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California Energy Commission

STAFF FINAL REPORT

Forms and Instructions for Submitting Electricity Demand Forecasts

Prepared in Support of the *2019 Integrated Energy Policy Report*

California Energy Commission

Edmund G. Brown Jr., Governor

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California Energy Commission

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ABSTRACT

The Energy Commission collects electricity demand forecast information from load serving entities in California in support of the *2019 Integrated Energy Policy Report*. This staff report provides forms and instruction that identify the information load-serving entities must submit on electricity demand forecasts, demand-side management and energy efficiency impacts, private supply impacts, and related information for 2019 through 2030, and historical years 2017 and 2018.

Keywords: Electricity demand, consumption, forecast, peak, self-generation, conservation, demand-side, energy, efficiency, price, retail, end use.

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EXECUTIVE SUMMARY

This report provides forms with instructions that identify the electricity demand forecast information load-serving entities with annual peak demand greater than 200 megawatts must submit to the Energy Commission. This includes information related to demand forecasts, energy efficiency and demand-side management impacts, private supply impacts, and related information for 2019 through 2030, and historical years 2017 and 2018. The Energy Commission will use the information collected to prepare electricity demand forecasts and assessments, as part of the *2019 Integrated Energy Policy Report*.

The Energy Commission is authorized to require California market participants to submit historical data, forecast data, and assessments. California Public Resources Code Sections 25216 and 25216.5 provide broad authority for the Energy Commission to collect data and information "on all forms of energy supply, demand, conservation, public safety, research, and related subjects."

The Energy Commission is directed by California Public Resources Code Sections 25300-25323 to regularly assess all aspects of energy demand and supply. These assessments will be included in the *2019 Integrated Energy Policy Report,* or in supporting reports, and provide a foundation for policy recommendations to the Governor of California, the California State Legislature, and other state agencies. The broad strategic purpose of these policies is to conserve resources, protect the environment, ensure energy reliability, enhance the state's economy, and protect public health and safety.

The Energy Commission electricity demand forecasts are used by the California Public Utilities Commission in integrated resource planning and resource adequacy proceedings and by the California Independent System Operator in transmission planning and grid reliability studies. The demand forecast information will also be used to analyze and develop recommendations on issues including progress in achieving energy efficiency, demand response, and renewable energy goals.

General Instructions for Demand Forecast Submittals

California Public Resources Code (PRC) Section 25301 directs the California Energy Commission to develop energy policies that conserve resources, protect the environment, ensure energy reliability, enhance the state's economy, and protect public health and safety, and to conduct regular assessments of all aspects of energy demand and supply. These assessments serve as the foundation for analysis and policy recommendations to the Governor, Legislature, and other agencies in the *Integrated Energy Policy Report* (*IEPR*). PRC Section 25301(a) allows the Energy Commission to carry out these assessments by requiring the

> submission of demand forecasts, resource plans, market assessments, related outlooks, individual customer historic electric or gas service usage, or both, and individual customer historic billing data, in a format and level of granularity specified by the commission from electric and natural gas utilities, transportation fuel and technology suppliers, and other market participants.

The Energy Commission's data collection regulations authorize these forms and instructions to collect data identified in California Code of Regulations (CCR), Title 20, Section 1345.

The Energy Commission is preparing to conduct assessments for the *2019 Integrated Energy Policy Report* (*2019 IEPR*). The adopted demand forecast, or range of forecasts, will provide a foundation for the analysis and recommendations for the *2019 IEPR*, including resource assessments and analysis of progress toward meeting energy efficiency, demand response, and renewable energy goals. These forecasts are used by the California Public Utilities Commission (CPUC) in integrated resource planning and resource adequacy proceedings and by the California Independent System Operator (California ISO) in transmission planning, resource adequacy, and grid reliability studies.

The Energy Commission uses data provided by the utilities to consider a range of perspectives on demand trends. The Energy Commission is requesting electricity demand forecasts, associated demand-side management (DSM), energy efficiency, and private supply impacts, and other related information from all load-serving entities (LSEs) with annual peak demand greater than 200 megawatts (MW). The forms and instructions in this report are to be used when submitting this information.

Separate documents will direct the contents and format of resource planning information. LSEs should verify that assessments submitted on resource plan forms are consistent with the submitted demand forecast.

Definitions of terms used in these forms and instructions are found on Page 33.

Questions relating to these forms and instructions should be directed to Kelvin Ke, Demand Analysis Office, by phone at (916) 654-4502 or by email at Kelvin.Ke@energy.ca.gov.

Who Must File

Data are requested from all LSEs whose annual peak demand in the last two consecutive years exceeded 200 MW.

PRC Section 25301 and CCR, Title 20, Section 1345 give the Energy Commission authority to require forecast submittals from all entities engaged in generating, transmitting, or distributing electric power by any facilities. These entities include utility distribution companies (UDCs), energy service providers (ESPs), community choice aggregators (CCAs) permitted to operate under Assembly Bill 117 (Migden, Chapter 838, Statutes of 2002), and all other entities that serve end-use loads, collectively referred to as LSEs. However, according to existing regulations, small LSEs[1] need not comply with the complete reporting requirements but may be required to submit demand forecasts in an alternative abbreviated form established by the Energy Commission. For this specific *IEPR* proceeding, the Energy Commission is not requesting long-term forecast data using these forms from any LSE with peak demand less than 200 MW.

Summary of Requested Data

UDCs (IOUs and POUs) are to submit Forms 1 through 6 and Form 8; ESPs are to submit Forms 7.1 and 8.1a (ESP); and CCAs are to submit Forms 4, 7.2, and 8.1a (POU/CCA) only. **Table 1** describes the data requested in each form and filing requirements for each type of LSE. More detailed descriptions of each form appear later in this report.

1 A small LSE has an annual peak demand of 200 megawatts or less in two consecutive calendar years preceding the required data filing date and is regulated by the CPUC or owned or operated by a public government entity.

Table 1: Demand Forecast Form Descriptions

Form	Form Description	Associated Forms	LSEs Required to Submit Data
1	Historical and Forecast Electricity Demand – annual sales and peak demand, private supply, and hourly loads	**1.1a** – Retail Sales of Electricity by Class or Sector (Bundled and Direct Access)	IOUs
		1.1b – Retail Sales of Electricity by Sector (Bundled)	IOUs/POUs
		1.2 – Total Energy to Serve Load	IOUs/POUs
		1.3 – LSE Coincident Peak Demand by Sector	IOUs/POUs
		1.4 – Distribution Area Coincident Peak Demand	IOUs
		1.5 – Peak Demand Weather Scenarios	IOUs/POUs
		1.6a – Recorded LSE Hourly Loads	IOUs/POUs
		1.6b – Hourly Loads by Transmission Planning Subarea	IOUs
		1.7a – Cumulative Historical and Forecasted Impacts of Photovoltaics and Combined Heat and Power	IOUs/POUs
		1.7b – Cumulative Historical and Forecasted Impacts of Battery Energy Storage	IOUs/POUs
		1.7c – Cumulative Historical and Forecasted Peak Impacts of Battery Energy Storage	IOUs/POUs
		1.8 – Monthly Photovoltaic Interconnection	IOUs/POUs
2	Forecast Input Assumptions–economic and demographic assumptions and electricity rate forecasts	**2.1** – Forecast Economic and Demographic Assumptions	IOUs/POUs
		2.2 – Electricity Rate Forecast	IOUs/POUs
		2.3 – Customer Count & Other Forecasting Inputs	IOUs/POUs

