CALIFORNIA
ENERGY
COMMISSION

# FINAL DEMAND FORECAST FORMS AND INSTRUCTIONS FOR THE 2007 INTEGRATED ENERGY POLICY REPORT

COMMISSION ADOPTED REPORT

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STATE OF CALIFORNIA ENERGY COMMISSION

Arnold Schwarzenegger, *Governor*

**CALIFORNIA ENERGY COMMISSION**

Lynn Marshall
***Principal Author***

Lynn Marshall
***Project Manager***

Sylvia Bender
***Manager***
**DEMAND ANALYSIS OFFICE**

Scott W. Matthews
***Chief Deputy Director***

B.B. Blevins
***Executive Director***

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# GENERAL INSTRUCTIONS FOR DEMAND FORECAST SUBMITTALS

## INTRODUCTION

To develop energy policies that conserve resources, protect the environment, ensure energy reliability, enhance the state's economy, and protect public health and safety, the California Energy Commission (Energy Commission) is directed by Public Resources Code (PRC) Section 25301 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)*. To carry out these assessments, "the Energy Commission may require submission of demand forecasts, resource plans, market assessments, and related outlooks from electric and natural gas utilities, transportation fuel and technology suppliers, and other market participants." (PRC Section 25301[a])

The Energy Commission is preparing to undertake assessments for the *2007 IEPR*. The adopted forecast, or range of forecasts, will provide a foundation for the analysis and recommendations of the *2007 IEPR*, including resource assessment and analysis of progress towards energy efficiency, demand response, and renewable energy goals. Energy Commission forecasts are used in the California Public Utilities Commission (CPUC) procurement and resource adequacy proceedings, by the California Independent System Operator (CA ISO), and in transmission planning studies. Energy Commission demand and supply assessments are also used in the *California Gas Report*.

To provide the Energy Commission and the public with the opportunity to consider a range of perspectives on demand trends, the Energy Commission is requesting electricity demand forecasts, demand-side management impacts, and related information from all load-serving entities (LSEs) with annual peak demand greater than 200 megawatts (MW). These submittals are to be prepared and documented according to the attached instructions.

Separate documents and workshops will direct the contents and format of other resource planning information. Each LSE should take care that the assessments submitted on the resource plan forms are consistent with the submitted demand forecast.

Definitions of terms used in the instructions are found at the end of this document.

## Who Must File

Data are requested from all load serving entities whose annual peak demand in the last two years exceeded 200 MW.

Statutes found in the Public Resources Code and supporting regulations give the Energy Commission authority to require forecast submittals from all entities engaged in generating, transmitting, or distributing electric power by any facilities. This includes utility distribution companies (UDCs), energy service providers (ESPs), community choice aggregators (CCAs) permitted to operate pursuant to AB 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 format 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 UDC with peak demand less than 200 MW.

## Summary of Requested Data

UDCs are to submit Forms 1 through 5. ESPs submit Form 6.

- Form 1. Historic and Forecast Electricity Demand – annual sales and peak demand, private supply, and hourly loads.
- Form 2. Forecast Input Assumptions – economic and demographic assumptions and electricity rate forecasts.
- Form 3. Demand Side Management (DSM) Program Impacts and Costs (Committed and Uncommitted), including demand response and distributed generation program impacts.
- Form 4. Forecast Methodology Documentation
- Form 5. DSM Methodology Documentation (Committed and Uncommitted).
- Form 6. ESP Load Forecasts.

### Changes from *2005 IEPR*

This data request is largely the same as the *2005 IEPR* demand forecast data request, except for two notable additions:

1. In Form 1.6b, investor-owned utilities (IOUs) are asked for hourly loads by geographic subarea, such as climate zones or zones used for transmission system small area forecasts. This is to support the development of a more

[1] A small LSE is one that has experienced a peak demand of 200 megawatts or less per year in both of the two calendar years preceding the required data filing date and is owned or operated by a public government entity or regulated by the California Public Utilities Commission.

disaggregate Energy Commission demand forecast that is better suited for applications such as resource adequacy and transmission system planning.

2. In Forms 1 and 4, all UDCs must quantify and document their assumptions about migrating load to support compliance with AB 1723 (La Malfa, Chapter 703, Statutes of 2005). AB 1723 enacted PRC 25302.5 requiring that all LSEs provide the Energy Commission with their "forecasted load that may be lost or added" by a publicly owned utility (POU) or CCA or served by an ESP. The Energy Commission is to perform an assessment of migrating load in each IOU service territory and submit the results to the CPUC.

   IOUs are to document how departing or newly departed load is accounted for in their forecast, and provide the data used. POUs must report how they project possible acquisition of migrating load in their forecasts. This is discussed in more detail in the instructions for Forms 1.1-1.4.

Also, while the data requested on Form 1.5 has not changed significantly, given the summer 2006 heat storm, staff expects the topic of demand under hot weather conditions to receive greater attention. LSEs should provided detailed documentation of their methods and results.

## Due Date

Forms must be submitted to the Energy Commission on or before February 1, 2007. LSEs who require additional time may request an extension by submitting a written request to the Executive Director, as described in California Code of Regulations, Title 20, Article 2, Section 1342. The data do not have to be distributed to the *IEPR* service list.

## Submittal Format

To expedite the forecast comparison and review process, an Excel template with formats for each form in 1, 2, and 3 is provided. 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 the information is clearly labeled.

Parties submitting data <u>without</u> a request for confidentiality are requested to submit a diskette, compact disk, or electronic file containing the data and documentation:

By electronic mail to:
Docket@energy.state.ca.us
Please include "Docket #06-IEP-1I Demand Forecast", in the subject line.

Or by mail to:
California Energy Commission

Docket Office
Attn: Docket 06-IEP-1I
1516 Ninth Street, MS-4
Sacramento, CA 95814-5512

If you are requesting confidentiality for any part of your submittal, please read and carefully follow the instructions below in the section "How to Request Confidentiality."

## 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 California Code of Regulations, Title 20, Section 2505(a)(5). Note that 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.

Data that are not included in these categories but that the filer believes are entitled to confidential treatment should be submitted 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 below.

The application must include three attributes:

1) A hard copy of the application for confidentiality must be submitted to the Executive Director:

    B. B. Blevins, Executive Director
    California Energy Commission
    1516 Ninth Street **MS-39**
    Sacramento, CA 95814-5504

2) The information being provided to the Energy Commission must be included as an attachment (either hard copy or electronic), marked as **Docket #06-IEP-1I**, and the confidential data categories must be clearly and properly

labeled. Note, each *IEPR* topic area has its own subdocket; demand forecasting is subdocket "I".

