California Energy Commission

Staff Draft
Electricity Demand Forecast Forms and Instructions

Prepared in Support of the
2011 Integrated Energy Policy Report

Docket 11-IEP-1C

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Nick Fugate & Tom Gorin
Demand Analysis Office

Staff Proposed Data Request

- Energy Commission Staff requests demand forecasts and supporting information from LSEs with annual peak demand >200 MW
- Data are due by March 30, 2011
- Instructions and procedures requesting confidentiality are summarized in the draft staff report ***Forms and Instructions for Electricity Demand Forecasts*** (CEC-200-2010-007-SD)

Role of CEC Demand Forecast

Energy Commission demand forecasts serve as a baseline for:

- Resource adequacy assessments
- Procurement and Transmission planning
- Impact analysis of demand-side programs and policies:
  - energy efficiency
  - demand response
  - renewables

Requested Data

- Provides alternative views of demand trends throughout the state
- Supports staff forecast development by:
  - Accounting for energy efficiency, renewable, and other demand-side program plans
  - Providing historical data for calibration and geographic disaggregation of the staff forecast
  - Informing staff's assessment of migrating loads

Notable Changes from 2009 IEPR

- Removed Form 2.1 (National Econ/Demo Assumptions)
- Altered Form 3.1 (DSM impacts) to distinguish between net and gross savings
- Altered Form 1.7 (private supply) to distinguish between technology types
- History now runs from 2000 to 2010

Overview of Demand Forecast Process

(Dates are approximate)

- Both staff and LSEs prepare forecasts (March 2011)
- Staff publishes Forecast Comparison Report (April 2011)
- Hearing on differences in demand forecasts (May 2011)
- Revised staff forecasts following Committee direction (May 2009)
- Revised staff forecast (Summer 2011)

Forecast Conventions

- Data to be submitted through 2022
- Forecast to include "committed" energy efficiency, renewable, and nondispatchable demand response impacts:
  - Committed programs are those with approved funding and at least a preliminary program plan
  - Uncommitted programs are those expected or scheduled, but not approved
  - Impacts of dispatchable demand response programs are reported, but not included in the forecast

Form 1 Electricity Demand

1.1 Sales by Sector or Class to Bundled Customers

- Record assumptions about migrating load

1.2 Total Distribution Area Sales by customer category (bundled, resale, Direct Access, CCA, etc.)

Form 1 Electricity Demand (cont.)

1.3 Annual Peak Demand of Bundled Customers by Sector or Class

- Record assumptions about migrating load

1.4 Total Distribution Area Peak Demand by customer category

- Add direct access and other departed loads and losses to bundled load to obtain distribution area coincident peak

Form 1 Electricity Demand (cont.)

- **1.5** Peak demand under high temperature conditions with 1-in-5, 1-in-10, 1-in-20, and 1-in-40 probabilities of occurring
- **1.6b** Hourly loads by climate zone or transmission subarea (for example, Divisions or “A-Bank Substations)

Form 1 Electricity Demand, cont.

1.7a and **1.7b** Private supply forecast

- Includes self generation, customer side of the meter distributed generation, over the fence sales, and wheeling from a cogenerator to a final user
- Reports annual energy and expected coincident peak (not capacity)
- Represents total private supply, including the incremental program effects in Form 3.3
- Distinguishes between technologies

Form 1 Electricity Demand, cont.

Forms 1.7c and 1.7d

- Newly added
- Form 1.7c requests total installed capacity of private supply
- Form 1.7d requests uncommitted private supply

Form 2 Assumptions

- Include all economic and demographic drivers used to develop the forecast. LSEs should modify forms as appropriate:
    - **2.1** Service area Economic and Demographic Assumptions
    - **2.2** Electricity rate forecast
    - **2.3** Customer counts, and any other drivers used to develop the forecast
- Document data sources and assumptions in Form 4

Form 3

- Report both committed and uncommitted impacts:
  - 3.1 Efficiency Program First Year Costs and Impacts
  - 3.2 Efficiency Program Cumulative Impacts (savings from current year program, plus decayed savings from previous years)
  - 3.3 Renewable And Distributed Generation Program Costs and Impacts – including programs to comply with CSI/SB 1
  - 3.4 Demand Response Program Costs and Impacts

Form 3 (cont.)

- Methodology, assumptions, and data sources are to be documented in the Form 5 Report
- In particular, include how expected coincident peak impacts of renewable programs were developed

Form 4 Forecast Methodology

In addition to demand forecast methodology, include:

- Definition of subareas used in Form 1.6b, including a zip code or other geographic identifier
- Description of the accounting of migrating load
- Description of methods and data used to develop loss factors

Form 4 Forecast Methodology (cont.)

- Weather adjustment methods, including what weather stations are used, and how weather sensitivities were developed
- Discuss forecast performance and present summary statistics

Forms 5 & 6 Demand-Side Program Methodology

- Form 5 - Methodology, assumptions, and data sources for *Committed* Demand-Side Program impacts
- Form 6 - Methodology, assumptions, and data sources for *Uncommitted* Demand-Side Program impacts
- How are impacts estimated in the absence of program plans
- In particular, include how expected coincident peak impacts of renewable programs were developed

Form 7 ESP Forecasts

- ESPs submit a forecast of contracted load by IOU area
- ESPs may, also, submit an expected load forecast to be consistent with the resource plan submittal
- Include an explanation of the basis of the forecast

Form 8.1a and 8.1b

- Data requested from 2008 through forecast period
- 2008 – 2010 data should be in nominal dollars and represent actual revenue requirements
- 2011 and beyond should be in 2009 real dollars and be based on current or anticipated authorization levels

Form 8.1a – Revenue Requirements

- Three versions of Form 8.1a, each specific to a type of Utility Distribution Company:
    - IOUs – Revenue requirements by cost category
    - POUs – Revenue requirements by expense category
    - LSEs – Estimated power supply costs

Form 8.1b – Revenue Allocation

- Two versions of Form 8.1b
- Revenue allocation by bundled customer/rate class
- Revenue allocation for direct access service customers

Form 8.2

- Residential electricity sales by baseline percentages
- Only need to be reported by utilities with tiered rates
- Monthly kWh and customers by 10% increments of baseline consumption (0-10% of baseline to 300%+)
- For years 2008-2010
- Needed to examine continuing impacts of AB1x and determine distribution of residential consumption by baseline territory

Requests for Confidentiality

- Follow filing instructions in Appendix A
- Clearly identify and describe the data
- Citations & non-disclosure justifications
- Sign "penalty of perjury" certification
- Correct defects within 14 calendar days
- Applicants may simply identify information that is substantially similar to information that was previously deemed confidential if the relevant facts and circumstances remain unchanged
- Confidential data may be disclosed after aggregation, according to CCR, Title 20, 2507(d)