Item 6

NOTICE OF COMMISSION ADOPTION OF PROPOSED ADDITIONS TO AND MODIFICATIONS OF REGULATIONS GOVERNING DATA COLLECTION AND DESIGNATION OF CONFIDENTIAL INFORMATION

AND

NOTICE OF AVAILABILITY OF 15-DAY LANGUAGE AND ADDENDUM TO THE INITITAL STATEMENT OF REASONS

California Code of Regulations

Title 20, Division 2

Chapter 3, Article 1, Sections 1302, 1304, 1306, 1308, & 1314

Chapter 3, Article 2, Sections 1344 & 1353

Chapter 7, Article 2, Section 2505

California Energy Commission
Docket No. 16-OIR-03
January 26, 2018

INTRODUCTION

Summary: The California Energy Commission (Energy Commission) will hold a public hearing for consideration and possible adoption of proposed additions to and modifications of regulations governing data collection and designation of confidential information on ***February 21, 2018***. The regulations proposed to be adopted incorporate changes to originally-proposed text published on August 4, 2107. In addition, the Energy Commission has added to the rulemaking record an addendum to its Initial Statement of Reasons (ISOR) to reflect changes to its estimates of economic and fiscal impacts.

Procedural History: On August 4, 2017, the Energy Commission docketed, posted, and mailed a Notice of Proposed Action (NOPA) identifying proposed additions to and modifications of the Energy Commission's regulations governing data collection and the designation of confidential information. The changes fall into three categories: 1) collection of individual customer data and other information about activities that affect electric loads, including photovoltaic generation, energy storage, utilization of electric vehicles, and natural gas consumption; 2) collection of data needed to perform hydraulic modeling of the natural gas system; and 3) minor clarifications and corrections, including the automatic designation of customer level data as confidential. The Energy Commission also published the Express Terms and the ISOR. After the receipt of comments on the originally-proposed text, the Energy Commission issued a notice of postponement to consider whether additional changes to the regulations were required.

The Energy Commission has since determined that several minor revisions to the originally-proposed text are necessary to respond to market participant concerns and to clarify language. These revisions are sufficiently related to the originally-proposed text that the public was placed on notice that they could result from the originally proposed regulatory action. The Energy Commission invites the public to review and comment on these revisions. They are summarized below and identified in the 15-day language attached to this notice (Attachment A). Additionally, the Energy Commission prepared an addendum to the ISOR to reflect needed changes in its assessment of economic and fiscal costs as a result of these revisions. The 15-day language and the addendum are available on the Energy Commission website at http://www.energy.ca.gov/sb350/energydata/

The public may also request copies of the 15-day language and the addendum by contacting Malachi Weng-Gutierrez at malachi.weng-gutierrez@energy.ca.gov or (916) 654-4588. Additionally, the Energy Commission has available all the information upon which the proposed regulations – including the revisions -- are based at the website listed above. For those without internet access, copies or assistance can be obtained by contacting Malachi Weng-Gutierrez at malachi.weng-gutierrez@energy.ca.gov or (916) 654-4588. The Energy Commission also has the entire rulemaking file available for inspection and copying throughout the rulemaking process at its office at 1516 9th Street, Sacramento, CA 95814.

Background: The Energy Commission is charged with preparing assessments and forecasts to achieve a series of public policy goals, including the efficient and reliable operation of the state's electrical grid, and to track progress in meeting the state's ambitious greenhouse gas emissions reduction goals. To prepare these assessments and forecasts, the Legislature has provided the Energy Commission with expansive authority to collect energy-related information from all market participants. The Energy Commission first adopted data collection regulations in the 1970s and has amended them several times to reflect changed market structures and statutory mandates. This rulemaking addresses information needed to evaluate the operation of the natural gas system in the state, information needed to better understand the effect of changes in the generation and consumption of electricity, as well as minor clarifications in the existing language of the data collection regulations.

PROPOSED 15-DAY LANGUAGE

The changes identified in the 15-day language include:

- *Non-substantial grammatical corrections*

  A comma is added to subdivision (b)(18) of Section 1302; in subdivision (a)(2)(A)(5) of Section 1308, the word "pipeline" is capitalized; and in subdivision (b)(1)(K) of Section 1353, the word "is" is changed to "are."

- *Modifications to subdivision (b) of Section 1304 to re-organize existing and proposed reporting requirements for interconnected power plants and energy storage systems*

  The originally-proposed text combined all reporting requirements for power plants and energy storage systems in subdivision (b). The proposed modifications delineate the reporting requirements by type of device (power plant and energy storage systems) and by size of power plant.

- *Clarification of the proposed language in proposed Section 1314*

  Conversations with the gas utilities about the proposed terms and definitions allowed the Energy Commission to refine the language identifying the natural gas hydraulic modeling data to be provided. In addition, language is added to ensure that the Energy Commission receives all data used for gas modeling in 2018 as well as that used after the effective date of the new regulation.

- *Modification of the proposed language in subdivision (f) of Section 1344*

  Conversations with the utility distribution companies (UDCs) about the proposed terms and definitions allowed the Energy Commission to refine the language identifying the load impact research information to be provided. In addition, language is added to ensure that the Energy Commission receives a summary of all load research data used in 2018 as well as that used after the effective date of the new regulation.

- *Changes in timing and type of information required under proposed Section 1353*

  In response to UDC concerns about the readiness of the Energy Commission to receive certain datasets, the Energy Commission now proposes to modify Section 1353(b) to defer the reporting by the 5 largest UDCs of detailed usage information for electric customers until 2019, at which point the UDCs would provide the information going forwards and for 2018. As a result, subdivision (b)(2) now provides that all information except the usage information of customers with interval meters would be provided beginning in 2018 and that in 2019, the detailed usage information would be provided for 2018 and going forwards. Subdivisions (b)(1), (b)(3), and (c) are also modified to ensure that the Energy Commission received the more detailed information identified in those subdivisions for all of 2018.

- *Changes in the dates on which customer data is to be provided to the Energy Commission pursuant to Sections 1306, 1308.*

  The originally-proposed text in Section 1353 identified 2018 as the year in which the 5 largest UDCs and 2 largest gas utilities would begin providing quarterly filings of detailed electric and gas customer data. Sections 1306 and 1308, which identify a lower level detail for electric and gas customers respectively and are applicable to all gas utilities and UDCs, were originally proposed to be modified to eliminate the reporting requirements for the 5 large UDCs and 2 large gas utilities reporting under 1353 after one year of reporting under both sections. This year of overlap allows the Energy Commission to ensure consistency between the datasets created with 1306 information and 1308 information, and the new datasets created with the electric and gas data collected pursuant to Section 1353. However, the Energy Commission has determined that one year of overlap may be insufficient and that two full calendar years of data is required to ensure consistency. As a result, the date that utilities subject to Section 1353 no longer need to report to the Energy Commission pursuant to Sections 1306 and 1308 is changed from after January 1, 2019 to after February 15, 2020.

MODIFICATION TO ECONOMIC IMPACT ASSESSMENT

As a result of revisions to the proposed regulations, reporting under the amendments adopted in this rulemaking in fiscal year 2017/2018 will not occur as originally anticipated. The Economic Impact Assessment has been updated to reflect the fact that reporting will begin in fiscal year 2018/2019, including all start-up costs, and costs in fiscal year 2020/2021 have been added to ensure that cost estimates are included for the first three years of implementation. The updated document also corrects errors made in transposing cost numbers from a spreadsheet to the Economic Impact Assessment.

The specific elements required to be included in the Economic Impact Assessment pursuant to subdivision (b)(1)(A)-(D) of Gov. Code section 11346.3 are addressed at the end of the discussion of each section and subsection in the Economic Assessment. The Commission's assessment of these elements has not changed as a result of the updates to the Economic Impact Assessment.

All changes are noted using underline and strikeout format. The addendum to the ISOR has been docketed and is part of the record of the rulemaking proceeding. Information about reviewing or obtaining a copy of the addendum can be found in the Introduction section of this Notice.

PUBLIC HEARING

The Energy Commission will consider adopting the proposed regulations during its regularly scheduled business meeting on:

February 21, 2018
10:00 a.m.
California Energy Commission
1516 Ninth Street
Art Rosenfeld Hearing Room
Sacramento, California
(Wheelchair accessible)

Remote Access Available by Computer or Phone via WebEx™

Instructions for accessing Energy Commission hearings using either method can be found at: http://www.energy.ca.gov/webcast/index.html. If you have a disability and require assistance to participate in these hearings, please contact Poneh Jones at (916) 654-4425 or by email at poneh.jones@energy.ca.gov at least 5 days in advance.

PUBLIC COMMENT

Any interested person may submit written comments on the proposed changes. The written comment period for the 15-day language and the addendum to the ISOR will be from ***January 27, 2018 through February 12, 2018***.

Please submit comments using the Energy Commission's e-commenting feature by going to the Energy Commission website at http://www.energy.ca.gov/sb350/energydata/index.html and clicking "Submit comment." Your name, email address, comment title, and either a comment or an attached document (.doc, .docx, or .pdf format) will be required. After a challenge-response test to ensure that responses are generated by a human user and not a computer, click the "Agree & Submit Your Comment" button to submit the comment to the Energy Commission's Docket Unit. Please note that written comments, attachments, and associated contact information included within the written comments and attachments, (e.g., your name and contact information) become part of the viewable public record. If you are unable to submit your comments through the docket system, you may send a paper copy of your comments to:

California Energy Commission

Docket No. 16-OIR-03

Docket Unit

1516 Ninth Street, MS-4

Sacramento, CA 95814-5504

Or email them to: DOCKET@energy.ca.gov

The Energy Commission will also accept oral comments during the hearing on February 21, 2018. Comments may be limited to three minutes per speaker. All comments will become part of the public record of this proceeding.

PUBLIC ADVISER AND OTHER COMMISSION CONTACTS

The Energy Commission's Public Adviser's Office is available to assist any person who wishes to participate in this proceeding. If you want information on how to participate in this proceeding, please contact the Public Adviser, Alana Mathews, at PublicAdviser@energy.ca.gov or (916) 654-4489, or toll-free in California at (800) 822-6228.

News media inquiries should be directed to the Media and Public Communications Office at (916) 654-4989, or by email at mediaoffice@energy.ca.gov.

If you have questions on the subject matter of this proceeding, please contact Malachi Weng-Gutierrez at malachi.weng-gutierrez@energy.ca.gov or (916) 654-4588. If you have legal questions about this proceeding, please contact Caryn Holmes at caryn.holmes@energy.ca.gov or at (916) 654-4178.

NOTICE OF EXTENSION OF PUBLIC COMMENT PERIOD FOR 15-DAY LANGUAGE AND ISOR ADDENDUM TO FEBRUARY 13, 2018

PROPOSED ADDITIONS TO AND MODIFICATIONS OF REGULATIONS GOVERNING DATA COLLECTION AND DESIGNATION OF CONFIDENTIAL INFORMATION

California Energy Commission
Docket No. 16-OIR-03
January 29, 2018

California Code of Regulations

Title 20, Division 2

Chapter 3, Article 1, Sections 1302, 1304, 1306, 1308, & 1314

Chapter 3, Article 2, Sections 1344 & 1353

Chapter 7, Article 2, Section 2505

On January 26, 2018, the Energy Commission posted the *Notice of Commission Adoption of Proposed Additions to and Modifications of Regulations Governing Data Collection and Designation of Confidential Information and Notice of Availability of 15-Day Language and Addendum to the Initial Statement of Reasons* (Notice), 15-Day Express Terms for the Data Collection Rulemaking (15-Day Language), and ISOR Addendum and Revised Attachment A (ISOR Addendum) to the website for this proceeding. The Energy Commission also emailed the Notice to the persons specified in Gov. Code section 11347.1 and section 44 of Title 1 of the California Code of Regulations; however, the 15-Day Language was inadvertently omitted from that mailing.

Therefore, the written comment period for the 15-Day language and the ISOR Addendum that was identified in the Notice is hereby extended to: ***February 13, 2018***.

The 15-Day Language is available here:
http://docketpublic.energy.ca.gov/PublicDocuments/16-OIR-03/TN222370-3_20180126T112509_15day_Express_Terms_Data_Collection_Rulemaking.pdf

The ISOR Addendum is available here:
http://docketpublic.energy.ca.gov/PublicDocuments/16-OIR-03/TN222370-1_20180126T112508_ISOR_Addendum_and_Revised_Attachment_A.pdf

The date for proposed adoption of the proposed regulations is unchanged, and remains February 21, 2018.

EXPRESS TERMS

California Code of Regulations

Title 20. Public Utilities and Energy

Division 2. State Energy Resources Conservation and Development Commission

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CHAPTER 3. DATA COLLECTION

Major changes in Chapter 3 include the expansion of data collection in Sections 1304, 1308, 1314, 1344, and 1353. These changes augment the current data collection requirements, clarifying many of the data needs and introduce two new subdivisions requiring gas hydraulic modeling and customer-level data.

Article 1. Quarterly Fuel and Energy Reports

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 <u>output</u> ~~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 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 11331, 31-33, 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 11331), 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) “Energy storage system” means commercially available technology that is capable of absorbing energy, storing, and dispatching the energy.

(19~~8~~) “Executive Director” means the Executive Director of the Commission, or his or her designee.

(20~~19~~) “Fuel cost” means the delivered cost of fuel consumed by an electric generator, expressed in dollars.

(21~~0~~) “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.

(22~~1~~) “Gas processor” means any company that extracts, in California, natural gas liquids from natural gas produced from California reservoirs.

(23~~2~~) “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.

(24~~3~~) “Gas service area” means the geographic area where a gas utility distributes, or has distributed during an applicable reporting period, natural gas to customers.

(25~~4~~) “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.

(26~~5~~) “Generation service” means those services provided by an LSE when it procures electrical energy for consumption by its end-user customers.

(27~~6~~) “Gross generation” means the total amount of electricity produced by an electric generator.

(28~~7~~) “Hourly demand” means demand integrated over a single clock hour, measured in megawatt hours.

(29~~8~~) “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.

(30~~29~~) “Hourly sector load” means the hourly load of customer sectors measured at customer meters. Hourly sector data does not include losses.

(31~~0~~) “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.

(32~~1~~) “Interchange” means electric power or energy that flows from one control area to another control area.