**Table 1: *2007 IEPR* Subdockets**

| | |
|---|---|
| A | Scope/ General |
| B | Transportation Assessment |
| C | Renewables & Distributed Generation |
| D | Natural Gas Forecasts & Issues |
| E | Energy Efficiency & Conservation |
| F | Transmission Planning/ Issues |
| G | Environmental Performance Report |
| H | Electricity Price Forecasts |
| I | Electricity Demand Forecasts |
| J | Electricity Supply Forecasts |

3) A "penalty of perjury certification" must be included. 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).

Applications deemed incomplete in these three respects will not be docketed by Energy Commission staff. Applications deemed incomplete will be returned, and the data will be placed in a confidential "suspense" file. The filer will be notified by mail and e-mailed 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 an incomplete application for confidentiality (based on the three attributes listed above) will be deemed public and docketed accordingly. In addition, an application may be deemed incomplete and returned to the applicant if it does not contain the following information:

1) Identification of the information being submitted, including title, date, size (for example, pages, sheets, MB), and docket number;

2) Description of the data for which confidentiality is being requested (for example, particular contract categories, specific narratives, and time periods);

3) A clear description of the length of time for which confidentiality is being sought, with an appropriate justification, for each confidential data category request;

4) Applicable provisions of the California Public Records Act (Government Code Section 6250 *et seq*.), and/or other laws, for each confidential data category request;

5) 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 non-disclosure of these particular facts clearly outweighs the public interest in disclosure; and

6) A statement that describes how each category of confidential data may be aggregated with other data for public disclosure.

Parties should be aware that some confidential data may be disclosed after aggregation according to CCR, Title 20, 2507(d). Both historic 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 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 electric service provider groups as these groups are defined by the U.S. Census Bureau in their North American Industry Classification System (NAICS) tables.

Other aggregations may be considered on a case-by-case basis, but no disclosure of data aggregated in this manner will be released without notice and consultation by the Executive Director.

The Executive Director signs confidentiality determination letters. The applicant has 14 calendar days to appeal this decision.

An applicant can request confidentiality at any time. The Energy Commission strongly encourages filers to provide data and any confidentiality requests concurrently.

# PROTOCOLS FOR SUBMITTED DEMAND FORECASTS

In general, the demand forecast submitted should be the most likely projection of unmanaged total consumption. Unmanaged consumption means that the forecast should not include uncommitted DSM, and total consumption means that the forecast should include total electricity usage irrespective of the type of LSE, although locally supplied energy is reported separately from sales. Because one use of these forecasts will be to 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. Since local private supply reduces system requirements and losses, forecasts of local private supply are also required from distribution utilities.

The primary purpose of most of the data requested is for each UDC to provide its view of demand trends and document the methods and data it uses to develop its forecast. Some data are also used for development of the staff forecast. The Energy Commission is not requiring the use of specific forecasting methods.

General instructions on how the forecast is to be prepared:

1. UDC forecasts are to project expected electricity demand for 2007-2018. Data for 2006 should represent the UDC's best estimates available at the time of filing. ESPs should provide projections for the period through which they have contracted load.

2. UDCs are to provide forecasts for both their expected "bundled" customers (customers to whom they provide both generation and distribution services) and for all customers to whom they provide distribution services, 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, and total load on Forms 1.2 and 1.4.

3. UDCs are to prepare demand forecasts using either:
   (A) franchise service area defined by applicable state law or regulatory decisions lawfully determined by the CPUC, or
   (B) a definition of distribution utility service area that has been mutually agreed upon by the distribution utility and Energy Commission staff.

4. Impacts of demand-side management (DSM) and demand response programs on energy and peak demand should be provided according to the guidelines below:

   Section 1345 of the Energy Commission's regulations (found in Title 20 of the California Code of Regulations) requires that demand forecasts are to account for all conservation "reasonably expected to occur." Since the *1985 Electricity Report*, reasonably expected to occur conservation programs have been split into two types: committed and uncommitted. This demand forecast continues that distinction. Committed programs are defined as programs that have been implemented or for which funding has been approved. While conservation "reasonably expected to occur" includes both committed and uncommitted programs, only the effects of committed programs should be included in the demand forecast.

   For the IOUs, committed conservation programs are those programs included in the 2006-2008 program plans approved in the CPUC Energy Efficiency Rulemaking Proceeding (R01-08-028) or in other CPUC decisions. For post -

2008, forecasts should include as committed the impacts associated with the 2006 level of programs only to the extent they represent impacts associated with replacement of aging building stock and equipment, or installation of new stock and equipment at efficiency levels that comply with current building and appliance standards. Uncommitted effects are defined as the incremental impacts of the 2006 level of programs (e.g., savings associated with new equipment that exceeds current standards, or early replacement of existing stock), impacts of new programs, and impacts from expansion of current programs.

For publicly owned utilities, "committed" means the governing board for a municipal utility has authorized spending for at least a preliminary program plan from which impacts can be quantified.

The term "demand response" encompasses a variety of programs, including traditional direct control (interruptible) programs and new price-responsive demand programs. For this filing, a key distinction is whether the program is dispatchable. 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.
LSEs 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 its usage in response to ongoing price signals. Impacts from committed *nondispatchable* programs should be included in the demand forecast, for example, load reductions at on-peak hours subtracted from the "base" forecast and load building or load shifting in off-peak hours added to the "base" forecast.

To summarize, parties submitting demand forecasts are required to include the energy and peak impacts of all committed conservation and nondispatchable demand response in these demand forecasts. The impacts of: (1) uncommitted conservation and nondispatchable demand response programs; and (2) committed and uncommitted dispatchable demand response programs are to be excluded from the demand forecasts but reported in Form 3 as appropriate.

5. The Energy Commission will be holding a workshop and adopting separate forms and instructions for reporting information on electricity resources. The demand forecast and aggregate forecast of demand response and uncommitted DSM impacts should be consistent with the data submitted by the LSE on those electricity resource plan forms.

# SPECIFIC INSTRUCTIONS

UDCs are to complete Forms 1 through 5 only. ESPs complete Form 6 only.

## 1. Historic and Forecast Electricity Demand

Several forms request data by sector. Definitions of the sectors used in the Energy Commission forecast models are listed in the Definitions section at the end of this document. **However, UDCs who 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 1.1**

Form 1.1 is for the entry of total retail sales of electricity to bundled customers, measured on the customer side of the meter in gigawatt hours (GWh). Each UDC should modify the sectors listed on Form 1.1 template to reflect the sectors or classes by which they forecast.

This form also asks 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 those historic data.

**Form 1.2**

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 1.1),
- 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 accounts for 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. IOUs should use this form to show the amount of load expected to be gained in newly developed areas, or lost to municipalized or “newly departed load.” 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, and
- 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 generation, as well as any other unaccounted for losses in the system.

**Form 1.5 Peak Demand Weather Scenarios**
This form is for recording distribution area peak demand forecasts under high temperature conditions. The cases, referred to as 1-in-5, 1-in-10, 1-in-20, and 1-in-40, refer to peak demand under temperature conditions that have a 20 percent, 10 percent, 5 percent, and 2.5 percent chance of being met or exceeded, respectively. These conditions should be contrasted with the baseline weather condition of 1-in-2 temperatures that have a 50 percent chance of being met or exceeded.