3	Incremental Demand Side Management Program Impacts, including energy efficiency, demand response, and distributed generation program impacts	**3.2** – Cumulative Incremental Impacts of Energy Efficiency	IOUs
		3.4 – Cumulative Incremental Impacts of Demand Response	POUs
4	Forecast Methodology Documentation	**4** – Forecast Methodology Documentation	IOUs/POUs/CCAs
6	Demand Side Management Methodology Documentation	**6** – Demand Side Management Methodology Documentation	IOUs/POUs
7	CCA and ESP Load Forecasts	**7.1** – ESP Report of Loads and Resources Under Contract	ESPs
		7.2 – CCA Forecast of Electricity Demand by Sector	CCAs
8	Price and Rate Forms	**8.1a (IOU)** – IOU Revenue Requirements by Major Cost Categories/Unbundled Rate Component	IOUs
		8.1a (ESP) – Estimated Power Supply Costs	ESPs
		8.1a (POU/CCA) – Budget Appropriations or Actual Costs and Cost Projections by Major Expense Category	POUs/CCAs
		8.1b (Bundled) – Revenue Requirements Allocation	IOUs/POUs
		8.1b (Direct Access) – Revenue Requirements Allocation for Direct Access Service Customers	IOUs

Changes From Previous *Integrated Energy Policy Report*

Changes to the *2019 Forms and Instructions for Submitting Electricity Demand Forecasts* are as follows:

- Forms 1.6c-1.6d Residential and Non-Residential Load Shapes; Form 3.3 Cumulative Incremental Impacts of Distributed Generation; and Form 8.2 Monthly Residential Sales by Baseline are no longer required.
- IOUs, POUs, CCAs, ESPs will each have a separate template for submitting the required data that contains only the forms relevant for each type of LSE.
- Forms 1.7a, 1.7b, and 1.7c were updated to streamline collection of distributed energy resource (DER) impacts and avoid duplication in data submissions.
- Form 4 was updated to request a description of the data and method used to prepare forecasts of DERs.
- Forms 8.1a-8.1b, revenue requirements, received minor updates. Items that previously would have been reported in more aggregate form now are reported as separate line items. These items include greenhouse gas allowance revenue returns, procurement costs for storage, and other revenue requirements allocated to generation and distribution rates. Obsolete items, such as DWR contract costs, were removed.

Due Dates

Historical sales information (Form 1.1a for years 2017-2018) and photovoltaic (PV) interconnection data (Form 1.8) must be submitted to the Energy Commission on or before **Monday, February 11, 2019**.

Forms 1 through 7 and Form 8.2 must be submitted on or before **Monday, April 15, 2019**.

Forms 8.1a and 8.1b must be submitted on or before **Monday, June 3, 2019**.

LSEs that require additional time may request an extension by submitting a written request to the Executive Director of the Energy Commission, as described in CCR, Title 20, Article 2, Section 1342.

Submittal Format Requirements

For all filings, parties are required to use the Energy Commission's e-filing system. This requires LSEs to submit their demand data and narratives electronically by uploading files using an internet connection and a modern browser. A user's guide to the Energy Commission's e-filing system is posted at http://www.energy.ca.gov/e-filing/.

After completing registration, log in and select the following proceeding from the drop-down menu: **19-IEPR-03 Electricity and Natural Gas Demand Forecast**.

When naming an attached file of 50 megabytes or less, please include the LSE's name in the filename. Attachments should be submitted as separate files and clearly identified. Cover letters that identify documents that are part of the filing are unnecessary.

If requesting confidentiality for any part of the submittal, please read and follow the instructions in *Appendix A: Confidentiality Applications*. For confidentiality applications that require document signatures, the words "Original signed by" and the signee's typed name can serve in lieu of a wet signature. **Yellow fill should be used to highlight all cells for which the LSE is requesting confidentiality**. Energy Commission staff will use color coding to track these requests and to protect data determined to be confidential.

Electronic information files are required for:

Data on specified forms using Microsoft Excel®.

Reports, narratives, and cover letters in Microsoft Word® or Adobe Acrobat®.

A template with data forms will be available on the Energy Commission website or by request. While it is preferred that filers use this template, participants may provide these results in their own format as long as the equivalent information is provided and clearly labeled.

Protocols for Submitted Demand Forecasts

The demand forecast submitted should be the projection of unmanaged total consumption most likely to occur. Unmanaged consumption means that the forecast should include impacts from demand-side management (DSM) activities that are approved and funded, and have a detailed implementation plan, but should not include impacts from programs or policies that are not finalized. Total consumption means that the forecast should include total electricity usage. Locally supplied energy is reported separately from sales. Because these forecasts provide a basis for resource assessments, total consumption at the end-user level must be adjusted by losses to reflect total usage at the generation level. Local private supply reduces system requirements and losses; therefore, forecasts of local private supply are also required from distribution utilities.

The primary purpose of the data requested is for each UDC to provide its view of demand trends and to document the methods and data used to develop the forecast. Some data may also be used for developing the staff forecast. The Energy Commission does not require the use of specific forecasting methods.

General instructions on how to submit the forecast:

- UDC forecasts are to provide projected electricity demand for 2019 to 2030 and historical data for 2017 and 2018. The historical data should represent actual amounts or the UDC's best estimate at the time of filing. ESPs should provide projections for the period through which they have contracted load.

- UDCs are to provide forecasts for expected “bundled” customers (customers to whom they provide both generation and distribution services) and for all customers they provide distribution services to, including direct access, CCA load, and any other form of LSE providing generation services to end users. Bundled load is reported on Forms 1.1 and 1.3. Total load is reported on Forms 1.2 and 1.4.
- UDCs are to prepare demand forecasts using one of the following:
  - Franchise service area defined by applicable state law or regulatory decisions lawfully determined by the CPUC
  - A definition of distribution utility service area that is mutually agreed upon by the distribution utility and Energy Commission staff
- The demand forecast and aggregate forecasts of incremental demand response and DSM impacts reported in these forms should be consistent with data submitted in accordance with the *2019 Forms and Instructions for Submitting Electricity Resource Plans*.

Specific Instructions

Data are requested from all LSEs whose annual peak demand in the last two consecutive years exceeded 200 MW.

UDCs are to complete only Forms 1 through 6 and Form 8. ESPs complete only Forms 7 and 8.1a (ESP). CCAs complete only Forms 4, 7, and 8.1a (POU/CCA).

Several forms request data by sector. Definitions of the sectors used in the Energy Commission forecast models are listed in the Definitions section on Page 32. However, UDCs that use other sectors or customer classes to develop their forecast should modify forms as needed to report the forecast using their own categories and document their sector or customer class definitions.

Form 1 Historical and Forecast Electricity Demand

Form 1.1 Retail Sales of Electricity by Class or Sector

Form 1.1a is for the entry of total retail sales of electricity to bundled and direct access customers, measured on the customer side of the meter in gigawatt-hours (GWh). Each UDC should modify the sectors listed on the Form 1.1 template to reflect the sectors or classes by which they forecast. The historical series (2002-2018) submitted through Form 1.1a should be consistent with the data used by that UDC in developing its sales forecast.

Form 1.1b is for the entry of total retail sales of electricity to bundled customers only. The distinction between Forms 1.1a and 1.1b is meant to streamline potential confidentiality requests for retail sales to bundled customers.

These forms also ask for documentation of the amount of load assumed to be migrating to or from the UDC and load growth associated with previously unserved areas. If the forecast of departing load is based on historical trends, this form should report historical data. IOU forecasts impacted by the planned formation or service expansion of a specific CCA should include the name of the CCA along with the expected magnitude of the load departure by sector (residential and nonresidential). Load forecasted to depart to yet unplanned CCA expansions should be indicated separately.

Form 1.2 Distribution Area Net Electricity or Generation Load

Form 1.2 is for the entry of electricity deliveries in GWh by type of customer and the addition of losses to calculate utility system energy requirements. Each UDC should report deliveries for the following categories, as applicable:

- Sales to bundled customers (from Form 1.1b)
- Deliveries to direct access customers

- Deliveries to customers of CCAs
- Deliveries to customers of other publicly owned departed or departing load (such as irrigation districts) in the UDC's distribution area

Losses are to be calculated at generation busbar and should represent total transmission and distribution losses, as well as any other unaccounted-for losses in the system.