(33~~2~~) “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.

(34~~3~~) “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.

(35) “Interval meter” means any energy meter capable of collecting and transmitting demand data at intervals of an hour or less.

(36) ”Interval meter data” means demand data collected and transmitted by interval meter.

(37~~4~~) “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.

(38~~5~~) “Local publicly-owned electric utility” or “local publicly owned electric utility” has the same definition as provided in Public Utilities Code section 9604.

(39~~6~~) “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.

(40~~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.

(41) "Meter identification number" means the unique number assigned by a utility to an individual meter for purposes of tracking demand and providing billing services.

(42~~38~~) "Monthly system peak demand" means the highest system hourly demand in a calendar month.

(43~~9~~) "Nameplate capacity" means the full-load continuous rating of an electric generator or a power plant under specific conditions as designated by the manufacturer.

(44~~0~~) "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.

(45~~1~~) "Natural gas sales" means the amount of natural gas sold by a Gas Retailer to a customer.

(46~~2~~) "Net generation" means gross generation less plant use by an electric generator for auxiliary equipment.

(47~~3~~) "Noncore customer" means a natural gas customer that is not a core customer.

(48~~4~~) "North American Industry Classification System" or "NAICS" means the system of classification for business establishments set forth in the most recent version of 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 thereafter in the Federal Register ~~for 2007 pursuant to 71 Fed. Reg. 28532 (May 16, 2006)~~.

(49~~5~~) "NAICS Code" means the applicable 6-digit (unless otherwise specified) code in the NAICS for the entity being classified.

(50~~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.

(51~~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.

(52~~48~~) “Person” means an individual human being.

(53~~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.

(54~~0~~) “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.

(55~~1~~) “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.

(56) “Premise identification number” means the unique identification number assigned by a utility to a collection of buildings and/or meters serving an individual customer at a contiguous location.

(57~~2~~) “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.

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

(59) “Rate schedule” means the alphanumeric designation for the utility service customer agreement including all service rates and charges and all classifications, practices, rules, or regulations which in any manner affect or relate to the utility services, rates, and charges.

(60) “Secure electronic method” means any method of data transmission that uses end-to-end encryption such that information is encrypted at its origin and decrypted at its intended destination without intermediate decryption.

(61) “Service account number” means the unique identification number assigned by a utility to an account to track demand and provide billing services.

(62~~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.

(63~~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.

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

(<u>6</u>5~~5~~) “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.

<u>(66) “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.</u>

(<u>67</u>~~56~~) “Utility distribution company” or “UDC” means an electric utility, or a business unit of an electric utility, that distributes electricity to customers.

<u>(68) “Waste heat” means the thermal energy produced during electrical generation but not utilized for a useful purpose as defined in “useful thermal output,” i.e., the total heat content of the fuel used to generate electricity minus the energy content of the useful thermal output and electricity production.</u>

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, <u>25305, 25305.1, 25310,</u> 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 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 a~~n~~ 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~~;

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

(H~~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

(I~~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 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 output ~~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 useful thermal output ~~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;~~.~~

8. for cogenerators, useful thermal output provided by each cogenerator to each recipient, in million British thermal units, classified by Customer Classification Code; and

9. for cogenerators, waste heat of each electric generator, in million British thermal units.

(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 output ~~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 useful thermal output ~~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, monthly useful thermal output provided by each cogenerator to each recipient, in million British thermal units, classified by Customer Classification Code; and

9. for cogenerators, monthly waste heat of each electric generator, in million British thermal units.

(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 output ~~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 useful thermal output ~~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, monthly useful thermal output provided by each cogenerator to each recipient, in million British thermal units, classified by Customer Classification Code;

9. for cogenerators, monthly waste heat of each electric generator, in million British thermal units; 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:

(A) Environmental information related to water supply and water / wastewater discharge

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 for the previous calendar year:

a. a description of the type of cooling technology being used for each unit within a power plant;

b. the name of the water supplier(s) 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. the daily average and daily maximum water use volumes in gallons for all power plant purposes;

d. the monthly and annual amounts of water used for all power plant purposes in acre-feet; and

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 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 for the previous calendar year:

a. a description of the physical and chemical characteristics of the source water or the 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. the wastewater disposal system(s) used at the power plant for discharges related to power plant cooling and operations, the manufacturer(s), and the year of installation;

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

c. 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 wastewater that are created from power plant operations in acre-feet; and

f. the daily average and daily maximum waste water discharge volumes in gallons.

(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" of terrestrial, avian and aquatic wildlife subject to legal protection under California Fish & G. Code § 2050 et seq., 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. 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 and energy storage system ~~that has a generating capacity of 100 kilowatts or more,~~ located in the UDC's service area and for which data is collected. 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;~~ power plants with a generating capacity of 100 kilowatts or more:

(A) facility name; and

(B) ~~(2)~~ facility code assigned by the EIA.~~;~~

(2) all power plants:

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

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

(C) 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);

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

(E) fuel type (e.g., natural gas, biogas, diesel, solar, wind.).

(3) all power plants and energy storage systems:

(A~~5~~) address where the power plant or energy storage system is physically located, including the street address, city, state, and zip code;

(B~~6~~) power plant or energy storage system owner's full legal name and, if a non-residential customer, address of principal place of business, including the street address, city, state, and zip code;

(C~~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);~~

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

(D~~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~~

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

(E~~12~~) date of interconnection approval;

(F~~13~~) if the power plant or energy storage system is no longer interconnected, the date the power plant or energy storage system is no longer interconnected to the utility distribution system; and

(G~~14~~) if the power plant or energy storage system is connected to that part of the customer's electrical system not owned by UDC, provide the following;

1. ~~(A)~~ service account number;

2. ~~(B)~~ premise identification number;

3. ~~(C)~~ meter identification number; and

4. ~~(D)~~ rate schedule.

Note: Authority cited: Sections 25213, 25218(e) and 25320, Public Resources Code. Reference: Sections 25005.5, 25216, 25216.5, 25300-25303, 25305, 25305.1, 25310, 25401, 25401.2, 25403, 25403.5, 25602 and 25604, Public Resources Code.

Section 1306 LSE and UDC Reports, and Customer Classification Reports

(a) Quarterly UDC Reports.

(1) Each UDC 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.

(5) After ~~January 1~~February 15, 20~~19~~20, the requirements of subdivisions 1 through 4 of subdivision (a) of this Section shall not apply to UDCs reporting under Section 1353 (b).

(b) Quarterly LSE Reports. LSEs not reporting under 1306(a), 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 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. Ruby ~~p~~Pipeline at Malin

6~~5~~. Other California Border Receipt Points (Designate)

(B) Instate locations

1. Questar Pipeline at Essex ~~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 Kern River Station ~~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) <u>Freemont Peak</u> ~~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 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.

(3) After ~~January 1~~ February 15, 20~~19~~20, the requirements of subdivisions 1 and 2 of subdivision (c) of this Section shall not apply to gas utilities reporting under Section 1353 (c).

(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 1314 Natural Gas System Analysis

(a) 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 15~~, on

August 1, 2018 and on March 15 every year thereafter, via secure electronic method, provide files that are used by ~~report all data~~ the gas utility ~~used~~ to conduct gas hydraulic modeling for ~~model~~ its natural gas system ~~using DNV-GL Synergi Gas software~~ during the previous calendar year, including the scenarios (1) – (4) below:

(1) average summer day (June through September);

(2) average winter day (November through March);

(3) 1-in-10 peak summer and winter day; and

(4) any additional summer and winter day representing demand higher than that identified in subdivisions (1)-(3) above.

(b) The files provided need not identify natural gas infrastructure dedicated to retail customers other than power plants.

~~(c) Definitions~~

~~(1) "deliveries" means gas volumes delivered to customers expressed in therms.~~

~~(2) "natural gas supply system" means the natural gas infrastructure, including transmission and distribution and storage facilities, operated by a gas utility for the purpose of delivering natural gas to customers.~~

Note: Authority cited: Sections 25213, 25218(e) and 25320, Public Resources Code. Reference: Sections 25005.5, 25216, 25216.5, 25300-25303, 25303.5, 25305, 25400, 25401, 25401.2, 25403, and 25602, Public Resources Code.

Article 2. Forecasting and Assessment of Energy Loads and Resources

Section 1344 Load Metering Reports

(a) Annual LSE Customer Load Data by Hour. Beginning March 15, 2008, and every year thereafter, each LSE that has experienced a peak electricity demand of 200 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;

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

(b) Annual Distribution System Load Data by Hour. Beginning March 15, 2008, and every year thereafter, each UDC that has experienced a peak electricity demand of 200-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;

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

(4) Hourly loads shall be submitted in two formats: (1) the composite of the hourly loads (the composite of customer loads plus distribution losses) for all LSEs supplying electricity in the UDC's distribution service area, and (2) format (1) expanded to include-hourly transmission losses for each hour.

(c) Hourly Load Estimates by Customer Sector. Beginning September 1, 2007, and every year thereafter, each UDC that has experienced a peak electricity demand of 1000 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 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.

(d) Monthly Distribution System Load Data by Hour. Beginning March 15, 2008, 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;

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

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

(e) Annual Electric Transmission System Peak Load Data by hour and subarea. Beginning June 1, 2008, 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 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;

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

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

(5) Subareas are climate zones or geographic subdivisions of the transmission system area 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.

(f) ~~Behind-the-meter~~ Emerging Load Impacts. ~~Beginning February 15~~, On August 1, 2018 and March 15 every year thereafter, each UDC that has experienced a peak electricity demand of 1000 megawatts or more in both of the two calendar years preceding the filing shall provide ~~any analyses, as well as supporting data,~~ a summary of load research data used by the UDC during the previous calendar year for characterizing, assessing, and forecasting load impacts associated with any of the following ~~activities that occur on that part of the customer's electrical system that is not owned by the UDC~~:

(1) Photovoltaic generation;

(2) Plug-in electric vehicle charging; and

(3) ~~Operation of e~~Energy storage system~~s~~ operation.

Note: Authority cited: Sections 25213, 25218(e) and 25320, Public Resources Code. Reference: Sections 25005.5, 25216, 25216.5, 25300, 25301, 25302, ~~and~~ 25303, 25305, 25305.1, and 25310, Public Resources Code.

Section 1353 Disaggregated Demand Data

(a) Disaggregated Demand Data Reporting. Each entity subject to requirements identified in this Section shall submit the required data via secure electronic method and shall adhere to the reporting requirements identified in Section 1342.

(1) Quarterly Reports and Data. Unless provided otherwise, data or reports referred to as "quarterly" shall be submitted for the previous calendar quarter on the 15th day of February, May, August, and November.

(2) No entity subject to reporting requirements pursuant to this Section shall be required to provide data or reports that it does not collect in the regular course of business; however, if the entity begins to collect some or all of the data not previously collected, it must submit the data in accordance with the requirements of this section.

(3) All interval meter data provided pursuant to this Section may be submitted at the interval collected.

(4) A detailed explanation of any methods used by utility to estimate missing, misread, or non-metered data provided with each quarterly filing.

(b) Electricity 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:

(1) For each non-interval meter:

(A) the street address, city, and zip+4 code where service is provided;

(B) service account number;

(C) premise identification number(s);

(D) monthly charge in dollars (positive or negative);

(E) start of billing cycle;

(F) number of days in billing cycle;

(G) customer participation in UDC energy efficiency program;

(H) rate schedule;

(I) NAICS code;

(J) whether there is interconnected PV associated with the premise identification number;

(K) whether there ~~is~~ are energy storage systems associated with the premise identification number;

(L) meter identification number;~~ and~~

(M) monthly volume of electricity sold or delivered in kWhs; and

(N) any information identified in (b)(1)(A) - (M) that has not already been provided for 2018.

(2) For each ~~an~~ interval meter:

(A) all information from subdivision (b)(1) (A) through (L);

(B) in 2018, monthly volume of electricity sold or delivered in kWhs, including volumes for months in 2018 that have not already been provided;

(C) beginning in 2019, the following information:

(i) start of interval;

~~(C)~~(ii) duration of interval;

(~~D~~iii) volume of electricity sold or delivered over the interval in kWh; and

(~~E~~iv) interval peak demand (kW);

(3) For all remaining consumption which is not associated with a meter:

(A) All information from subdivision (b)(1)(A) through (K);

(B) An estimate of the monthly volume of electricity sold or delivered in kWhs; ~~and~~

(C) An estimate of the monthly peak demand (kW, day, and hour); and

(D) Any information identified in (b)(3)(A)-(C) for 2018 that has not already been provided.

(c) Natural Gas 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 date, shall on a quarterly basis provide for each meter:

(1) Service address of account number, including the street address, city, and zip+4 code;

(2) Service account number;

(2) Premise identification number;

(3) Meter identification number;

(4) Monthly volume of natural gas sold or delivered in therms;

(5) Monthly charge in dollars (positive or negative), aggregate revenues 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;

(6) NAICS code;

(7) Energy efficiency program participation identification; ~~and~~

(8) Rate schedule~~.~~; and

(9) Any information identified in (c)(1)-(8) for 2018 that has not already been provided.

Note: Authority cited: Sections 25213, 25218(e) and 25320, Public Resources Code. Reference: Sections 25005.5, 25216, 25216.5, 25300, 25301, 25302, 25302.5, 25303, 25305, 25305.1, and 25310, Public Resources Code.

CHAPTER 7. ADMINISTRATION

The Administration chapter deals extensively with confidentiality, methods of aggregation, and procedures for the release of data. Changes reflected in these sections include changes to deal with new and expanded data collection as well as updated data handling procedures.

Article 2. Disclosure of Commission Records

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.)

9. All information provided pursuant to Section 1314 of Article 1 of Chapter 3 and Section 1353 of Article 2 of Chapter 3.

(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.

ADDENDUM TO INITIAL STATEMENT OF REASONS

ADDITIONS TO AND MODIFICATIONS OF REGULATIONS GOVERNING DATA COLLECTION AND DESIGNATION OF CONFIDENTIAL INFORMATION

California Code of Regulations
Title 20, Sections 1302, 1304, 1306, 1308, 1314, 1344, 1353, & 2505

California Energy Commission
Docket Number 16-OIR-03
January 26, 2018

The Energy Commission posted, mailed, and docketed an Initial Statement of Reasons (ISOR) on August 4, 2017, for the above-captioned rulemaking proceeding. The ISOR contained an Economic Impact Assessment as Attachment A. The Energy Commission is now proposing revisions to the original text that require changes to the Economic Impact Assessment. The *REVISED ATTACHMENT A, Updated Economic Impact Assessment for Title 20 Data Collection Regulation Modifications*, attached hereto, is hereby incorporated into the ISOR originally published on August 4, 2017. This document supersedes the original Economic Impact Assessment referenced on page 33 of the ISOR and attached thereto as Attachment A.

