UDC's whose installed capacity exceeds one percent of the UDC's annual peak load in response to stakeholder comments.

(1) hourly estimates shall be delivered to the Commission in electronic form;

(2) the hourly behind-the-meter load estimates by load modifier shall, at a minimum, include identification of each of the following components:

(A) behind-the-meter generation by technology, including but not limited to photovoltaic, wind, and fuel cell;

(B) charging and discharging from energy storage systems using onsite generation to charge energy storage device by customer sector segregated by units operated in response to retail utility tariffs versus units dispatched by aggregator for benefit of electric system;

(C) charging and discharging from energy storage systems using the grid to charge energy storage device by customer sector segregated by units operated in response to retail utility tariffs versus units dispatched by aggregator for benefit of electric system; and

(D) light-duty plug-in onroad electric vehicle, including disaggregation by vehicle type (for example, full battery electric and plug-in hybrid electric), tariff, and metering details;

(3) An electronic file containing geographic identifiers of the subarea shall be included;

(4) Subareas are climate zones or geographic subdivisions of the transmission system areas specified by the Energy Commission.

(h) Load for Networked Electric Vehicle Supply Equipment. Beginning March 15, 2018, and every year thereafter, networked EVSE provider will be required to provide, or authorize access to, the following information to the Energy Commission:

(1) The service provider of electric vehicle service equipment at an electric vehicle charging station or its designee shall disclose the following when the station is commissioned or when any changes occur to any item identified:

(A) station identifier;

(B) station_name;

(C) street_address;

(D) city;

(E) state;

(F) zip;

(G) geocode status;

(H) latitude;

(I) longitude;

(J) geocoding notes;

(K) number of level 1 chargers and connectors per charger;

(L) number of level 2 chargers and connectors per charger;

(M) number of DC Fast Chargers;

(N) number and type of non-SAE J1772 plugs;

(O) type of available connectors at station;

(P) name(s) of EVSE manufacturer;

(Q) name(s) of EVSE network, if applicable;

(R) EVSE network website(s), if applicable;

(S) general information about each charging station including kilowatts, volts, and amps;

(T) identification if wireless charging if available;

(U) pricing structure, if applicable;

(V) type of on-site renewable power generation, if applicable;

(W) date station was available to charge vehicles;

(X) for planned stations, the data the station is expected to be available for charging;

(Y) hours of operation;

(Z) type of organization that owns infrastructure;

(AA) description of who is allowed to access the station (e.g. public, fleet, key card);

(BB) the start date when the reported station location data is commissioned or is planned for commissioning; and

(CC) the end date for the reported station location data (if station is closed).

(2) If any changes are made to the information identified in Section (g)(1) during the course of a single year multiple submittals shall be provided and the start and end dates of the year shall be specified to identify the portion of the year the data associated with the current status of the station.

(3) Networked electric vehicle charging station status, operational, and billing information shall be provided to the Energy Commission as frequently as is possible for the electric vehicle station equipment or at least daily. When available through a

standardized application program interface, the Energy Commission will be provided access at the discretion of the Energy Commission.

(4) For each identified networked electric vehicle supply equipment at a site address the following information shall be provided to the Energy Commission for each charging session:

(A) hourly consumption

(B) hourly peak load

(C) charging start time

(D) charging duration

(E) maximum charging rate

(5) For each identified electric vehicle supply equipment site address the hourly combined peak of all charging session shall be provided for each hour of the year.

Modified the language to clarify the obligated parties responsible for reporting are networked EVSE providers not owners, operators, or utilities unless an EVSE owner, operator, or utility is considered a networked EVSE provider under the definition in Section 1302. Data identified in this subsection leverages currently collected by network providers.

(i) Interval Metered Customer Energy Consumption. Beginning March 15, 2018, and every year thereafter, each UDC that has experienced a peak electricity demand of 1,000 megawatts or more in both of the two calendar years preceding the filing date shall submit customer interval meter data and loads for the previous calendar year in accordance with the following:

(1) interval meter data shall be provided consistent with customer level data submitted pursuant to Section 1306 (b) where interval meters are installed and interval data is collected;

(2) data submitted shall include peak interval load for each interval, total consumption over interval, interval period of time, and account and billing data specified by the Energy Commission;

(3) information shall be provided explaining any methods used to resolve issues related to data quality, missing data, and misread data; and

(4) data submitted will comply with reporting requirements detailed in Section 1342.

Note: Authority cited: Sections 25213, 25218(e) and 25320, Public Resources Code. Reference: Sections 25005.5, 25216, 25216.5, 25300, 25301, 25302 and 25303, Public Resources Code.

Section 1353 Failure to Provide Information

The Commission may, after notifying any person of the failure to provide information pursuant to Sections 1301-1352 and allowing 30 days to provide required information, take such action to secure the information as is authorized by any provision of law, including, but not limited to, Public Resources Code Section 25321.