**Form 1.6a: Distribution System Hourly Loads**
This form is for reporting actual system hourly loads and losses for 2004-2006 and forecasted hourly loads for 2007, 2012, and 2018. If complete loads for 2006 are not yet available, filers are asked to submit at least through Sept. 15, 2006. UDCs who have already submitted 2004 or 2005 loads to the Energy Commission through other data requests need not resubmit them.

MW in each hour reflects integrated end-user load and effects of committed demand-side programs and excludes private supply. IOUs are asked to report bundled and unbundled loads and losses separately. For historic years only, also provide the estimated amount of curtailed load resulting from triggering of demand response and interruptible programs. Finally, UDCs are asked for estimates of actual outages in hours with a significant amount of outages, such as during the heat storm of late July 2006. Outage estimates are of the most importance for summer peak periods.

The template illustrates a preferred data layout; UDCs may submit equivalent data in other text, spreadsheet, or database formats (such as Access).

**Form 1.6b: Hourly Loads by Zone (IOUs only)**
This form is for reporting hourly loads at a more disaggregate level of geography than 1.6a. The zones used should be climate zones or other geographic subareas used, for example, for transmission planning studies or rate making. Loads may be based on actual metered load or estimated from load metering samples. Six years of historic loads, 2000-2006, and forecasted hourly loads for 2007 are requested.

**Forms 1.7a and 1.7b: Private Supply Annual Peak and Energy**
Forms 1.7a and 1.7b allow for the reporting of local private supply by sector or customer class for both annual energy and annual peak demand coincident with the distribution area peak. Private supply includes self-generation, distributed generation on the customer side of the meter, "over-the-fence" sales from a cogeneration facility, or wheeling from a cogeneration facility to a final user. Energy and peak load forecasts should reflect how facilities are expected to operate, not simply installed capacity or potential energy. These forms represent the UDC's estimate of total private supply in the distribution area, including the effects of committed renewable and distributed generation programs reported on Form 3.3.

LSEs may provide additional forms if they wish to show other categories of energy or peak demand in their filing.

# 2. 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 their own 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 include documentation of 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.

**Forms 2.1 and 2.2**
Document economic and demographic variables used to develop the forecast as follows:

Form 2.1: National, statewide, and/or regional projections, such as gross domestic and/or state product, personal income, per capita income, employment, population and aggregate measures of labor productivity.

Form 2.2: Economic and demographic variables having narrower definitions and geographic limits, and 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 housing type, 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 sub-utility regional breakdowns of population and income projections used in the development of the economic, demographic, or energy forecasts. Sub-utility regions may be individual counties, groups of counties, and/or weather zones.

It must be emphasized that variables need to 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 2.3 Electricity Rate Forecast**

Forms 2.3 allows for the reporting of projected electricity prices for the sectors or classes used to develop the forecast. The price forecasts should be reported using the same customer sectors or classes as Form 1.1. Prices should not include city taxes. Electricity prices are to be presented in 2005 cents per kWh. Provide the deflator series used to convert nominal to real prices, or real to nominal prices. Where the electricity price projections are derived from a specific resource supply plan, those plans should be documented or referenced.

**Form 2.4 Customer Counts and Other Inputs**

Form 2.4 provides recorded and projected customers counts by major customer sector as used to develop the forecast. These 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, but only the bundled service customers. The most convenient consistent series is acceptable, but a narrative should explain the units reported (for example, number of customers or number of accounts), and whether the annual values are derived from a specific point in time, a specific month, an average of months across the year, or other methodology.

**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. Provide narrative and spreadsheets as appropriate.

# 3. Demand Side Management (DSM) Program Impacts

This section of the forms and instructions summarizes the format requirements for reporting:

- Historic and forecasted energy and coincident peak impacts of conservation, load shifting, demand response, and distributed generation and renewable programs, both committed and uncommitted.
- Costs of DSM programs.

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 they consider their peak period.

All reported impacts should reflect net savings, defined as the change in load attributed to the program adjusted for the effects of free drivers, free riders, state or federal conservation standards, changes in the level of energy service, and natural change effects.

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 methodology used to estimate impacts for each program should accompany these and are to be presented in Form 5.

The following forms are to be submitted:

**Form 3.1a and b, and 3.2 Energy Efficiency Costs and Impacts**
These forms are for the recording of costs and impacts of energy efficiency programs. Each program entry should specify whether the program is committed or uncommitted. Form 3.1 is for first-year impacts and total costs by program category and sector. Form 3.1b reports program costs for each program by cost category. The following categories are requested for program costs: Administrative, Incentives, Measurement and Evaluation, and Participant cost.

Form 3.2 is for reporting of cumulative impacts by program and sector through 2018. Cumulative savings refers to all savings that can be attributed to a program in a given year. Cumulative savings is equal to current first-year savings plus residual savings from previous year impacts.

On Forms 3.1 and 3.2, IOUs should also provide the estimated total impacts associated with bundled customers only.

**Form 3.3 Renewable and Distributed Generation Programs**
Form 3.3 is for the reporting of the costs and expected energy and coincident peak impacts of customer-side of the meter renewable and distributed generation programs, including engine, turbine, microturbine, photovoltaic, wind, and fuel cell technologies. This should include any program that results in displaced utility sales to the end user through self-generation or distributed generation, but not all distributed generation. Distributed generation that adds power to the grid should be reported in resource plans.

In particular, IOUs should report projected impacts of the Self Generation Incentive Program and the California Solar Initiative. Public utilities should include impacts of current solar and other renewable programs and planned programs to comply with Senate Bill 1 (Murray, 2006, Chapter 132, Statutes of 2006).

Energy and peak impacts should be reported as distributed generation facilities are expected to operate, not based on installed capacity or potential energy. Thus, there is an interaction with retail electricity rates, fuel prices and how end users choose to operate these facilities.

**Form 3.4 Demand Response Program Costs and Impacts**
Form 3.4 should report costs and expected coincident peak impacts for each demand response and interruptible program. Programs should be identified as committed or uncommitted, and dispatchable or nondispatchable, as discussed in item four in the section on Protocols for Submitted Demand Forecasts.

# 4. Demand Forecast Methods and Models

Each LSE shall document the electricity demand forecast methods and models used to develop the submitted forecast and shall include a discussion of the following topics.

**Demand Forecast Methodology**
Explain the conceptual basis of the forecast: (1) the energy modeling approach, (2) the definition of customer classes, including which rate classes are included in the categories for which forecasts are submitted, (3) economic and demographic data used, and (4) data sources. Define the area for which the forecast is developed. Identify isolated loads and resale customers and describe how they are included or excluded.