Changes to the original Economic Impact Assessment are indicated in underline and strike-out.

REVISED ATTACHMENT A TO INITIAL STATEMENT OF REASONS

Updated Economic Impact Assessment for Title 20 Data Collection Regulation Modifications

~~July 18, 2017~~ January 26, 2018

Explanation of Updates To Economic Impact Assessment

As a result of revisions to the proposed regulations, reporting under the amendments adopted in this rulemaking in fiscal year 2017/2018 will not occur as originally anticipated. This Economic Impact Assessment has been updated to reflect the fact that reporting will begin in fiscal year 2018/2019, including all start-up costs. In addition, costs in fiscal year 2020/2021 were added to ensure that cost estimates are included for the first three years of implementation.

The specific elements required to be included in the Economic Impact Assessment pursuant to subdivision (b)(1)(A)-(D) of Gov. Code section 11346.3 are addressed at the end of the discussion of each section and subsection below. The Commission's assessment of these elements has not changed as a result of the updates to this document.

Summary of Cost Impacts

The following table summarizes the costs for all modifications proposed for the Title 20 data collection regulations for the first three fiscal years of the data collection implementation. In the first row of each box, the total cost for each of the three years for the subsection or section is identified. The breakdown of these costs is identified in subsequent rows and discussed in detail in the portion of the document that follows the table. (Individual values are rounded to whole numbers and the reported totals may not match the sums of the individual rounded costs.)

Table 1. Summary of Costs for Proposed Regulations

	Fiscal Year				
Proposed Regulation Sections	**2017/18**	**2018/19**	**2019/20**	**2020/21**	**Total**
Section 1302 Definitions (Total)	**$0**	**$0**	**$0**	**$0**	**$0**
Private Obligated Party Costs	$0	$0	$0	$0	$0
Local Public Obligated Party Costs	$0	$0	$0	$0	$0
State Costs	$0	$0	$0	$0	$0
Section 1304 (a) Combined Heat and Power Data (Total)	**$0 ~~169,497~~**	**$196,965 ~~67,695~~**	**$69,726**	**$71,818**	**$338,510 ~~307,406~~**
Private Obligated Party Costs	$0 ~~119,552~~	$141,477 ~~47,024~~	$48,435	$49,888	$239,800 ~~215,011~~
Local Public Obligated Party Costs	$0 ~~44,070~~	$52,152 ~~17,334~~	$17,855	$18,390	$88,397 ~~79,259~~
State Costs	$0 ~~6,363~~	$3,336	$3,437	$3,540	$10,313 ~~13,136~~

	Fiscal Year				
Proposed Regulation Sections	**2017/18**	**2018/19**	**2019/20**	**2020/21**	**Total**
Section 1304 (b) Interconnection Data (Total)	**$0** **~~696,570~~**	**$1,049,178** **~~665,088~~**	**$682,658**	**$703,137**	**$2,434,973** **~~2,044,316~~**
Private Obligated Party Costs	$0 ~~58,590~~	$94,079 ~~68,969~~	$71,038	$73,169	$238,286 ~~198,597~~
Local Public Obligated Party Costs	$0 ~~637,980~~	$933,720 ~~574,740~~	$591,982	$609,742	$2,135,444 ~~1,804,702~~
State Costs	$0	$21,379	$19,638	$20,227	$61,244 ~~41,017~~
Section 1306 (a) Quarterly UDC Reports (Total)	**$0**	**$0** **~~1,896~~**	**$1,953** **~~3,719~~**	**$2,011**	**$3,964** **~~5,615~~**
Private Obligated Party Avoided Costs*	$0	$0 ~~758~~	$781 ~~1,561~~	$804	$1,585 ~~2,319~~
Local Public Obligated Party Avoided Costs*	$0	$0 ~~505~~	$520 ~~1,041~~	$536	$1,056 ~~1,546~~
State Avoided Costs*	$0	$0 ~~633~~	$652 ~~1,117~~	$671	$1,323 ~~1,750~~
Section 1308 (a) and (b) Monthly Natural Gas Data (Total)	**$0**	**$0**	**$0**	**$0**	**$0**
Private Obligated Party Costs	$0	$0	$0	**$0**	$0
Local Public Obligated Party Costs	$0	$0	$0	**$0**	$0
State Costs	$0	$0	$0	**$0**	$0
Section 1308 (c) Monthly Natural Gas Deliveries (Total)	**$0**	**$0** **~~4,438~~**	**$4,571** **~~9,142~~**	**$4,708**	**$9,279** **~~13,579~~**
Private Obligated Party Avoided Costs*	$0	$0 ~~3,579~~	$3,686 ~~7,373~~	$3,797	$7,483 ~~10,951~~
Local Public Obligated Party Avoided Costs*	$0	$0	$0	$0	$0
State Avoided Costs*	$0	$0 ~~859~~	$884 ~~1,769~~	$911	$1,796 ~~2,628~~
Section 1314 Natural Gas Modeling Data (Total)	**$0** **~~10,300~~**	**$14,482**	**$14,917**	**$15,364**	**$44,763** **~~39,699~~**
Private Obligated Party Costs	$0 ~~6,541~~	$6,737	$6,939	$7,147	$20,823 ~~20,216~~
Local Public Obligated Party Costs	$0	$0	$0	$0	$0
State Costs	$0 ~~3,760~~	$7,745	$7,978	$8,217	$23,940 ~~19,483~~

	Fiscal Year				
Proposed Regulation Sections	**2017/18**	**2018/19**	**2019/20**	**2020/21**	**Total**
Section 1344 (f) Load Impact Data (Total)	**$0 ~~147,172~~**	**$57,346 ~~46,984~~**	**$31,440 ~~48,394~~**	**$32,383**	**$121,169 ~~242,549~~**
Private Obligated Party Costs	$0 ~~60,264~~	$33,335 ~~17,242~~	$17,759	$18,292	$69,387 ~~95,266~~
Local Public Obligated Party Costs	$0 ~~40,176~~	$22,223 ~~11,495~~	$11,840	$12,195	$46,258 ~~63,510~~
State Costs	$0 ~~46,732~~	$1,787 ~~18,247~~	$1,841 ~~18,794~~	$1,896	$5,525 ~~83,773~~
Section 1353 (a) Disaggregated Data Reporting (Total)	**$0 ~~146,248~~**	**$179,373 ~~35,477~~**	**$36,542**	**$37,638**	**$253,552 ~~218,267~~**
Private Obligated Party Costs	$0 ~~93,000~~	$114,948 ~~22,990~~	$23,679	$24,390	$163,017 ~~139,669~~
Local Public Obligated Party Costs	$0 ~~46,500~~	$57,474 ~~11,495~~	$11,840	$12,195	$81,508 ~~69,834~~
State Costs	$0 ~~6,748~~	$6,951 ~~993~~	$1,023	$1,053	$9,027 ~~8,764~~
Section 1353 (b) Monthly and Interval Meter Data (Total)	**$0 ~~159,173~~**	**$486,186 ~~227,815~~**	**$486,962 ~~155,292~~**	**$676,307**	**$1,649,455 ~~542,280~~**
Private Obligated Party Costs	$0 ~~53,568~~	$110,350 ~~64,371~~	$18,943	$19,512	$148,805 ~~136,882~~
Local Public Obligated Party Costs	$0 ~~35,712~~	$73,567 ~~42,914~~	$12,629	$13,008	$99,203 ~~91,255~~
State Costs	$0 ~~69,893~~	$302,269 ~~120,530~~	$455,390 ~~123,720~~	$643,787	$1,401,446 ~~314,143~~
Section 1353 (c) Monthly Natural Gas Customer Data (Total)	**$0 ~~248,587~~**	**$437,615 ~~371,466~~**	**$265,106 ~~226,297~~**	**$229,519**	**$932,240 ~~846,349~~**
Private Obligated Party Costs	$0 ~~94,860~~	$136,264 ~~80,464~~	$82,878	$85,364	$304,505 ~~258,201~~
Local Public Obligated Party Costs	$0	$0	$0	$0	$0
State Costs	$0 ~~153,727~~	$301,352 ~~291,002~~	$182,228 ~~143,419~~	$144,155	$627,735 ~~588,148~~
Section 2505 Designation of Confidential Records (Total)	**$0**	**$0**	**$0**	**$0**	**$0**
Private Obligated Party Costs	$0	$0	$0	$0	$0
Local Public Obligated Party Costs	$0	$0	$0	$0	$0
State Costs	$0	$0	$0	$0	$0

	Fiscal Year				
Proposed Regulation Sections	**2017/18**	**2018/19**	**2019/20**	**2020/21**	**Total**
Total Private Obligated Party Costs	$0 ~~486,374~~	$637,189 ~~307,796~~	$269,672	$277,762	**$1,184,622 ~~1,063,842~~**
Total Local Public Obligated Party Costs	$0 ~~804,438~~	$1,139,136 ~~657,978~~	$646,145	$665,529	**$2,450,810 ~~2,108,561~~**
Total State Costs	$0 ~~287,223~~	$644,820 ~~463,234~~	$671,534 ~~318,008~~	$822,876	**$2,139,230 ~~1,068,464~~**
Total Costs	**$0 ~~1,578,035~~**	**$2,421,145 ~~1,429,008~~**	**$1,587,350 ~~1,233,825~~**	**$1,766,167**	**$5,774,662 ~~4,240,867~~**
Private Obligated Party Avoided Costs*	$0	$0 ~~4,337~~	$4,467 ~~8,934~~	$4,601	**$9,068 ~~13,271~~**
Local Public Obligated Party Avoided Costs*	$0	$0 ~~505~~	$520 ~~1,041~~	$536	**$1,056 ~~1,546~~**
State Avoided Costs*	$0	$0 ~~1,491~~	$1,536 ~~2,886~~	$1,582	**$3,119 ~~4,378~~**
Total Avoided Costs*	**$0**	**$0 ~~6,334~~**	**$6,524 ~~12,861~~**	**$6,719**	**$13,243 ~~19,194~~**

* The avoided costs derive from the deletion of a requirement to file aggregated data, with some utilities being required to file disaggregated data. These avoided costs, therefore, should be considered in conjunction with the costs associated with the requirement to file disaggregated data, addressed under the discussion for Section 1353.

General Assumptions

The underlying assumptions regarding evaluating the cost impacts of the proposed regulations include assumptions about the implementation date of regulations, the date reporting by obligated parties is first required, the amount of time required of obligated parties to report and of the Energy Commission to process and store the data, salaries and annual increases in salaries of both Energy Commission staff and the staff of employees responsible for filing the information, the availability of Energy Commission data repositories that will be used for data, and modifications of existing data handling procedures and processes that may be required.

The evaluation assumes that the proposed regulations are adopted in early 2018~~2017~~ and are effective July 1, 2018~~when approved~~. The first reporting of data would be in ~~early~~summer 2018.

Staffing Resources Assumptions

To estimate the impact of the proposed changes in reporting requirements on staffing resources, the Energy Commission looked at the time associated with ~~the~~ any increased or decreased reporting requirements and the salaries of Energy Commission employees and the employees who would be responsible for filing the information with the Energy Commission. The general cost calculation for the proposed regulations follows the basic formula of:

$$Cost_y = Hourly\ Salary^{(Inflation)^{(y-2017)}} \times\ Hours\ \times Parties$$

Where:

$Cost_y$ = Total Fiscal Year cost in year y.

y = the fiscal year in which costs are being evaluated.

Hourly Salary = is the annual average hourly rate in 2017 for the work being performed.

Hours = the estimated number of hours needed to perform the activities in a Fiscal Year.

Inflation = the assumed annual salary inflation of three percent.

Parties = the number of obligated parties for the proposed regulations.

Depending on the proposed regulations being evaluated, there may be additional factors included in the calculation such as frequency of reporting or scaling to distribute to private or public obligated parties.

Hourly Salary Assumptions

The private industry 2017 annual average hourly salaries were developed by looking at consultant rates established by the Department of General Services IT Consulting Services Contractor Classifications and Rates for contractors eligible to perform programing activities. (See Master Services Agreement for contracts with a value of up to $1.5 million. This list can be found on the DGS website:

http://www.dgs.ca.gov/Portals/9/Documents/MAU%201/ITMSA/Contractorslist.xlsx)

The Energy Commission concluded that a Programmer classification was appropriate for estimating private salaries. The average hourly salary of contractors for the Programmer classification was determined to be $93 per hour in 2017; this hourly salary is used throughout most of the regulation cost estimates.

For Energy Commission employees, the Energy Commission assumed that the workload for one contractor (System Analyst) and three different classifications of state employees (Electric Generation System Specialist I, Energy Commission Specialist II, and Senior Programmer Analyst) would be affected by the proposed regulations. For classifications Electric Generation System Specialist I (EGSS I) and Energy Commission Specialist II (ECS II), the Energy Commission used the highest salary converted to an hourly rate for the purposes of these estimates, $57.84 and $48.20, respectively. For the Senior Programmer Analyst, staff did a survey of the classification and took the highest salary and converted it into an hourly rate. The hourly salary for the state Senior Programmer Analyst is $51.75.

The System Analyst position is a contractor who would be employed by the state and is conservatively assumed to earn the same rate as the Programmer, $93 per hour. The Energy Commission also assumed that analytical activities associated with collection of the new data - developing disaggregated forecasts, tracking the effectiveness of GHG emissions reduction efforts, and making policy recommendations for achieving additional GHG emissions reductions and meeting other important state energy goals - would not require new staff resources. This is due to the fact that staff can use highly automated methodologies for processing the new data; these analytical efforts will replace some of the more laborintensive efforts that have been used in the past to conduct forecasting activities and develop concomitant policy recommendations.

Over the course of evaluation, all salaries, both consultant and state, are increased by 3 percent annually.