Form 1.3 Peak Demand by Sector (Bundled Customers)

Form 1.3 records coincident peak demand by sector as well as for losses. The coincident peak is the sector peak at the time of the distribution area peak. Reported losses should be calculated at the generation busbar and include distribution, transmission, and unaccounted-for energy. Peak demand for residential and commercial sectors should, if possible, be separated into base load or weather-sensitive peak demand.

UDCs should also show the amount of migrating load assumed in the forecast. Investor-owned utilities (IOUs) should use this form to show the amount of load expected to be gained in newly developed areas or lost to municipalized load or community choice aggregation. Publicly owned utilities (POUs) should identify expected load growth or loss from migrating load or newly developed areas included in their base forecast.

Form 1.4 Distribution Area Peak Demand

Form 1.4 is for the entry of peak demand and losses at the time of the distribution system peak by type of customer, where the categories provided are:

- Coincident peak demand and losses of bundled customers (from Form 1.3).
- Coincident peak demand and losses of direct access customers.
- Coincident peak demand and losses of CCA entities.
- Coincident peak demand and losses of other publicly owned departing or departed load (such as irrigation districts) that are still in the distribution area.

Losses entered should represent total transmission and distribution losses at the point of generation, as well as any other unaccounted-for losses in the system.

Form 1.5 Peak Demand Weather Scenarios

This form records distribution area peak demand forecasts under high-temperature conditions. The cases, referred to as 1-in-5, 1-in-10, and 1-in-20, refer to peak demand under temperature conditions that have a 20, 10, and 5 percent chance of being met or exceeded, respectively. These conditions should be contrasted with the 1-in-2 baseline temperature condition that has a 50 percent chance of being met or exceeded.

Form 1.6a and 1.6b System Hourly Loads

Form 1.6a reports actual system hourly loads and losses for 2017 and 2018 and forecasted hourly loads for 2019. Hourly system loads are to be reported in MW. UDCs should provide a brief explanation of how loads were measured including the timing of hourly readings such as the beginning of the hour, the ending of the hour, or integration within the hour. In addition, corrections for Daylight Saving Time should be highlighted and include a description of correction method. If complete loads for 2018 are not yet available, filers are asked to submit at least through September 30, 2018.

Hourly loads should reflect integrated end-user load and the effects of demand-side programs, excluding private supply. IOUs are asked to report bundled and unbundled loads and losses separately. For historical years only, provide the estimated amount of curtailed load resulting from the triggering of demand response and interruptible programs. Moreover, UDCs are asked for estimates of actual outages by hour.

Form 1.6b is for reporting hourly loads for the same years as Form 1.6a but at a more disaggregate, or broken down, level of geography. The zones used should geographic subareas used for transmission planning studies or rate making (if applicable to the respondent).

Forms 1.7a, 1.7b, and 1.7c Private Supply Annual Capacity, Energy, and Peak

Forms 1.7a, 1.7b, and 1.7c are for the reporting of local private supply by sector or customer class and technology type. These forms represent the UDC’s estimate of total historical and forecasted private supply in the distribution area. Furthermore, drivers underlying growth in private supply over the forecast period should be discussed in Form 4. These forms represent the UDC’s estimate of total private supply in the distribution area. Policy decisions to pursue large goals of rooftop PV or other distributed generation (DG) on the customer side of the meter, such as combined heat and power (CHP) or cogeneration, implies the need for documentation of these influences on demand forecasting.

Form 1.7a focuses on capacity, energy, peak impacts from customer-owned (behind-the-meter) technologies such as photovoltaic, combined heat and power (cogeneration), and fuel cells. Forms 1.7b and 1.7c focus on capacity and peak impacts of battery energy storage systems.

Energy and peak load estimates should reflect how power generation systems are expected to operate, not simply installed capacity or potential energy. Private supply includes self-generation, DG on the customer side of the meter, "over-the-fence" sales from a CHP facility, or wheeling from a CHP facility to a final user. Indicate whether the installed capacity reported on these forms reflects nameplate rating or some other rating scheme.

Form 1.8 Photovoltaic Interconnection Data

Energy Commission staff has typically relied on PV incentive program data, such as the California Solar Initiative (CSI) and the Publicly Owned Utilities' SB 1 Solar Program (SB 1 POU), to track behind-the-meter customer-owned PV installations. In recent years, the CSI and SB 1 POU rebates are either expired or reduced to the extent that customers install systems without participating in an incentive program. As a consequence, the CSI and SB1 POU program data are no longer a comprehensive source for tracking PV installations. For this reason, Energy Commission staff requests utility interconnection data. Specifically, UDCs are required to report the total number and total capacity of customer-owned, behind-the-meter, interconnected PV systems, gathered by ZIP Code and county, interconnection date, and customer class. These data are requested for 2017 through 2018.

Specific variables to be reported include:

- Five-digit ZIP Codes and county in which systems were interconnected.
- Year and month in which projects received approval to interconnect.
- Total number of systems interconnected.
- Total capacity of interconnected systems in kilowatt (based on Energy Commission alternating current ratings).
- Customer sector installing systems.

CCR, Title 20, Section 1304(b) requires UDCs, on January 1 and July 1 of each year, to report comprehensive system-level PV and storage interconnection data to the Energy Commission. Any UDC that has already submitted to the Energy Commission interconnection data in compliance with CCR, Title 20, Section 1304(b) is not required to report interconnection data through Form 1.8, so long as the previously submitted data contain all the information required by Form 1.8, covering the years and aggregations described above.

Form 2 Electricity Forecast Input Assumptions

Electricity demand forecasts are based in part on projections of economic and demographic variables. Document these projections on Forms 2.1 through 2.4. UDCs may provide these variables in a different format as long as the equivalent information is provided and the variables are clearly labeled. The deflator series used to convert variables from nominal to real values should be provided in these forms. If different deflators are used for different variables, each deflator series should be provided.

UDCs should document the methods used to develop the economic and demographic projections, including historical data sources, projected data sources, appropriateness of source for forecast and a discussion of the plausibility of those projections in the Form 4 methodology report.

Form 2.1 Economic and Demographic Variables

Form 2.1 documents economic and demographic variables that are used directly in an LSE's energy demand forecast models. Examples include employment and output by industry, local population, and population by age groups, households and/or housing by type, and taxable sales.

Only those variables actually used to develop the forecast need be reported. UDCs, particularly those with large geographic planning/service areas, should provide any subutility regional breakdowns of population and income projections used in the development of the economic, demographic, or energy forecasts. Subutility regions may be individual counties, groups of counties, and/or weather zones.

Variables must be precisely defined. For example, population estimates should be accompanied by an identification of the source of the estimates and whether the estimates are midyear or end of year, and whether the estimates are for total population, civilian population, household population, or other subgroups.

Form 2.2 Electricity Rate Forecast

Form 2.2 allows for the reporting of projected retail electricity rates to develop the forecast. The rate forecasts should be reported using the same customer sectors or classes as Form 1.1. If forecasted rates are not available, report historic and current year estimates. Prices should not include local taxes and may be presented in nominal or real dollars, including the deflator. If the rate projections are derived from a specific resource supply plan, those plans should be documented or referenced.

Form 2.3 Customer Counts and Other Inputs

Form 2.3 provides recorded and projected customer counts by major customer sector as used to develop the forecast. Customer counts should reflect end users with whom the UDC has a generation services relationship. For example, an IOU should not report all customers in its service area, only the bundled service customers. The most convenient and consistent series is acceptable, but a narrative should explain the units reported and whether the annual values are derived from a specific point in time, a specific month, an average of months across the year, or another method.