Describe model capabilities in forecasting electricity demand components (such as end uses, fuel types, or structure types) and key forecast model structural equations (econometric relations, other behavioral equations, and identities). Algebraic variables and computer mnemonics should be defined. For sector models developed using aggregate econometric methods, provide data for the independent and all dependent variables for the entire estimation period. Report all standard statistical parameters for econometric models. LSEs may include existing forecast model reports as an appendix to this form if this report includes a brief summary.

Discuss how the submitted forecast is reasonable in light of economic, demographic, price, demand-side management, and state policy trends. Discuss the reasonableness of differences between historic and forecast growth patterns.

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

**Historic Forecast Performance**

Report and discuss the past performance of the forecasting method, including comparison of previous forecasts to actual annual weather-adjusted peak and energy demand.

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

Distribution utilities 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. This should include a list of current and projected ESP and CCA entities in the distribution utility's planning area.

POUs who 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. 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 in Form 1 or 2 as appropriate.

**Local Private Supply Estimates**

Describe fully the methods, assumptions, and data sources used to develop both historic estimates and future projections in Forms 1.7a and 1.7b. Because these are expected energy and on-peak effects, they necessitate 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 brief summary.

**Weather Adjustment Procedures**

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

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

- 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-5, 1-in-10, 1-in-20, and 1-in-40) 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.

### Forecast Calibration Procedures

Most forecasts are calibrated to historic energy consumption and peak demand to "scale" the backcast to more closely coincide with historic data. Provide a comprehensive description of the method of forecast calibration.

The *Quarterly Fuel and Energy Report* (QFER) system is the principal source of data on historical sales of electricity by economic sector for the Energy Commission staff's demand forecast calibration procedure. In October 2006, Energy Commission staff provided for review each participating LSE with a copy of its QFER sales data on file by sector code for 1990 through 2005.

### Energy and Peak Loss Estimates

Forms 1.2, 1.3, and 1.4 include estimates of losses. Describe fully the method and data sources used to develop historic 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.

### Hourly Loads by Subarea

Provide definitions of the subareas for which hourly loads in Form 1.6b are provided. 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 the subarea loads, as applicable.

### Economic and Demographic Projections

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 appropriateness of source for forecast.

## 5. Demand-Side Program Methodology

### Efficiency Program Costs and Impacts

Work papers should be provided to document the estimated load impacts provided. Describe how the peak and energy impacts were calculated. Describe the basis or method used to estimate how first-year impacts might change over time. Document the net-to-gross ratios used to convert gross measure or program impacts into net impacts. Describe how the per-measure impact estimates were aggregated and how any interactive effects between the measures were estimated or accounted for. List any studies or sources relied on to support these assumptions.

Discuss and document the different funding sources used and how funds are allocated to programs.

Also describe any additional assumptions and methods used to develop the uncommitted projections. Discuss the current status of programs included in the uncommitted forecast.

**Demand Response Program Costs and Impacts**
Discuss how the estimates of peak impacts for each program were derived. Describe assumptions about eligible population, participation rates, price elasticities, wholesale market conditions, and prices used to develop the projections. Describe the methodology 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 Costs and Impacts**
Discuss how the estimates of energy and peak impacts for each program were derived, for both uncommitted and committed programs. In particular, describe in detail the methodology 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. Describe what criteria are used in deciding how to model customer decisions to use these facilities in peak shaving or baseload modes.

Please include program descriptions of both committed and uncommitted programs and their funding and implementation status.

# 6. ESP Demand Forecast (ESPs Only)

For each utility distribution area in which they serve 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 variables to be reported, by utility distribution area, are:

(1) Annual Metered Sales: Projected annual sales for customers under contract, before any losses, in megawatt-hours (MWH).
(2) Annual Peak Demand in MW. This should include distribution losses, comparable to settlement data.

(3) 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.

The submitted load forecast should correspond to the loads the ESP will report on the forthcoming 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.

# DEFINITIONS

Bundled Customers: Customers who receive both 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 North American Industrial Classification (NAICS) categories:

| | NAICS |
|---|---|
| Residential: private households, including single and multiple family dwellings. | RE00-RE39, 001-003, 814 |
| Commercial | 115, 2331, 326212, 42, 44-45, 48841, 493, 512, 514, 518-519, 52-55, 561, 61, 62 (excluding 62191), 71, 72, 81 (excluding 81293 and 814), and 92 (excluding 92811) |
| Industrial | 11331, 21 and 23 (excluding 22131); 31-33, 511, and 54171 |
| Agricultural | 111, 112, 113, 114 |
| Water Pumping | 22131 |
| Transportation, Communication, Utility (TCU) | 221, 48, 49, 513, 517, 562, 62191, and 92811 |
| Street Lighting | 9225, 9226 |

Dollar Denomination: Unless otherwise specified, any dollar denominated variable is to be measured in 2005 dollars.

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

Utility Distribution Company (UDC): 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.

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

Load-Serving Entity (LSE): An umbrella term encompassing all entities that provide generation services to end-use customers, 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 pursuant to 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 wheeling from a cogeneration facility to a final user.

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.

# DEMAND FORECAST FORMS

## California Energy Commission
## 2007 Integrated Energy Policy Report
## Docket Number 06-IEP-1I

## Electricity Demand Forecast Forms

The following spreadsheets are the California Energy Commission (Energy Commission) forms for collecting data and analyses relating to electricity demand. The Energy Commission's statues and regulations specify that a broad array of information can be collected and analyzed to prepare the ***Integrated Energy Policy Report*** . Specifically, Public Resources Code (PRC) Section 25301 directs the Energy Commission to conduct regular assessments of all aspects of energy demand and supply to that it may develop energy policies that conserve resources, protect the environment, ensure energy reliability, enhance the state's economy, and protect public health and safety. To carry out these assessments the Energy Commission may require submission of data from market participants in California:

To perform these assessments and forecasts, the Energy Commission may require submission of demand forecasts, resource plans, market assessments, and related outlooks from electric and natural gas utilities, transportation fuel and technology suppliers, and other market participants. PRC 25301(a)

Submittal Format

Parties are requested to submit a diskette or compact disk containing:
data from Forms 1, 2, 3, and 6, and
reports on Forms 4 and 5 in Word or Acrobat.

Data with no confidentialy request should be sent to:
California Energy Commission
Docket Office
Attn: Docket 06-IEP-1I
1516 Ninth Street, MS-4
Sacramento, CA 95814-5512
or email to: Docket@energy.state.ca.us. Please include "Docket #06-IEP-1I Demand Forecast", in the subject line.

If you are requesting confidentiality, please review the detailed instructions.

To expedite the forecast comparison and review process, an Excel template with formats for each form in 1, 2, and 3 is provided. 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 the information is clearly labeled.

Due Date:

| | |
|---|---|
| All Forms | Thursday, February 01, 2007 |

The data do not have to be distributed to the IEPR service list.