Data Storage Costs

Changes to Sections 1306 and 1308 will result in a reduction of data submitted to the Energy Commission; changes to Sections 1304, 1314, and 1344 will result in additional data that can be accommodated on existing servers. Therefore there are no data storage costs associated with these proposed changes. Section 1353, however, would result in new data storage needs that are addressed below.

The Energy Commission developed an annual data storage cost estimate for proposed Section 1353 (b) and (c). The amount of data to be collected in Section 1353 (b) is estimated by creating a proxy data set consisting of a single customer record with ~~scaling the number of fields currently collected for the Energy Commission's Clean Energy Jobs Act program (under which the Energy Commission receives interval meter data) to~~ the number of fields identified in the proposed regulation. [1] This leads to an estimated size for each customer data record reported of 2.072 ~~9.375~~ megabytes per year for the interval meter data and 0.2 megabytes per year for monthly data. The number of customers for the five largest utilities was estimated using Energy Information Administration reported values for 2015.[2] Multiplying 13,887,678, the number of customers, by the annual per-customer data record size of 2.072 ~~9.375~~ megabytes for interval meter data and 0.2 megabytes for monthly data yielded an estimated data size of about 28.8~~130.2~~ TB of interval meter data and about 2.8 TB of monthly data being collected each year. The cost for storage was then calculated using the storage rate for the state data center housed at California Natural Resources Agency~~commercial prices for Amazon Web Services' (AWS) Standard S3 Storage rates~~.[3] This resulted in an estimated cost of $204,462~~39,659~~ for Fiscal Year 2018/19,~~ and~~ $390,926~~78,718~~ for Fiscal Year 2019/20, and $577,390 for Fiscal Year 2020/21. ~~However, the Energy Commission will likely be using a cheaper service from the Resources Agency which will require a cost of $50,000 in Fiscal Year 2018/19 but should result in lower costs in the long run. To be conservative, the Energy Commission used $50,000 for Fiscal Year 2018/19 and $78,718 for Fiscal year 2019/20.~~ This estimate is for storage of electricity data collected pursuant to Section 1353 only; the amount of natural gas data that will be collected is much smaller. In fact, the Energy Commission estimates that the overall size of the natural gas data would be between 20 GB and just over 1 TB, all of which is easily held on a single hard drive or server. Assuming however, that Amazon Web Services' Standard S3 Storage ~~AWS S3~~

[1] Existing detailed data used for this evaluation included school consumption data, proxy consumption data, ~~which was compared to other data sets including~~ industrial sector consumption, energy efficiency evaluation data, and discussions with data contractors. The proxy data set for the ~~school data was approximately 12.5 MB per record of 21~~ 15 fields for 15 minute annual data was approximately 2 megabytes per year per record. ~~Since the regulations involve only 15 fields and may be at 15 minute intervals, the 12.5 MB value was reduced by nearly a quarter and resulted in the 9.375 MB estimate.~~

[2] https://www.eia.gov/electricity/data.php#sales

[3] The current rate for storage is $0.06 per gigabyte per month.~~https://aws.amazon.com/s3/pricing/~~

prices are used for the estimate, the cost of natural gas data storage may be an additional $1 - $28 a year. Because this amount is exceedingly small and speculative, we have not included it in the cost estimate.

Identifying Costs to Private and Public Obligated Parties

The regulations impose new or modified reporting requirements on owners of cogeneration facilities, and natural gas utilities and UDCs, with some of the modifications affecting only the larger of the latter two. Owners of cogeneration facilities can be private (e.g., a small business or an investor-owned utility regulated by the California Public Utilities Commission or CPUC) or public (e.g., a local publicly-owned electric utility). Natural gas utilities are private, while UDCs can be either private (e.g., an investor-owned utility regulated by the CPUC) or public (e.g., a local publicly-owned electric utility). In order to separately identify the costs of private and public obligated parties, the Energy Commission assumed all obligated parties for each proposed section had the same costs for each data requirement and scaled the costs to the number of private and public entities impacted by the proposed regulations. For example, the proposed language in Sections 1344 and 1345 impacts the five largest California UDCs, three of which are private investor-owned utilities and two of which are local publicly-owned electric utilities. Thus, 60 percent of the estimated costs would be borne by investor-owned utilities and the remaining 40 percent would be borne by local publicly-owned electric utilities.

An exception to this approach was used for 1304(a). Of the 349 cogeneration facilities impacted by Section 1304 (a) changes, 94 are local publicly-owned units and 255 are private. Because costs are established on a per unit basis, 73 percent of the costs are private and 27 percent are public. The proposed changes to Section 1304 (a) only impact cogenerator owners, not the owners of approximately 450 other power plants for which data is reported under Section 1304.

Natural gas utilities are all privately owned so there is no need to differentiate between public and private costs for changes to natural gas data collection requirements.

Estimates for First 3 Fiscal Years

Estimates are provided for fiscal years ~~2017/18,~~ 2018/19, ~~and~~ 2019/20, and 2020/21. ~~Although t~~The regulations are expected to go into effect ~~January 1,~~ July 1, 2018~~, or shortly thereafter, some~~ with one-time startup costs captured in the first fiscal year 2018/19. ~~may be incurred before the regulations go into effect during the first fiscal year, so we have provided an estimate for fiscal year 2017/18.~~

Fiscal year 2018/19 is the first year in which compliance with the regulation is required. However, general costs may be higher than a typical compliance year in fiscal year 2018/19 ~~2017/18~~ as new data activities are undertaken.

Fiscal year 2019/20 represents full implementation, representative of the costs associated with the regulations on an ongoing basis.

Section 1302 Definitions

The proposed regulatory changes within Section 1302 focus on clarifying and adding definitions to improve the understanding of the proposed regulations. Since the changes to Section 1302 are administrative in nature and do not independently require reporting, the Energy Commission estimates there would be no cost impacts due to the proposed regulations in this section.

Costs to Obligated Parties

There are no cost impacts to any obligated parties due to clarifying and adding definitions to this section. The proposed language would not result in any changes to reporting processes.

Costs to the State

There are no cost impacts to the state due to clarifying and adding definitions to this section. The proposed language would not result in any changes to reporting processes.

Potential Impacts of Proposed Regulations (Gov. Code § 11346.3, subd.(b).)

The proposed regulations within Section 1302 would not result in the creation or elimination of any jobs within California. Existing businesses and staff would perform all the work necessary to meet the new obligation. No new businesses would be created and neither would any existing business be eliminated by the new regulations. The proposed regulatory changes would not expand any existing businesses doing business in California and there would be no direct benefits of the data collection to the health and welfare of California residents, to worker safety, or to the state's environment.

Section 1304 (a)(1) and (2) Cogeneration Data

Changes to these subdivisions require the provision of waste heat and useful thermal output along with customer classification codes of recipients by the 139 owners of 349 cogeneration facilities. These owners already provide detailed energy data about the facilities to the Energy Commission as part of the existing Section 1304 (a)(1) and (2) regulations. Non-cogenerator power plant owners who currently report under Section 1304 will not be impacted by the proposed regulatory changes.

The changes will allow the Energy Commission to collect information needed to estimate cogeneration (also referred to as combined heat and power or CHP) efficiencies by obtaining the useful thermal output. Current regulations focus only on total thermal energy data and do not distinguish between the useful and waste components. Most of the targets/goals for CHP development are based on the idea that they are more fuel-efficient and therefore have lower emissions. Currently CHP facility fuel-efficiency is estimated. The useful thermal output data would provide a solid analytical basis for current and future CHP policy and ensure promoting CHP development is still consistent with state environmental goals.

Costs to Obligated Parties

Obligated parties impacted by the proposed regulations are comprised of 139 power plant owners of an estimated 349 cogeneration facilities; these entities report generation data to the Energy Commission as part of the existing Section 1304 regulations. Non-cogeneration power plant owners will continue to report in accordance with the Section 1304 and will not be impacted by the proposed modifications. Of the 139 owners required to report on cogeneration facilities, 37 are public, and the rest are private. The proposed regulations would require two additional data points for each unit to identify the useful thermal output that is being captured and the customer classification code of the recipient.

There would be no expansion of any industries to comply with the data request. Staff estimates that obligated parties maintain this data for business purposes and would be able to retrieve it from existing datasets. The new requirement may involve the development of an additional process or query to extract the detailed data for reporting. Developing a single initial process for pulling data from an existing system would take, approximately 24 minutes for each facility. Staff estimates it would take about 3.5 hours to test (24 minutes), revise (24 minutes), obtain internal approval on reporting (just under 1.6 hours), and integrate with existing reporting processes (1.2 hours). This leads to a conservative estimate of approximately 4 hours to develop a reporting process for the new data reporting requirement per unit for a one-time effort in the first fiscal year.

Not all obligated parties have staff on hand to perform this work and it may require using a database administer or programmer to perform some of these tasks. Therefore, the Energy Commission has used the average hourly rate of $93 for a Programmer as defined in the California Department of General Services procurement list for IT services.

The described estimates results in a fiscal year 2018/19~~2017/18~~ cost, including development work, of $141,477~~119,552~~ for private cogeneration facility owners, and $52,152~~44,070~~ for local public cogeneration facility owners.[4]

Once developed, the recurring reporting will be accomplished through the use of a standard query to collect the data, followed by a creation of a summary, and filing a report. Querying, validating, and summarizing two additional data points should take no more than 30 minutes (0.25 hours + 0.25 hours) and reporting the data on the Energy Commission's modified forms would take a couple of minutes per unit. Including additional time to confirm the data is entered properly, staff has estimated the reporting to take 7 and half minutes (0.125 hours) per unit. About 69 percent of units (242 units of 349 total units) report quarterly while the remaining unit data is reported annually. ~~In fiscal year 2017/18 only two quarterly reports are assumed to be submitted.~~

Using the $93 per hour average programmer rate and the fact that 73 percent of units are private, the recurring reporting costs are estimated for fiscal year 2018/19 to be $141,477~~47,024~~ for private cogeneration facility owners and $52,152~~17,334~~ for local public cogeneration facility owners. For fiscal year 2019/20 costs are estimated at $48,435 for private cogeneration facility owners and $17,855 for local public cogeneration facility owners. For fiscal year 2020/21 costs are estimated at $49,888 for private cogeneration facility owners and $18,390 for local public cogeneration facility owners.

[4] The total costs are allocated equally across all cogeneration facilites with 255 of the 349 units being identified as private. The remaining 94 units are public.

Costs to the State[5]

The proposed section 1304 (a)(1)&(2) would require Energy Commission staff to undertake two categories of activities.

First, in order to facilitate the reporting of the new data Energy Commission staff would need to modify, disseminate, and answer questions regarding updated templates used to collect related data. Additionally, Energy Commission staff responsible for extracting the data would need to be informed about the new data. In total, over the course of modifications, staff estimates this would result in 80 hours of staff time dedicated to the one-time modifications necessary to obtain the data. This work would be completed by an Electric Generation System Specialist I at an hour rate of $57.84 and result in a total one-time cost of $4,628 in fiscal year 2017/18 only.

Second, for each reported value, Energy Commission staff would need to acquire, validate, and review the data submittal. Since this is part of an existing data management process, the staff time to perform these activities would take less than a minute for each data point submitted. As there would be two new data points (useful thermal energy and customer classification code of the recipient) for each of the 349 cogeneration facilities and considering the frequency of reporting, either quarterly or annually based upon total generation capacity by obligated party, there would be approximately 1182 new data points for a half year of reporting and 2150 new data points for a full year of reporting. A conservative estimate would be that this reporting would require 1200 minutes or 20 hours of Energy Commission staff time for a half year of reporting and 2150 minutes or approximately 36 hours for a full years of reporting This work is assumed to be completed by an Electric Generation System Specialist I at a rate of $57.84 per hour and would result in a total annual cost of ~~$1,157 in fiscal year 2017/18,~~ $2,145 in fiscal year 2018/19, ~~and~~ $2,209 in fiscal year 2019/20, and $2,276 in fiscal year 2020/21. As a conservative estimate, the Energy Commission also assumed a need to resolve data reporting issues with the reporting parties. These efforts are estimated to result in an additional 5 hours of work for each quarter although this may decrease as parties become familiar with the required data. This work is assumed to be completed by an Electric Generation System Specialist I at a rate of $57.84 per hour and would result in a total annual cost of ~~$578 in fiscal year 2017/18,~~ $1,192 in fiscal year 2018/19, ~~and~~ $1,227 in fiscal year 2019/20, and $1,264 in fiscal year 2020/21.

Summing the costs associated with these two categories of activities together, the revisions to section 1304 (a) are estimated to cost the state ~~$6,363 in fiscal year 2017/18,~~ $3,336 in fiscal year 2018/19, ~~and~~ $3,437 in fiscal year 2019/20, and $3,540 in fiscal year 2020/21.

[5] As this data would be collected and managed with other data reported to the Energy Commission, there should be no cost to the state outside of staff time to update the relevant data reporting templates. Staff time consists of entering two additional pieces of data to the updated reporting templates, which should conservatively take approximately 2 minutes. Given that approximately 349 cogeneration facilities have data reported to the Energy Commission, this should result in approximately 35 hours 50 minutes of staff time per year.
(2 staff minutes/facility report) x ((242 facilities) x (4 facility reports/facility/year)+(107 facilities) x (1 facility report/facility/year)) = 2,150 staff minutes per year = 35 hours 50 minutes of staff time per year.

Potential Impacts of Proposed Regulations (Gov. Code § 11346.3, subd.(b).)

Only the owners of cogeneration facilities are required to comply with the reporting requirements of this section. For these entities, the costs associated with compliance with the proposed revisions to this section are negligible, and could be performed by existing staff, without creating new positions. Similarly, the Energy Commission would be able to process this information with existing staff, without creating new positions. Consequently, the proposed revisions to Section 1304 (a)(1) and (2) would likely not result in the creation or elimination of any jobs within California. Furthermore, because compliance with this section would not affect facility operations, this section would neither create nor eliminate any businesses doing business in California, or would it expand any existing businesses in California. Finally, because this regulation only provides for the collection of information by the Energy Commission for analytical purposes, there would be no direct benefit of the data collection to the health and welfare of California residents, to worker safety, or to the state's environment. However, collecting this information would have indirect benefits, including estimating the efficiency of these facilities and their role in helping the state meets its greenhouse gas emissions reduction goals. These are discussed generally in the Benefits section of the initial statement of reasons (ISOR), and specifically in the explanation of the Purpose and Necessity for this section.