Load Migration Drivers and Other Assumptions

Economic, demographic, and energy price projections may not exhaust all variables used by the participant to drive the energy demand forecast model(s). In particular, UDCs should identify the data used to project expected load migration. Some utilities may evaluate such factors as the amount and zoning of undeveloped land within the boundaries of the utility district; local residential, commercial, and industrial development policies; local population and income trends; annexation policies; and the general plan of the municipality. If other input assumptions affect the forecast, it is critical that they be documented. Additional narrative and spreadsheets can be provided, as appropriate.

Form 3 Demand-Side Management Program Impacts

This section of the forms and instructions summarizes the format requirements for reporting energy and coincident peak impacts of conservation, load shifting, demand response, and DG and renewable programs that are expected to be achieved by the reporting UDC. The impacts reported on this form should be incremental to DSM considerations embedded in the UDCs unmanaged demand forecast described by Forms 1.1 through 1.5.

Peak impacts should represent the expected impact at the time of distribution area peak. Alternatively, UDCs may report average impacts during their peak period. Each UDC should document what the peak impacts represent and which hours are considered the peak period.

These forms request data by market sector, such as residential, commercial, industrial, and agricultural. UDCs may modify the sectors used as needed to be consistent with the UDC analysis and forecasting methods.

Documentation of the method used to estimate impacts for each program should accompany these and are to be presented in Form 6.

Form 3.2 Incremental Energy Efficiency Impacts

Form 3.2 reports the estimated cumulative impacts resulting from programs or policies that are incremental to those considered in the unmanaged demand forecast, but that may still be considered reasonably likely to occur, particularly in pursuit of goals established by regulatory agencies. The combined impacts reported on this form should be consistent with those reported in compliance with the *2019 Forms and Instructions for Submitting Electricity Resource Plans*.

Form 3.4 Incremental Demand Response Impacts

Form 3.4 is for reporting expected coincident peak impacts for each demand response program. The term “demand response” encompasses a variety of programs, including traditional direct control (interruptible) programs and price-responsive programs. Therefore, programs are identified as dispatchable or nondispatchable.

Dispatchable programs are defined here as programs with triggering conditions that the customer does not control and cannot anticipate, such as direct control, interruptible tariffs, or demand bidding programs. Programs with triggering conditions are dispatchable whether they are a day-of or day-ahead trigger, and whether the trigger is economic or physical. POUs should treat energy or peak load saved from dispatchable programs as a resource and not a reduction to the demand forecast.

Nondispatchable programs are not activated using a predetermined threshold condition but allow the customer to make the economic choice whether to modify usage in response to ongoing price signals. Impacts from nondispatchable programs should be included in the demand forecast. For example, load reductions at on-peak hours subtracted from the base forecast and load shifting in off-peak hours added to the base forecast.

Form 4 Demand Forecast Methods and Models

Form 4 is for LSEs to document the electricity demand forecast methods, models, and data used to develop the submitted forecast forms. LSEs may include existing forecast model reports as an appendix to this form if this report includes the following required information.

LSEs should begin Form 4 by defining the area for which the forecast is developed identifying isolated loads and resale customers and describe how they are included or excluded from the forecast. Provide definitions of customer classes, including which rate classes are included in the categories for which forecasts are submitted.

After defining the forecast area and included customers, describe the method for forecasting electricity demand components such as end uses, fuel types, or structure types. Include key forecast model structural equations, for example, econometric models, behavioral equations, or identities. For sector models developed using aggregate econometric methods, provide data for all dependent and independent variables, reporting all standard statistical parameters for econometric models. Algebraic variables and variable mnemonics should be clearly defined.

LSEs should also discuss data sources and method used to forecast the growth in distributed energy resources (DER) such as photovoltaic and battery energy storage systems, as reported in Forms 1.7a through 1.7c. In particular, state assumptions characterizing customer profiles, retail rates, net energy metering, and technology specific costs and operational assumptions when developing forecasts of DERs. LSEs should also discuss policy and regulatory drivers behind its forecast of DERs such as zero-net-energy homes and electrification and proceedings at the California Public Utilities Commission, such as the distribution resources plan proceeding and the integrated resource plan. LSEs should also discuss assumptions behind photovoltaic production profiles such as geographic granularity, impact of extreme temperatures on photovoltaic production, and degradation rates. LSEs need to discuss assumptions behind battery energy storage charging and discharging. LSEs should also discuss the cumulative impacts of DERs in potentially shifting the hour of its system peak.

Last, discuss the reasonableness of differences between historical and forecasted growth patterns. Report the past performance of the forecasting method, including comparison of previous forecasts to actual annual weather-adjusted peak and energy demand; then discuss how the submitted forecast is reasonable in light of economic and demographic data, energy prices, demand-side-management technology and programs, state policy trends, and climate change.

Additional Forecast Detail

The following are additional topics that should be addressed in forecast method discussion:

Forecast Calibration Procedures

Most forecasts are calibrated to historical energy consumption and peak demand. Provide a comprehensive description of the method of forecast calibration.

Economic and Demographic Data

UDCs are required to provide documentation of the methods used to develop the economic and demographic projections reported in Form 2 and a discussion of the plausibility of those projections. They may include an economic and demographic methodology report as an appendix to this form. Documentation should include historical data sources, projected data sources, and reasoning of these sources for the forecast.

Historical Peak and Projected Peak Loads

Describe the methods and data used to develop the historical and projected peak loads of sectors or customer classes reported in Form 1.3.

Energy and Peak Loss Estimates

Forms 1.2, 1.3, and 1.4 include estimates of energy losses. Describe fully the method and data sources used to develop historical and forecast energy and peak losses. If the method uses a loss factor, specify what that factor is and discuss if that factor varies by year or by customer sector.

Estimates of Direct Access, Community Choice Aggregation, and Other Departed Load

UDCs should describe the methods, assumptions, and data used to forecast direct access, community choice aggregation, and other departed load reported in Forms 1.2 and 1.4. These should include a list of current and projected ESP and CCA entities in the distribution utility's planning area.

IOUs should describe the methods and data used to account for expected migrating municipal load in their forecasts. Data used to account for migrating or newly departed municipal load should be reported on Form 1 or 2, as appropriate.

POUs and CCAs that anticipate load growth from newly acquired load should identify the areas in which they are acquiring load and describe the data sources used to account for that load growth.

Weather Adjustment Procedures

Describe the process for adjusting the forecast to normal weather conditions and the sources of the meteorological data, including:

- Names and locations of the weather stations.
- Weights used for each weather station.
- Temperature variables used, such as daily maximum, heating and cooling degree days, or apparent temperature values.
- Base values of the temperature variables used and annual data used in the adjustment process.

UDCs should also describe the methods and assumptions used to develop the high-temperature cases (1-in-2, 1-in-5, 1-in-10, and 1-in-20) reported in Form 1.5. Provide a narrative discussion of the baseline peak temperature assumptions, how the high-temperature scenarios were developed, sources for the weather data, and the methods used to develop the temperature probability distributions. Include any climate change considerations used to adjust the expected relationship among these scenarios.

Hourly Loads by Subarea

If an LSE is submitting hourly loads for subareas of their service area in Form 1.6b, provide definitions of the reported subareas. Attach a file with geographic identifiers, such as ZIP codes, that define the region covered by each zone. Also, describe the source of the data, if from metered load, or the methods used to develop estimates of the subarea loads.

Local Private Supply Estimates

Describe fully the methods, assumptions, and data sources used to develop the estimates provided in Forms 1.7a through 1.7c. Because these are expected energy and on-peak effects, they require estimates of how facilities will actually be operated. Indicate the degree to which conservation efforts, financial incentives, and interruptible programs and negotiated rates have been incorporated into the self-generation forecast. Separate reports may be attached as long as these demand forms include a summary.

Energy Efficiency and Demand-Side Management

Explicitly discuss how energy efficiency and other demand-side impacts are incorporated into the final forecast for each sector. The description of how this is accomplished should be explicit for each sector, for both energy and peak demand. Methods might include:

- Direct inclusion of use of end-use models and appropriate inputs characterizing the impacts of standards or programs.
- Calculation of the difference from an unmitigated forecast without program savings in the historical or forecast period and a forecast with both historical and forecast program savings included.