Technical questions relating to the electricity demand forecast should be directed to Lynn Marshall of the Demand Analysis Office at (916) 654-4767 or by email at lmarshal@energy.state.ca.us.

## Please Enter the Following Information:

| | |
|---|---|
| **Participant Name:** | Participant Name |
| **Date Submitted:** | |
| **Contact Information:** | Participant technical contact<br>Address<br>Telephone<br>Email |

| | |
|---|---|
| Form 1.1 | RETAIL SALES OF ELECTRICITY BY CLASS OR SECTOR (GWh) |
| Form 1.2 | DISTRIBUTION AREA NET ELECTRICITY FOR GENERATION LOAD |
| Form 1.3 | LSE COINCIDENT PEAK DEMAND BY SECTOR (Bundled Customers) |
| Form 1.4 | DISTRIBUTION AREA COINCIDENT PEAK DEMAND |
| Form 1.5 | PEAK DEMAND WEATHER SCENARIOS |
| Form 1.6 | DISTRIBUTION AREA HOURLY LOAD |
| Form 1.7 | LOCAL PRIVATE SUPPLY BY SECTOR OR CLASS |
| Form 2.1 | STATE OR NATIONAL ECONOMIC AND DEMOGRAPHIC INPUTS* |
| Form 2.2 | PLANNING AREA ECONOMIC AND DEMOGRAPHIC ASSUMPTIONS* |
| Form 2.3 | ELECTRICITY RATE FORECAST |
| Form 2.4 | CUSTOMER COUNT & OTHER FORECASTING INPUTS |
| Form 3.1a | EFFICIENCY PROGRAM FIRST YEAR COSTS AND IMPACTS |
| Form 3.1b | EFFICIENCY PROGRAM COSTS BY COST CATEGORY (2005$) |
| Form 3.2 | EFFICIENCY PROGRAM CUMULATIVE IMPACTS |
| Form 3.3 | RENEWABLE AND DISTRIBUTED GENERATION PROGRAM COSTS AND IMPACTS |
| Form 3.4 | DEMAND RESPONSE PROGRAM COSTS & IMPACTS |
| Form 4 | Report on Demand Forecast Methods and Models |
| Form 5 | Report on Demand-Side Program Methodology |
| Form 6 | ESP Report of Loads and Resources under Contract |

## FORM 1.1

**Participant Name**

### RETAIL SALES OF ELECTRICITY BY CLASS OR SECTOR (GWh)

### MIGRATING LOAD INCLUDED IN

(Modify the categories below as needed to be consistent with forecast method)

| YEAR | RESIDENTIAL | COMMERCIAL | INDUSTRIAL | AGRICULTURAL | WATER PUMPING | STREET-LIGHTING | TCU | TOTAL |
|---|---|---|---|---|---|---|---|---|
| 1990 | | | | | | | | 0 |
| 1991 | | | | | | | | 0 |
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| 2016 | | | | | | | | 0 |
| 2017 | | | | | | | | 0 |
| 2018 | | | | | | | | 0 |

| Migrating/ Newly Served Load included in Forecast | | |
|---|---|---|
| Name of LSE / IOU | Name of LSE / IOU | Newly Served Load |
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AVERAGE ANNUAL GROWTH RATE (%)

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 1990-2005 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| 2005-2010 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| 2010-2018 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| 2005-2018 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |

# FORM 1.2

**Participant Name**

## DISTRIBUTION AREA NET ELECTRICITY FOR GENERATION LOAD

**(GWh)**

| YEAR | SALES TO BUNDLED CUSTOMERS (from 1.1) | DIRECT ACCESS | COMMUNITY CHOICE AGGREGATORS | Other Departed Load remaining in distribution system | OTHER (Define as needed) | TOTAL SALES | LOSSES | TOTAL DISTRIBUTION SYSTEM ENERGY REQUIREMENTS | | Total Uncommitted Impacts from Form 3.2 | Forecast Net of Uncommitted Impacts |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1990 | 0 | | | | | 0 | | 0 | | | 0 |
| 1991 | 0 | | | | | 0 | | 0 | | | 0 |
| 1992 | 0 | | | | | 0 | | 0 | | | 0 |
| 1993 | 0 | | | | | 0 | | 0 | | | 0 |
| 1994 | 0 | | | | | 0 | | 0 | | | 0 |
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| 1996 | 0 | | | | | 0 | | 0 | | | 0 |
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| 2005 | 0 | | | | | 0 | | 0 | | 0 | 0 |
| 2006 | 0 | | | | | 0 | | 0 | | 0 | 0 |
| 2007 | 0 | | | | | 0 | | 0 | | 0 | 0 |
| 2008 | 0 | | | | | 0 | | 0 | | 0 | 0 |
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| 2014 | 0 | | | | | 0 | | 0 | | 0 | 0 |
| 2015 | 0 | | | | | 0 | | 0 | | 0 | 0 |
| 2016 | 0 | | | | | 0 | | 0 | | 0 | 0 |
| 2017 | 0 | | | | | 0 | | 0 | | 0 | 0 |
| 2018 | 0 | | | | | 0 | | 0 | | 0 | 0 |

| AVERAGE ANNUAL GROWTH RATE (%) | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1990-2005 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | | | |
| 2005-2010 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | | 0.0% | 0.0% |
| 2010-2018 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | | 0.0% | 0.0% |
| 2005-2018 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | | 0.0% | 0.0% |

**FORM 1.3**

**Participant Name**

## LSE COINCIDENT PEAK DEMAND BY SECTOR (Bundled Customers)

**(MW)**

(Modify categories below to be consistent with sectors or classes reported on Form 1.1)

| | RESIDENTIAL | | COMMERCIAL | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| YEAR | BASE LOAD | WEATHER SENSITIVE | BASE LOAD | WEATHER SENSITIVE | INDUSTRIAL | AGRICULTURE | WATER PUMPING | TCU & STREETLIGHTING | LOSSES | TOTAL PEAK |
| 1990 | | | | | | | | | | 0 |
| 1991 | | | | | | | | | | 0 |
| 1992 | | | | | | | | | | 0 |
| 1993 | | | | | | | | | | 0 |
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| 2018 | | | | | | | | | | 0 |

| AVERAGE ANNUAL GROWTH RATE (%) | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| 1990-2005 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| 2005-2010 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| 2010-2018 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| 2005-2018 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |

## MIGRATING LOAD INCLUDED IN FORECAST (MW)

| Migrating/ Newly Served Load included in Forecast | | |
|---|---|---|
| Name of LSE / IOU | Name of LSE / IOU | Newly Served Load |
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| 0.0% | 0.0% | 0.0% |
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# FORM 1.4