Section 1304 (b) Interconnection Data

The proposed changes in subdivision (b) would require the inclusion of energy storage systems data in reporting interconnections and would eliminate the reporting threshold for interconnected electric generation resources, thereby expanding the interconnected resources required to be reported to the Energy Commission.[6] Utility Distribution Companies (UDCs) would be required to provide interconnection data collected as part of the interconnection application process twice a year. There are 56 California UDCs that will be impacted by this regulation, most of which are smaller local publicly-owned electric utilities, the remainder of which are private investor-owned utilities.[7]

Costs to Obligated Parties

All UDCs are obligated to provide interconnection data to the Energy Commission under the existing regulation. The modifications would result in the elimination of the size threshold, so that all interconnected facilities would need to be reported by each UDC. In addition, UDCs would be required to report the interconnection of energy storage systems. Of the 56 obligated parties, five UDCs have an electric load greater than 1,000 MW. The three large UDCs that are investor-owned utilities that currently have the obligation to collect and provide some of the interconnection data identified in the proposed modifications to the California Public Utilities Commission, and the additional reporting to the Energy Commission should involve negligible cost. Additionally, the two largest local publicly-owned electric utilities have significant electric generation resources that are tracked in detailed electronic databases. As such, the cost impacts to these five large UDCs for reporting data to the Energy Commission would be small and would primarily involve sending information to the Energy Commission

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[6] The term "interconnections" refers to electric generators, including roof top solar, and storage systems interconnections to utility distribution company (UDC) distribution systems.

[7] http://www.energy.ca.gov/almanac/electricity_data/utilities.html

that is already collected in the course of business. Still, these five UDCs may need to revise existing queries to capture the data required in the proposed regulations. This would involve expanding the existing process of gathering interconnection data by revising current queries, testing, resolving issues, and developing reports for the submission to the Energy Commission. Staff estimates this should take 10 hours to complete since much, if not all, of the data is already collected in an electronic format. The recurring costs would involve running the query, summarizing the data appropriately, and sending the data to the Energy Commission and annually would take 60 hours, 40 hours, and 20 hours, respectively.[8]

For the smaller UDCs with electric load that is 1,000 MW and lower, data delivery to the Energy Commission may involve querying existing interconnection agreement data and summarizing into a single data set for delivery to the Energy Commission. The one-time cost of query development is estimated as 80 hours to write the query, test the query, and identify and resolve any issues with the data reporting. Similar to the larger UDCs, the recurring costs would involve running the query, summarizing the data appropriately, and sending the data to the Energy Commission. The smaller UDCs would likely have much lower costs than estimated here due to the smaller number of interconnected resources.[9]

The five largest UDCs would likely employ a programmer to write and implement the queries at an average rate of $93 per hour. As another conservative assumption, $93 per hour is also used to estimate the costs for other obligated parties, although data entry would likely be performed by someone at a lower rate than $93 an hour. Taking into account the difference in costs between large and small UDCs, total costs for fiscal year ~~2017/18~~ 2018/19 are $94,079~~58,590~~ for investor-owned utilities, and $933,720~~637,980~~[10] for local publicly-owned electric utilities. (The costs are greater for local publicly-owned electric utilities both because there are a greater number of them, and because some may lack the automated systems used by the larger UDCs.)

In each of the following years, because the query will already be developed, the estimated costs for all obligated parties would be lower. Costs are estimated to be ~~$68,969 and $574,740 respectively for privately owned and local publicly-owned electric utilities in 2018/19, and~~ $71,038 and $591,982

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[8] Since fiscal year 2017/18 is only half a year, the costs are estimated as 30 hours for data collection, 20 hours for summarizing, and 10 hours for reporting.

[9] Not all UDCs have fully automated systems to report the information and, in some instances, procedures would need to be implemented for summarizing and reporting the data. In 2014, there were a total of 4,826 interconnections reported to the Energy Commission by the 51 smaller obligated parties. Historically, approximately 17 of these UDCs have identified fewer than 10 total interconnections. Entering the information manually for all 4,826 interconnections into a file from interconnection agreement documents is conservatively estimated to take just over three hours for each obligated party. Staff arrived at the 3 hour estimate by performing its own timed data entry for 18 data elements, as requested in the proposed regulations, and deriving an estimate of just over 3 minutes per entry. Rounding this up to 4 minutes, multiplying by 4,826 for all the interconnections and dividing by 60 minutes per hour, 51 obligated parties, and 2 for each annual reporting event resulted in an estimate of 3 hours and 9 minutes.

[10] Of the 56 electricity utilities obligated to report under this section, 6 are investor-owned utilities while 50 are publicly-owned utilities. Most of the publicly-owned utilities are smaller and would need to spend more time automating their data collection processes in contrast to the larger utilities whose billing and metering systems are mature and are largely automated.

respectively for privately owned and local publicly-owned electric utilities in 2019/20, and $73,169 and $609,742 respectively for privately owned and local publicly-owned electric utilities in 2020/21. These costs increase slightly over time as salaries increase and as the number of interconnections increase although these increases would be mitigated by possible reporting automation.

Costs to the State

In order to facilitate the reporting of the new data, Energy Commission staff would be modifying, disseminating, and answering questions regarding new data requirements. The data provided under Section 1304 (b) is~~n't~~ not standardized; UDCs can use any format they find convenient. This practice would continue under the proposed change to Section 1304 (b). Energy Commission staff responsible for extracting the data would need to be informed about the new data and staff may need to answer questions regarding the new fields. In total, over the course of modifications, staff estimates this would result in 40 hours of staff time dedicated to the one-time modifications necessary to obtain the data. This one time activity would add a cost of $2,314 to the state's costs in fiscal year 2018/19 since data reporting is required semi-annually requiring the first data to be submitted in July of 2018.

Energy Commission staff would also need to acquire, validate, and review the new data submittal. Much of this is handled with automated validation checks of submitted data and would not result in significant additional time. In total additional staff time to manage the new data is estimated at 125 hours to process and validate the data, 30 hours to resolve any data issues, and 5 hours to ensure the data is properly imported for each reporting event. Annually this would result in a total of 320 hours (250 hours to process, 60 hours for data issues, 10 hours for importing) of work being performed since there are two reporting events each year and combined with the one-time development costs (40 hours, costing $2,314) would result in an estimated cost of $21,379[11] in fiscal year 2018/19, ~~and~~ $19,638 in fiscal year 2019/20, and $20,227 in fiscal year 2020/21. Note that state costs are expected to decrease in the final year as staff becomes familiar with data, issues with data reporting are resolved, and data management processes are automated.

Potential Impacts of Proposed Regulations (Gov. Code § 11346.3, subd.(b).)

California investor and publicly-owned utilities are required to comply with the reporting requirements of this section. For these utilities, the costs associated with compliance with this section are negligible, and can likely be performed by existing staff, without creating new positions. Similarly, the Energy Commission would be able to process this information with existing staff, without creating new positions. Consequently, the proposed revisions to Section 1304 (b) would likely not result in the creation or elimination of any jobs within California. Furthermore, because compliance with this section would not affect UDC operations, this section would neither create nor eliminate any businesses doing business in California, or would it expand any existing businesses in California. Finally, because this regulation only provides for the collection of information by the Energy Commission for analytical purposes, there would be no direct benefit to the direct benefits of the data collection to the health and welfare of California residents, to worker safety, or to the state's environment. However, collecting this information would have indirect benefits, including monitoring the expansion and adoption of

[11] Assumes the work is performed by an Electric Generation System Specialist at an hourly rate of $57.84.

interconnected resources, and their role in the state's efforts to achieve greenhouse gas emissions reduction and other energy goals. These are discussed generally in the Benefits section of the ISOR, and specifically in the explanation of the Purpose and Necessity for this section.

Section 1306 (a) Quarterly UDC Reports

The proposed modifications would relieve the five largest utility distribution companies (UDCs) from quarterly reporting of customer data identified in Section 1306 (a) after ~~January 1~~February 15, 2020~~19~~. This change would result in a savings to both UDCs and Energy Commission staff for processing, managing, and validating the submitted data. It is important to note that the reduction in reporting under this section is coupled with a new requirement that more customer data be provided by the five UDCs under proposed Section 1353. The costs associated with those reporting requirements are addressed in the discussion of that section, below. The following costs savings are estimated for both obligated parties and state staff due to the reduction in reporting requirements under this section.

Avoided Costs to Obligated Parties

UDCs under the current regulation have to report various types of customer data on a quarterly basis to the Energy Commission. The UDCs that will be relieved of the reporting obligation under this proposed modification have automated much of the reporting process and submit their information via email. The submittal is internally automatically processed at the Energy Commission. If there are specific issues with reporting, Energy Commission staff must resolve the issues by talking with UDC staff. On a quarterly basis, about 30 minutes is estimated to query the data and format, 30 minutes to compose the message to the Energy Commission, attach the data file, and transfer the data. Historically there are a few mistakes in data reporting, which take an estimated 4 hours every quarter to discuss and resolve. The reporting requirement is not eliminated until ~~January 1~~ after February 15, 2020~~19~~; therefore, there are ~~is~~ no avoided costs in the first and second fiscal years. Elimination of the reporting requirement would result in an avoided cost in fiscal year 2019/20~~2018/19~~ of $781~~758~~ for the three investor-owned utilities, and $520~~505~~ for the two local publicly-owned electric utilities. In fiscal year 2020/21~~2019/20~~, avoided costs are estimated to be $804~~1,561~~ for investor-owned utilities and $536~~1,041~~ for local publicly-owned electric utilities).[12]

Avoided Costs to the State

The Energy Commission has two staff that manage and work on the electricity data which is submitted through Section 1306 (a). According to estimates from past reporting, staff estimates that they would annually spend 4 hours less on validating and reviewing data, 16 hours less on resolving data issues, and 4 hours less on appending and updating the database. It is assumed this work would be performed by an Energy Commission Specialist I at an hour rate of $43.88. The reporting requirement does not change until ~~January 1~~after February 15, 2020~~19~~; therefore, there is no avoided cost in fiscal year ~~2017/18 and~~ 2018/2019. Estimated savings of $652~~633~~ begin in fiscal year ~~2018/19 and $1,117 in the fiscal year~~ 2019/20 and rise to $671 in fiscal year 2020/21.

[12] Assumes the work is performed by a senior engineering utility staff with an hourly rate of $68.13 estimated from a PG&E engineering positions Glassdoor salary survey.

Potential Impacts of Proposed Regulations (Gov. Code § 11346.3, subd.(b).)

The proposed regulations within Section 1306 (a) would not result in the creation or elimination of any jobs within California. Existing businesses and staff would perform the work necessary to meet the new obligation. No new businesses would be created and neither would any existing business be eliminated by the new regulations. The proposed regulatory changes would not expand any existing businesses doing business in California and there would be no direct benefits of the data collection to the health and welfare of California residents, to worker safety, or to the state's environment.

Section 1308 (a) and (b) Monthly Natural Gas Data

The proposed regulatory language is a clarification of existing language that has been inserted at the request of obligated parties to reflect current conditions within California's natural gas distribution network. No changes to reporting would result from the changing of the proposed location names.

Costs to Obligated Parties

There are no cost impacts to obligated parties due to clarifying distribution location names. The proposed language would not result in any changes to reporting processes.

Costs to the State

There are no cost impacts to obligated parties due to clarifying distribution location names. The proposed language would not result in any changes to reporting processes.

Potential Impacts of Proposed Regulations

The proposed regulations within Section 1308 (a) and (b) would not result in the creation or elimination of any jobs within California. Existing businesses and staff would perform all the work necessary to meet the new obligation. No new businesses would be created and neither would any existing business be eliminated by the new regulations. The proposed regulatory changes would not expand any existing businesses doing business in California and there would be no direct benefits of the data collection to the health and welfare of California residents, to worker safety, or to the state's environment.

Section 1308 (c) Monthly Natural Gas Deliveries

The proposed regulation would relieve the three largest natural gas utilities from quarterly reporting of customer data identified in Section 1308 (c) after ~~January 1~~February 15, 2020~~19~~. This change would result in a savings to both natural gas utilities and Energy Commission staff for processing, managing, and validating the submitted data. It is important to note that the reduction in reporting under this section is coupled with a new requirement that more customer data be provided by the natural gas utilities under proposed Section 1353. The costs associated with those reporting requirements are addressed in the discussion of that section, below. The following costs savings are estimated for both obligated parties and state staff from the reduction in reporting requirements under this section.

Avoided Costs to Obligated Parties

Natural gas utilities have to report under the current regulation various types of customer data on a quarterly basis to the Energy Commission. The natural gas utilities that would be relieved of the reporting obligation under this proposed modification have automated much of the reporting process and only have to submit their information in electronic format; this information is then internally automatically processed. If there are specific issues with reporting, Energy Commission staff must resolve the issue by talking with natural gas utilities. On a quarterly basis, about 30 minutes is estimated to query the data and format, 30 minutes to compose the message to the Energy Commission, attach the data file, and transfer the data. There can be a few mistakes that take time to resolve and this is estimated to take about 30 hours every quarter and would involve communicating with Energy Commission staff to resolve. The three natural gas utilities would no longer be required to report after ~~January 1~~February 15, 2020~~19~~; therefore, there are ~~is~~ no avoided cost in the first and second fiscal years. For fiscal year ~~2018/19 estimated savings are $3,579 and fiscal year~~ 2019/20 estimated savings are $3,686~~7,373~~ and for fiscal year 2020/21 estimated savings are $3,797 .[13]

Avoided Costs to the State

The Energy Commission has staff that manages and works on the natural gas data which is submitted through Section 1308 (c). Based on past experience working with this data, staff estimates that every year they would spend 4 hours fewer on validating and reviewing data, 30 hours fewer on resolving data issues, and 4 hours fewer on appending and updating the database. It is assumed this work would be performed by an Energy Commission Specialist I at an hour rate of $43.88. The reporting requirement does not change until ~~January 1~~after February 15, 2020~~19~~; therefore, there are ~~is~~ no avoided costs in the first and second fiscal years. In the fiscal year 2019/20~~18/19~~ state avoided costs are estimated at $884~~859 and $1,769 for fiscal year 2019/20~~ and in fiscal year 2020/21 state avoided costs are estimated at $911.