- Separately computed savings for programs from other analytic techniques with some or all of these savings subtracted from a “raw model output” to produce the final forecast.

Climate Change and Electrification

The *IEPR* forecast includes the potential impacts of climate change and electrification that may cause forecasted demand to deviate from historical trends. UDCs are required to document any such considerations embedded within their own demand forecast, including references to studies, plans, and other sources that support their assumptions.

Form 6 Incremental Demand-Side Program Methodology

Form 6 is for providing a narrative description of the method used to determine DSM program impacts from Form 3, Demand-Side Program Impacts.

Efficiency Program Impacts

Discuss how estimates for potential efficiency program impacts were derived in Form 3.2. List and provide documented studies or sources used to support these assumptions. Moreover, describe the method by which potential load impacts are reconciled with the UDC’s demand forecast as reported in Form 1.

Demand Response Program Impacts

Discuss how the estimates of peak impacts were derived for each program in Form 3.3. Describe assumptions about eligible population, participation rates, price elasticities, wholesale market conditions, and prices used to develop the projections. Describe the method used to develop estimates of nondispatchable program impacts and the extent to which the forecast is consistent with recent program performance. For dispatchable programs, describe what criteria will be used in deciding whether to dispatch and how they will be operated to reduce the peak. For example, will the dispatch signal be sent each year to all or most customers, or only during emergencies, or on days when peak load passes a critical value?

Renewable and Distributed Generation Program Impacts

Discuss how the estimates of energy and peak impacts for each program were derived in Form 3.4. In particular, detail the method and data used to project impacts of solar programs. Describe assumptions about eligible population, participation rates, price elasticities, fuel prices, wholesale market conditions, and prices used to develop the projections. Last, describe criteria used in deciding how to model customer decisions to use these facilities in peak shaving or baseload modes.

Form 7 Energy Service Provider and Community Choice Aggregator Demand Forecasts

Form 7.1 Energy Service Provider Loads and Resources Under Contract

For each utility distribution area in which it serves load, each ESP should provide a projection of annual sales and peak demand for load currently under contract, for as many years as they have any contracted load. The submitted load forecast should correspond to the loads the ESP will report in the resource plan data request. ESPs may also choose, but are not required, to provide a forecast of expected load if that approach will be more consistent with the submitted resource information. Forecasts should not include reserve margins.

The variables to be reported, by utility distribution area, are:

- Annual metered sales in MWh, for customers under contract, before any losses.
- Annual peak demand in MW, including distribution losses, comparable to settlement data.
- Customer counts – residential and nonresidential. Note whether the units reported are number of customers or number of accounts, and whether the annual values represent a specific point in time, a specific month, or an average of months across the year.

Form 7.2 Community Choice Aggregator Load Forecast

Each CCA should provide projections of annual sales, peak demand, and customer counts for the service territory in which it offers generation services identifying the UDC providing distribution services. Using Form 4 as a guide, CCAs should provide narrative description of their forecast method, including assessments of energy efficiency programs, distributed resources, or any other programs or technologies that may impact long-term forecasts of electricity demand.

Form 8 Retail Price and Rate Forms

These forms gather financial data on electric costs, revenue requirements, and cost allocation.

General Instructions

- Provide all financial data in thousands of nominal (current-year) dollars through 2030.
- LSEs may use either fiscal year or calendar year data to report (or project) annual data. For LSEs that report based on a fiscal year, the “year” is the starting year of the fiscal year. Note if the data are on a fiscal year basis, and the start and end dates used.

Form 8.1a Revenue Requirements by Major Cost Categories/Unbundled Rate Component

Form 8.1a includes three forms: Form 8.1a (IOU), Form 8.1a (POU/CCA), and Form 8.1a (ESP). Investor-owned utilities are to complete Form 8.1a (IOU), publicly owned utilities are to complete Form 8.1a (POU), and retail energy service providers are to complete Form 8.1a (ESP).

Form 8.1a (Investor-Owned Utilities)

This form requests each IOU's major costs in the recent past and estimates of major costs over the next 10 years. For 2017 through 2019, IOUs are requested to report their CPUC-authorized revenue requirements, not actual costs.

Form 8.1a (IOU) identifies 10 major revenue-requirement categories: Generation, Transmission, Distribution, Nuclear Decommissioning, Public Purpose Programs, California Department of Water Resources (DWR) Bond Charge, Ongoing Competitive Transition Charge, Regulatory Asset for Energy Recovery Bond (PG&E only), Taxes and Franchise Fees, and Other Costs Not Already Reported. The following instructions explain which financial information to report or project under each category.

Generation Revenue Requirements

The IOUs must base their generation revenue requirements upon the same quantities and types of electricity supply reported to the Energy Commission in their electricity resource plan submittals, Forms S-1 and S-2. Generation revenue requirements include utility-owned generation and purchased power. Utility-owned generation costs distinguish between fuel and nonfuel revenue requirements. Fuel-related revenue requirements include fuel purchases and associated carbon allowance costs, transportation, and storage. Nonfuel revenue requirements are the sum of operations and maintenance expenses, depreciation, return on investment, and all other costs.

Utility-owned means generation built or acquired by the IOU that is either placed in the rate base or treated as a cost-based asset for rate recovery. The utility-owned generation section is further subdivided into of the following generating resource types:

- Nuclear
- Conventional Hydroelectric
- Hydroelectric Pumped Storage
- Natural Gas-Fired Generation
- Coal
- Renewables Portfolio Standard (RPS)-Eligible Resources
- Battery Storage

Conventional hydroelectric generators and hydroelectric pumped-storage plants are defined here as facilities that do not qualify as eligible for California's RPS to avoid double-counting of costs to avoid double-counting of generating facilities that are hydroelectric and RPS-eligible. Natural gas-fired generation includes all utility-owned steam generation units, combined-cycle power plants, combustion turbines, and DG facilities.

For conventional hydroelectric generation, projected "fuel" costs are for water rights. "Fuel" costs for hydroelectric pumped storage are the energy costs associated with off-peak pumping.

For utility-owned generation that is natural gas-fired or coal-fired, report the average annual fuel price that was used to estimate generation-fuel revenue requirements in dollars per million British thermal units. Also report the projected California carbon allowance price in dollars per metric ton of carbon dioxide equivalent used to estimate future procurements costs.

RPS-eligible renewables are electricity-generating facilities that use one or more types of renewable energy resources or fuels to operate and that meet the RPS eligibility criteria. IOUs may aggregate, or combine, revenue requirement dollar amounts for all types of renewable energy facilities.

Form 8.1a (IOU) will subtotal each year's projected costs for each type of utility-owned generation. In addition, it will subtotal the revenue requirement amounts for all types of utility-owned generation.

Purchased power costs are requested for:

- Qualifying facilities (QF), excluding QF contract expenses that are recovered through the competition transition charge (CTC). These are reported in "CTC" costs.
- Non-QF renewable resource costs.
- Battery electric storage resource costs.
- All other bilateral contracts, such as any other contracts for forward energy, capacity, or call or put options.[2]
- Residual market transactions, including energy-related short-term market activity such as short-term contracts (less than three months) and spot-market purchases.

2 A *forward contract* allows two parties to buy or sell an energy resource at a price and at a future time both specified by the contract. Call and put options guarantee the holder the right to buy and sell, respectively, an energy resource at a specified price.

- Payments to California ISO for market charges: report non-energy-related market participation costs such as grid management charges, ancillary services, and California ISO uplift costs.
- All other generation expenses, program costs, or balancing accounts not reported elsewhere.