**Participant Name**

## DISTRIBUTION AREA COINCIDENT PEAK DEMAND

**(MW)**

| YEAR | BUNDLED CUSTOMER PEAK (from 1.3) | DIRECT ACCESS | | COMMUNITY CHOICE AGGREGATORS | | OTHER PUBLICLY OWNED DEPARTING LOAD | | OTHER (DEFINE) | TOTAL PEAK DEMAND | Total Uncommitted MW Impacts from Form | Forecast Net of Uncommitted Impacts |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | End User Peak Demand | Losses | End User Peak Demand | Losses | End User Peak Demand | Losses | | | | |
| 1990 | 0 | | | | | | | | 0 | | 0 |
| 1991 | 0 | | | | | | | | 0 | | 0 |
| 1992 | 0 | | | | | | | | 0 | | 0 |
| 1993 | 0 | | | | | | | | 0 | | 0 |
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| 2017 | 0 | | | | | | | | 0 | 0 | 0 |
| 2018 | 0 | | | | | | | | 0 | 0 | 0 |

| AVERAGE ANNUAL GROWTH RATE (%) | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1990-2005 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | | |
| 2005-2010 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| 2010-2018 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| 2005-2018 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |

**FORM 1.5**

**Participant Name**

## PEAK DEMAND WEATHER SCENARIOS
### DISTRIBUTION AREA COINCIDENT PEAK DEMAND
### (MW)
### (Report all available cases)

| | UTILITY SYSTEM ENERGY REQUIREMENTS | | | | |
|---|---|---|---|---|---|
| YEAR | 1-in-2 Temperatures | 1-in-5 Temperatures | 1-in-10 Temperatures | 1-in-20 Temperatures | 1-in-40 Temperatures |
| 1990 | | | | | |
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| AVERAGE ANNUAL GROWTH RATE (%) | | | | | |
|---|---|---|---|---|---|
| 1990-2005 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| 2005-2010 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| 2010-2018 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| 2005-2018 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |

# FORM 1.6a

**Participant Name**

## DISTRIBUTION AREA HOURLY LOAD

**(MW)**

Years requested: 2006, 2007, 2012, 2018

**UDCs may provide equivalent data in an alternative format if desired.**

| Date | Hour | Bundled Load | Bundled Losses | Unbundeld Load | Unbundled Losses | Other Load(Resale, Dep. Load) | Total System Load | Estimated Interruptible & Demand Response (History only) | Estimated Outages (History only) | Net Internal Load |
|---|---|---|---|---|---|---|---|---|---|---|
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## FORM 1.6b

**Participant Name**

### Hourly Loads by Transmission Planning Subarea or Climate Zone (IOUs Only)
### (MW)

Years requested: 2000-2007

**Identify by zones by name and attach definitions of zones.**

| Date | Hour | Zone1 | Zone2 | Zone3 | Zone4 | | |
|---|---|---|---|---|---|---|---|
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## FORM 1.7a

**Participant Name**

### LOCAL PRIVATE SUPPLY BY SECTOR OR CLASS

**ENERGY (GWh)**

**(Modify categories below to be consistent with sectors or classes reported on Form 1.1)**

| YEAR | RESIDENTIAL | COMMERCIAL | INDUSTRIAL | AGRICULTURAL | OTHER | TOTAL |
|---|---|---|---|---|---|---|
| 1990 | | | | | | 0 |
| 1991 | | | | | | 0 |
| 1992 | | | | | | 0 |
| 1993 | | | | | | 0 |
| 1994 | | | | | | 0 |
| 1995 | | | | | | 0 |
| 1996 | | | | | | 0 |
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| 2013 | | | | | | 0 |
| 2014 | | | | | | 0 |
| 2015 | | | | | | 0 |
| 2016 | | | | | | 0 |
| 2017 | | | | | | 0 |
| 2018 | | | | | | 0 |

AVERAGE ANNUAL GROWTH RATE (%)

| | | | | | | |
|---|---|---|---|---|---|---|
| 1990-2005 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| 2005-2010 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| 2010-2018 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| 2005-2018 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |

## FORM 1.7b

**Participant Name**

### LOCAL PRIVATE SUPPLY BY SECTOR OR CLASS

**COINCIDENT PEAK DEMAND (MW)**

| YEAR | RESIDENTIAL | COMMERCIAL | INDUSTRIAL | AGRICULTURAL | OTHER | TOTAL |
|---|---|---|---|---|---|---|
| 1990 | | | | | | 0 |
| 1991 | | | | | | 0 |
| 1992 | | | | | | 0 |
| 1993 | | | | | | 0 |
| 1994 | | | | | | 0 |
| 1995 | | | | | | 0 |
| 1996 | | | | | | 0 |
| 1997 | | | | | | 0 |
| 1998 | | | | | | 0 |
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| 2001 | | | | | | 0 |
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| 2011 | | | | | | 0 |
| 2012 | | | | | | 0 |
| 2013 | | | | | | 0 |
| 2014 | | | | | | 0 |
| 2015 | | | | | | 0 |
| 2016 | | | | | | 0 |
| 2017 | | | | | | 0 |
| 2018 | | | | | | 0 |

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|---|---|---|---|---|---|---|
| 1990-20 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| 2005-20 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| 2010-20 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| 2005-20 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |

## FORM 2.1

**Participant Name**

## STATE OR NATIONAL ECONOMIC AND DEMOGRAPHIC INPUTS*

**(Modify categories below as needed to report actual drivers used for forecast)**

| YEAR | GDP IMPLICIT PRICE DEFLATOR (2005=100) | POPULATION (000s) | HOUSEHOLDS | GSP (Millions 2001$) | TOTAL NON-AGRICULTURAL EMPLOYMENT (1,000s) | PERSONAL INCOME | TAXABLE SALES |
|---|---|---|---|---|---|---|---|
| 1990 | | | | | | | |
| 1991 | | | | | | | |
| 1992 | | | | | | | |
| 1993 | | | | | | | |
| 1994 | | | | | | | |
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| 2013 | | | | | | | |
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| 2015 | | | | | | | |
| 2016 | | | | | | | |
| 2017 | | | | | | | |
| 2018 | | | | | | | |

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|---|---|---|---|---|---|---|---|
| 1990-2005 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| 2005-2010 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| 2010-2018 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| 2005-2018 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |

# FORM 2.2

**Participant Name**

## PLANNING AREA ECONOMIC AND DEMOGRAPHIC ASSUMPTIONS*

**Projections for Service Area**

**(Modify categories below as needed to report actual drivers used for forecast)**

| | GDP IMPLICIT PRICE DEFLATOR (2005=100) | POPULATION (000s) | HOUSEHOLDS | GSP (Millions 2001$) | TOTAL NON-AGRICULTURAL EMPLOYMENT (1,000s) | PERSONAL INCOME | TAXABLE SALES | FLOORSPACE MM SQFT) |
|---|---|---|---|---|---|---|---|---|
| 1990 | | | | | | | | |
| 1991 | | | | | | | | |
| 1992 | | | | | | | | |
| 1993 | | | | | | | | |
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| 2016 | | | | | | | | |
| 2017 | | | | | | | | |
| 2018 | | | | | | | | |