Potential Impacts of Proposed Regulations (Gov. Code § 11346.3, subd.(b).)

The proposed regulations within Section 1308 (c) would not result in the creation or elimination of any jobs within California. Existing businesses and staff would perform all the work necessary to meet the new obligation. No new businesses would be created and neither would any existing business be eliminated by the new regulations. The proposed regulatory changes would not expand any existing businesses doing business in California and there would be no direct benefits of the data collection to the health and welfare of California residents, to worker safety, or to the state's environment.

Section 1314 Natural Gas System Analysis ~~Modeling Data~~

The natural gas utilities are responsible for monitoring and managing the natural gas distribution systems to ensure the safe operation of the distribution system, and to ensure an adequate supply of cost effective resources is available to customers, including electric generators. One important activity natural gas utilities perform to meet these responsibilities is modeling the natural gas distribution

[13] Assumes the work is performed by a senior engineering utility staff with an hourly rate of $68.13 estimated from a PG&E engineering positions Glassdoor salary survey.

system using hydraulic modeling software. The proposed data regulations require the three California natural gas utilities to provide their hydraulic modeling data to the Energy Commission.

Costs to Obligated Parties

Since the modeling work is already performed in the normal course of business for the obligated three largest natural gas utilities, this regulation would not require them to collect additional data. Similarly, the data infrastructure already exists to manage the data and there is no need for additional databases or querying to gather the data. However, there is estimated to be a small cost associated with gathering the data, transferring it to the Energy Commission, and being available to address any questions and resolve data issues. Gathering the data is expected to cost $2,105~~2,044~~ and the data transfer is estimated to cost $421~~409~~ in fiscal year 2018/19~~2017/18~~ and would involve the delivery of the data via a secure electronic method. Although the natural gas utility staff time to address questions and data issues may change over time, the Energy Commission estimates that on average it would take 20 hours at a total annual cost of $4,210~~4,088~~ in the first year of reporting, assuming the work is performed by a Senior Gas Control System Engineer with an hourly rate of $68.13. In summary, the Energy Commission estimates the total costs for all three obligated natural gas utilities to be ~~$6,541 in fiscal year 2017/18,~~ $6,737 in 2018/19,~~ and~~ $6,939 in 2019/20, and $7,147 in 2020/21.

Costs to the State

The state has approved one position for the Energy Commission through a Budget Change Proposal (BCP). This position is for an engineer who will perform modeling and assessment of the natural gas sectors to ensure electric service reliability. The Department of Finance 2016-2017 Finance Letter Worksheet (3360-001-0381-2016) indicates a net impact of $579,666 for the one position with salary and wages, staff benefits, and operating expenses. Because this position has already been approved, the costs associated with it are not included in the fiscal impacts associated with the new regulation. No special equipment or infrastructure is required to handle or house the data.

In addition to the approved position, other Energy Commission employees will work with this data. State costs attributable to this work include those associated with data validation and review, resolving any issues, and finalizing data sets for simulation work. Annually the validation, resolving issues, and data finalization work will require 90 hours, 30 hours, and 10 hours, respectively.[14] This work is estimated to total ~~$3,760 in fiscal year 2017/18,~~ $7,745 in fiscal year 2018/19, $7,978 in fiscal year 2019/20, and $8,217 in fiscal year 2020/21.

Potential Impacts of Proposed Regulations (Gov. Code § 11346.3, subd.(b).)

Only the three largest natural gas utilities are required to comply with the reporting requirements of this section. For these utilities, the costs associated with compliance with this section are negligible and can likely be performed by existing staff, without creating new positions. Similarly, the Energy Commission would be able to process this information with existing staff, without creating new positions. Consequently, the proposed Section 1314 would likely not result in the creation or elimination of any

[14] Reporting will being half way through fiscal year 2017/18 so the costs are estimated at half the total annual costs.

jobs within California. Furthermore, because compliance with this section would not affect natural gas utility operations, this section would neither create nor eliminate any businesses doing business in California, nor would it expand any existing businesses in California. Finally, because this regulation only provides for the collection of information by the Energy Commission for analytical purposes, there would be no direct benefit of the data collection to the health and welfare of California residents, to worker safety, or to the state's environment. However, collecting this information would have indirect benefits, including the ability to perform modeling of the natural gas distribution network and develop associated energy policies to address natural gas and electric system reliability and impacts to the environment associated with the state's natural gas and electricity systems. These are discussed generally in the Benefits section of the ISOR, and specifically in the explanation of the Purpose and Necessity for this section

Section 1344 (f) Emerging ~~Behind-the-meter~~ Load Impacts

At any given time, the energy demand information collected from customer meters represents only the amount of energy sold to the customer at that time, not the actual amount of energy being consumed by the customer. For example, if the customer owns generation, such as a photovoltaic system or storage, such as a battery system, the amount of energy sold by the UDC to the customer does not necessarily reflect the amount of energy consumed. In addition, the use of electric vehicles can have a profound effect on the grid. Electric vehicles (EV) require charging and also have the potential to act as mobile energy storage resources. Much research has been performed to evaluate the process for what is referred to as vehicle-to-grid integration, creating the infrastructure and information to utilize electric vehicles to assist with electric grid management.

These resources and loads modify the consumption measured by the UDC meter. In order to evaluate and understand the magnitude of these resources on the broader energy needs, the rates of adoption, and the operational behaviors, the amount of energy consumed by electric vehicles and the amount generated by PV systems and storage (including EVs) need to be quantified. This requires data on activities that occur 'behind-the-meter,' meaning that the information being collected must come from the location where the activity occurs, and not at the UDC meter, where customer demand and supply are aggregated. This information can be collected by methods such as surveying or monitoring representative populations over time, measuring the demand of specific end-uses or generation (called sub-metering), collecting information from generation sources through smart inverters, or estimating loads by leveraging other studies or research. As part of the operation, planning, and monitoring of the electricity grid, utilities study grid impacts using these methods.

In order to improve the peak demand load forecasts, disaggregate the impacts of these new behind-the-meter resources, track the success or failures of specific policies and programs, and assist with development of new policies, the amendments proposed for this regulation would require the five largest UDCs to provide a detailed summary of ~~the detailed load data from~~ their behind-the-meter research targeting three specific potential impacts: photovoltaic installations, energy storage systems, and electric vehicles.

Costs to Obligated Parties

The proposed regulations obligate the five largest UDCs to provide a summary of their ~~the~~ behind-the-meter impact research ~~information~~ to the Energy Commission. Since the regulation is explicitly limited to work being performed by the UDCs, there is only a cost to transmit the information to the Energy Commission. In some cases, there would be minimal coordination required by the UDC staff to gather the information obtained during the load research to provide to the Energy Commission.

There are likely instances where multiple groups within a UDC would lead different areas of load research, which would require some coordination within the UDC to gather the summary information necessary to comply with the proposed regulations. Most of the cost would involve the initial identification ~~and coordination~~ of the research performed ~~data collection~~ with a much shorter amount of time required afterwards, since key UDC staff would be engaged in the reporting process. The Energy Commission estimates that it would take approximately 80~~160~~ hours in the first fiscal year to gather the existing reports~~data~~ for reporting, which would include identifying and contacting appropriate UDC staff, internally discussing and reviewing information, and collecting the required summary documents~~data~~. Energy Commission staff estimates it would take 40 hours each subsequent year to complete this work, since it assumed a procedure for communication, identification, and delivery of summary reports ~~data~~ would be promulgated.

Once the information is collected, the summary reports ~~data~~ would be organized and transferred to the Energy Commission. The Energy Commission estimates that it would take 8 hours to organize and describe the data and another 8 hours to determine appropriate transfer methods and transfer the files to the Energy Commission in fiscal year 2017/18. Once the initial procedures are developed for document ~~data~~ transfer, it is estimated to take only 4 hours to transfer the information. Following delivery, clarifying questions regarding the research~~data~~ would need to be addressed and are estimated to initially cumulatively involve 20~~40~~ hours of UDC staff time for the first document~~data~~ delivery and only 8 hours for future documents~~data~~, since many of the types of questions would have been identified. Using the hourly rate for a Systems Analyst of $93, the total costs for fiscal year 2018/19~~2017/18~~ are $33,335~~60,264~~ for the three investor-owned utilities and are $22,223~~40,176~~ for the two local publicly-owned electric utilities. Costs for fiscal year 2019/20~~2018/19~~ are estimated to be $17,759~~17,242~~ and $11,840~~11,495~~ respectively for investor-owned utilities and local publicly-owned electric utilities, and for fiscal year 2020/21~~2019/20~~ are estimated to be $18,292~~17,759~~ and $12,195~~11,840~~ respectively for investor-owned utilities and local publicly-owned electric utilities.

Costs to the State

The energy load impact research ~~data~~ would need to be reviewed~~,~~ and categorized~~, and formatted~~. After the load research summaries are~~data is~~ provided to the Energy Commission, the documentation~~data~~ would need to be evaluated for to understand the scope and depth of the research performed~~quality, representativeness, and any missing data~~. This work is estimated to take Energy Commission staff 20~~40~~ hours. Energy Commission staff would then need to resolve any issues with the summary documentation~~data~~ collaboratively with the obligated utilities. The resolution of issues should be straightforward and would primarily involve obtaining additional descriptive or explanatory information from the utilities. Communicating with UDC staff and clarifying the documents~~data~~ is estimated to take 8~~16~~ hours. ~~Once the data is complete and clearly understood, Energy Commission staff would evaluate the data and format to integrate into the development of regional or local area peak load estimates. The evaluation and formatting of the data is estimated to take 80 hours.~~ This work involves an understanding of both the research~~data~~ and the peak load evaluations and would be performed by a mid-level Energy Commission staff, Energy Commission Specialist II. The fiscal year 2018/19~~2017/18~~ total annual cost for these activities is estimated at $1,787~~6,556~~, for fiscal year 2019/20~~2018/19~~ the costs are $1,841~~6,752~~, and for fiscal year 2020/21~~2019/20~~ the costs are $1,896~~6,955~~.

Potential Impacts of Proposed Regulations (Gov. Code § 11346.3, subd.(b).)

Only the five largest UDCs are required to comply with the reporting requirements of this section. For these utilities, the costs associated with compliance with this section are negligible, and can likely be performed by existing staff, without creating new positions. Similarly, the Energy Commission would be able to process this information with existing staff, without creating new positions. Consequently, the proposed Section 1344 (f) would likely not result in the creation or elimination of any jobs within California. Furthermore, because compliance with this section would not affect UDC operations, this section would neither create nor eliminate any businesses doing business in California, or would it expand any existing businesses in California. Finally, because this proposed regulation only provides for the collection of information by the Energy Commission for analytical purposes, there would be no direct benefit of the data collection to the health and welfare of California residents, to worker safety, or to the state’s environment. However, collecting this information would have indirect benefits by incorporating peak load impacts from emerging behind-the-meter loads into the load data provided using electric meters. These benefits are discussed generally in the Benefits section of the ISOR, and specifically in the ISOR explanation of the Purpose and Necessity for this section.

The proposed regulations within Section 1344 (f) would not result in the creation or elimination of any jobs within California. Existing businesses and staff would perform all the work necessary to meet the new obligation. No new businesses would be created and neither would any existing business be eliminated by the new regulations. The proposed regulatory changes would not expand any existing businesses doing business in California and there would be no direct benefits of the data collection to the health and welfare of California residents, to worker safety, or to the state’s environment. However, collecting this information would have indirect benefits, including the development of better electricity demand forecasts and an improved ability to track the role of these specific behind-the-meter activities in meeting the state’s greenhouse gas emissions reduction and other energy goals. These are discussed generally in the Benefits section of the ISOR, and specifically in the explanation of the Purpose and Necessity for this section.

Section 1353 Disaggregated Demand Data

The proposed Section 1353 regulation requires each UDC that has either a peak electricity demand of 1,000 megawatts or more or natural gas utility that delivers 200 million therms or more for both of the two preceding calendar years to report detailed customer data to the Energy Commission. This data would include interval meter data when available and would provide the data necessary to support data quality measures, track progress to meet goals, and allow for local forecasting analytics. Similar data is also required from the state's largest three natural gas utilities.

Section 1353 (a) Disaggregated Data Reporting

As the Energy Commission begins collecting more detailed information from the UDCs and natural gas utilities, specific reporting requirements associated with the new detailed information are required to ensure appropriate reporting, transmission, and explanations of the data. The proposed data reporting regulations specify the frequency and scope of the data delivery. In addition, the proposed regulations require the obligated parties to provide explanations of the data provided so the Energy Commission understands what the data represents and can make informed decisions about the appropriateness and uncertainty of the data use for Energy Commission analytical purposes.

Costs to Obligated Parties

The only costs attributable to subdivision (a) are those associated with the requirement that the obligated parties provide information regarding the methodology and procedures for estimating values would involve work on the part of the utilities to summarize and report to the Energy Commission. On the electric side, UDCs San Diego Gas &~~and~~ Electric Company, Southern California Edison Company, Pacific Gas and Electric Company, Los Angeles Department of Water and Power, and Sacramento Municipal Utility District will report. On the natural gas side, natural gas utilities Southern California Gas Company, San Diego Gas &~~and~~ Electric Company, and Pacific Gas and Electric Company will report. The six electric and natural gas utilities (four investor-owned utilities and two local publicly-owned electric utilities) required to report under Section 1353 (b) and (c) would need to identify and determine all methods used to estimate data that they would be reporting.[15] It is estimated that it would take 160 hours in fiscal year 2018/19~~2017/18~~ to identify all the appropriate methods and would involve communication within the utilities across staff. The explanation of the methods and procedures would have to be summarized, which is estimated to take 80 hours. Once completed, the report would need to be provided to the Energy Commission and is estimated to take 5 hours each reporting cycle. It is assumed each of the six obligated parties use Systems Analyst staff at a rate of $93 per hour.[16] This results in costs for fiscal year 2018/19~~2017/18~~ of $114,948~~93,000~~ for investor-owned utilities, and $57,474~~46,500~~ for local publicly-owned electric utilities.[17] Recurring costs would include packaging and sending the information, estimated at 5 hours for each submittal, and the additional time necessary to update the document if there are any changes to the methods or procedures, estimated at an average of 20~~10~~ hours for fiscal year 2018/19~~2017/18~~ and 20 hours for each subsequent fiscal year. Using the

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[15] There are six obligated parties for 1353 (a) since it covers both electricity (5) and natural gas (3) with two overlapping obligated parties.

[16] The Energy Commission was unable to find a reference to salaries or rates specifically for a utility Systems Analyst but believes that the average contracted programmer rate of $93 is a conservative estimate of the potential costs for the utilities. The actual rate of a utility analyst would likely be lower.

[17] Of the 6 obligated utilities, 4 are investor-owned utilities while 2 are publicly owned.

$93 per hour rate for UDC staff time, fiscal year ~~2018/19 costs are $22,990 for investor-owned utilities and $11,495 for local publicly-owned electric utilities, and for fiscal year~~ 2019/20 costs are $23,679 for investor-owned utilities and $11,840 for local publicly-owned electric utilities<u>, and for fiscal year 2020/21 costs are $24,390 for investor-owned utilities and $12,195 for local publicly-owned electric utilities</u>.

Costs to the State

In order to understand the data provided to the Energy Commission, staff would need to evaluate and understand any estimation methodologies being used to compile the data provided to the Energy Commission. A review and discussion regarding the methodologies of the procedures identified by the utilities is estimated to take 120 hours. It is also estimated that staff would have questions regarding the methods and would need to work with utilities to clarify their understanding of the procedures. The communication and clarification of the methods is initially estimated to take 20 hours. The costs for fiscal year <u>2018/19</u>~~2017/18~~ are $<u>6,951</u>~~6,748~~, assuming an Energy Commission Specialist II would be responsible for this work. Once the procedures are understood, future changes to the methods and any clarification discussions are estimated to take 20 hours total per year and result in a cost for fiscal year ~~2018/19 of $993, and a cost for fiscal year~~ 2019/20 of $1,023<u>, and a cost for fiscal year 2020/21 of $1,053</u>.

Potential Impacts of Proposed Regulations (Gov. Code § 11346.3, subd.(b).)

Only the five largest electricity and three natural gas utilities are required to comply with the reporting requirements of this section. For these utilities, the costs associated with compliance with this section are negligible, and can likely be performed by existing staff, without creating new positions. Similarly, the Energy Commission would be able to process this information with existing staff, without creating new positions. Consequently, the proposed Section 1353 (a) would likely not result in the creation or elimination of any jobs within California. Furthermore, because compliance with this section would not affect UDC or natural gas utility operations, this section would neither create nor eliminate any businesses doing business in California, or would it expand any existing businesses in California. Finally, because this regulation only provides for the collection of information by the Energy Commission for analytical purposes, there would be no direct benefit of the data collection to the health and welfare of California residents, to worker safety, or to the state's environment. However, collecting the estimation methodologies would have indirect benefits, similar to those discussed below for subdivisions (b) and (c).

Section 1353 (b) Monthly and Interval Meter Electricity Data

The proposed data regulations require the largest five UDCs to provide customer-level monthly and interval data, with the interval depending on the metering technology for the customer. This data would be provided quarterly. Current data regulations require the UDCs to provide monthly consumption and revenue information aggregated by county and customer classification code on a quarterly basis. The proposed regulations would instead require the UDCs to replace the aggregated data by providing data by the customer meter.

Costs to Obligated Parties

The utilities are currently required to provide aggregated customer consumption information whereas the proposed regulations would require the UDCs to provide meter level customer data. Since the UDCs have been aggregating this data to report to the Energy Commission, providing the disaggregated information would require a modification of existing queries to their databases. The development of a query of the system to provide the proposed data is estimated to take 320~~160~~ hours for each UDC over the first ~~two~~ fiscal year~~s~~, costing ~~approximately~~ $153,264~~75,000 each year ($74,400 in fiscal year 2017/18 and $76,632 in fiscal year 2018/19)~~ assuming a consultant Systems Analyst rate of $93 per hour.

The collection of the data using the automated reporting process is estimated to take 10 hours for each quarterly report which would include data quality checks and resolving issues with the queried data. The data would need to be briefly summarized with a data dictionary or other explanations and then delivered to the Energy Commission. Summarizing the data is estimated to take 5 hours and reporting should only take an hour for each submitted report. This work would also be performed by a Systems Analyst with an hourly rate of $93 per hour.

This results in costs for fiscal year 2018/19~~2017/18~~ of $110,350~~53,568~~ for investor-owned utilities and $73,567~~35,712~~ for local publicly owned electric utilities.[18] Costs are estimated to be $18,943~~64,371~~ and $12,629~~42,914~~ respectively for privately owned and local publicly owned electric utilities in 2019/20~~2018/19~~, and $19,512~~18,943~~ and $13,008~~12,629~~ respectively for privately owned and local publicly-owned electric utilities in 2020/21~~2019/20~~.

Costs to the State

The Energy Commission is implementing a data repository solution that would be capable of managing the monthly and interval meter data proposed for collection in Section 1353 (b). The cost of data storage for this new data is discussed in the "Data Storage Costs" section of this Economic Impact Assessment. Because the Energy Commission's existing framework for data governance and data management processes will apply to this new data there are no governance or management costs associated with the receipt of this new data. As discussed in that section, the Energy Commission estimates costs of $204,462~~50,000~~ for f~~F~~iscal y~~Y~~ear 2018/19, ~~and~~ $390,926~~78,718~~ for f~~F~~iscal year 2019/20, and $577,390 for fiscal year 2020/21.~~[19]~~

The data acquisition staging, testing, validation, and developing access procedures work will take a group of Energy Commission staff comprised of Senior Programmer Analysts and Energy Commission

[18] Of the five obligated UDCs, three are investor-owned utilities while two are local publicly-owned electric utilities. All reporting and data collection costs are assumed to equal across all five utilities.

~~[19] As discussed in the General Assumption, Data Storage Costs estimation, the AWS S3 cost estimate is at $39,659 for Fiscal Year 2018/19 and $78,718 for Fiscal Year 2019/20. However, to be conservative, the Energy Commission has used $50,000 for Fiscal Year 2018/19 as estimated by the Resources Agency to provide storage services.~~

Specialist IIs an estimated 1240 hours to complete these one-time activities across fiscal years ~~2017/18 and~~ 2018/19 and 2019/20.

Ongoing data review and validation work would take about 160 hours each quarter. Resolving data issues is estimated to take 40 hours per quarter. Additionally, data analysis and making the data usable for forecasting staff is estimated to take another 60 hours per quarter. All of this work would be performed by Energy Commission Specialist IIs. The data review, data issue, and analysis work would result in fiscal year 2018/19~~2017/18~~ costs of $31,775~~15,4525~~, $7,944~~3,856~~, and $11,916~~5,784~~, respectively. The cost of housing the data is estimated to be $204,462~~50,000~~ fiscal year 2018/19. The total costs to the Energy Commission are estimated at $302,269~~69,893~~ in fiscal year 2018/19~~2017/18~~, $455,390~~120,530~~ in fiscal year 2019/20~~2018/19~~, and $643,787~~123,720~~ in fiscal year 2020/21~~2019/20~~.

Potential Impacts of Proposed Regulations (Gov. Code § 11346.3, subd.(b).)

Only the five largest UDCs are required to comply with the reporting requirements of this section. For these UDCs, the costs associated with compliance with this section are negligible, and the required reporting can likely be performed by existing staff, without creating new positions. Similarly, the Energy Commission would be able to process this information with existing staff, without creating new positions. Consequently, the proposed revisions to Section 1353 (b) would likely not result in the creation or elimination of any jobs within California. Furthermore, because compliance with this section would not affect UDC operations, this section would neither create nor eliminate any businesses doing business in California, or would it expand any existing businesses in California. Finally, because this regulation only provides for the collection of information by the Energy Commission for analytical purposes, there would be no direct benefit to the data collection to the health and welfare of California residents, to worker safety, or to the state's environment. However, collecting this information would have indirect benefits, including the to the ability to perform regional and local electricity demand forecasts, the ability to perform data quality analyses, and the ability to cross reference data across data sets. These in turn will allow the Energy Commission to track the various factors that affect electricity consumption and the effectiveness of programs and policies designed to assist the state in meeting its reliability, greenhouse gas emissions reduction, and other energy goals. These are discussed generally in the Benefits section of the ISOR, and specifically in the explanation of the Purpose and Necessity for this section.

Section 1353 (c) Monthly Natural Gas Customer Data

The proposed regulations obligate natural gas utilities whose annual natural gas deliveries exceed 200 million therms in the two preceding calendar years (Pacific Gas and Electric, Southern California Gas, and San Diego Gas & Electric~~PG&E, SoCalGas, and SDG&E~~), to provide monthly data for each customer to which service is provided. This is basically the disaggregated data set of what is already provided to the Energy Commission in aggregated form under Section 1308.

Costs to Obligated Parties

In order to provide customer level natural gas data, each of the three obligated parties would need to develop queries of their metering and billing systems. Given the current aggregated reporting requirements, the Energy Commission expects existing queries or methods for reporting could be modified to comply with the proposed customer-level data requirements. The Energy Commission estimates that to develop, test, validate the data collected, and develop reports for data delivery (the initial one-time query development) would take 200 hours in fiscal year 2018/19~~FY 2017/18~~. Data collection activities, compiling, validating, and summarizing the data is estimate to take a total of 60 hours (30 hours for collection and 30 hours for validation and summarizing) for each quarterly reporting. Once summarized, the data would be transferred to the Energy Commission to be incorporated into the existing data base that houses the current aggregated data. The Energy Commission estimates there to be an additional 10 hours of work for each quarterly reporting to deliver the detailed information. In fiscal year 2018/19~~2017/18~~, the total cost for obligated parties is estimated at $136,264~~94,860~~ and includes the one-time costs. Annual costs in fiscal year 2019/20~~2018/19~~ are estimated at $82,878~~80,464~~ and in fiscal year 2020/21~~2019/20~~ are estimated at $85,364~~82,878~~.

Costs to the State

The Energy Commission would need to modify the existing data collection process to accommodate the new customer level data. This would involve expanding the existing data base, modifying the data acquisition processes, and performing new data quality and validation work on the data. One time development costs are estimated using a consultant programmer at an hourly rate of $93 and Energy Commission Senior Programmer Analysts at an hourly rate of $51.75. Most of this work would be modifying the system to incorporate the new data, to manage a web-based data loading process for reporting, and to test the new system.[20] These costs estimates include contracting for programming services.

The Energy Commission staff time would focus on reviewing, validating the data, and resolving data issues. It is estimated that it would take Energy Commission staff 80 hours to review and validate and an additional 40 hours to resolve any reporting issues for each quarterly reporting. Costs estimates are $301,352~~153,727~~ for fiscal year 2018/19~~2017/18~~, $182,228~~291,002~~ for fiscal year 2019/20~~2018/19~~, and $144,155~~143,419~~ in fiscal year 2020/21~~2019/20~~.

Potential Impacts of Proposed Regulations (Gov. Code § 11346.3, subd.(b).)

Only the three largest natural gas utilities are required to comply with the reporting requirements of this section. For these utilities, the costs associated with compliance with this section are negligible, and can likely be performed by existing staff, without creating new positions. Similarly, the Energy Commission would be able to process this information with existing staff, without creating new positions. Consequently, the proposed revisions to Section 1353 (c) would likely not result in the creation or elimination of any jobs within California. Furthermore, because compliance with this section would not affect natural gas utility operations, this section would neither create nor eliminate any businesses doing business in California, or would it expand any existing businesses in California. Finally, because this regulation only provides for the collection of information by the Energy Commission for analytical purposes, there would be no direct benefit to the data collection to the health and welfare of California residents, to worker safety, or to the state's environment. However, collecting this information would

[20] The 3 year total hours for state work is 8410 hours of which 7210 is included as one time infrastructure costs.

have indirect benefits, including the data needed to perform regional and local forecasts, the ability to perform data quality processes, and the ability to cross reference data across data sets. These are discussed generally in the Benefits section of the ISOR, and specifically in the explanation of the Purpose and Necessity for this section. However, collecting this information would have indirect benefits, including the to the ability to perform regional and local natural gas demand forecasts and the ability to cross reference data across data sets. These in turn will allow the Energy Commission to track the various factors that affect natural gas consumption and the effectiveness of programs and policies designed to assist the state in meeting its reliability, greenhouse gas emissions reduction, and other energy goals. These are discussed generally in the Benefits section of the ISOR, and specifically in the ISOR explanation of the Purpose and Necessity for this section.

Section 2505 Designation of Confidential Records

The proposed regulatory changes within Section 2505 add a subdivision identifying new data collected under sections 1314 and 1353 as automatically confidential. Since the changes are purely administrative in nature and do not independently require additional reporting, the Energy Commission estimates there are no associated cost impacts.

Costs to Obligated Parties

There are no cost impacts to any obligated parties due to automatically designating new data submitted in sections 1314 and 1353 as confidential. The proposed language would not result in any changes to reporting processes.

Costs to the State

There are no cost impacts to the state due to automatically designating new data submitted in sections 1314 and 1353 as confidential. The proposed language would not result in any changes to reporting processes not already captured in other section evaluations.

Potential Impacts of Proposed Regulations

The proposed regulations within Section 2505 would not result in the creation or elimination of any jobs within California. Existing businesses and staff would perform all the work necessary to meet the new obligation. No new businesses would be created and neither would any existing business be eliminated by the new regulations. The proposed regulatory changes would not expand any existing businesses doing business in California and there would be no direct benefits of the data collection to the health and welfare of California residents, to worker safety, or to the state’s environment.

Form 399 Methodology Discussion

Economic Impact Statement

A. Estimated Private Sector Cost Impacts

The total economic impact of the proposed regulations is estimated at $5,774,662~~240,867~~ for the first three years, which would fall in the "below $10 million" per year category.

The number of total businesses being impacted is the sum of private cogenerator owners and investor-owned utilities. There are 102 private owners of cogeneration facilities and 7 investor-owned utilities for a total number of businesses of 109.

The Energy Commission has identified only a single private owner of a cogeneration facility which could meet the statutory definition of a small business. Given that the total number of businesses impacted is 109, the percent of small businesses impacted is 1 divided by 109 or approximately 0.9 percent.

B. Estimated Costs

Energy Commission estimates the total cost for the first three years of implementation as being $5,774,662~~240,867~~. As all reporting obligations would continue as long as the regulations were in place, salaries and state data storage costs would continue to increase, and the number of obligated parties might change, the total lifetime cost would be difficult to capture. Since the Economic and Fiscal Impact State document mentions a three-year time span, and because the regulations will be fully implemented after three years, Energy Commission staff used this as the basis of this total statewide cost estimate.

Table 2. Initial and Annual Ongoing Business Costs

Business	Number of Businesses	2017/18	2018/19	2019/20	2020/21
Investor Owned Utility	7	$0 ~~107,433~~	$142,652 ~~73,513~~	$59,933	$61,731
Private Cogenerator Owner	102	$0 ~~1,177~~	$1,393 ~~463~~	$477	$491
Weighted Average Cost	109	$0 ~~8,001~~	$4,295 ~~5,154~~	$4,295	$4,424

1. a. Small Business Cost Discussion

The small business "initial" cost is the estimated as the amount the small business is likely to pay in the year of implementation, fiscal year 2018/19~~2017/18~~. The small business is one of the 139 private and public owners of cogeneration facilities in the state and the total cost to these owners is $193,629~~163,622~~ ($129,270 + $25,744 + $25,744 + $12,872~~$119,552 + $44,070~~); therefore, the fiscal year 2018/19~~2017/18~~ cost would be $1,393~~1,177~~ (or (1/139) * $193,629~~163,622~~). Similarly, during fiscal year 2019/20~~2018/19~~ the cost to the small business would be $477~~463~~ (or (1/139) * $66,290~~64,359~~) and $491~~477~~ (or (1/139) * $68,278~~66,290~~) in fiscal year 2020/21~~2019/20~~ both of which include a 3 percent annual salary increase. The three-year average for the impacted small business is $623~~706~~.

1. b. Typical Business Cost Discussion

The typical initial costs for all affected businesses represents the cost of compliance with all new reporting requirements for private owners of cogeneration facilities and investor-owned utilities in fiscal year 2018/19~~2017/18~~, divided by the total number of such entities. The sum of all costs in fiscal year 2018/19~~2017/18~~ is $1,393~~1,177~~ for private owners of cogeneration facilities, and $142,652~~107,433~~ for investor-owned utilities. As mentioned above, the number of private owners of cogeneration facilities is 102 while the number of investor-owned utilities is 7. Therefore the weighted average initial cost impact is (($142,652~~107,433~~*7)+($1,393~~1,177~~*102))/(102+7) which equals $10,465~~8,001~~ in fiscal year 2018/19~~2017/18~~.

By fiscal year 2020/21~~2019/20~~, the regulations will be fully implemented; therefore, the costs in year three represent the ongoing cost of compliance, or the "typical annual impact" for each type of business affected by the proposed regulations. This represents $491~~477~~ for private owners of cogeneration facilities owners (including the single small business) and $61,731~~59,933~~ for investor-owned utilities, with a weighted average of $4,424~~4,295~~.

2. Discussion

The costs for owners of cogenerator facilities are ~~is~~ only due to proposed Section 1304 (a) regulations. The total cost over three years for owners of cogeneration facilities is $328,197~~294,270~~, the sum of both private and publicly-owned cogenerators three year costs in Table 1 ($239,800~~215,011~~ + $88,397~~79,259~~). The total three-year local public and private obligated party cost is $3,635,433~~3,172,403~~ (also from Table 1, $1,184,622~~1,063,842~~ + $2,450,810~~2,108,561~~). Therefore the percentage of costs for cogeneration facility owners is 9 percent and the percentage of utility costs is 91 percent.

C. Estimated Benefits

Over the first three fiscal years the total statewide benefit would be sum of avoided costs to all obligated parties and the state which totals $13,243~~19,194~~ as shown at the bottom of Table 1.

Fiscal Impact Statement

A. Fiscal Effect on Local Government

Approximate annual savings is calculated using the total avoided cost for public obligated parties (local publicly-owned electric utilities), $528~~1,546~~ from Table 1, and dividing by 2~~1.5~~ since the avoided costs are estimated for ~~will begin in the middle of~~ fiscal years 2019/20 and 2020/21~~18/19~~. Therefore the approximate annual savings is $1,559~~1,031~~.

B. Fiscal Effect on State Government

The approximate estimated expenditures are for the fiscal year when the regulations are implemented, fiscal year 2018/19~~2017/18~~. From Table 1 above, the total state costs in fiscal year 2018/19~~2017/18~~ are $644,820~~253,795~~.

Notice of Exemption

TO: Office of Planning and Research
1400 Tenth Street, Room 212
Sacramento, California 95814

FROM: California Energy Commission
1516 9th Street
Sacramento, California 95814

Project Title: *Data Collection Rulemaking*

Project Location: Statewide.

Description of Nature, Purpose, and Beneficiaries of Project: On February 21, 2018, the Energy Commission adopted modifications to its data collection regulations found in Chapter 3 and Chapter 7 of Division 2 of Title 20. Specifically, additions and/or deletions were made to Section 1302, 1304, 1306, 1308, 1344, 1353, and 2505. These modifications update the Energy Commission's data regulations to reflect changes needed as a result of changes in energy markets and new statutory mandates.

Name of Public Agency Approving Project: California Energy Commission

Name of Person or Agency Carrying Out Project: California Energy Commission

Exempt Status: (Check One)
___ Ministerial (Sec. 21080 (b)(1);15268);
___ Declared Emergency (Sec. 21080(b)(3); 15269(a));
___ Emergency Project (Sec. 21080(b)(4); 15269(b)(c));
___ Categorical Exemption: State type and section number: Action taken to protect the environment (CEQA Guidelines, § 15308)
___ Statutory Exemption: State code number:
_X_ Other: The report is not a "project" subject to CEQA (CEQA Guidelines, § 15378 (b)(2) & (5)); the report is exempt from CEQA pursuant to the "common sense" exemption (CEQA Guidelines, § 15061(b)(3)).

Reasons why project is exempt: The Data Collection Rulemaking is not a "project" subject to CEQA pursuant to CEQA Guidelines, Section 15378 (b)(2) and (5), in that it deals with general procedural activities or organizational and administrative activities and does not involve any commitment to any specific project that may result in a potentially significant physical impact on the environment. The report also falls within the so-called "common sense" exemption pursuant to CEQA Guidelines, Section 15061(b)(3), which indicates that CEQA only applies to projects that have a "significant effect on the environment" as defined in Public Resources Code section 21068 and in CEQA Guidelines, Section 15382, as being a substantial, or potentially substantial, adverse change in the environment. Furthermore, the report is categorically exempt from CEQA as an action taken to protect the environment pursuant to CEQA Guidelines, Section 15308.

Lead Agency Contact Person: Caryn Holmes
California Energy Commission
(916) 654-4178
caryn.holmes@energy.ca.gov

Signature: ___________________________

Date:____________________

Title:________________________________

☐ Signed by Lead Agency

Date Received for filing at OPR: _______________
Reference: Sections 21108, 21152, and 21152.1, Public Resources Code.

RESOLUTION NO: 18-0221-6

STATE OF CALIFORNIA

**STATE ENERGY RESOURCES
CONSERVATION AND DEVELOPMENT COMMISSION**

IN THE MATTER OF: **REGULATIONS GOVERNING DATA COLLECTION AND THE DESIGNATION OF CONFIDENTIAL INFORMATION**	**Docket No. 16-OIR-03** **RESOLUTION ADOPTING PROPOSED REGULATORY CHANGES**

WHEREAS, on August 4, 2017, the Energy Commission posted on the webpage for this proceeding, and filed in the docket of this proceeding the following:

1. the Notice of Proposed Action (NOPA) for the proposed regulations;
2. the Express Terms of the proposed regulations; and
3. the Initial Statement of Reasons (ISOR);

WHEREAS, on August 4, 2017, the Office of Administrative Law (OAL) published the NOPA for the proposed regulations in the California Regulatory Notice Register;

WHEREAS, the on August 4, 2017, Energy Commission mailed the NOPA to:

1. the Energy Commission's rulemaking and energydata electric mail list serve;
2. the sole small business enterprises that could be affected by the regulations;
3. every person who had requested notice of such matters; and
4. The Secretary of the California Natural Resources Agency; and

WHEREAS, the NOPA provided for a public comment period of 45 days, from August 5 through and including September 20. 2017;

WHEREAS, on January 26, 2018, the Energy Commission posted on the webpage for this proceeding, and filed in the docket of this proceeding public revised

Express Terms (15-day language) of the proposed regulations and an Addendum to the ISOR;

WHEREAS, on January 29, 2018, the Energy Commission notified the persons described in Government Code, section 11347.1(b) and California Code of Regulations, title 1, section 44 that the revised Express Terms (15-day language) and Addendum to the ISOR were available for public comment through and including February 13, 2018;

WHEREAS, the revised Express Terms (15-day language) of the proposed regulations were sufficiently related to the original text that the public was adequately placed on notice that the change could result from the originally proposed regulatory action.

THEREFORE BE IT RESOLVED, that the Energy Commission finds, based on the entire record for this proceeding, as follows:

A. <u>The Warren-Alquist Act</u>. The adopted regulations:

(1) provide for the delivery of data to the Energy Commission that is necessary for developing the policy reports and analyses required by Public Resources Code sections 35301 – 25310 inclusive;

(2) take into account the schedule of the integrated energy policy report, eliminate unneeded and duplicative data submittals from stakeholders, and are based on full consideration of the potential burden the data requirements impose on stakeholders;

(3) require only the submission of information that the reporting entity can be expected to acquire through its market activities;

(4) are based on an assessment of the practicability of using proxies and surveys, weighing the burden of compliance against the benefit of participant provided data for the public interest;

B. <u>The Administrative Procedure Act</u>. The adopted regulations:

(1) are not inconsistent or incompatible with existing state regulations;

(2) are not inconsistent or incompatible with existing federal law;

(3) impose a mandate on local governments or school districts (publicly-owned utilities (POUs)), but this mandate will not require reimbursement under Part 7 (commencing with Section 17500) of Division 4 of the Government Code

both because the mandates are not unique to POUs, affecting private sector and public sector large utilities equally, and because POUs have the ability to levy service charges to pay for any mandates, providing a revenue source for the POUs to recoup its costs of compliance;

(4) will result in costs to a state agency (the Energy Commission), as described in the NOPA and ISOR (including the addendum thereto);

(5) will result in savings to a state agency (the Energy Commission);

(6) will not result in nondiscretionary costs to local agencies or school districts, as describe in the as described in the NOPA and ISOR (including the addendum thereto);

(7) will not result in nondiscretionary savings to local agencies or school districts;

(8) will not result in costs or savings in federal funding to the State of California;

(9) will not have significant effect on housing costs;

(10) will not have a significant, statewide adverse economic impact directly affecting business, including the ability of California businesses to compete with other businesses in other states;

(11) will have cost impacts that a representative private person or business would necessarily incur in reasonable compliance with the regulations, as described in the as described in the NOPA and ISOR (including the addendum thereto);

(12) will not have an economic impact on California business enterprises and individuals in an amount exceeding fifty million dollars;

(13) will not have an impact on the creation of jobs within the state, as describe in the NOPA and ISOR (including the addendum thereto);

(14) will not have an impact on the elimination of jobs within the state;

(15) will not have an impact on the creation or elimination of businesses within the state;

(16) will not have an impact on the expansion of businesses currently doing business within the state, as describe in the NOPA and ISOR (including the addendum thereto);

(17) may result in benefits to the health and welfare of California residents, worker safety, and the state's environment, as described in the NOPA and ISOR (including the addendum thereto);

(18) will require a report from businesses, as described in the NOPA and ISOR (including the addendum thereto), which is necessary for the health and welfare of the people of the state, as the regulations should lead to improved understanding of the electricity and natural gas system operations, leading to better-targeted programs necessary to achieve state energy and environmental policies;

(19) have no alternatives that would be more effective in carrying out the purposes of the Warren-Alquist Act, that would be as effective and less burdensome to affected private persons in carrying out those purposes, or that would be more cost effective to affected private persons and equally effective in implementing those purposes; and

(20) will provide increased clarity to the regulated community.

C. <u>The California Environmental Quality Act (CEQA)</u>. The adopted regulations:

(1) are not a "project" subject to CEQA pursuant to CEQA Guidelines, section 15378 (b)(2) and (5), in that they deal with general policy and procedural activities or organizational and administrative activities and do not involve commitment to any specific project that may result in a potentially significant physical impact on the environment;

(2) are exempt from CEQA because they fall within the so-called "common sense" exemption pursuant to CEQA Guidelines, section 15061(b)(3), which indicates that CEQA only applies to projects that have a "significant effect on the environment" as defined in Public Resources Code section 21068 and in CEQA Guidelines, section 15382, as being a substantial, or potentially substantial, adverse change in the environment;

BE IT FURTHER RESOLVED, based on the entire record of this proceeding, the California Energy Commission hereby adopts the herein described amendments. We take this action under the authority of Public Resources Code sections 25213, 25218(e) and 25310, and to implement, interpret, and make specific Public Resources Code sections 25005.5, 25100-25141, 25216, 25216.5, 25223, 25300, 25301, 25302, 25303; 25303.5, 25305, 25302.1, 25302.2, 25310, 25322, 25324, 25330 et seq., 25364, 25366, 25400, 25401, 25401.2, 25403, 25403.5, 25602, and 25604 of the Public Resources Code, and sections 9615 and 9620 of the Public Utilities Code;

BE IT FURTHER RESOLVED, the Energy Commission directs the Executive Director, or an authorized designee, to take, on behalf of the Energy Commission, all actions reasonably necessary to have the adopted regulations go into effect, including but not limited to making any appropriate non-substantive changes to the regulations and preparing and filing all appropriate documents, such as the Final Statement of Reasons with the Office of Administrative Law, and making any changes to the rulemaking file required by OAL.

CERTIFICATION

The undersigned Secretariat to the Commission does hereby certify that the foregoing is a full, true, and correct copy of a Resolution duly and regularly adopted at a meeting of the California Energy Commission held on February 21, 2017.

AYE:
NAY:
ABSENT:
ABSTAIN:

Cody Goldthrite
Secretariat