Transmission Revenue Requirements

Report costs associated with Federal Energy Regulatory Commission–jurisdictional transmission assets for the following categories:

- Base transmission revenue requirement includes transmission system operations and maintenance, depreciation, and return on investment. Report authorized revenue requirements and projected expenses for network improvements and large transmission projects identified in the five-year transmission plan with the California ISO.
- Transmission Revenue Balancing Account Adjustment.
- Transmission Access Charge Balancing Account: reports amounts billed by the California ISO under the Transmission Access Charge structure to be recovered from retail customers.
- Reliability Services includes costs for exceptional dispatch and to operate reliability must-run generators for local voltage support.

Distribution Revenue Requirements

This section of Form 8.1a (IOU) reports authorized revenue requirements and projected expenses for each IOU's CPUC-jurisdictional distribution assets.

"Base Distribution Revenue Requirement" includes operations and maintenance, depreciation and amortization, return on investment, and other costs collected in the distribution rate.

In addition, report-authorized revenue requirements and projected costs to implement each of the following programs or other expenses:

- Self-Generation Incentive Program
- Demand response programs
- California Solar Initiative and successor programs such as the Multifamily Affordable Solar Housing and Single-Family Affordable Solar Housing programs
- Electrification programs or infrastructure Investment
- Catastrophic Event Memoranda Accounts addressing cost recovery for events such as wildfires, floods, or risk-reduction activity
- All other distribution programs and balancing account revenue requirements

Nuclear Decommissioning

IOUs with cost responsibility for decommissioning a nuclear power plant are requested to report authorized revenue requirements and estimated future costs.

Public Purpose Programs

Report annual cost projections for implementing for programs funded by ratepayers through public purpose program rates or related adjustment mechanisms:

- Low-income programs (including subsidies for medical/life-support equipment users)
- Energy efficiency programs and related costs
- Electricity Program Investment Charge

DWR Bond Charge

Provide projected annual costs for DWR revenue bond charges.

Competition Transition Charge

Each IOU is requested to project total annual costs to be collected through the ongoing competitive transition charge.

Greenhouse Gas (GHG) Emission Allowance Revenues

Provide data on actual and projected GHG emission allowance revenues to be returned to customers.

Taxes and Franchise Fees

Provide an annual estimate of future revenue requirements for taxes and franchise fees if not already reported in other revenue requirements. Taxes may include federal income, state corporation franchise, property, payroll, business, and superfund taxes. Franchise fees are those levied by city and county governments.

Other Costs Not Already Reported

IOUs are requested to include a forecast of the total of any other costs not already reported.

Total Revenue Requirements

The spreadsheet template will add all of the separate costs to produce total revenue requirements. The spreadsheet also duplicates the annual values for total revenue requirements onto the top rows of Form 8.1b (Bundled) and Form 8.1b (Direct Access).

Form 8.1a (Publicly Owned Utility and Community Choice Aggregator) Budget Appropriations or Actual Costs and Cost Projections by Major Expense Categories

Through this form, Energy Commission staff seeks to learn recent historical and projected annual revenue requirements of POUs and CCAs (collectively LSEs). Some categories on this form are not expected to apply to CCAs. The form identifies three major cost categories: operating expenses, capital outlay, and debt service, plus appropriations from LSE revenues into reserve funds, city general funds, or other municipal accounts.

The following instructions define what financial information to report or project under each cost category. For 2017 through 2018, LSEs are requested to report their approved budget appropriations or actual costs, whichever data are more readily available.

Operations Expenses

Operating expenses are costs to operate and maintain power generation, transmission, and distribution systems and to provide billing and information services to customers. Governing boards or city councils adopt annual or biennial operating expense budgets that appropriate electricity sales revenues (and other income) to pay these expenses. The same costs identified in the operating-expense budgets will be reported and projected in this section of the form.

Form 8.1a (POU/CCA) organizes operating expenses into two broad categories: operations and maintenance of power production, transmission, and distribution assets; and customer-related expenses.

Power Production

Form 8.1a (POU/CCA) divides power-production expenses into two categories (utility-owned generation and power purchases).

Utility-Owned Generation

Utility-owned generation expenses are costs for operating and maintaining electric generating facilities that were built or acquired by the LSE. Power plants built and jointly owned by multiple POUs through joint powers authorities (JPAs) are not included in this section. Similarly, if the LSE financed power plant construction through a subsidiary financing authority at that financing authority and now has a power purchase agreement with the POU, that power plant is not utility-owned generation.

Report data on expenses for utility-owned generation using the following resource categories:

- Nuclear
- Conventional hydroelectric
- Hydroelectric pumped storage
- Natural gas-fired generation
- Coal
- Generation from renewable resources

Costs are divided into two subcategories:

- Fuel expenses

- Other operations and maintenance expenses

In addition to the fuel commodity (for example, natural gas), fuel expenses include emission allowance costs, labor for purchasing and handling fuel, payments for natural gas pipeline use or coal transportation services, payments for fuel-storage facilities, insurance, sales commissions, and residual disposal expenses. For hydroelectric plants, fuel expenses include water purchases, payments for licenses or permits for water rights, and payments for riparian rights. For hydroelectric pumped-storage facilities, fuel expenses include electricity costs for off-peak pumping.

For natural gas-fired and coal-fired power plants, provide the fuel price forecasts used in dollars per million British thermal units. Also report the projected California carbon allowance price in dollars per metric ton of carbon equivalent that was used to estimate future procurements costs. “Other Operations and Maintenance” expenses include labor costs for operating and maintaining the structures and equipment used for electricity generation and for supplies and operating permits.

Power Purchases

Power-purchase expenses are costs to the utility for electricity purchased for resale. They include net settlements for exchanges of electricity or power, such as economy energy, and for transactions under pooling or interconnection agreements.

Federal Power

Provide cost information for federal power purchases, such as purchases from the Western Area Power Administration or Bonneville Power Administration.

Contracts With Joint Power Authority

California’s POUs have cofunded many power plant (and transmission line) projects through joint power authorities (JPAs), including the Northern California Power Agency and the Southern California Public Power Authority. Provide JPA power-purchase costs for the following categories of generating facilities:

- Nuclear
- Coal
- Conventional hydroelectric
- Natural gas-fired
- Renewable resources

Contracts With POU Subsidiaries

POUs may have financed power plant construction through subsidiaries (for example, the Sacramento Municipal Utility District Financing Authority) rather than the POU itself issuing a revenue bond or another type of debt instrument. Provide annual costs for purchased power from these subsidiaries. If more than one power purchase agreement exists, report an aggregated total.

Bilateral Contracts

Bilateral contracts are legally enforceable agreements between an LSE and a supplier for electricity deliveries in the future, including forward energy, capacity, and tolling agreements. Report bilateral contracts for power supplies separately for the total of all renewable resource contracts and all other bilateral contracts.

Other Resources

Under "Other Resources," provide cost projections for future power supplies not already reported in Form 8.1a as Utility-Owned Generation or as a type of purchased power because the ownership of these supplies is unknown at this time.

Surplus Power Sales Revenue

Report as a negative value the expected revenue generated from selling energy that is not needed to meet retail load.

Transmission Expenses

Form 8.1a (POU/CCA) provides three subcategories for reporting transmission expenses:

- Operations and maintenance of utility-owned transmission system
- Payments to JPAs for transmission investments or services
- Other transmission-related expenses

Operations and maintenance expenses of the utility-owned transmission system include the POU's cost of labor, materials, and other costs of operating and maintaining utility-owned transmission lines.

California's POUs have cofunded transmission line projects through JPAs, including the Transmission Agency of Northern California and the Southern California Public Power Authority. POUs are requested to report their annual payments to JPAs for these transmission investments/services. These expenses represent a POU's share of operating expenses, capital costs, and long-term debt service for JPA-owned transmission projects, as well as other services.

POUs may use "other transmission-related expenses" to document costs for transmitting POU electricity over transmission lines owned by others, such as the Western Area Power Administration, IOUs, and other private-sector owners.

Distribution Expenses

POUs' distribution expenses include the cost of labor, materials, and other supplies and services for operating and maintaining utility-owned distribution facilities. Distribution facilities include substations, line transformers, voltage regulators, poles, overhead and underground lines, utility-owned streetlights and signals, and meters.

Each POU is requested to provide an aggregate of all its distribution-related operations and maintenance expenses (recent historical and projected).

Customer-Related Expenses

Provide an annual total for all customer-related service expenses. Customer-related expenses include the cost of activities such as meter-reading, billing, service connections and disconnections, and advertising. Do not include expenses incurred to implement the LSE's public benefit programs.

General and Administrative Expenses

General and administrative expenses include salaries and wages for officers and employees who provide services not assignable to a specific utility function. For POUs that are electric departments, general and administrative expenses also include fund transfers for services provided to the electric department by other city departments.

Public Benefit Programs

Report costs to implement the following categories of public benefit programs:

- Low-income rate discounts and energy efficiency services
- Energy efficiency programs (excluding procurement)
- California Solar Initiative
- All other public benefit programs

Energy Efficiency Expenses From Procurement Budget

Expenses for energy efficiency programs paid from the generation or procurement budgets should be reported here.

Operating Expenses Not Already Reported

Form 8.1a (POU/CCA) includes this section for POUs to report and forecast all other operating expenses, if any.

Capital Improvement Plan Projects

This section requests approved budgets associated with long-range capital improvement plans for expenditures funded by utility revenues rather than debt instruments. Capital project expenditures are requested for four categories:

Generation

Capital expenditures for utility-owned generation include the cost for land and land rights, structures and improvements, the installed cost of all power plant equipment, and asset retirement costs. Hydroelectric capital expenditures also include the cost of dams, reservoirs, and waterways.

Transmission

Capital expenditures for the utility-owned transmission system include land and land rights, structures and improvements, and the installed cost of station equipment, towers and fixtures, poles and fixtures, overhead conductors and devices, underground conduit, underground conductors and devices, roads and trails, and asset retirement costs.

Distribution

Capital expenditures for the utility-owned distribution system include land and land rights, structures and improvements, and the installed cost of station equipment, poles, towers and fixtures, overhead conductors and devices, underground conduit, underground conductors and devices, line transformers, meters, street lighting and signal systems, and asset retirement costs. Report expenditures on this line for all distribution system capital improvement projects except deployment of advanced metering systems.

All Other Capital Improvement Projects

Report the sum of all other capital improvement project expenditures in this section, including capital improvement costs associated with public benefit programs. Add a footnote at the bottom of this form that explains that the reported amount includes capital costs for public benefit-related projects.

Debt Service

Debt service is the sum of an LSE's repayments of principal and interest due each year on its outstanding long-term debt (for example, revenue bonds) and commercial paper notes, and trustee fees and debt issuance costs.

Reserve Fund Contributions

LSEs make annual contributions to various reserve funds, such as rate stabilization funds, insurance and accident reserve funds, bond payment reserve funds, and credit support collateral reserve funds. Provide a total of all contributions to various reserve funds.

Transfers to City General Fund, Payments in Lieu of Taxes, and Other Fees

When a POU is an enterprise business within a municipal governmental, the city charter may direct the electric utility department to make annual contributions to the city's general fund. Such contributions may also be referred to as "Payments in Lieu of Taxes." POUs may also pay other municipal fees, such as right-of-way fees.

Provide recent historical and an annual forecast of annual payments to the city general fund and other municipal fees. For POUs that are electric departments, do not include fund transfers to other city departments for general and administrative services. Instead include such transfers in the general and administrative line of the Operating Expenses section.

Form 8.1a (Energy Service Provider)

Form 8.1a (ESP) reports data on historical and future power-supply costs to serve existing direct access customers for ESPs. Provide an annual estimate of historical and future costs for all supply contracts, reported by two categories:

- Bilateral contracts, including contracts for energy and/or capacity entered into before the delivery time. Bilateral contracts include capacity-only contracts to meet resource adequacy requirements
- Residual market transactions including short-term (less than three months) or spot-market purchases of electricity

Form 8.1b (Bundled)

Form 8.1b (Bundled) reports the allocation of revenue requirements among bundled-customer classes. Report allocation to the generation and distribution rate components and the aggregation of all other revenue requirement categories (for example, transmission and public purpose programs). Report the allocation for the following classes of bundled customers:

- Residential/Domestic
- Commercial
- Industrial
- Agricultural
- All other customer classes (for example, street lighting)

The customer classes listed above match those used by Energy Commission staff to forecast electrical demand; however, they may not match how some utilities define their commercial and industrial customer classes. Use rate schedules for small and medium-sized customers as the proxy for all “commercial” customers and rate schedules for large customers as the proxy for “industrial” customers. Alternatively, LSEs may modify the class categories to be consistent with the classes used on their submitted demand forecast.

Form 8.1b (Direct Access)

Respondents are requested to complete Form 8.1.b (Direct Access) by projecting the annual total of revenue requirements they intend to collect from direct access customers, if applicable. Respondents that do not have direct access customers do not need to fill out this form. Report the portion of annual revenue requirements intended for collection from residential and nonresidential customers.

ACRONYMS AND ABBREVIATIONS

Acronym/Abbreviation	**Original Term**
2019 IEPR	*2019 Integrated Energy Policy Report*
AC	Alternating current
California ISO	California Independent System Operator
CCA	Community choice aggregator
CCR	California Code of Regulations
CHP	Combined heat and power
CPUC	California Public Utilities Commission
CSI	California Solar Initiative
CTC	Ongoing Competitive Transition Change
DG	Distributed generation
DSM	Demand-side management
DWR	California Department of Water Resources
Energy Commission	California Energy Commission
ESP	Energy service provider
GWh	Gigawatt-hours
IEPR	*Integrated Energy Policy Report*
IOU	Investor-owned utility
JPA	Joint powers authority
kW	Kilowatt
kWh	Kilowatt-hour
LSE	Load-serving entity
MW	Megawatt
NAICS	North American Industry Classification System
PG&E	Pacific Gas and Electric Company
POU	Publicly owned utility
PRC	California Public Resources Code

Acronym/Abbreviation	Original Term
PV	Photovoltaic
QF	Qualifying facility
RPS	Renewables Portfolio Standard
SB1 POU	Publicly Owned Utilities SB1 Solar Program
UDC	Utility distribution company

DEFINITIONS

Ancillary Services: Those services necessary to support the transmission of electric power from seller to purchaser given the obligations of control areas and transmitting utilities within those control areas to maintain reliable operations of the interconnected transmission system.

Bonneville Power Administration: One of four power marketing administrations within the U.S. Department of Energy whose role is to market and transmit wholesale electricity from multi-use water projects. Bonneville Power Administration's service territory covers Washington, Oregon, and small pieces of western Montana and western Wyoming.

Bundled customers: Customers who receive distribution and generation services from the same LSE.

Cogeneration: An arrangement whereby a utility or customer-owned facility sequentially produces thermal energy for process heat or space conditioning use and electrical energy for private use, or for sale to an electric utility, or some combination thereof.

Customer sectors: Customer sectors used by the Energy Commission are defined using the following NAICS categories.

Table 2: Economic Sector Definitions and NAICS Codes

Economic Sector	NAICS Codes
Residential: private households, including single- and multifamily dwellings and mobile homes.	RE00-RE39, 001-003, and 814

Commercial	115, 326212, 42, 44-45, 493, 512, 514, 518-519, 52-55 (excluding 5324), 561, 61, 62, 71,72, 81 (excluding 814), 92 (excluding 9225, 9226, and 92811)
Industrial	11331, 21 (excluding 211-213), 31, 32 (excluding 326212), 33, and 511
Mining/Resource Extraction/Construction	211-213, 23
Agricultural and Water Pumping	111, 112, and 22131
Transportation, Communication, Utility (TCU)	221 (excluding 22131), 48, 49 (excluding 493), 513, 517, 5324, 562, and 92811
Street Lighting/Traffic Signals	922198, 922199, 9225, 9226, 925130, 925140, and 925190

Source: California Energy Commission

Distributed generation: Electricity production that is on-site or close to the load center and is interconnected to the utility distribution system. Large generation plants (such as qualifying facilities) that interconnect to the utility at transmission voltages would not be considered distributed generation.

Electricity consumption: The amount of electricity used to provide energy services through both utility sales and local private supply of electricity.

Forward energy: A forward contract allows two parties to buy or sell an energy resource at a price and at a future time both specified by the contract.

Load-serving entity: An umbrella term encompassing all entities that provide generation services to end users, whether or not it owns or operates a distribution system. Examples are traditional investor-owned utilities, municipal utilities, energy service providers permitted to operate under applicable law, community choice aggregators permitted to operate under AB 117, and all other entities that serve end-use loads.

Local private supply: Local private supply is supply from self-generation, customer-owned distributed generation, private sales "over-the-fence" from a cogeneration facility, or energy produced by a cogeneration facility and delivered over the transmission system to a final user.

Qualifying facilities: Cogeneration and small power production facilities that were provided certain benefits and exemptions under the Public Utility Regulatory Policies Act of 1978.

Self-generation: Any generation of electricity by a final user for his own use, regardless of the technology used. The portion of cogeneration retained for the customer's own use is self-generation even if this is a small portion of overall facility output.

Tolling agreement: A contract between a power buyer and a power generator, under which the buyer supplies the fuel and receives an amount of power generated based on an assumed heat rate at a specified cost.

Utility distribution company: A utility that owns and/or operates an electricity distribution system that interconnects end-user loads with a generator serving more than one end-user load or the interconnected transmission grid.

Western Area Power Administration: One of four power marketing administrations within the U.S. Department of Energy whose role is to market and transmit wholesale electricity from multi-use water projects. Western Area Power Administration covers California, Nevada, Utah, Arizona, New Mexico, Utah, most of Montana, most of Wyoming, west Texas, North and South Dakota, Nebraska, western and southern Kansas, and the western edges of Minnesota and Iowa.

APPENDIX A: Confidentiality Applications

Repeated Applications for Confidentiality

Information submitted to the California Energy Commission can be deemed confidential without the need for a new application under CCR, Title 20, Sections 2505(a)(1)(G) and 2505(a)(4) if you file a certification under penalty of perjury that the new information is substantiality similar to the previously granted confidentiality.

In this case, your current application will serve as your certification, and the designation of confidentiality will be under the same terms as the prior designation. The information will remain confidential under the same terms as the prior designation for the same or comparable period identified by the applicant in the application. When submitting substantially similar information, you may take advantage of the repeated application process by providing a certification along with the data.

How to Request Confidentiality

The Executive Director of the Energy Commission has responsibility for determining what information submitted with an application for confidentiality will be deemed confidential. Parties who seek such a designation for data they submit must make a separate, written request that identifies the specific information and provides a discussion of why the information should be protected from release, the length of time such protection is sought, and whether the information can be released in aggregated form.

Certain categories of data provided to the Energy Commission, when submitted with a request for confidentiality, will be automatically designated as confidential and do not require an application. The types of data that are eligible and the process for obtaining this confidential designation are specified in CCR, Title 20, Section 2505(a)(5). The Energy Commission has its own regulations distinct from those governing the CPUC, and CPUC determinations on confidentiality are not applicable to data submitted to the Energy Commission.

Parties should be aware that some confidential data may be disclosed after aggregation according to CCR, Title 20, Section 2507(d) or (e). Both historical and forecast energy sales data may be disclosed if reported at the following levels:

For individual ESPs, data may be aggregated at the statewide level by major customer sector.

For the sum of all ESPs, data may be aggregated at the service area, planning area, or statewide levels by major customer sector.

For the total sales of the sum of all electric retailers, data may be aggregated at the county level by major generator, utility, and ESP groups as these groups are defined by the U.S. Census Bureau in their NAICS tables.

Data that are not included in these categories, but that the filer believes are entitled to confidential treatment, should be submitted when due along with an application for confidential designation so that the Executive Director can review the information and make a determination about its confidential status. To do this, please carefully read and follow the instructions.

What a New or Repeated Confidentiality Application Must Have

Applications for confidentiality and the confidential documents must be uploaded directly to Dockets through the e-filing system. Paper copies or compact discs do not need to be submitted. Links to the e-filing system are provided on each proceeding's Web page under the link "**Submit e-filing.**" Registration is necessary the first time documents are uploaded. Once registration is complete, to submit a confidential filing click on **Quick Actions** from the **DASHBOARD** and select **Submit Confidential e-filing** from the dropdown tab. The application needs to be uploaded first, followed by the confidential materials. The application will then be acted upon by the Executive Director in consultation with the Chief Counsel of the Energy Commission. (Section 2505, subd. [a])

Table A-1: 2019 IEPR Subdockets

19-IEPR-01	General/Scope
19-IEPR-02	Electricity Resource Plans
19-IEPR-03	Electricity and Natural Gas Demand Forecast

Source: California Energy Commission

- A signed "penalty of perjury certification" must be included in the application. Suggested standard language is as follows:

  > 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. I also certify that I am authorized to make the application and certification on behalf of (ABC Utility or Corporation).

- For electronic filings containing a signature, including for submissions into electronic databases requiring a signature as attestation of information, the signature may be in electronic form and represented as a scanned signature graphic, or "Original Signed By," "/S/," or similar notation followed by a typewritten name.

What a New or Repeated Confidentiality Application Must Include

A complete application for confidentiality contains the following information:

- Identification of the information being submitted, including docket number, title, date, and size (for example, pages, sheets, megabytes).
- Description of the data or information for which confidentiality is being requested (for example, particular electricity supply contract categories for particular years).
- On Microsoft Excel® forms submitted with prospectively confidential data, identification of specific cells using yellow fills that are consistent with the confidentiality application.
- A clear description of the period for which confidentiality is being sought for each information category (for example, until December 31, 2017).
- An appropriate justification for each confidential data category request, including applicable provisions of the California Public Records Act (Government Code Section 6250 et seq.) and/or other laws.
- A statement attesting that a) the specific records to be withheld from public disclosure are exempt under provisions of the Government Code, or b) the public interest in nondisclosure of these particular facts clearly outweighs the public interest in disclosure.

What Happens If a New or Repeated Application Is Incomplete

Applications that are docketed will be reviewed by Energy Commission staff within 30 calendar days of receipt for clarity, completeness, content, and context. If the application is incomplete or ambiguous in one or more respects, or if the data are incomplete or questionable, staff will contact the filer to resolve these uncertainties or obtain needed information.

Staff may append data and information to the supply forms as requested by the filer. Also, an updated or corrected Excel file may be forwarded by the filer as necessary. Where an application is unclear or incomplete, a filer may submit a corrected replacement application for confidentiality. By arrangement, a corrected application may be submitted electronically to the Docket Office. Once a docketed application is considered complete, staff prepares a recommendation for determination by the Executive Director.

Applications deemed incomplete may not be docketed by Energy Commission staff and may result in delay in processing until the deficiency can be corrected. The filer will be notified by the Office of the Chief Counsel about deficiencies in the application. The applicant has 14 calendar days to correct defects in the application and return an amended application to the Energy Commission.

After 14 days, all information associated with a still–incomplete application for confidentiality will be deemed publicly disclosable and will be docketed accordingly.

Determinations and Additional Information for New Applications

The Executive Director signs confidentiality determination letters in response to New Applications for Confidentiality. The applicant has 14 calendar days to appeal this decision.

An applicant can request confidentiality at any time, but once information is publicly released, confidentiality cannot be granted. The Energy Commission strongly encourages filers to provide data and any confidentiality requests concurrently.

More specific questions about confidentiality may be directed to Jared Babula at Jared.Babula@energy.ca.gov or (916) 654-3843.