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|---|---|---|---|---|---|---|---|---|
| 1990-2005 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| 2005-2010 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| 2010-2018 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| 2005-2018 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |

# FORM 2.3

**Participant Name**

## ELECTRICITY RATE FORECAST

**(2005 cents/kWh)**

**(Modify categories below to be consistent with sectors or classes reported on Form 1.1)**

| YEAR | DEFLATOR SERIES USED (define) | RESIDENTIAL | COMMERCIAL | INDUSTRIAL | AGRICULTURAL | WATER PUMPING | STREET-LIGHTING | TCU |
|---|---|---|---|---|---|---|---|---|
| 1990 | | | | | | | | |
| 1991 | | | | | | | | |
| 1992 | | | | | | | | |
| 1993 | | | | | | | | |
| 1994 | | | | | | | | |
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| 2016 | | | | | | | | |
| 2017 | | | | | | | | |
| 2018 | | | | | | | | |

| AVERAGE ANNUAL GROWTH RATE (%) | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 1990-2005 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| 2005-2010 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| 2010-2018 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| 2005-2018 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |

# FORM 2.4

**Participant Name**

## CUSTOMER COUNT & OTHER FORECASTING INPUTS

**(Modify categories below to be consistent with sectors or classes reported on Form 1.1)**

| YEAR | CUSTOMER COUNT | | | | | OTHER INPUTS |
|---|---|---|---|---|---|---|
| | RESIDENTIAL | COMMERCIAL | INDUSTRIAL | AGRICULTURAL | OTHER | |
| 1990 | | | | | | |
| 1991 | | | | | | |
| 1992 | | | | | | |
| 1993 | | | | | | |
| 1994 | | | | | | |
| 1995 | | | | | | |
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| 2016 | | | | | | |
| 2017 | | | | | | |
| 2018 | | | | | | |

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|---|---|---|---|---|---|---|
| 1990-2005 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| 2005-2010 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| 2010-2018 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| 2005-2018 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |

**FORM 3.1a**

**Participant Name**

## EFFICIENCY PROGRAM FIRST YEAR COSTS AND IMPACTS

**-Costs are total first-year program costs**

| Sector | Program Name | Committed / Uncommitted | | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | MW | | | | | | | | | | | | | | | | | | | |
| | | | GWh | | | | | | | | | | | | | | | | | | | |
| | | | MMBTU | | | | | | | | | | | | | | | | | | | |
| | | | 2005$ | | | | | | | | | | | | | | | | | | | |
| | | | MW | | | | | | | | | | | | | | | | | | | |
| | | | GWh | | | | | | | | | | | | | | | | | | | |
| | | | MMBTU | | | | | | | | | | | | | | | | | | | |
| | | | 2005$ | | | | | | | | | | | | | | | | | | | |
| | | | MW | | | | | | | | | | | | | | | | | | | |
| | | | GWh | | | | | | | | | | | | | | | | | | | |
| | | | MMBTU | | | | | | | | | | | | | | | | | | | |
| | | | 2005$ | | | | | | | | | | | | | | | | | | | |
| | | | MW | | | | | | | | | | | | | | | | | | | |
| | | | GWh | | | | | | | | | | | | | | | | | | | |
| | | | MMBTU | | | | | | | | | | | | | | | | | | | |
| | | | 2005$ | | | | | | | | | | | | | | | | | | | |
| | | | MW | | | | | | | | | | | | | | | | | | | |
| | | | GWh | | | | | | | | | | | | | | | | | | | |
| | | | MMBTU | | | | | | | | | | | | | | | | | | | |
| | | | 2005$ | | | | | | | | | | | | | | | | | | | |
| | | | MW | | | | | | | | | | | | | | | | | | | |
| | | | GWh | | | | | | | | | | | | | | | | | | | |
| | | | MMBTU | | | | | | | | | | | | | | | | | | | |
| | | | 2005$ | | | | | | | | | | | | | | | | | | | |

* Please use the current CPUC reporting categories from the instructions. Municipal utilities may use additional program categories as needed.

| Totals | | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Committed | MW | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Committed | GWh | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Committed | MMBTU | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Committed | 2005$ | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Uncommitted | GWh | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Uncommitted | MMBTU | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Uncommitted | 2005$ | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

## FORM 3.1b

**Participant Name**

### EFFICIENCY PROGRAM COSTS BY COST CATEGORY (2005$)

| PROGRAM NAME | COST CATEGORY | Committed / Uncommitted | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
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Requested Cost categories: Admininstration, Incentives, Measurement and Evaluation, and Participant Cost

**FORM 3.2**

**Participant Name**

**EFFICIENCY PROGRAM CUMULATIVE IMPACTS**

| Sector | Program Name | Committed / Uncommitted | Units | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | MW | | | | | | | | | | | | | | | | | | | |
| | | | GWh | | | | | | | | | | | | | | | | | | | |
| | | | MMBTU | | | | | | | | | | | | | | | | | | | |
| | | | MW | | | | | | | | | | | | | | | | | | | |
| | | | GWh | | | | | | | | | | | | | | | | | | | |
| | | | MMBTU | | | | | | | | | | | | | | | | | | | |
| | | | MW | | | | | | | | | | | | | | | | | | | |
| | | | GWh | | | | | | | | | | | | | | | | | | | |
| | | | MMBTU | | | | | | | | | | | | | | | | | | | |
| | | | MW | | | | | | | | | | | | | | | | | | | |
| | | | GWh | | | | | | | | | | | | | | | | | | | |
| | | | MMBTU | | | | | | | | | | | | | | | | | | | |
| | | | MW | | | | | | | | | | | | | | | | | | | |
| | | | GWh | | | | | | | | | | | | | | | | | | | |
| | | | MMBTU | | | | | | | | | | | | | | | | | | | |
| | | | MW | | | | | | | | | | | | | | | | | | | |
| | | | GWh | | | | | | | | | | | | | | | | | | | |
| | | | MMBTU | | | | | | | | | | | | | | | | | | | |
| | | | MW | | | | | | | | | | | | | | | | | | | |
| | | | GWh | | | | | | | | | | | | | | | | | | | |
| | | | MW | | | | | | | | | | | | | | | | | | | |
| | | | GWh | | | | | | | | | | | | | | | | | | | |
| | | | MMBTU | | | | | | | | | | | | | | | | | | | |
| | | | MW | | | | | | | | | | | | | | | | | | | |
| | | | GWh | | | | | | | | | | | | | | | | | | | |

| Totals | | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Committed | MW | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Committed | GWh | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Committed | MMBTU | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Committed | 2005$ | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Uncommitted | MW | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Uncommitted | GWh | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Uncommitted | MMBTU | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