Note: Authority cited: Sections 25213 and 25218(e), Public Resources Code. Reference: Section 25321, Public Resources Code.

Inserted a 30-day period of time to comply with required information after obligated parties are notified of failure to comply with data submissions as suggested by stakeholder comments. The specific language added is: "and allowing 30 days to provide required information."

Draft Security and Confidentiality Regulatory Language

Section 2505 Designation of Confidential Records

(a) Third Parties.

(1) Any private third party giving custody or ownership of a record to the Commission shall specify if it should be designated a confidential record and not publicly disclosed. An application for confidential designation shall:

(A) be on a sheet or sheets separate from, but attached to, the record;

(B) specifically indicate those parts of the record that should be kept confidential;

(C) state the length of time the record should be kept confidential, and justification for the length of time;

(D) cite and discuss the provisions of the Public Records Act or other law that allow the Commission to keep the record confidential. If the applicant believes that the record should not be disclosed because it contains trade secrets or its disclosure would otherwise cause loss of a competitive advantage, the application shall also state the specific nature of that advantage and how it would be lost, including the value of the information to the applicant, and the ease or difficulty with which the information could be legitimately acquired or duplicated by others;

(E) state whether the information may be disclosed if it is aggregated with other information or masked to conceal certain portions, and if so the degree of aggregation or masking required. If the information cannot be disclosed even if aggregated or masked, the application shall justify why it cannot;

(F) state how the information is kept confidential by the applicant and whether it has ever been disclosed to a person other than an employee of the applicant, and if so under what circumstances;

(G) contain the following certification executed by the person primarily responsible for preparing the application:

1. "I certify under penalty of perjury that the information contained in this application for confidential designation is true, correct, and complete to the best of my knowledge," and

2. State whether the applicant is a company, firm, partnership, trust, corporation, or other business entity, or an organization or association, and

3. State that the person preparing the request is authorized to make the application and certification on behalf of the entity, organization, or association.

(H) If the record contains information that the applicant has received from another party who has demanded or requested that the applicant maintain the confidentiality of the information, the applicant shall address the items in (B) through (F) of this subsection to the greatest extent possible and shall explain the demand or request made by the original party and the reasons expressed by the original party. If the basis of an application for confidential designation is an order or decision of another public agency pursuant to the Public Records Act or the Freedom of Information Act, the application shall include only a copy of the decision or order and an explanation of its applicability. The Executive Director shall consult with that agency before issuing a determination.

(2) A deficient or incomplete application shall be returned to the applicant with a statement of its defects. The record or records for which confidentiality was requested shall not be disclosed for fourteen days after return of the application to allow a new application to be submitted except as provided in Section 2507 of this Article.

(3) Executive Director's Determination.

(A) The Executive Director shall, after consulting with the Chief Counsel, determine if an application for confidential designation should be granted. An application shall be granted if the applicant makes a reasonable claim that the Public Records Act or other provision of law authorizes the Commission to keep the record confidential. The Executive Director's determination shall be in writing and shall be issued no later than thirty days after receipt of a complete application. The Executive Director or the Chief Counsel may, within fourteen days after receipt of an application for confidential designation, require the applicant to submit any information that is missing from the application. If the missing information is not submitted within fourteen days of receipt of the request by the Executive Director or Chief Counsel, the Executive Director may deny the application.

(B) If an application is denied by the Executive Director, the applicant shall have fourteen days to request that the Commission determine the confidentiality of the record. If the applicant makes such a request, the Commission shall conduct a proceeding pursuant to the provisions of Section 2508.

(C) After an application has been denied, the information sought to be designated confidential shall not be available for inspection or copying for a period of fourteen days, except as provided in Section 2507 of this Article.

(4) Repeated Applications for Confidential Designation. If an applicant is seeking a confidential designation for information that is substantially similar to information that was previously deemed confidential by the Commission pursuant to Section 2508, or for which an application for confidential designation was granted by the Executive Director pursuant to subdivision (a)(3)(A) of this section, the new application need contain only a certification, executed under penalty of perjury, stating that the information submitted is substantially similar to the previously submitted information and that all the facts and circumstances relevant to confidentiality remain unchanged. An application meeting these criteria will be approved.

(5) Automatic Designation. Information submitted by a private third party shall be designated confidential without an application for confidentiality if the requirements of subsections (a)(5)(A) and (B) of this Section are met. If the requirements of subsection (a)(5)(A) and (B) are not met, the Executive Director shall inform the private third party that the record will not be deemed confidential. Except as provided in Section 2507 of this Article, the record for which confidentiality was requested shall not be disclosed for fourteen days to allow the requirements of subsection (a)(5)(A) and (B) to be met or to allow the filing of an application pursuant to subsection (a)(1) of this section.

(A) The entity submitting the information shall label each individual item of the submittal that is entitled to be designated confidential.

(B) The entity submitting the information shall attest under penalty of perjury that the information submitted has not been previously released and that it falls within one of the following categories:

1. Information that is derived from energy consumption metering, energy load metering research projects, or energy surveys provided pursuant to Section 1343 or 1344 of Article 2 of Chapter 3, and that is one or more of the following:

a. for the residential customer sector and the commercial customer sector - customer identifiers, energy consumption, and any other information that could allow a third party to uniquely identify a specific respondent;

b. industrial major customer sector - all information;

c. survey design information - all information used to design a survey, stratify billing records, devise a sample scheme, select a sample, sample specific end-users for participation in a survey or a pre-test of a questionnaire or interview form.

2. Energy sales data provided pursuant to Section 1306, 1307, or 1308(c) of Article 1 of Chapter 3, if the data is at the greatest level of disaggregation required therein.

3. Information submitted by each LSE that is not a UDC that consists of:

a. Load forecasts and supporting customer projections by UDC distribution service area submitted pursuant to subdivision (b) of Section 1345 of Article 2 of Chapter 3.

b. Retail electricity price forecasts submitted pursuant to subdivision (a) of Section 1348 of Article 2 of Chapter 3.

4. Fuel cost data provided for individual electric generators under Section 1304 and fuel price data provided pursuant to subdivision (d) of Section 1308 of Article 1 of Chapter 3.

5. Records of Native American graves, cemeteries, and sacred places maintained by the Native American Heritage Commission.

6. Electric power plant-specific hourly generation data.

7. Electric power plant name, nameplate capacity, voltage at which the power plant is interconnected with a UDC system or transmission grid, address where the power plant is physically located, power plant owner's full legal name and address or longitude and latitude, if power plant is privately owned and its identity as a power plant is not public knowledge, (e.g., backup generator or solar installation at residence or business) under Section 1304 of Article 1 of Chapter 3.

8. Information the release of which is prohibited pursuant to the Information Practices Act (Civil Code Section 1798 et seq.)

<u>9. Natural gas delivery information provided for individual pipeline segments and natural gas characteristics pursuant to subdivision (e) of Section 1308 of Article 1 of Chapter 3.</u>

(6) Failure to request confidentiality at the time a record is submitted to the Commission does not waive the right to request confidentiality later; however, once

a record has been released to the public, the record can no longer be deemed confidential. Although a record designated as confidential shall remain confidential during the application and appeal process, subject to the provisions of Section 2507(b) of this Article, the application itself is a public document and can be released.

(b) Governmental Entities. When another federal, state, regional, or local agency or state-created private entity, such as the California Independent System Operator, possesses information pertinent to the responsibilities of the Commission that has been designated by that agency as confidential under the Public Records Act, or the Freedom of Information Act, the Commission, the Executive Director, or the Chief Counsel may request, and the agency shall submit the information to the Commission without an application for confidential designation. The Commission shall designate this information confidential.

(c) Commission Generated Information

(1) The Executive Director in consultation with the Chief Counsel, may designate information generated by Commission staff as confidential under the Public Records Act. A confidential designation made in this manner shall be summarized in the agenda for the next Commission Business Meeting. Any private third party or public entity may request to inspect or copy these confidential records by filing a petition pursuant to Section 2506 of this Article.

(2) Contracts and Proposals

(A) Information received by the Commission in response to a solicitation shall be kept confidential by the Commission and its evaluators before posting of the notice of the proposed award. The solicitation document shall specify what confidential information the proposal may contain and how that confidential information will be handled after the posting of the notice of the proposed award.

(B) The Executive Director, in consultation with the Chief Counsel, may designate certain information submitted under a contract as confidential in accordance with the Public Records Act or other provisions of law. The designation and its basis shall be in writing and contained in the contract governing the submittal of the information or in a separate statement. The contract or written statement shall also state exactly what information shall be designated confidential, how long it shall remain confidential, the procedures for handling the information, and all other matters pertinent to the confidential designation of the information.

(3) All data generated by the Commission that is the same type as the data described in Section 2505(a)(5)(B) of this Article shall be kept confidential by the Commission.

(d) All documents designated confidential pursuant to this Section shall be treated as confidential by the Commission except as provided in Section 2507.

(e) Every three months, the Executive Director shall prepare a list of data designated confidential pursuant to this Section during the previous three months. The Executive Director shall give the list to each Commissioner. The list shall also be made available to the public upon request.

Note: Authority cited: Sections 25213 and 25218(e), Public Resources Code; and Section 6253(a), Government Code. Reference: Sections 25223, 25322, 25364 and 25366, Public Resources Code; and Bakersfield City School District v. Superior Court (2004) 118 Cal.App.4th 1041.