**FORM 3.3**

**Participant Name**

## RENEWABLE AND DISTRIBUTED GENERATION PROGRAM COSTS AND IMPACTS

| Sector | PROGRAM NAME | Committed / Uncommitted | | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | MW | | | | | | | | | | | | | | | | | | | |
| | | | GWh | | | | | | | | | | | | | | | | | | | |
| | | | MMBTU | | | | | | | | | | | | | | | | | | | |
| | | | 2005$ | | | | | | | | | | | | | | | | | | | |
| | | | MW | | | | | | | | | | | | | | | | | | | |
| | | | GWh | | | | | | | | | | | | | | | | | | | |
| | | | MMBTU | | | | | | | | | | | | | | | | | | | |
| | | | 2005$ | | | | | | | | | | | | | | | | | | | |
| | | | MW | | | | | | | | | | | | | | | | | | | |
| | | | GWh | | | | | | | | | | | | | | | | | | | |
| | | | MMBTU | | | | | | | | | | | | | | | | | | | |
| | | | 2005$ | | | | | | | | | | | | | | | | | | | |
| | | | MW | | | | | | | | | | | | | | | | | | | |
| | | | GWh | | | | | | | | | | | | | | | | | | | |
| | | | MMBTU | | | | | | | | | | | | | | | | | | | |
| | | | 2005$ | | | | | | | | | | | | | | | | | | | |
| | | | MW | | | | | | | | | | | | | | | | | | | |
| | | | GWh | | | | | | | | | | | | | | | | | | | |
| | | | MMBTU | | | | | | | | | | | | | | | | | | | |
| | | | 2005$ | | | | | | | | | | | | | | | | | | | |
| | | | MW | | | | | | | | | | | | | | | | | | | |
| | | | GWh | | | | | | | | | | | | | | | | | | | |
| | | | MMBTU | | | | | | | | | | | | | | | | | | | |
| | | | 2005$ | | | | | | | | | | | | | | | | | | | |
| | | | MW | | | | | | | | | | | | | | | | | | | |
| | | | GWh | | | | | | | | | | | | | | | | | | | |
| | | | MMBTU | | | | | | | | | | | | | | | | | | | |
| | | | 2005$ | | | | | | | | | | | | | | | | | | | |
| | | | MW | | | | | | | | | | | | | | | | | | | |
| | | | GWh | | | | | | | | | | | | | | | | | | | |
| | | | MMBTU | | | | | | | | | | | | | | | | | | | |
| | | | 2005$ | | | | | | | | | | | | | | | | | | | |
| | | | MW | | | | | | | | | | | | | | | | | | | |
| | | | GWh | | | | | | | | | | | | | | | | | | | |
| | | | MMBTU | | | | | | | | | | | | | | | | | | | |
| | | | 2005$ | | | | | | | | | | | | | | | | | | | |

| Totals | | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Committed | MW | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Committed | GWh | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Committed | MMBTU | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Committed | 2005$ | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Uncommitted | MW | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Uncommitted | GWh | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Uncommitted | MMBTU | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

## FORM 3.4

**Participant Name**

**DEMAND RESPONSE PROGRAM COSTS & IMPACTS**

| PROGRAM NAME | DISPATCHABLE/ NONDISPATCHABLE | Demand Response/ Interruptible | Committed / Uncommitted | | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | MW | | | | | | | | | | | | | | | | | | | |
| | | | | GWh | | | | | | | | | | | | | | | | | | | |
| | | | | 2005$ | | | | | | | | | | | | | | | | | | | |
| | | | | MW | | | | | | | | | | | | | | | | | | | |
| | | | | GWh | | | | | | | | | | | | | | | | | | | |
| | | | | 2005$ | | | | | | | | | | | | | | | | | | | |
| | | | | MW | | | | | | | | | | | | | | | | | | | |
| | | | | GWh | | | | | | | | | | | | | | | | | | | |
| | | | | 2005$ | | | | | | | | | | | | | | | | | | | |
| | | | | MW | | | | | | | | | | | | | | | | | | | |
| | | | | GWh | | | | | | | | | | | | | | | | | | | |
| | | | | 2005$ | | | | | | | | | | | | | | | | | | | |
| | | | | MW | | | | | | | | | | | | | | | | | | | |
| | | | | GWh | | | | | | | | | | | | | | | | | | | |
| | | | | 2005$ | | | | | | | | | | | | | | | | | | | |
| | | | | MW | | | | | | | | | | | | | | | | | | | |
| | | | | GWh | | | | | | | | | | | | | | | | | | | |
| | | | | 2005$ | | | | | | | | | | | | | | | | | | | |
| | | | | MW | | | | | | | | | | | | | | | | | | | |
| | | | | GWh | | | | | | | | | | | | | | | | | | | |
| | | | | 2005$ | | | | | | | | | | | | | | | | | | | |
| | | | | MW | | | | | | | | | | | | | | | | | | | |
| | | | | GWh | | | | | | | | | | | | | | | | | | | |
| | | | | 2005$ | | | | | | | | | | | | | | | | | | | |
| | | | | MW | | | | | | | | | | | | | | | | | | | |
| | | | | GWh | | | | | | | | | | | | | | | | | | | |
| | | | | 2005$ | | | | | | | | | | | | | | | | | | | |
| | | | | MW | | | | | | | | | | | | | | | | | | | |
| | | | | GWh | | | | | | | | | | | | | | | | | | | |
| | | | | 2005$ | | | | | | | | | | | | | | | | | | | |

**FORM 6**

**Participant Name**

# ESP Report of Loads and Resources under Contract

| | PG&E | | | | SCE | | | | SDG&E | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| YEAR | Retail Sales (mWh) | Peak Demand (MW) | Customer Counts | | Retail Sales (mWh) | Peak Demand (MW) | Customer Counts | | Retail Sales (mWh) | Peak Demand (MW) | Customer Counts | |
| | | | Residential | Nonresidential | | | Residential | Nonresidential | | | Residential | Nonresidential |
| 2004 | | | | | | | | | | | | |
| 2005 | | | | | | | | | | | | |
| 2006 | | | | | | | | | | | | |
| 2007 | | | | | | | | | | | | |
| 2008 | | | | | | | | | | | | |
| 2009 | | | | | | | | | | | | |
| 2010 | | | | | | | | | | | | |
| 2011 | | | | | | | | | | | | |
| 2012 | | | | | | | | | | | | |
| 2013 | | | | | | | | | | | | |
| 2014 | | | | | | | | | | | | |
| 2015 | | | | | | | | | | | | |
| 2016 | | | | | | | | | | | | |
| 2017 | | | | | | | | | | | | |
| 2018 | | | | | | | | | | | | |

| AVERAGE ANNUAL GROWTH RATE (%) | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2005-2010 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| 2010-2018 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| 2005-2018 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |