CALIFORNIA
ENERGY
COMMISSION

FORMS AND INSTRUCTIONS FOR SUBMITTING ELECTRICITY RESOURCE PLANS

Prepared in Support of the 2007 Integrated Energy Policy Report

COMMITTEE REPORT

December 2006
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Arnold Schwarzenegger, *Governor*

CALIFORNIA ENERGY COMMISSION

2007 Integrated Energy Policy Report Committee

Jackalyne Pfannenstiel
Presiding Member

John L. Geesman
Associate Member

Mike Jaske
David Vidaver
Jim Woodward
Principal Authors

Scott Mathews
Deputy Director, Electricity Analysis Division

Lorraine White
Program Manager, Integrated Energy Policy Report

B. B. Blevins
Executive Director

TABLE OF CONTENTS

Executive Summary and Background

This report describes information for electricity planning that is needed by the California Energy Commission (Energy Commission) to prepare its *2007 Integrated Energy Policy Report* (IEPR or *2007 Energy Report*). This report also provides forms with instructions that define the electricity resource planning and procurement information that must be submitted by load-serving entities (LSEs), using common terms and conventions.

The Energy Commission is directed by Public Resources Code (PRC) Sections 25300-25323 to conduct regular assessments of all aspects of energy demand and supply. These assessments will be included in the *2007 Energy Report* or in supporting reports. These assessments provide a foundation for policy recommendations to the Governor, Legislature, and other 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.

To carry out these energy assessments, the Energy Commission is authorized to require California market participants to submit historical data, forecast data, and assessments. 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."

These assessments will provide a foundation for recommendations of the *2007 Energy Report*. Resource plans from the Investor Owned Utilities (IOUs) may also serve as a reference case in the 2006 Long-Term Procurement Plan proceeding (R. 06-02-013) at the California Public Utilities Commission (CPUC). Many LSE resource plans, individually and collectively, are expected to inform controlled grid studies by the California Independent System Operator (CAISO). Energy Commission demand and supply assessments are also used in the *California Gas Report*.

General Instructions

When to File

In adopting these forms and instructions, the Energy Commission specifically requires the relevant parties to file certain electricity resource planning information by February 7, 2007. This requirement includes three electricity supply forms and narratives on publicly owned utility (POU) protocols to assure resource adequacy.

At a later date, the IEPR Committee may direct LSEs to file additional data needed to assess particular scenarios, topical issues, or policy proposals under consideration.

Who Must File

Electricity supply information is required from every load-serving entity (LSE) in the state whose non-coincident peak retail load was greater than 200 megawatts (MW) in either 2005 or 2006. Each such LSE is required to file the information requested on each form in accordance with the accompanying instructions. For the purposes of this filing requirement, LSE means every IOU, Publicly Owned Utility (POU), and Electric Service Provider (ESP) that has retail end-use customers in California.

Exemptions for Small Load-Serving Entities

A "small" LSE means a load-serving entity whose non-coincident peak retail load in both 2005 and 2006 was less than 200 MW. For the *2007 Energy Report*, small LSEs are exempt from filing 10-year resource plans. However, these same LSEs are *not* exempt from filing transmission project plans.

This exemption for small LSEs applies to approximately 11 registered ESPs, 4 IOUs, 4 rural electric cooperatives, 1 recreation improvement district ,1 community aggregator, all potential community choice aggregators (CCAs), and approximately 35 POUs. Together, the non-coincident peak loads of these small LSEs in 2006 amounted to about 1,800 MW.

What Must be Filed

The electricity supply information to be provided is identified on the following forms, which are included with these instructions:

- S-1 Capacity Resource Accounting Table,
- S-2 Energy Balance Accounting Table,
- S-3 New Capacity for Local Reliability, and
- S-5 Bilateral Contracts.

In 2005, Form S-4 was used to request projections on Qualifying Facility (QF) energy and costs. For the *2007 Energy Report*, Energy Commission staff is not requesting information from the IOUs about QF contracts.

POUs are asked to provide narrative reports that describe adopted adequacy standards, procurement requirements by control areas and regulatory authorities, and the LSE's planning protocols used to assure those obligations are being met.

Alternative Filing Format Considerations for LSEs

The Energy Commission will consider alternate formats for LSEs to provide the requested data as described in these instructions. The Energy Commission will review such filings and determine if the requests for data have been satisfied by the LSEs. To facilitate this determination where there are differences in format, LSEs are directed to provide “maps,” concordances, cross-references, and descriptions linking their proposed alternative filing with the expectations described in these instructions.

The CPUC has directed the IOUs to file candidate resource plans on December 11, 2006, in the long-term procurement proceeding (LTPP). The Energy Commission strongly encourages IOUs to develop their resource plan filings for the CPUC using terminology, counting conventions, and descriptions that are consistent with these instructions. To accommodate this outcome, and to reduce the burdens involved with reformatting the same data to be filed with the CPUC, the Energy Commission will consider accepting the LTPP filings in fulfillment with this data request.

The IOUs may propose to use their “candidate resource plans” to be provided to the CPUC to satisfy some or all of the information reporting requirements in this proceeding. To the extent these filings are identical in form and content, this will eliminate redundant filing burdens on utility staff. It will also reduce uncertainties and discrepancies that could result from dissimilar filings submitted to the two different commissions. To avoid such potential discrepancies, the CPUC Assigned Commissioner Ruling on September 25, 2006, directed IOUs to consult with Energy Commission staff on the monthly energy balance and capacity reporting forms. To the maximum extent feasible, these instructions have endeavored to adopt common formats, definitions, and instructions to accommodate resource plan filings by IOUs in both proceedings, while simultaneously accommodating resource plan filings by other LSEs for the IEPR proceeding.

Where the candidate resource plans provided to the CPUC do not sufficiently provide the information requested in these instructions, IOUs are expected to provide clearly labeled supplemental data, information, footnotes, and assessments. Energy Commission staff will determine whether the original format and supplemental data satisfy these forms and instructions.

Submittal Format Requirements

For all filings, parties are requested to submit a brief cover letter along with diskette or compact disk containing:

- Data on specified forms using Microsoft Word or Excel
- Reports and cover letters in Microsoft Word or Adobe Acrobat

To expedite the review, comparison, and assessment process, an Excel template with data forms is available on the Energy Commission website and by request. This template is the preferred format. Participants may provide these results in a different format as long as equivalent information is provided timely and clearly labeled.

General questions about these forms or instructions may be directed to Jim Woodward at jwoodwar@energy.state.ca.us or (916) 654-5180.

How to File

The Energy Commission encourages filings by e-mail attachments. Each e-mail should be 4 MB or less in size. When naming your attached file, please include your name or your organization's name. The attachment should be in either Microsoft Word or Excel. The e-mail subject line should begin with "06-IEP-1J" followed by your name or your organization's name. Send your e-mail filings to Docket@energy.state.ca.us.

Filings on paper and electronic filings larger than 4 MB must be sent to:

California Energy Commission
Docket Office
Attn: Docket 06-IEP-1J
1516 Ninth Street, MS-4
Sacramento, CA 95814-5512

Confidentiality Designations and Applications

The Executive Director of the Energy Commission has overall responsibilities for determining what information provided to the Energy Commission will be deemed confidential. Parties must make a separate, written request that specific types of information be determined confidential. The application must include three attributes:

1) A hard copy cover letter 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-1J**, and the confidential data categories must be clearly and properly labeled.

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 placed in a "suspense" file, and the filer will be notified by mail and email 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.

Certain categories of data provided to the Energy Commission, along with a request for confidentiality, will be designated as confidential almost automatically. The types of data that are eligible for this nearly automatic designation and the process for obtaining this confidential designation are specified in Section 2505(a)(5) of the Energy Commission's regulations (found in Title 20 of the California Code of Regulations). These categories include specific hourly generation of electric power plants, fuel cost data, and some energy price data.

All confidentiality applications submitted to the Executive Director for rendering a decision must contain the following information:

1) Identification of the information being submitted, including title, date, size (for example, pages, sheets, megabytes), 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 a) that the specific records to be withheld from public disclosure are exempt under provisions of the Government Code, or b) that 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.

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 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 electric service provider groups as these groups are defined by the U.S. Census Bureau in their North American Industry Classification System (NAICS) tables.

The Executive Director of the Energy Commission has 30 days to render a decision on a complete application. Confidentiality determination letters are signed by the Executive Director. 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.

Information submitted to the Energy Commission without a request for confidentiality should be filed directly, either electronically (preferred) Docket@energy.state.ca.us or by mail:

California Energy Commission
Docket Office
Attn: Docket #06-IEP-1J
1516 Ninth Street, MS-4
Sacramento, CA 95814-5512

More specific questions about confidentiality may be directed to Fernando DeLeon at fdeleon@energy.state.ca.us or (916) 654-4873.

Different Reporting Requirements Among LSE Types

The information requested differs depending on whether the LSE is an IOU, a POU, or an ESP. This difference stems from different requirements imposed upon each class of LSE by the Legislature and state agencies, and from materials created by each class of LSE while doing business. While a single format is presented in the sample forms accompanying this document, the detail to be provided will vary by class of LSE.

Some information is requested about the grid management services that LSEs may provide to other LSEs. Some utilities operate control areas or maintain distribution systems benefiting retail customers other LSEs. These information requests are discussed below.

Requirements Unique to Investor-Owned Utilities

IOUs are asked to submit some categories of information that is not requested from other LSEs: information related to contracts signed by the Department of Water Resources (DWR) and information about contracts with qualifying facilities (QFs).

The terms investor-owned utility and “IOU” refer to all seven state-regulated corporations that provide bundled electricity service to retail customers in California. By definition, this includes:

- Pacific Gas and Electric Company (PG&E),
- Southern California Edison Company (SCE),
- San Diego Gas and Electric Company (SDG&E),
- PacifiCorp,
- Sierra Pacific,
- Bear Valley Electric Service, and
- Mountain Utilities (Kirkwood).

The four smallest IOUs are exempt from the requirement to file multi-year supply resource plans, because the peak load for their customers in California is less than 200 MW. In practice, therefore, when these instructions refer to investor-owned utilities, they generally apply only to the three large IOUs: PG&E, SCE, and SDG&E.

Requirements Unique to Utility Distribution Companies

IOUs provide distribution services to the customers of other LSEs. In this role as a utility distribution company (UDC), also called local distribution company, each IOU has load data and does load forecasting for all the customers in its service area. These instructions and forms ask for information that will help to better distinguish those shares of UDC loads that derive from 1) IOU bundled customers; 2) particular medium and large ESPs; 3) the aggregate of all small ESPs; and 4), POU loads met by partial services requirements, WAPA preference contracts, or other arrangements.

Requirements Unique to POU Control Area Operators

Four POUs serve as control area operators. For Imperial Irrigation District, the boundaries and obligations for the control area and the LSE service area are essentially synonymous. LADWP, SMUD, and Turlock Irrigation District operate control areas that include other POUs. These three POUs are asked to carefully identify and describe those control area responsibilities as they affect and influence resource plans (above and beyond the obligations intrinsic to the role of a utility serving its own retail customers). These three POUs are asked to discuss how control area responsibilities affect planning reserve margins, procurement options, and dispatch flexibility. This discussion should be presented as a section within the narratives on POU policies and actions being taken to ensure resource adequacy.

Publicly Owned Utilities and Resource Adequacy

All POUs are being asked to explain how their planning and procurement standards relate to their customer service obligations, to physical reliability expectations, and to control area operating requirements. POUs are also asked to demonstrate how their planning activities are leading to adequate resource procurement for 2007.

With these forms and instructions, resource plan information is being requested from 11 medium size POUs (200 MW to 1,000 MW peak demand) and two large POUs (LADWP and SMUD).

In a parallel and concurrent project, small POUs are being asked for information on their resource commitments to meet peak monthly loads during 2007. Together, these two projects can provide complete sets of data about POU resources for 2007 and narratives explaining current POU planning and procurement standards. Using these filings, the Energy Commission will be able to report to the Legislature, as required by AB 380, how POUs meet their customer and control area obligations for resource adequacy, and how they will continue to do so under expected conditions and predictable contingencies.

Requirements Unique to Electric Service Providers

For the 2007 IEPR, large and medium-size ESPs are asked to provide some minimal disaggregated data on their statewide forecasted loads. All or nearly all ESP customers are believed to be located in PG&E, SCE, or SDG&E service territories, though some direct access customers may be located elsewhere. ESPs are asked to file a separate S-1 and S-2 form for each UDC service area in which they have forecasted loads. These separate filings by local distribution company need only identify the amounts of energy and capacity shown on lines 1, 2, and 3 of the S-1 and S-2 forms. Single S-1, S-2, and S-5 forms from each ESP will suffice for reporting all other categories of requested resource plan information. For the *2007 Energy Report*, narrative assessments are not being solicited from ESPs.

This new requirement is necessary to assess load migration and local reliability concerns at a geographic level commensurate with the load forecasts of other LSEs. ESP loads are part of utility transmission planning areas and are often located in generation load pockets. For both these geographic contexts there are special sensitivities about serving customers in the long run. Since the UDC load forecasts include small ESPs and some small POUs that are not required to file resource plans, the disaggregated resource plans of larger ESPs are essential for various physical system assessments.

With due respect and consideration for ESP business models and their limited-term obligations to serve current direct access customers, the resource plans provided by ESPs are required to cover only five years, 2007 through 2011. This avoids the "long ruler" approach to a speculative demand forecast linked to generic supply portfolios.

ESPs have not been asked to provide hourly demand forecasts to the Energy Commission. The need for this information has largely been met by the IOUs in their role as utility distribution companies. The demand instructions asked IOUs to forecast hourly loads for 1) their expected "bundled" customers; and 2) all their customers to whom they provide distribution services. (Energy Commission Demand instructions, page 7).

The IOUs, in their UDC roles, were asked to report and forecast the amount of energy delivered annually to ESP loads (Demand Form 1.2) and the annual peak for all ESPs (Form 1.4). IOUs were also asked to show the sum of all UDC loads with customer counts (Form 2.4), how UDC loads are disaggregated by customer class (Form 1.7), and how UDC loads are disaggregated by climate zone or transmission planning area (Form 1.6b). ESPs are now being asked to provide a disaggregated load forecast simply by UDC areas. This information will help to verify and confirm the independent IOU and ESP load forecasts. This disaggregated reporting will likely be helpful in better estimating local area load forecasts that are used in reliability studies.

Public Purposes to Be Served by Supply Resource Data

General Purposes and Authorities

The general purpose of these forms and instructions is to provide the Energy Commission with a better understanding of LSE planning assumptions and resource adequacy commitments. From this information, staff will assess current conditions in electric generation system infrastructure and identify major statewide trends affecting electricity supply and reliability. The information being collected from LSEs is designed and intended to meet the following public purposes.

Needed Capacity, Retirements, and Repowering

All medium and large utilities are asked to identify new and existing capacity that will be needed to meet forecasted end-use loads over the next 10 years through 2016.

The continued need for existing utility-owned generation, along with potential retirement and repowering possibilities, will be part of this demonstration.

Medium and large ESPs are asked to identify how their contractual obligations to direct access customers will be met over the next five years through 2011. ESPs are also asked to identify their expected new and renewing customer loads for the next five years. LSEs are asked to identify their monthly and annual bundled customer loads. Utilities are also asked to identify, if applicable, other forecasted loads included within their distribution systems. These load forecasts will help identify how the interconnected LSEs will likely serve their local and zonal loads in the coming five years. The supply components of these resource plans will help assess the scope and temporal context of LSE open positions. Some of these open positions are subject to load migration uncertainties. In broad terms, the aggregate of these open positions will indicate where, when, and for whom new physical or contractual resources will be needed.

Long-Term Procurement Authorizations

For investor-owned utilities, the 10-year resource plans will identify the amounts of needed capacity and energy that need to be filled over time by procurement actions. From these resource plans, the CPUC is expected to authorize procurement volumes for IOUs to continue serving their bundled customers. Such an authorization would be incorporated in the current or future Long-Term Procurement Proceedings (LTPP) administered by the CPUC.

When quantified uncertainties are factored in, these volume limits are often called a “range of need.” After the CPUC approves a long-term procurement plan for an IOU, authorization to fill these identified resource needs may be given in the form of “position limits” over certain time periods, with assurance of cost recovery linked to ratable rates. For this purpose, a connection can be drawn from the net short capacity amounts on Form S-1 and from the net short energy amounts on Form S-2 to authorized volume limits and ratable rates for each IOU in their AB 57 long-term procurement plans.

The estimates of needed and available capacity among several LSEs may also be used to flag resource additions considered physically necessary to maintain electrical reliability standards, either at the local or system level. For example, the resource plan data could be aggregated to demonstrate how UDC customers or planning area loads would be supplied by IOUs, POUs, and ESPs. Aggregated data could also be used to roughly identify for UDC customers prospective net short capacity amounts, contractual needs, and types of services needed to maintain local reliability.

Planning Reserve Margin Assumptions

These instructions ask IOUs and ESPs to apply the 15% planning reserve margin to the entire planning horizon (10 years for IOUs, five years for ESPs). This amount is included on the Excel template for Form S-1, line 9. This 15% planning reserve margin is considered appropriate for 10-year resource plans and was used this way by IOUs and ESPs in their previous 2005 filings with the Energy Commission.

Most POUs also used the 15% planning reserve margin in 2005. Some POUs have adopted a higher planning reserve margin based on their own portfolio contingencies or reliability goals. POUs are asked to apply this 15% planning reserve margin, or their own adopted planning reserve criteria, for all 10 years in the planning horizon.

None of the ESPs and very few utilities can afford to secure all the generating resources needed to meet loads for the next 10 years. By 2016, most LSEs will have open positions for capacity in the summer months. A standardized application of the 15% planning reserve margin allows the open positions of individual LSEs to be compared and summed using common assumptions.

In their month-ahead resource adequacy filings, LSEs under CPUC jurisdiction must now show that they have procured 115% of the capacity needed to meet hourly peak demand for the subsequent month. The “year ahead” resource adequacy filings require a showing that 90% of this need has been procured (90% of 115%) for each of the subsequent summer months.

In these year-ahead and month-ahead filings, all LSEs have been authorized to use a “peak coincidence” adjustment. This adjustment factor varies by the month, and effectively reduces the 15% planning reserve margin by about 2.5%. This adjustment can be considered a transitional requirement as LSEs go from a 15% planning reserve margin above their *non*-coincident peak, year ahead, and eventually are responsible for scheduling resources to meet a 6% to 7% operating reserve margin.

This peak coincidence adjustment is not authorized for use on 10-year resource plans, which forecast the *non*-coincident peak of each LSE. The year-ahead and month-ahead resource adequacy filings carry with them two significant regulatory obligations. One involves penalties for inadequate procurement, including the cost of backstop purchasing by CAISO. The second involves a commitment by LSEs to make resources available to the CAISO. With appropriate exclusions and conditions, once a resource is listed in the resource adequacy filings, if that resource is not scheduled by the LSE in the day ahead, it must be made available to CAISO for grid reliability or for sales within markets administered by CAISO. Listing a resource in the 10-year resource plans carries no such obligations or potential penalties.

Load Pocket Considerations

For many areas of the state, CAISO has identified specific amounts of local capacity needed to maintain reliable service under specified grid-related contingencies. The Local Capacity Requirements (LCR) process has delineated three “load pocket” areas in Southern California and seven load pockets in Northern and Central California. The LCR designations apply only to 2007. However, substantial continuity into future years is expected for the major load pockets, especially the Greater Bay Area, LA Basin, and San Diego.

For consistent data collection, the S-3 form assumes that control area boundaries and load pocket areas will persist unchanged throughout the forecast period. LSEs are asked to indicate preferred locations on Form S-3 for all new generating resources listed on form S-1. This non-binding and general location, relative to recognized load pockets, represents the LSE’s preference about where needed resources for its bundled customer loads would also provide the most benefits for operational security of the interconnected grid.

Loading Order Considerations

As with the request for data for the *2005 Energy Report*, LSEs are asked to include realistic estimates of capacity and energy to be achieved from loading order programs. Do not assume that officially prescribed or formally adopted targets will be met precisely on schedule. These estimates affect the calculation of Net Short capacity and open energy positions. If the loading order program estimates are too optimistic, the authorized procurement volume limits may be too low, which could adversely affect planning and operating reserve margins in future years.

The loading order is not to be confused with dispatch order preferences. For example, demand response is high in the loading order, but dispatchable DR interruptible and emergency options, herein considered a supply resource, are obviously low in the priorities for daily dispatch. LSEs are not asked to comment directly on the decision criteria or analytical methods that were part of establishing loading order targets. The resource plan is meant to be a practical guide based upon reasonable expectations, limitations, and contingencies as currently known. LSEs are expected to meet service obligations at reasonable cost, to generate within environmental permits, and to contract for deliveries within prudent risk tolerances. If a deficiency or contract problem with preferred resources has become apparent, the LSE must fill that need from other long-term or short-term procurement options. If particular loading order targets adopted for LSE procurement will likely not be met, the LSE is asked to footnote the S-1 and S-2 forms to flag that discrepancy with some attribution regarding probable cause.

The resource plans can be used to demonstrate the extent to which LSEs expect to meet or exceed particular program goals. As such, the estimated numbers depicted here may serve as a useful benchmark for expected results given everything currently known about technical capabilities, market incentives, regulatory constraints, statutory mandates, and policy guidance. Some programmatic goals are general in nature, not yet quantified or tied to specific locations. For example, these forms ask for data on expected outputs and reductions from distributed generation (DG), though the loading order does not identify annual targets for this resource type. Some legislation does not prescribe or proscribe specific procurement actions, such as the AB 1576 encouragement to repower older plants. Another non-prescriptive loading order preference is for utilities to simultaneously consider transmission and generation alternatives.

Definitions and Aggregated Data

Deliverability of Resources

Electricity resources must be deliverable to the respective LSE load centers to be fully counted as existing or planned resources. The one notable exception to this general deliverability requirement is the long-term Sempra contract with the California Department of Water Resources (DWR), a contract that is not tied to specific generating plants and which allows a delivery point anywhere in the State of California. Each LSE is expected to perform deliverability screening, filtering, or other appropriate criteria for matching loads with resources. However, the disclosure of these criteria is not requested on these forms. Unlike past Electricity Reports, the electricity supply resources forms do not address transmission facilities or transmission planning.

Deliverability needs are not being overlooked or minimized. The Energy Commission recognizes that costs of transmission congestion can be substantial. New transmission facilities can face insuperable difficulties in siting approval and cost allocation. This can be a barrier to developing new generating resources, whether they are utility-owned, merchant-built, or eligible renewables.

Definitions

For existing and planned electricity supply resources, all LSEs in California are expected to use reasonably consistent and compatible terms and counting conventions. This consistency is needed to facilitate a general evaluation of statewide supply adequacy. This evaluation includes some limited assessments of coincident peak supply needs within specific control areas, primarily that of the CAISO.

Existing Demand Side Management (DSM) programs that are not dispatchable are incorporated into the demand forecast and are not herein considered to be supply resources.

Planned resources are those that an LSE deems either most likely or most preferred as additions to the portfolio. For IOUs, planned resources are those specific facilities and contracts that the CPUC has approved but are not yet on line (for example, Otay Mesa, Humboldt Wartsila, and up to 250 MW of new quick-start black-start peaking turbines in SCE's service territory). For other LSEs, they are resources that are either committed or for which the LSE has a reasonable expectation of commitment. This would include SMUD's Cosumnes 2 power plant (if SMUD presently intends to go forward with the second unit). An LM 6000 plant may be a planned resource if a utility expects to use it to meet load growth. The listing of planned resources should reflect the most probable long-term resource plan for an LSE and its preferred "loading order,"[1] especially where an LSE must add new resources to accommodate forecast load growth or capacity retirements.

Hydroelectric generation is considered to be an existing resource for the duration of time that an LSE has legal authority to integrate production of forecast energy and dependable capacity. After the expiration date of a Federal Energy Regulatory Commission (FERC) hydro license, or operating agreement, or integration agreement, it would be a planned resource if the LSE expects to retain it in its portfolio.

The term "planned resources" can include physical and contractual resources about which there is considerable uncertainty due to regulatory, financial, or legislative risks. For example, the need for regulatory approvals and permits might keep a specific planned resource from becoming a committed resource for many months. The distinction between planned and committed resources was important in past Electricity Reports (such as ER 1994); however, this distinction is not important for data collection in support of the *2007 Energy Report*.

A more complete set of definitions may be found in the proposed changes to the California Energy Commission's regulations governing data collection for the Energy Policy Report (Title 20, California Code of Regulations, Section 1301 et seq. and 1340 et seq.), regulations implementing the Energy Commission's complaint and investigation process (Title 20, California Code of Regulations, Section 1230 et seq.), and regulations governing the disclosure of Energy Commission records Title 20, California Code of Regulations, Section 2501 et seq.). The definitions are found in Chapter 3, Article 1, Section 1302.

Utility-controlled resources are those that an IOU or POU can dispatch or schedule and then integrate in real time. This category includes all forms of ownership and joint

[1] For example, the *2003 Energy Action Plan* adopted the following loading order: First, the agencies want to optimize all strategies for increasing conservation and energy efficiency to minimize increases in electricity and natural gas demand. Second, recognizing that new generation is both necessary and desirable, the agencies would like to see these needs met first by renewable energy resources and distributed generation. Third, because the preferred resources require both sufficient investment and adequate time to "get to scale," the agencies also will support additional clean, fossil fuel, central-station generation. Simultaneously, the agencies intend to improve the bulk electricity transmission grid and distribution facility infrastructure to support growing demand centers and the interconnection of new generation.

powers authority. Resource data about facilities controlled by one LSE but owned by another, such as an irrigation district, should be reported by the controlling utility. LSEs have the reporting responsibility for generating resources owned by non-LSE irrigation and water districts. For example, PG&E should include Placer County Water Agency, the City and County of San Francisco (Hetch Hetchy), and other irrigation districts and water agencies with generation that is dispatched or integrated by PG&E.

Integration means the ability of an LSE or control area to use the generation output of facilities to serve load or balance the grid. The rights and obligations to integrate the output from cogeneration, wind, and "run of river" hydro are typically detailed in contractual agreements. Special integration concerns may exist for resources like this that are not dispatched by LSEs, especially those which operate intermittently, those which are difficult to predict or schedule day-ahead, and those which do not have an obligation to be available.

Aggregated Data

As a general requirement, each individual resource should have a line-item entry on forms S-1 and S-2. Each resource should have a numeric entry showing capacity or energy for each month that the LSE expects to own, control, or contract with that resource. This includes all supply resources, existing or planned, physical or contractual.

There are three exceptions to this general requirement where the LSE may prefer to report aggregated data. First, all utility-controlled hydroelectric assets (non-QF) may be aggregated into two categories (more than and less than or equal to 30 MW nameplate). Second, QF contracts may be aggregated by technology or fuel types (for example, biofuels, geothermal, small hydro, solar, wind, natural gas – cogen, and other). Third, all micro-supply contracts supplying less than 1 MW may be aggregated by fuel type, resource type, or program type. Examples include contracts with end-use customers involving program categories such as distributed generation, demand response, and the California Solar Initiative.

Supply Form S-1: Capacity Resource Accounting Table (MW)

Scope

LSEs are asked to estimate how much power in megawatts (MW) is needed to serve monthly peak retail customer load, plus reserves and other obligations. LSEs are also asked to identify how much power will come from various electricity supply resources. These estimates are required for all months of the forecast period, January 2006 through December 2016. LSEs are requested to provide these data on Supply Form S-1, Capacity Resource Accounting Table, also called a CRATs table. The data submitted by each LSE on Form S-1 should correspond one-to-one with the data submitted on the Energy Balance table, Form S-2.

A completed Form S-1 provides a forecast of non-coincident peak demand for each LSE, followed by a summary of how that demand will be met with existing, planned, and generic resources.

Qualifying Capacity or Dependable Capacity

LSEs that provide end-use electrical services in the CAISO control area are asked to report supply resources as qualifying capacity. Numbers should be consistent with year-ahead and month-ahead resource adequacy filings. CAISO's list of updated Net Qualifying Capacity (NQC) values is posted at http://www.caiso.com/1796/179688b22c970.html.

If there is a difference between qualifying capacity and dependable capacity numbers for a particular resource, LSEs are asked to use the lower number on the S-1 form, though the higher number may be used if an explanatory footnote is provided. Do not use or report values for nameplate capacity, installed capacity, or Pmax capacity (unencumbered capacity).

Please report the amount of capacity from each generation source that is considered firm and reliable for meeting loads forecast to occur in the monthly peak hour. This amount would be measurable at the busbar. For intermittent resources without flexible dispatch (such as wind), dependable capacity estimates should reflect the non-firm nature of this supply. Those LSEs in CAISO under CPUC jurisdiction may use the higher calculated qualifying capacity values for wind but are asked to indicate dependable capacity in a footnote.

For CPUC-jurisdictional LSEs, following the CPUC decision on resource adequacy and qualifying capacity, energy supply contracts with provisions for liquidated damages ("LD contracts") may only be counted as dependable capacity through 2009. These LD contracts do not identify a particular generator that must be available to serve system loads in CAISO when needed by the independent operator (as distinct from generators that are scheduled and dispatched solely by LSEs to meet LSE loads).

Capacity values should not be adjusted for expected forced outages. However, specific forecast months should incorporate any capacity reductions for scheduled outages, such as annual hydro maintenance in November and scheduled nuclear shutdowns from refueling.

Resource Adequacy Counting Rule Issues

Resources should only count to the extent that their capacity can be relied upon to perform. Unless otherwise specified by CPUC, CAISO, the Energy Commission, or the LSE's adopted counting conventions, a resource must be able to operate for four consecutive hours for three consecutive days at the capacity listed on Form S-1. For contractual resources, show how much capacity will be available to the LSE throughout the forecast period.

It is reasonable to count all generation as deliverable by assuming that transmission upgrades will be completed by participating transmission owners. For LSEs not under CPUC jurisdiction, dependable capacity for exchanges and imports is the amount that can be counted on with high certainty for meeting the LSE's non-coincident peak demand.

Do not include utility distribution company wheeling deliveries, such as direct access supplies to Stanford University within PG&E distribution territory.

QFs and Hydro
The RA counting rules require the resource adequacy capacity of QF hydro units to be calculated based on the SO1 peak period generation in an average dry year (defined to be a 1-in-5 dry year). However, if hourly generation for QF hydro is not available for the average dry year, LSEs may calculate qualifying capacity from the next driest hydro year with reliable hourly data. If a hydro unit owned by the LSE or under contract to the LSE experienced significant outages during the 1-in-5 dry year, the next closest dry year may be used to calculate RA for these units.

Non-Hydro Renewables
The Resource Adequacy counting rules in general require the capacity of renewable resources to be based on the historical performance over the last three years. However, if three years of generation data is not available, the LSE may use available generation data to calculate the resource adequacy capacity.

For solar and wind resources, a three-year rolling average of performance history during peak hours is appropriate to assess qualifying capacity. For LSEs under CPUC jurisdiction, the peak period is defined as noon to 6 p.m. year-round (based on Standard Offer 1 contracts defining summer peak hours).

Consistency with the Demand Forecast and the Retail Price Forecast

The resource plan from each LSE shall demonstrate how the LSE can meet its obligations to serve end-use loads and to meet other firm obligations. This load forecast and supply plan shall be consistent with and compatible with the demand forecast provided to the Energy Commission according to the requirements of Section 1345(a).

Peak Load Calculations

Line 1 Forecast Total Peak-Hour Load

On line 1, all LSEs are asked to forecast their total non-coincident load during the peak hour of each month in the forecast period. This number, in MW, must include all power needed to serve end-use loads along with the power needed to deliver supplies to these loads. Therefore, the monthly peak hour estimates must include allowances for transmission losses, distribution line losses, and unaccounted for energy (UFE). Do not include generator station (parasitic) loads. For the end-use customer load forecast, LSEs are required to use their best estimates about their future customers and their loads. These estimates may be greater than or less than the current obligation to serve end-use customers.

For each year in the forecast period, the largest monthly Forecast Total Peak Load on line 1 of the S-1 form should correspond to the LSE non-coincident peak load previously reported on demand Form 1.3.

Forecast Total Peak Hour Load already includes adjustments for distributed generation, and for energy efficiency programs that are "committed" (or funded). The load forecast on Form S-1, line 1, also includes adjustments for committed demand response programs that are *not* dispatchable by the LSE.

For this filing (as it was in 2005), a key distinction is whether or not the program is dispatchable by the Load-Serving Entity (or by the UDC or control area operator). Dispatchable programs, such as direct control, interruptible tariffs, or demand bidding programs, have triggering conditions that are not under the control of end-use customers, and cannot be anticipated by these customers. All price response programs that have specified triggering conditions should be treated as dispatchable. This includes critical peak pricing, real-time pricing, and demand response bidding. Energy or peak load saved from dispatchable programs is to be treated as a supply resource on the S-1 and S-2 forms and is not be accounted for in the demand forecast.

Nondispatchable programs are not activated using a predetermined threshold condition. Nondispatchable programs allow the customer to modify their own electricity consumption in response to time-varying prices or other contingencies. Impacts from committed nondispatchable programs should be included in the LSE demand forecast. This includes fixed time-of-use tariffs that result in load reductions.

Other adjustments to the Total Forecast Peak Load are discussed below, including uncommitted programs for energy efficiency (line 6) and all uncommitted programs for demand response (line 7). The term “demand response” encompasses a variety of programs and agreements. This term includes traditional direct control (interruptible) programs, price-responsive tariffs, and new cafeteria-style choices for customers to reliably reduce loads.

Peak Load estimates on line 1 should not include capacity amounts needed for a planning reserve margin (shown on line 9), or for firm wholesale obligations of the LSE (shown on line 10).

Line 2 ESP Peak Load: Existing Contracts

ESPs are asked to identify how their expected loads are divided between new and renewing customers. On line 2, ESPs are asked to indicate the load obligations to serve existing customers. Include all continuing loads of those customers under contract, along with contracts that have future start dates.

Line 3 ESP Peak Load: New and Renewed Contracts

On line 3, ESPs are asked to estimate total monthly capacity needs that arise from new customers, plus future contract renewals or extensions to serve existing customers. This forecast should be the “most likely” case as judged by the ESP. The sum of this value on line 3, plus the value entered on line 2, should equal the monthly peak load number entered on line 1.

Line 4 CCA and Departing / Arriving-New Municipal Loads (-) (+)

IOUs are asked to identify a particular amount of existing IOU load that it expects to depart to Community Choice Aggregation (CCA), or to POUs (commonly called departing “municipal,” or MDL, in this context). As likely CCA/DML values are both very uncertain and are apt to be utility-specific, each IOU is asked to choose a CCA/DML level for its reference case that reflects a median value among reasonable estimates, centered on the most likely or probabilistic outcome. CCA and departing municipal load amounts can be listed separately or combined on line 4. For IOUs, this amount will be subtracted from line 1 as part of calculating net peak load to serve bundled IOU customers. For each year, the highest hourly peak load shown on Form S-1, line 4 should match the sum of numbers shown on Demand Form 1.4 in Columns 4 and 5 (Community Choice Aggregators and Other Publicly Owned Departing Load, including Losses).

POUs are asked to show estimated amounts of monthly peak load that are expected to “depart” from existing IOU service. (These estimates should not be included on line 1.) Also on line 4, POUs are asked show service to new bundled customers in developing areas where POU and IOU service territories overlap (such as Modesto ID and Merced ID). Data reporting here is not designed or intended to resolve ongoing legal conflicts related to retail competition between IOUs and POUs. Instead, the intent here is to clearly account for load growth and customer migration, and to avoid double counting.

POUs with arriving load or new load need to change the formula on the Excel sheet to add this load instead of subtract.

Line 5 Uncommitted Price-Sensitive DR Programs (-)

All LSEs are asked to assume a reasonable level of effectiveness for price-responsive DR programs that may or may not correspond with specified targets. Price-sensitive demand response (DR) goals for the IOUs were established in CPUC D.03-06-032 (p. 10). These are 4% of the annual peak demand in 2006, and 5% in 2007 and thereafter.[2] Capacity amounts from committed price-sensitive DR programs should already be included in the total peak load forecast shown on line 1. The remaining, uncommitted portion should be shown on line 5 in the CRATs table.

LSEs serving loads in CAISO are asked to use the CPUC-adopted standards for counting DR qualifying capacity. "The Commission determined that DR resources should be available at least 48 hours each summer season to count as qualifying capacity, and that DR resources that operate two hours per day should be eligible but subject to a limit of 0.89% of monthly peaks." (D.04-10-035, pp. 26-27 and D.04-10-035, quoted in D.05-10-042)This standard for year-ahead RA capacity should be applied to projected DR resources throughout the forecast period.

Line 6 Uncommitted Energy Efficiency (2009-2016) (-)

On line 6, IOUs and POUs are asked to estimate median values for achievable and cost-effective savings from *future* programs that are not yet implemented or funded. Do not include the effects of energy efficiency programs that are already embedded in the LSE demand forecast (Demand Forms 1.1 and 1.3) or in LSE load forecast (Supply Form S-1, line 1).

For IOUs, there are funding commitments for energy efficiency programs through 2008, so spreadsheet cells through Dec 2008 may be grayed out. IOUs are asked to estimate monthly peak hour load reductions reasonably expected from future efficiency programs starting with Jan 2009. For IOUs, the CPUC established energy efficiency targets for both peak demand and energy for each of the IOUs. CPUC specified these targets in D.04-09-060. In 2005, the three large IOUs were asked to assume these targets will be precisely met in supply and demand forecasts. This will not be the case in 2007. Realistic estimates of energy savings as reported on line 6 may vary from program targets.

For POUs, supporting studies may not be available to predict EE reductions to load that would be listed on line 6. Where studies to identify a reasonable offset are

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[2] It was further established in D. 04-06-011 that interruptible and emergency programs do not qualify to satisfy these price-responsive demand goals.

lacking, enter zero. Where studies have identified potential EE programs, POUs should assume that these programs are funded and implemented and become reasonably effective. If future programs already have a funding commitment established in rates, the EE reductions should be embedded in the load forecast.

Line 7 Distributed Generation for Customer Use (-)

LSEs are asked to provide their own best estimates of the load impacts from distributed generation (DG). The amounts shown on line 7 represent a deduction from total peak hour customer loads that utilities are otherwise obligated to serve. This adjustment also reduces amounts of planning reserves that utilities would otherwise need to procure.

DG is defined here to be self-generation at distribution level voltages, with power sources limited to less than 20 MW. (A broader definition of DG, which was considered but not used in these instructions, would include all forms of self generation and cogeneration, along with smaller independent systems capable of supplying many of the electrical needs of residential and small commercial customers. Self generation capacity includes capacity used by a project for on-site demands and any capacity sold by the project to third parties. Self generation capacity is normally not available to the LSE and may not have any unit-specific qualifying capacity for LSEs in the CAISO.)

Do not count on line 7 amounts of output from DG facilities that are surplus to customer loads. Supplies of DG power that are surplus to customer needs should be reported on lines 41 (renewable DG) and 46 (non-renewable DG).

For the IOUs, the CPUC has not established targets for customer-side DG. In its October 27, 2005, decision on Resource Adequacy (D.05-10-042), the CPUC concluded that DG programs in CAISO “appear to have no more than a few hundred megawatts.” While DG programs may have more impact on loads in the future, they are less substantial than EE and DR programs and therefore had less stringent measurement and evaluation criteria for estimating qualifying capacity.

Line 8 Net Peak Demand for End-Use Customers

IOUs are asked to take the amount on line 1 and subtract all amounts shown on lines 4, 5, 6, and 7. For ESPs, if there are no amounts shown on lines 4 through 7, enter on line 8 the same amount shown on line 1.

POUs will take the amount shown on line 1, and subtract any amounts shown on lines 5, 6, and 7. POUs need to add any amounts shown on line 4. (Do this automatically by changing cell formulas on line 8. Change the sign to add line 4 instead of subtract.)

Line 9 Net Peak Demand + 15% Planning Reserve Margin

To determine amounts on line 9, IOUs and ESPs shall multiply the sum in line 8 by 115%. Pursuant to D. 04-101-050, IOUs and ESPs are now required to meet a 15% month-ahead planning reserve margin. The year-ahead resource adequacy showing for summer months (May-September) is due September 30 in the year before (or as specified by the CPUC).[3] By conceptually extending this requirement to the entire forecast period, IOUs and ESPs are asked to show this as part of the capacity needed to reliably serve load obligations.

The Energy Commission encourages POUs to use the same 15% planning reserve margin. However, if a POU consistently uses a different number for its resource planning and procurement responsibilities, then that number should be used to calculate line 9. Some POUs have a higher planning reserve margin based on single or multiple contingency criteria.

If POUs use a different planning reserve margin, such as a fixed megawatt number or a higher percentage, they are encouraged to modify the formulas accordingly for the cells on line 9.

Line 10 Planning Reserve Credits

Some LSEs have firm imports or other resources that carry their own reserves. All such resources should be clearly identified and explained with a footnote. For these supplies, LSEs may show an appropriate capacity credit on line 10. As an example, if a Northern California POU uses a 15% planning reserve margin, and has a contract for 100 MW of firm supply delivered to NP15, that POU may show a 15 MW credit on line 10.

Line 11 Firm Sales Obligations

On line 11, list total amounts of firm capacity that the LSE has contracted to deliver to other parties. If this capacity obligation is measured at some distant delivery point, add an appropriate amount to accommodate line losses and station load. Please include 15% reserves for the share of sales obligations for which reserves are required.

Line 12 Firm LSE Peak Resource Requirement

Add line 9 to line 10, and subtract line 11 to calculate amount of capacity here called the firm peak resource requirement. Enter this amount on line 12.

Utility-Controlled Fossil and Nuclear Resources

This section asks for forecast data on fossil and nuclear resources that the LSE owns or controls. For nuclear resources, include the ownership or contractual rights to the output San Onofre and Palos Verde nuclear generating stations. For fossil resources, include ownership, contracts, and power purchase agreements for the output from natural gas-fired plants, coal plants, and other resources that primarily use fossil fuels.

Beginning on line 13, submit one row of capacity forecast data for each fossil and nuclear plant. From this point forward on Form S-1, the line numbers on LSE submittals may not match those shown on the forms. The CRATS table, Form S-1,

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[3] Meeting this reserve requirement in 2006 was directed in R.04-04-003.

provides a generic illustration with minimal direction, so that line 13 begins the listing of individual fossil and nuclear resources. Line 14 shows an ellipse representing one row for other plants in the series, and line 15 is for the last plant in the series, "Unit N." If the LSE controls a large number of resources in this section, they may be listed on a separate tab in Excel, with the totals summed on line 16. LSEs may use a line numbering system for entries that seems most appropriate (for example, the 4th fossil resource could be on a line designated 15B or line16, or it could be listed without a number).

Line 13 Unit 1 [List each fossil and nuclear resource.]
Line 14 …..
Line 15 Unit N

Line 16 Total Fossil and Nuclear Capacity
On line 16, enter the sum of lines 13 through 15 (or on as many lines as needed to list each and every utility-controlled fossil and nuclear generating facility).

Utility-Controlled Hydroelectric Resources

Unlike the section on fossil plants above, LSEs are not being asked to report capacity estimates for individual hydroelectric generating plants that they own or control. Lines 17 and 18 on Form S-1 ask for the total capacity of all LSE-controlled hydroelectric resources under median (1-in-2) hydrological conditions, with one notable exception. The exception is Hoover Dam because the U.S. Bureau of Reclamation (USBR) publishes highly reliable forecasts of capacity and energy looking forward 24 months. Therefore, LSEs with Hoover entitlements should use the latest USBR forecast for 2007 and 2008, and use 1-in-2 estimates for 2009 and beyond.

In general, a hydro resource must be able to operate during four super-peak hours for three consecutive days for capacity in that month to count. If individual LSEs use a significantly different definition of qualifying or dependable capacity, they are asked to provide a footnote to these numbers with explanatory information.

During the 2007-2016 forecast period FERC licenses will expire for about 5,000 MW (nameplate) of existing hydroelectric resources. LSEs are instructed to identify appropriate reductions in capacity considered most probable. The most probable outcomes for hydro relicensing must consider eventual settlement negotiations, new FERC license conditions, and mandatory conditions set by the State Water Resources Control Board (SWRCB) for water quality certification according to Section 404 of the federal Clean Water Act.

Line 17 Total for All Hydro Plants over 30 MW
On line 17, provide the capacity of all hydro resources over 30 MW nameplate. Use median year (1-in-2) hydrological conditions for those plants where capacity is affected by year-to-year variations in rainfall and snowpack. This distinction follows

FERC definitions of large and small hydro. Thirty MW is also the upper plant size limit that is eligible to be counted as a producer of “renewable energy” by IOUs, ESPs, and CCAs under California’s Renewables Portfolio Standard (RPS).

Line 18 Total for all Hydro Plants 30 MW or less

On line 18, provide the total capacity for all hydro resources equal to or less than 30 MW nameplate. Again, use median year (1-in-2) hydrological conditions.

Line 19 Hydroelectric Capacity in Dry-Year Conditions

Line 19 asks for total capacity in a dry hydro year, defined here as 1-in-5 hydrological conditions. If historical data is used as a proxy, LSEs should use generation numbers that were exceeded in 4 of the last 5 years, or 16 of the last 20 years, or some similar series considered most appropriate. If there is no “derate” for dry year conditions, the number on line 19 will equal the sum of lines 17 and 18.

The CPUC has adopted this 1-in-5 dry hydro standard for the IOUs to estimate the year-ahead qualifying capacity for utility-controlled hydroelectric resources. Therefore, the total capacity numbers shown on lines 17 and 18 may be slightly higher than the resource adequacy filings listing individual hydro plants.

LSEs with Hoover entitlements are asked not to derate capacity shares for 2007 or 2008. This exception is based on the highly reliable web-published forecasts provided by USBR for the lower Colorado River.

Line 20 Hydroelectric Capacity in Wet-Year Conditions

Line 20 asks for total capacity in a wet hydro year, defined here as 1-in-5 hydrological conditions. If historical data is used as a proxy, LSEs should use generation numbers that were exceeded in just 1 of the last 5 years, or 4 of the last 20 years, or some similar series considered most appropriate.

This estimate is for comparative interest and systemwide assessments and is a new request this year. The number on this line stands alone; it is not added to other numbers on the form.

Utility-Controlled Renewable Resources

This section asks for forecast data on individual renewable resources (other than hydro) that are under LSE ownership or control. The data include existing resources and planned resources (specific, named generating facilities that have been announced). List each generating resource on a separate row, similar to the section above on utility-controlled fossil fuel resources. If an LSE has a large number of renewable resources that it owns or dispatches, these may be listed on a separate tab with the total number brought forward to Form S-1, line 24.

Line 21 Unit 1 (fuel) [List each non-hydro resource.]

Line 22 …
Line 23 Unit N (fuel)

Line 24 Total Renewable Capacity

Line 25 Total Utility-Controlled Physical Resources
Take total amounts of capacity listed in the three sections above for utility-controlled physical resources. This includes fossil fuel and nuclear resources (line 16), hydroelectric capacity in dry-year conditions (line 19), and other renewable resources (line 24). Enter the sum of these three numbers on line 25.

DWR Contractual Resources

The state's three major IOUs are asked to report qualifying capacity from specific DWR contracts. This refers to supply contracts negotiated by the California Energy Resources Scheduling Office of the California Department of Water Resources. These DWR contracts were signed in 2001 during the energy crisis to provide capacity and energy from third parties to meet IOU loads. To avoid the potential for double counting, do not report these contracts elsewhere on the forms. List each contract on a separate row, starting with line 26, and sum the total on line 29.

Line 26 Contract A
Line 27 ….
Line 28 Contract N

Line 29 Total DWR Contracts
On line 29, enter total capacity from all DWR contractual resources, summing lines 26 through 28.

Qualifying Facility Contractual Resources

Beginning on line 30, IOUs are asked to provide total amounts of capacity from qualifying facilities (QFs) as defined by the Public Utilities Regulatory Policy Act (PURPA), summarized by fuel/technology type. This section on QF contract resources does not ask LSEs for data about individual QF generating resources.

IOUs are asked to indicate the amounts of capacity expected from QFs through 2016. As existing contracts expire, many of these generating resources will likely remain available to IOUs under new contract terms. Some QF owners may win new contracts in competitive renewable solicitations. Other QF owners may negotiate tolling agreements or new dispatch terms that would increase capacity ratings of the resource in return for capacity payments.

IOUs need not assume that existing QF contracts will be renewed or extended beyond those terms for which an extension has already been mandated, requested, or approved. To the extent that an IOU assumes current QF resources will continue to be available, these resources should be listed on lines 31-35.

The capacity total for QF resources includes everything that the IOU deems likely to be available during the peak hour of a specific month. Estimates of QF capacity should be based on average historical generation during peak hours as defined in Standard Offer 1 contracts, which is noon to 6 p.m. on summer weekdays, excluding holidays. Qualifying capacity includes both firm contract capacity, plus that portion of as-available contract capacity that the LSE deems likely to be available based upon historical performance. Any changes to this methodology and related impacts to the derived values shall be explained in an attachment or footnote to the CRATs table.

Line 30 Natural gas

Line 30 asks for the total capacity of all QF resources powered by natural gas.

Line 31 Biofuels

Line 31 asks for the total capacity of QF resources powered by biofuels. This is a large generic term including landfill gas, forest products, almond shells, dairy waste, and discarded fast food cooking oils.

Line 32 Geothermal

Line 32 asks for the total capacity of all types of geothermal production including dry vapor and dual-flash systems.

Line 33 Small Hydro

Line 33 asks for the total capacity of small hydro QF, meaning only those plants rated 30 MW nameplate or less. Provide a derated qualifying capacity total showing what can be expected for a 1-in-5 dry year.

Line 34 Solar

Line 34 asks for the total capacity from all types of solar resources, including photovoltaic and gas-assisted central station plants. Do not include solar generation that only reduces end-use demand. Include only the output of solar facilities injected into distribution or transmission systems that will help serve monthly LSE peak loads.

Line 35 Wind

Line 35 asks for a summary of existing and planned wind QF resources that the LSE knows or expects will be under QF contract terms. New wind resources are not expected to have new QF contracts. New wind should be listed elsewhere on the form, either as a planned renewable resource (line 21 if they are utility-controlled), under renewable contracts for identified projects (line 38), or as generic renewables (line 51) to meet future targets with facilities that are not yet specifically identified. Provide the qualifying capacity total for QF wind on line 35.

Line 36 Other
Line 36 is for reporting all other generating resources under QF contracts, including resources that once had QF eligibility according to PURPA.

Line 37 Total QF Qualifying Capacity
On line 37, enter the sum of all QF resources listed on lines 30 through 36.

Renewable Energy Contractual Resources

LSEs are asked to list capacity from renewable resources that are acquired to meet renewable procurement targets. Capacity data on individual generating facilities, such as wind turbines, is not requested in this section. To *avoid double counting*, do not repeat a listing of contract resources if they are already included in earlier sections on utility-controlled hydro resources or QF contract resources. LSEs with a large number of renewable contracts may list them on a separate spreadsheet. Renewable contracts providing less than 1 MW of supply may be aggregated by fuel type.

Line 38 Contract A
Line 39 ….
Line 40 Contract N

Line 41 Renewable Distributed Generation (DG) Supply
LSEs are asked show amounts of renewable DG supply that is surplus to customer consumption during the peak hour of each month. Do not include DG output that is produced and consumed on the customer's side of the meter. Include only amounts of DG injections that can supply *other* connected loads.

LSEs are encouraged to distinguish among different renewable DG supply programs by adding and labeling additional rows. Examples include the California Solar Initiative, New Solar Homes Partnership, and the Solar Photovoltaic Incentive Program.

DG supply is listed here with other renewable contractual supplies as a matter of convenience. While all end-use customers with DG facilities must sign interconnection agreements, development of these resources does not result from RFOs, bilateral negotiations, or other typical contracting activities. No assumption is made or implied here regarding contractual rights of any party to the renewable attributes of DG supply. LSEs are asked to list here only DG capacity for which the LSE has purchased or expects to purchase from end-use customers all the renewable attributes. If the customer retains ownership of renewable attributes, the DG supply should be listed on line 46 below.

Line 42 Total Capacity from Renewable Energy Contracts
On line 42, enter the total capacity of all renewable contract resources, summing lines 38 through 41.

Other Bilateral Contracts

All LSEs are asked to list supplies from other bilateral contracts with durations longer than three consecutive months. List all such bilateral contracts that are not already reported in earlier sections. Each bilateral contract should be named and listed on a separate row beginning with line 43, except that contracts providing less than 1 MW may all be aggregated. Capacity data on individual generating facilities is not being requested in this section. If an LSE has more than 25 contracts in this category, it may be appropriate to aggregate reporting at a higher level. Any aggregate reporting for contracts that individually provide more than 1 MW should be based on prior consultation with Energy Commission staff.

Line 43 Contract A
Line 44 ….
Line 45 Contract N

Line 46 Non-Renewable Distributed Generation (DG) Supply
LSEs are asked to show amounts of *non*-renewable DG supply that is surplus to the amount the DG customer consumes. Again, do not include DG output consumed by the DG customer. Include only amounts of DG injected into the distribution system for *other* end-use customers, amounts that would otherwise be supplied by the LSE.

Line 47 Total Other Bilateral Contracts
Add the total capacity of all other non-renewable bilateral contracts, summing lines 43 through 46. Enter the total on line 47.

Short-Term and Spot Market Purchases and Sales

Line 48 Short-Term Purchases
All LSEs are asked to indicate how much of their monthly peak capacity needs are expected to come from short-term purchases. List these amounts, if any, on line 48 or enter zero. Short-term purchases are defined here to include all procurement that is more than two days and less than three consecutive months in duration.

Line 49 Spot Market Purchases
All LSEs are asked to indicate how much of their monthly non-coincident peak capacity needs are expected to come from spot market purchases. List these amounts, if any, on line 49 or enter zero. Spot market purchases are defined here to include all procurement that is two days or less in duration.

Line 50 Short-Term Sales (-)
All LSEs are asked to indicate how much of their available capacity, if any, is likely to be sold (or which might typically be sold) to others under short-term contracts. This

non-firm capacity would be considered surplus to LSE needs under "normal" or expected conditions. For example, some LSEs routinely expect to make surplus winter-month capacity available for export to the Pacific Northwest once near-term needs and market conditions are clarified.

Line 50 can be used to balance lines 63 and 64 as discussed below. An apparent surplus capacity position indicated on line 64 could generally be offset, in whole or in part, by increasing amounts of Short-Term Sales shown on line 50.

For consistency with CPUC and IOU usage, "short-term sale" is defined here to mean duration of more than two days and less than 90 consecutive days. Where POUs and ESPs use different definitions for "short term" in this context, please explain usage with a footnote.

Line 51 Net of Short-Term Spot Market Purchases and Sales

On line 51, show the sum of line 48 plus line 49, and subtract the amount on line 50.

Line 52 Total: Existing and Planned Capacity

On line 52, enter the sum of existing and planned electricity supply resources that were counted in earlier sections. The amount to enter on line 52 is the sum of lines 25 (utility-controlled resources), 29 (DWR contracts), 37 (QF contracts), 42 (renewable energy contracts), 47 (other bilateral contracts), and 51 (the net of short-term and spot market transactions).

Dispatchable Load Management Programs

Line 53 Interruptible / Emergency (I/E) Programs

On line 53 IOUs and POUs are asked to enter the load reduction amounts (stated as positive numbers) that are expected to be available from emergency programs. Only interruptible load subject to LSE dispatch should be counted on line 53. In the CAISO control area, for example, many LSEs can cycle power to residential air conditioners during Stage 2 emergencies to avoid reaching a Stage 3 emergency with forced load shedding. To count, interruptible and emergency programs need only be dependable for two consecutive hours in a month. When these programs are called on, the corresponding amount of energy saved is quite small, so there is no comparable line for emergency programs on the energy balance table, Form S-2.

Line 54 Dispatchable Demand Response

On line 54, estimate the amount of load reduction (stated as a positive number) that will likely be available from future dispatchable demand response programs (DDR). Include curtailable loads and new interruptible tariff schedules and all other uncommitted dispatchable demand response programs. Do not include capacity amounts from price-responsive demand or critical peak pricing programs.

Line 55 Total Capacity with I/E and DDR

To determine the amount on line 55, add the amounts on line 52 (existing and planned capacity) together with line 53 (interruptible/emergency programs) and line 54 (dispatchable demand response). This amount is the LSE's total capacity including all interruptible, emergency, and dispatchable demand response programs.

Future Generic Resource Needs

Lines 56 through 62 are for non-specific "generic" resources that will be needed to meet forecast load obligations. Most LSEs will need to procure additional resources during the next 10 years.

In some instances, LSEs have committed to specific but yet-to-be-built physical resources. All announced projects with plant names and known physical locations should be listed in earlier sections on utility-controlled resources (lines 13 to 25), or contract resources (lines 26 to 47).

Some LSEs have not seriously considered specific projects to serve loads after 2011 or determined if these loads could be better served with physical or contractual resources. During a 10-year planning horizon, many supply and demand uncertainties are compounded, making peak load forecasts and financial investment decisions highly contingent or tentative. Nonetheless, the daily and seasonal shapes of LSE load obligations may be reasonably estimated. Each LSE knows its own portfolio of existing and planned resources and how that portfolio matches up with forecast loads. For projected load and necessary reserves that are *not* covered by existing and planned resources, all LSEs are expected to provide estimates of generic resources needed to meet forecast obligations.

On Form S-1, first identify new renewable resources that will be needed to meet adopted renewable energy targets. Second, identify generic non-renewable baseload, shaping, and/or peaking resources that will be needed through 2016.

Generic Renewable Resources

Line 56 Generic Renewable Resources

On line 56, enter the aggregate qualifying or dependable capacity reasonably expected from renewable resources that will be new to the LSE's portfolio. Show only capacity beyond that for specific, named resources that already exist or that are already listed in earlier sections as planned contractual or utility-controlled renewable resources.

Generic Non-Renewable Resources

Line 57 Capacity for Baseload Energy
On line 57, enter the capacity associated with baseload energy needs not met by existing resources, planned resources, or generic renewable resources. All LSEs are directed to use the definition provided in Public Utilities Code Section 8340 (a), added by SB 1368 (Perata) Chapter 598, Statutes of 2006: "'Baseload generation' means electricity generation from a powerplant that is designed and intended to provide electricity at an annualized capacity factor of at least 60 percent."

Values that are sustained year-round over a long period reflect needs for which the LSE might consider construction, purchase, or a long-term power purchase agreement (PPA) for the output of a baseload resource. Values that are sustained for shorter periods reflect baseload needs for which the LSE might consider a shorter-term energy contract (for example, all energy, for 7 days x 24 hours, from a 200 MW resource during Q3 of years 2014-2016).

Line 58 Capacity for Load-following and Peaking Energy
On line 58, enter the capacity associated with cyclical energy needs not met by existing resources, planned resources, or generic renewable resources. Values sustained over long periods reflect needs for which the LSE might consider resource construction, resource purchase, or a long-term power purchase agreement with a load-following or peaking resource. Values sustained for shorter periods reflect needs for which the LSE might consider shorter-term contracts for peak and super-peak energy.

Line 59 Load-Following (Year-Round) Capacity
On line 59, enter the capacity associated with physical, contractual, or demand-side (year-round) resources to meet load following, shaping, or peaking needs.

Line 60 Peaking (Seasonal) Capacity
On line 60, enter the capacity associated with contractual or demand-side resources needed to meet seasonal peaking capacity needs.

Line 61 Total Capacity of Non-Renewable Generic Resources
On line 61, enter the sum of lines 57, 58, 59, plus 60.

Line 62 Total Capacity of Future Generic Resources
On line 62, enter the sum of line 55 plus line 61.

Capacity Balance Check

Line 63 Total Capacity of All Resources
On line 63, enter the sum of lines 55 plus 62.

Line 64 Net Open or Net Surplus Capacity Position

On line 63, enter the difference between line 63 minus the Firm LSE Peak Resource Requirement shown on line 11. A positive number on line 63 indicates a net surplus capacity position for that month. A negative number indicates a net open position.

In theory, most LSEs will be able to show a “zero” open or surplus position based on adjustments elsewhere on the form. A surplus capacity position would generally be offset by increasing Short-Term Sales (line 50). A net open capacity position would generally be filled by increasing generic new resource procurement (lines 56 through 60).

UDC Loads and System Reliability

This section is designed to collect information that is consistent with utility procurement needed for “system reliability,” which often goes beyond what an individual utility needs for serving all its distribution system customers. This new section is separate from the capacity balance calculations above, though most lines ask for a repeat or sum of earlier lines on the form. This new section asks IOUs and POUs to identify what the “electrical system” requirements will likely be, above and beyond the bundled customer needs of the utilities’ end-use customers.

Line 65 below shows the capacity needed to meet the utility’s bundled customer load, an amount that copies directly on the Excel template from Form S-1, line 11 above. Line 66 below shows the capacity that IOUs will distribute to direct access customers in its service territory. This amount must be consistent with what the IOUs show on the demand forecast form for direct access loads including distribution losses.

Together, lines 65 and 66 are sometimes referred to as “service area” loads, which some have defined as bundled utility customer loads plus direct access loads. As defined in Public Utilities Code Section 9604(b), " ’Service area’ means an area in which, as of December 20, 1995, an investor-owned electric utility or a local publicly owned electric utility was obligated to provide service.“

Lines 65 through 67, taken together, represent a monthly forecast of distribution system loads that each utility can reasonably expect to deliver in their role as a utility distribution company (UDC, also called Local Distribution Company). UDC loads include all forecast loads of other LSEs that use the IOU or POU distribution system to serve their end-use customers. This includes forecast loads of ESPs, CCAs, and any other LSEs operating in the distribution service area.

Line 69 should be used to indicate amounts of capacity that will likely be needed for system reliability, above and beyond what has been identified for delivery to UDC loads.

Line 65 Firm Peak LSE Resource Requirement

On line 65, repeat the sum shown on line 12.

Line 66 Direct Access Loads in the UDC Territory

On line 66, utilities are asked to enter the sum of all forecast loads for all direct access (DA) customers in the service territory of their Utility Distribution Company (UDC). For each year, the highest hourly peak load shown on this line should equal the sum of two numbers shown on Demand form 1.4, Column 3 (Direct Access: End User Peak Demand and Losses).

POUs may not have any Direct Access customers in their service territories. However, POUs are asked to estimate and include any ongoing DA loads in areas that are likely to be annexed from IOU service territories.

For the reference case in the *2007 Energy Report* cycle, all utilities should use their own assumptions and assessments about load migration and the potential adoption of new "coming and going" rules. If a significant change in direct access is expected during the forecast period, the numbers provided should reflect that change, and an explanatory footnote should be provided.

Line 67 Other Non-IOU and Non-DA Loads in the UDC

On line 67, list all other distribution system loads in the UDC service territory. This would include wheeling deliveries to Stanford University, BART, and other WAPA preference customers in PG&E service territory. It could also include partial requirements services to POUs in SCE service territory, and scheduled deliveries to the Rincon Reservation procured by Escondido in SDG&E territory. For Edison, include all loads in the SCE-controlled sub-transmission system if these parties are billed for distribution services. For example, this would probably include energy delivered to Bear Valley Electric Service and Anza Rural Electric Service.

UDC loads includes the partial service requirements of Southern California cities that have contractual agreements with SCE for this service. UDC load obligations may accrue to PG&E from metered sub-system agreements for Northern California cities that have contractual agreements for this service. UDC loads probably include POU loads embedded within IOU service territory, such as Gridley, Shelter Cove, and McAllister Ranch (all in PG&E service territory). Accounting for UDC loads probably includes irrigation districts and water agencies whose contractual loads are served entirely, or in part, by the Water and Power Resources Pooling Authority (a little-known LSE). UDC loads include non-utility end-users who receive electricity over utility-controlled wires, such as Stanford University, BART, other WAPA preference customers, some DWR pumping loads, and some MWD pumping loads.

There is no assumption here about a utility obligation to serve UDC loads. These estimates are requested only for system assessments and perhaps some analysis of trends. Nor is there any assumption here that the information requested is directly related to or sufficient for local or system reliability studies. UDC reliability may depend on other infrastructure attributes not related to this request, such as quick start or black start capability, or VARS (reactive power), or AGC (automatic generator control) dispatch needs for 10-minute load-following adjustments. Similarly, local reliability may depend on transmission upgrades, distribution system upgrades, siting of new local generation, or locational dispatch of demand side resources. For most load pockets, reliability depends on interconnected equipment involving both POUs and IOUs, along with privately owned merchant, QF, and cogeneration facilities. Except for San Diego, load pockets as defined by CAISO are a subset of the UDC service area.

In one small area, UDC loads may be slightly less than IOU bundled customer loads. In Mono and Inyo counties, SCE and Valley Electric have agreed to serve and distribute to rural customers in each other's service territories. This practical agreement has an annual "true up" that avoids the need for expensive new transmission. Slight differences and discrepancies such as this can be identified with a footnote.

Line 68 Total UDC Capacity Needs

On line 68, enter the sum of lines 65 through 67.

Line 69 System Reliability Needs (Black Start, VARs, and others)

On line 69, show amounts of new capacity that will likely be needed to meet local reliability standards. This would be new capacity beyond that needed to serve forecasted peak loads of all the end-users in the UDC. In particular, utilities are asked to show here all new capacity that will probably be needed for grid stability or ancillary services. This includes recognized deficits for quick start or black start capacity, and facilities that would provide needed voltage stability. This number is not added to other rows on Form S-1.

Utilities are asked to use a definition of "electrical system" that includes all UDC loads and a definition that is consistent with utility filings and CPUC rulings in other proceedings.

IOUs are expected to show on line 69 all capacity that they have been directed to acquire by the CPUC in D.06-07-029. IOUs are also expected to show on line 69 all capacity they have petitioned to acquire or that they expect to petition for according to D.06-07-029. These CPUC decisions and rulings and subsequent IOU petitions involve the output from new generation facilities that are procured expressly to preserve system reliability.

For example, the Assigned Commission Ruling on August 15, 2006, directed SCE to pursue development of up to 250 MW of black-start, quickly dispatchable peaking turbines that could be brought online by summer 2007. On October 4, 2006, SCE filed a petition requesting authorization to procure an additional 500 MW from new generation facilities. The CPUC is expected to rule on this petition *within* the long-term procurement proceeding, using consistent determinations of need (LSE, UDC, local reliability) within a single proceeding.

CPUC rulings and decisions have authorized, in concept, a mechanism for allocating the costs to new capacity for system reliability. These costs will be allocated to all “benefiting customers,” even if their consumption is met by electricity supplies from other LSEs. Reliability benefits, from procurement shown on line 69, may be allocated to all appropriate customers for duration the procurement commitment. Thus, the allocation of costs may last for 10 to 20 years from the month when new power plants begin operating.

The pleadings about how much capacity is needed for electrical reliability (where, when, what types, how long, and so forth) should be made in other proceedings. Line 69 is simply designed to provide a showing of needed resources that is consistent with those proceedings. Justifications for additional power purchases should be made in other workshops.

Capacity amounts shown on line 69 should appear in the month they will first be needed, such as August 2007, and continue over time for the duration of need. If a utility has not identified system reliability needs for, say, a period of time beginning with 2012, for example, this should be explained in a footnote.

Significant amounts of new capacity needed to integrate other resources may be shown on line 69 if the basis for such estimates is footnoted or explained elsewhere.

Supply Form S-2: Summary of Energy Resources (GWh)

LSEs are asked to estimate how much energy in Gigawatt-hours (GWh) is needed to serve forecast needs, and how much energy will come from various electricity supply resources. These estimates are required for all months of the forecast period (Jan. 2007 through Dec. 2011 for ESPs, and Jan. 2007 through Dec. 2016 for utilities). LSEs are requested to provide this data on Supply Form S-2, Summary of Energy Resources, also called an energy balance table. The data submitted on Form S-2 should correspond one-to-one with the data submitted on the CRATs tables, Form S-1.

The instructions for individual lines on Form S-2 often repeat those provided for lines on Form S-1. This repetition is meant to provide clarity and convenience for people who will be completing these forms. The data categories on the two forms differ only slightly. On Form S-2, it is not necessary for LSEs to estimate amounts of energy saved by price-sensitive demand response, interruptible programs, emergency programs, or uncommitted demand response programs. Also, there are no resource adequacy requirements or 15% planning reserve margins that LSEs need to include in their 10-year energy plans.

Energy Demand Calculations

Line 1 Forecast Total Energy Demand

On line 1, all LSEs are asked to estimate total monthly energy demand for all retail customers. Total energy demand includes transmission losses, distribution losses, energy needed to serve station loads of utility-controlled resources, and unaccounted for energy (UFE).

Line 2 ESP Energy Demand: Existing Contracts

ESPs are asked to identify how their expected loads are divided between new and renewing customers. On line 2, electric service providers (ESPs) are asked to estimate total monthly energy needs of their existing customers. Energy totals on line 2 should include only obligations for current contract service periods.

Line 3 ESP Energy Demand: New and Renewed Contracts

On line 3, ESPs are asked to estimate total monthly energy needs that arise from new customers, plus contract renewals and extensions to serve existing customers. This forecast should be the “most likely” case. Enter the amount of energy needed to serve new customers plus existing customers who are expected to renew or extend ESP service. The amount on line 3 should equal the amount on line 1 less the amount on line 2.

Line 4 CCA and Departing / Arriving-New Municipal Loads (-) (+)

IOUs are asked to identify a particular amount of community choice aggregation (CCA) and departing municipal load (DML) from a specified range of possibilities. As likely CCA/DML values are both very uncertain and apt to be utility-specific, each IOU is asked to choose a CCA/DML level for its reference case that represents the most likely or median values during the forecast period. If there is a wide range of uncertainty about these types of departing load, more detail can be presented in a footnote.

POUs are asked to show on line 4 their assumptions regarding increased loads that may depart from IOU bundled service. (These estimates should not be included on line 1). Also on line 4, POUs are asked to list service to new bundled customers in developing areas where POU and IOU service territories overlap.

Line 5 Uncommitted Energy Efficiency (2009-2016) (-)

On line 5, IOUs and POUs are asked to estimate amounts of achievable, cost-effective savings from *future* energy efficiency programs that are not yet implemented or funded. Do not include the effects of energy efficiency programs that are already embedded in the LSE demand forecast (Demand Forms 1.1 and 1.3) or in LSE load forecast (Supply Form S-1, line 1).

For IOUs, there are funding commitments for energy efficiency programs through 2008, so spreadsheet cells through Dec 2008 may be grayed out. On line 5, IOUs are asked to estimate energy savings from currently uncommitted programs that should begin showing up starting in Jan 2009. For IOUs, the CPUC-established energy efficiency targets for both peak demand and energy for each of the IOUs. CPUC specified these targets in D.04-09-060. In 2005, the three large IOUs were asked to assume these targets will be precisely met in supply and demand forecasts. This is not the case in 2007. Realistic estimates of energy savings as reported on line 5 may vary from program targets.

For POUs, supporting studies may not be available to predict EE reductions to load that would be listed on line 5. Where studies are lacking to identify a reasonable offset, enter zero. Where studies have identified potential EE programs, POUs should assume that these programs are funded and implemented and become reasonably effective. If future programs already have a funding commitment established in rates, the EE reductions should be embedded in the load forecast.

Line 6 Distributed Generation (-)

On line 6, IOUs and POUs are asked to estimate how much energy will be produced by DG and consumed by DG owners on the customer side of the meter. This number should represent new amounts of self-generation that would be subtracted from future LSE load obligations. For IOUs, the CPUC has not established a target for customer-side DG. This number does not include the supply of DG-produced energy that will be injected into the grid for use by IOU customers. That supply, if it is meaningful, should be listed elsewhere under existing and planned contractual resources.

Line 7 Net Energy Demand for End-Use Customers
Line 7 asks for the net energy demand for end-use customers. For IOUs and POUs these are “bundled” customers. From the forecast energy demand on line 1, IOUs will subtract the numerically positive amounts shown on lines 4, 5, and 6.

POUs will take the amount shown on line 1 and subtract any amounts shown on line 5 or 6. POUs need to add any amounts shown on line 4. (Do this automatically by changing cell formulas on line 7. Change the sign to add line 4 instead of subtract.) For ESPs, if there are no amounts shown on lines 4 through 6, enter on line 7 the same amount shown on line 1.

Line 8 Firm Sales Obligations
On line 8, list total amounts of firm energy that the utility has contracted to deliver to other parties, both within the LSE’s control area and beyond. If this obligation is measured at some distant delivery point, add an appropriate amount to accommodate line losses and station load.

Line 9 Total Energy Requirement
Add line 7 to line 8 to calculate what is here called the total energy requirement. Enter this amount on line 9.

Utility-Controlled Fossil and Nuclear Resources

This section asks for forecast data on fossil and nuclear resources owned or controlled by utilities. Beginning on line 10, submit one row of forecast energy production for each fossil plant. From this point forward on Form S-2, the line numbers on LSE submittals may not match those shown on the draft forms and instructions.

Line 10 begins the listing of individual fossil and nuclear resources. Line 11 shows an ellipse representing one row for other plants in the series, and line 12 is for the last plant in the series, “Unit N.” If the LSE controls a large number of resources in this section, it may be preferable to list them on a separate tab in Excel and list the totals on line 13.

Line 10 Unit 1 [List each fossil and nuclear resource.]
Line 11 …..
Line 12 Unit N

Line 13 Total Fossil and Nuclear Energy Supply
On line 13, enter the sum of lines 10 through 12 (or as many lines as are needed to list every utility-controlled fossil and nuclear generating facility).

Utility-Controlled Hydroelectric Resources

Unlike the section on fossil and nuclear plants above, LSEs are not being asked to report energy estimates for individual hydroelectric generating plants that they own or control.

Lines 14 and 15 on the S-2 energy balance table ask for total monthly hydroelectric energy production from all resources under LSE ownership or control. Energy production estimates should use median (1-in-2) hydrological conditions, with one notable exception, Hoover Dam, because USBR publishes highly reliable 24-month forecasts of capacity and energy for the lower Colorado River. Therefore, LSEs with Hoover entitlements should use the latest USBR forecast for 2007 and 2008, and then use 1-in-2 estimates for 2009 and beyond.

During the 2007-2016 forecast period FERC licenses will expire for about 5,000 MW (nameplate) of existing hydroelectric resources in California. LSEs are instructed to identify appropriate reductions in energy that are considered most probable. The most probable outcomes for hydro relicensing must consider eventual settlement negotiations, new FERC license conditions, and mandatory conditions set by SWRCB for water quality certification according to Section 404 of the federal Clean Water Act. Forecast energy reductions as a result of relicensing could easily be in the range of 4% to 13%.

Line 14 Total for all Hydro Plants over 30 MW

On line 14, estimate total hydroelectric energy production from all LSE owned or controlled hydro resources over 30 MW nameplate. This distinction follows FERC definitions of large and small hydro. Thirty MW is also the upper plant size limit that is eligible to be counted as a producer of “renewable energy” under California’s RPS.

Line 15 Total for all Hydro Plants 30 MW or Less

On line 15, estimate total hydroelectric energy production from all LSE owned or controlled hydro resources equal to or less than 30 MW nameplate.

Line 16 Hydroelectric Energy in Dry-Year Conditions

On line 16, estimate total monthly hydroelectric energy produced during a “dry year” defined as 1-in-5 hydrological conditions that have an 80% chance of being exceeded each year. If historical data is used as a proxy, LSEs should use generation numbers that were exceeded in 4 of the last 5 years, or 16 of the last 20 years.

If feasible, use historical production data adjusted to current operating constraints and license conditions. If those conditions are expected to change during the forecast period, 2007-2016, adjust the averages accordingly so that this number represents what might be expected during a 1-in-5 dry year. (Do not derate amounts of energy from Hoover Dam for 2007 or 2008. Use the latest 24-month forecast by USBR.)

This estimate is for comparative interest and systemwide assessments. The number on this line stands alone; it is not added to other numbers on the form.

Line 17 Hydroelectric Energy in Wet-Year Conditions
On line 17, utilities are also asked to estimate the amount of generation from hydroelectric facilities in a "wet year" defined as 1-in-5 hydrological conditions that have a 20% chance of being exceeded every year. If historical data is used as a proxy, LSEs should use generation numbers that were exceeded in just 1 of the last 5 years, or 4 of the last 20 years. (As with the request for dry year energy estimates, do not increase amounts of energy from Hoover Dam above those shown in the latest 24-month forecast by USBR.)

This estimate is for comparative interest and systemwide assessments and is a new request this year. The number on this line stands alone; it is not added to other numbers on the form.

[Line 18 intentionally left blank]

Utility-Controlled Renewable Resources

This section asks for forecast data on individual renewable resources (other than hydro) that are under utility ownership or control. List all existing resources and all specific generating facilities that have been announced. List each generating resource on a separate row, similar to the section above on utility-controlled fossil fuel resources. If a utility has a large number of renewable resources that it owns or dispatches, these may be listed on a separate tab with the total number brought forward to Form S-2, line 22.

Line 19 Unit 1 (fuel) [List each non-hydro resource.]
Line 20 …
Line 21 Unit N (fuel)

Line 22 Total Utility-Controlled Renewable Energy
On line 22, enter the sum of lines 19 through 21 for utility-controlled renewable energy (other than small hydro).

Line 23 Total Utility-Controlled Physical Resources
Take total amounts of forecast energy production listed in the three sections above for utility-controlled physical resources. These totals include fossil fuel and nuclear resources (line 13), utility-controlled hydro in median-year conditions (lines 14 and 15), and other renewable resources (line 22). Enter the sum of these four numbers on line 23.

DWR Contractual Resources

The state's three major IOUs are asked to report energy supplies from specific DWR contracts. To *avoid the potential for double counting*, do not report these contract amounts elsewhere on the forms. List each contract on a separate row, starting with line 25. Actual line numbers for each IOU will vary from the line numbers in these instructions and on the form templates.

Line 24 Contract A
Line 25 ….
Line 26 Contract N

Line 27 Total Energy Supply from DWR Contracts
On line 27, enter the sum of forecast monthly energy from all DWR contracts.

Qualifying Facility Contractual Resources

Beginning on line 28, IOUs are asked to provide total amounts of monthly energy from Qualifying Facilities (QFs) as defined by the Public Utilities Regulatory Policy Act (PURPA), summarized by fuel/technology type. This section on QF contract resources does not ask LSEs for data about individual QF generating resources.

IOUs are asked to indicate the amounts of energy expected from QFs through 2016. As existing contracts expire, many of these generating resources will likely remain available to IOUs under new contract terms. Some QF owners may win new contracts in competitive renewable solicitations. Other QF owners may negotiate tolling agreements or new dispatch terms that would increase or decrease amounts of energy expected from these resources.

IOUs need not assume that existing QF contracts will be renewed or extended beyond those terms for which an extension has already been mandated, requested, or approved. If an IOU assumes current QF resources will continue to be available, these resources should be listed on lines 28-34.

Line 28 Natural Gas
Line 28 asks for total monthly energy of all QF resources powered by natural gas.

Line 29 Biofuels
Line 30 asks for QF monthly energy from biofuels, a large generic term including landfill gas, dairy waste, forest products, almond shells, and discarded fast food cooking oils.

Line 30 Geothermal
Line 30 asks for all types of geothermal energy including dry vapor and dual-flash systems.

Line 31 Small Hydro
Line 31 asks for small hydro QF totals, meaning only those plants rated 30 MW nameplate or less.

Line 32 Solar
Line 32 asks for total monthly energy from all QF solar resources, including photovoltaic and gas-assisted central station plants. Do not include solar generation that only reduces end-use demand. Include only the output of solar facilities injected into distribution or transmission systems that will help serve monthly IOU peak loads.

Line 33 Wind
Line 33 asks monthly QF wind energy from resources that the IOU knows or expects will be under contract. New wind resources are not expected to have new QF contracts and should probably be listed elsewhere on the form.

Line 34 Other
Line 34 includes monthly energy from all other QF contract generating resources.

Line 35 Total Energy Supply from QF Contracts
On line 35, enter the arithmetic sum of all QF resources listed on lines 28 through 34.

Renewable Energy Contractual Resources

All LSEs are asked to list forecast energy supplies from renewable resources that are acquired to meet renewable energy procurement targets. Each contract with durations longer than three consecutive months should be named and listed on a separate row beginning with line 36. Energy from individual generating facilities, such as wind turbines, is not being requested in this section. To avoid double counting, do not repeat a listing of contract resources if they are already included in earlier sections on utility-controlled hydro resources or QF contract resources. If an LSE has or projects a large number of renewable contracts, they may be listed on a separate spreadsheet, equal to lines 36 to 38.

Line 36 Contract A
Line 37 ….
Line 38 Contract N

Line 39 Renewable Distributed Generation (DG) Supply
LSEs are asked to show amounts of monthly energy from renewable DG supply that is surplus to customer consumption. Do not include DG output that is produced and consumed on the customer's side of the meter. Include only amounts of DG injections that can supply *other* connected utility loads. Only show renewable DG amounts for which the LSE has procured or expects to purchase from the end-use customer all the

renewable attributes of this supply. If the customer retains ownership of renewable energy credits, the DG supply should be listed below on line 44.

Line 40 Total Energy Supply from Renewable Contracts

On line 40, enter total energy amounts from all renewable contract resources, here represented as lines 36 through 39.

Other Bilateral Contracts

All LSEs are asked to list forecast energy supplies from other bilateral contracts that are not already counted in earlier sections on utility-controlled hydro, DWR contracts, QF contracts, and renewable resource contracts. Each bilateral contract should be named and listed on a separate row beginning with line 40. Energy output from individual generating facilities is not being requested in this section. If an LSE has or projects a large number of such bilateral contracts, they may be listed on a separate spreadsheet, equal to lines 41 to 44. Any aggregate reporting for contracts that individually provide more than 1 MW should be based on prior consultation with Energy Commission staff.

Line 41 Contract A
Line 42 ….
Line 43 Contract N

Line 44 Non-Renewable Distributed Generation (DG) Supply

LSEs are asked to show amounts of *non*-renewable DG supply that is surplus to the amount the DG customer consumes. Again, do not include DG output consumed by the DG customer. Include only monthly energy from DG injected into the distribution system for *other* end-use customers, amounts that would otherwise be supplied by the LSE.

Line 45 Total Energy Supply from Other Bilateral Contracts

On line 45, enter total energy amounts from all other bilateral contracts, here represented as lines 41 through 44.

Short-Term and Spot Market Purchases

Line 46 Short-Term Purchases

On line 46, all LSEs are asked to indicate how much of their monthly energy needs may be met by short-term purchases. Short-term purchases are defined here to include all procurement that is less than three consecutive months and more than two days in duration. Amounts shown on line 46 may represent historical averages, estimates of future purchases, or some other reasonable expectation.

Line 47 Spot Market Purchases

On line 47, indicate how much of the LSE's monthly energy needs are expected to come from spot market purchases under average or expected conditions. Spot market purchases are defined here to include all procurement that is two days or less in duration. As the operating day approaches, LSEs recognize that significant amounts of energy can often be purchased in spot markets at less cost than energy from other dispatchable resources. Line 47 is not asking for optimum or median values related to "economy energy" purchases. Instead, line 47 is intended to represent a small residual "open position" of end-use customer need that is typically filled by spot market purchases.

Line 48 Short-Term Sales (-)

All LSEs are asked to indicate how much energy, if any, is likely to be sold (or which typically be sold) to others under short-term contracts. These amounts of non-firm energy would be considered surplus to LSE needs under "normal" or expected conditions. For example, some LSEs routinely expect to make surplus winter-month energy available for export to the Pacific Northwest once near-term needs and market conditions are clarified.

Line 48 can be used to balance lines 61 and 62 as discussed below. An apparent monthly energy surplus indicated on line 62 could generally be offset, in whole or in part, by increasing amounts of Short-Term Sales shown on line 48.

For consistency with CPUC and IOU usage, "short-term sale" is defined here to mean duration of more than two days and less than 90 consecutive days. Where POUs and ESPs use different definitions for "short term" in this context, please explain usage with a footnote.

Line 49 Net of Short-Term and Spot Market Purchases and Sales

On line 49, show the sum of line 47 plus line 48 minus line 49.

Line 50 Total: Existing and Planned Energy

On line 50, enter the sum of existing and planned electricity supply resources that were counted in earlier sections. The amount to enter on line 50 is the sum of lines 23 (utility-controlled resources), 27 (DWR contracts), 35 (QF contracts), 40 (renewables contracts), 45 (other bilateral contracts), and 49 (the net of short-term and spot market purchases and sales).

Future Generic Resource Needs

Lines 51 through 57 are for non-specific "generic" resources that will be needed to meet forecast load obligations. Most LSEs will need to procure additional resources during the next 10 years.

In some instances, LSEs have committed to specific but yet-to-be-built physical resources. All announced projects with names and locations should be listed in earlier sections on utility-controlled resources, or contractual resources.

Some LSEs have seriously considered specific projects to serve loads after 2011 or determined if these loads could be better served with physical or contractual resources. During a 10-year planning horizon, many supply-and-demand uncertainties are compounded, which makes peak load forecasts and financial investment decisions highly contingent or tentative. Nonetheless, the daily and seasonal shapes of LSE load obligations may be reasonably estimated. Each LSE knows its own portfolio of existing and planned resources, and how that portfolio matches up with forecast loads. For projected loads and necessary reserves that are *not* covered by existing and planned resources, all LSEs are expected to estimate what would be needed to meet forecast obligations.

On Form S-2, first identify new renewable resources that will be needed to meet adopted renewable energy targets. Second, identify generic non-renewable baseload, shaping, and/or peaking resources that will be needed through 2016. The listings of generic resources on Form S-2 must be consistent with those listed on Form S-1.

Generic Renewable Resources

Line 51 Generic Renewable Energy

On line 51, enter the aggregate amounts of energy expected from renewable resources that will be new to the LSE portfolio. Show only energy amounts beyond what is already listed in earlier sections. Include only energy with all its renewable attributes (no stripped of RECs), energy that the LSE expects to receive and have delivered to its end-use customers.

Estimates from LSEs about renewable generation performance should reflect realistic appraisals of likely outcomes from authorizations, solicitations, direct investments, regulatory incentives, and many other decisions too numerous to list here. The obligation and opportunity to acquire new renewable resources varies among different LSEs and across different classes of LSEs (IOUs, POUs, and ESPs). Most LSEs have a policy preference to acquire more renewable energy in proportion to annual retail energy sales. With targets such as these foremost in mind, these instructions do not ask LSEs to anticipate the location, technologies, fuel types, or generating performance attributes likely associated with generic new renewable resources.

Generic Non-Renewable Resources

Line 52 Generic Baseload Energy

On line 52, enter the energy associated with baseload generation needs that will not be met by existing resources, by planned resources, or by generic renewable resources. All LSEs are directed to use the definition provided in Public Utilities Code Section 8340 (a), added by SB 1368 (Perata) Chapter 598, Statutes of 2006:

"'Baseload generation' means electricity generation from a powerplant that is designed and intended to provide electricity at an annualized capacity factor of at least 60 percent."

Values that are sustained year-round over a long period reflect needs for which the LSE might consider construction, purchase, or a long-term power purchase agreement (PPA) for the output of a baseload resource. Values that are sustained for shorter periods reflect baseload needs for which the LSE might consider a shorter-term energy contract (for example, all energy, for 7 days x 24 hours).

Line 53 Generic Load-Following and Peaking Energy
On line 53, enter the cyclical energy needs that will not be met by existing resources, planned resources, or generic renewable resources.

Line 54 Generic Load-Following (Year-Round) Energy
On line 54, enter the energy associated with year-round load-following needs that will not be met by existing resources, or planned resources, or generic renewable resources. This estimate is for the energy needed to meet predictable daily load swings that can or do occur throughout the year.

Line 55 Generic Peaking (Seasonal) Energy
On line 55, enter the energy associated with contractual or demand-side resources needed to meet strictly seasonal peak energy needs.

Line 56 Total Non-Renewable Generic Energy Needs
On line 56, enter the sum of lines 52 through 55.

Line 57 Total Future Generic Resource Needs
On line 57, enter the sum of lines 51 and 56.

Energy Balance Check

Line 58 Total Monthly Energy from All Resources
On line 58, enter the sum of line 50 (existing and planned energy) plus line 57 (future generic resource needs).

Line 59 Net Open or Net Surplus Energy Position
On line 59, enter the difference between line 9 (the Firm LSE Peak Resource Requirement) minus the amount shown on line 58. A positive number on line 59 indicates a net surplus capacity position for that month. A negative number indicates a net open position.

In theory, most LSEs will be able to show a "zero" open or surplus position based on adjustments elsewhere on the form. Surplus monthly energy position would generally be offset by increasing Short-Term Sales (line 48). A net open position for energy would generally be filled by increasing generic new resource procurement (lines 51 through 56).

Renewable Energy Accounting

This section of the S-2 form is separate from the energy balance calculations above, though most lines ask for a repeat or sum of earlier lines on the form. This new section is intended to compile forecast information showing trends in renewable energy generation and procurement. This information can be used to assess how different classes of LSE expect to use renewable energy resources to serve their forecasted loads over time, and what shares these resources represent in comparison to end-use demand over time.

Line 60 Utility-Controlled Renewable Resources
On line 60, enter the sum of line 15 (small hydro) and line 22 (total renewable supply other than small hydro).

Line 61 Renewable QF Resources
On line 61, enter the sum of all QF renewable resources (lines 29 through 33).

Line 62 Existing and Planned Renewable Contracts
On line 62, repeat the total from existing and planned renewable contracts (line 40).

Line 63 Generic Renewable Energy
On line 63, repeat the total of expected generic renewable energy (line 51).

Line 64 Total State-Eligible Renewable Energy
On line 64, enter the sum of expected monthly energy that comes from facilities and contracts meeting the state's definition of an eligible renewable energy resource. This is the numeric sum of lines 60 through 63.

Line 65 Other Renewable Energy amounts
On line 65, enter any amounts of other renewable energy or credits that the LSE expects to claim or procure. For all LSEs, this includes the potential purchase of renewable energy credits. If the LSE has a net metering agreement with an end-use customer who has on-site renewable generation, and if the LSE has an agreement allowing the LSE to claim credit for the renewable energy generated and consumed on the customer side of the meter, then these amounts should be included on line 65.

For POUs, the amounts listed on line 65 should include renewable energy from facilities that meet the POU's but not the state's eligibility criteria for this designation. This would include calculated amounts of electricity produced from digester gas and landfill gas that is pumped directly into the combustion boilers of fossil fuel resources.

For some POUs, this certainly includes renewable energy from large hydroelectric resources, such as utility-owned shares of Hoover generation.

Line 66 Total Expected Renewable Energy
On line 66, enter the sum of lines 64 and 65.

Line 67 Renewable Energy and End-Use Demand
On line 67, show what proportion of energy provided to end-use customers (line 7) can reasonably be attributed to renewable energy supplies (line 66). Enter this number as a percent rounded off to the nearest tenth of percent (for example, 17.5%) End-use demand includes an allowance for transmission, distribution, and UFE energy losses. Retail sales are less than end-use demand, because the former amount does not include losses. End-use demand may be larger than retail sales due to energy exchange agreements, serving water agency loads remote from their generation, and other factors. These caveats highlight only some of the uncertainties about future renewable energy supplies and how they might be related to LSE retail sales through 2016.

Biomass Energy Accounting

Line 68 Biofuels (QF Contractual Resources)
On line 68, IOUs are asked to repeat the amount shown for QF Biofuels on line 29.

Line 69 Other Biomass Energy
On line 69, all LSEs are asked to enter total monthly biomass energy from all other supplies. These supplies may be utility-owned or contractual. Again, this amount can include renewable energy from facilities that do not meet the state's eligibility criteria for this designation, such as digester gas and landfill gas pumped into the combustion boilers of a fossil fuel resource.

Line 70 Total Biomass Energy
On line 70, enter the sum of lines 68 and 69.

Supply Form S-3: New Capacity and Local Reliability

Background on Locational Capacity Needs

The first column on Form S-3 lists all eight control areas located totally within or partially within California. For the CAISO control area, eight large load pockets were identified by engineering studies completed in 2006. These load pockets were used to develop Local Area Requirements (LARs) that defined how much capacity is needed to meet specific reliability standards. LSEs were assigned to procure their fair share of qualifying capacity needed to meet these local area requirements. In the final capacity procurement assessment meted out to IOUs and ESPs, five load pockets were aggregated. Kept separate in this assessment were the capacity needs associated with three load pockets: Greater Bay Area, LA Basin, and San Diego.

Where LSEs did not procure sufficient qualifying capacity to meet local area requirements, CAISO was prepared to contract for capacity needed to maintain grid reliability. This “backstop” procurement option, benefiting all relevant LSE customers, was meant to reduce or eliminate the exercise of market power by the owners of merchant plants. For some power plants in load pockets, the potential exercise of market power could not be reasonably avoided by placing year-ahead local capacity obligations on the LSEs. These needed power plants, located in load pockets without sufficient market competition, were designated as Reliability Must-Run (RMR) units for 2007. The number and megawatt total of RMR plants were substantially reduced for 2007 compared to previous years.

There is strong state, federal, and stakeholder interest in further reducing or eliminating RMR designations in the future, all of which may be construed as backstop interventions by regulatory authorities in competitive markets. Some plants designated as RMR have high heat rates that make them uncompetitive or inefficient compared to more newly built plants. Some RMR plants use ocean or estuary water for once-through cooling, a technology that may be phased out in time. However, many RMR plants are expected to continue in service for several years. Capacity payments by LSEs or CAISO will likely keep several plants available to meet peak-hour loads, at least until replacement capacity can be brought online.

For proceeding, these eight load pockets, first identified in 2006, are assumed to persist through 2016. CAISO has identified “sub-pockets” for most of these areas. Documents and studies related to these load pockets and sub-pockets may be found at http://www.caiso.com/docs/2004/10/04/2004100410354511659.html.

Preferred New Capacity Locations

IOUs and POUs are asked to indicate the general location where new capacity is likely to occur. Amounts of new capacity shown on Form S-3 should compare reasonably well with amounts of new capacity each year that is shown (or implied) on Form S-1. On Form S-3, list the amount of new capacity just once in the year when it is likely to become available. Only positive numbers should be shown; retirements and powerplant derates (for any reason) should not be listed on this form.

"New capacity" is defined here to mean generating resources that have not previously been available to the system. This includes capacity from new construction, from replacement or repowering of existing generating facilities, and from other major investments that increase the generating capacity of a facility that will be available to the system.

Utilities are asked to list expected new capacity in the row (the general location) where additional generating resources would provide the most benefits, as judged by the LSE. For the POUs, the preferred location of new capacity can be listed with some confidence. For the IOUs, this showing is more of a "wish list," recognizing that most specific locations for new powerplants cannot be known in advance of responses to an authorized long-term procurement RFO. The intent here is merely to indicate the extent to which long-term needs for new capacity to meet LSE bundled-customer load obligations can also attenuate an ongoing need for annual load-pocket designations.

If the LSE operating in CAISO cannot show or does not wish to show a load pocket area where expected new capacity would most advantageously be developed, the LSE should list this capacity on the last line labeled "CAISO system." This line should also be used to indicate capacity that will likely be built outside the designated load pockets but will nonetheless be connected to CAISO-managed grid.

Supply Form S-4: QF Energy and Cost Projections

For the *2007 Energy Report*, Energy Commission staff is not requesting information from the IOUs about contracts with qualifying facilities (QFs).

Supply Form S-5: Bilateral Contracts

Scope and Purpose

All LSEs are asked to provide a few standard types of information regarding existing bilateral contracts that have been signed with suppliers of capacity and/or energy. Do not include short-term contracts with durations of less than three consecutive months.

Only three minor changes to Form S-5 have been made since 2005. Qualifying capacity is now the preferred term and metric for LSEs in CAISO. Aggregations of supply contracts that individually are less than 10 MW are acceptable. Definitions have been added under "unit contingent" to distinguish portfolio and system purchases.

This information on Form S-5 is needed to assess the following characteristics of statewide supply and demand balances:

- Does the contract encumber in-state capacity or is it likely to do so?
- Does the contract encumber out-of-state capacity in service to California loads?
- Is the supplier in control of a physical resource or likely to be so?
- Under what circumstances, if any, may the energy or capacity associated with the contract be unavailable during peak hours?
- Under what general terms does the contract provide qualifying capacity for LSEs serving loads within CAISO?
- Under what general terms does the contract provide dependable capacity for LSEs serving loads in other control areas?

Information Format Requirements

All LSEs are asked to submit the required information on Electricity Supply Form S-5: Bilateral Contracts. A sample template is provided in Excel format. Some of the information requested is categorical, and some is numeric. Several topics are primarily descriptive. Information provided in Word or Acrobat files will be accepted, provided that responses are complete and follow the prescribed sequence. A separate form is needed for each bilateral contract supplier that provides capacity in amounts over 10 MW.

An ESP may have numerous procurement contracts with the same supplier; these different contracts may specify a small MW share of output from the same generating unit. ESPs may aggregate such contracts for reporting on Form S-5, even though delivery periods and specific terms will vary among the individual contracts.

Some LSEs may have many supply contracts, numbering in the scores or hundreds, each of which provides less than 10 MW. To reduce reporting burdens on LSEs and to facilitate broad and general assessments by Energy Commission staff, such contracts may be aggregated for reporting on Form S-5. LSEs may aggregate reporting according to technology or fuel types, ownership, or performance attributes. Renewable energy contracts must be distinguishable from non-renewable supplies. Potential categories for aggregation include wind, solar, small hydro, and biofuels; natural gas-fired cogeneration; and contracts with options or multiple phases.

Aggregated reporting of individual sub-10 MW supply contracts must identify the number of contracts and the capacity sum. Individual contract attributes may not be answerable or relevant when these contracts are aggregated for reporting according to other groupings. LSEs are asked to characterize performance requirements of these contracts in general terms as deemed appropriate (for example, 5% are dispatchable; 40% expire in 2012; 80% are deliverable in NP15, and 10% in ZP26; etc.).

Contracts Covered and Not Covered By This Request

For each and every bilateral contract that specifies a supply of energy or capacity lasting at least three consecutive months, LSEs must provide the information described below and shown on Form S-5. There are four exceptions to this requirement:

- QF contracts
- DWR contracts
- Aggregations of supply contracts, each of which is less than 10 MW
- Contracts between California IOUs and public utilities for the integration of hydro resources (for example, a PG&E hydropower contract with Nevada Irrigation District).

Line-by-Line Instructions

Supplier

Name the contracted supplier/producer of energy and/or capacity according to the contract. This entity is sometimes called the counterparty to the contract.

Start Date

State the initial delivery date of the product(s) being purchased. If this is contingent upon future actions by parties to the contract, market conditions, or other future events, this should be explained in notes appended to the form.

Expiration Date

Provide the date for final delivery of the product(s) being purchased. If this date is contingent upon future actions by parties to the contract, market conditions, or other future events *before the contract's inception*, this should be explained in notes appended to the form. Information regarding the ability of one party to unilaterally terminate the contract after its inception should be entered under Performance Requirements and Termination/Extension Clauses and Rights, or in notes appended to the form.

Contract Capacity (MW)

For each contract, list the maximum qualifying capacity (preferred) or dependable capacity (for LSEs outside CAISO). As a general expectation for LSEs in CAISO, and unless specified elsewhere, this is the amount of product that will be available to the LSE during annual superpeak weekday hours (12 Noon through 6 P.M.) during May through September. (Note: An estimate of qualifying capacity on these forms does not constitute a commitment to make that resource available to CAISO.)

If the available MW varies across months of the year, days of the week, or hours of the day, this variation should be described under Availability below. If capacity that will be available to the LSE is determined somewhere other than the busbar nearest a named generator, name that location.

Contract Product(s)

Indicate the commodity and service products for which delivery is being contracted. Examples include tolling agreement, forward energy purchase, seasonal energy exchange, qualifying capacity for RAR demonstrations, physical call (or put) option for capacity or energy, financial call (or put) option, other market-contingent products, structured transactions (combining one or more product types, varying expiration dates, tiered prices, etc.), and ancillary services.

Availability of Contract Products

Indicate time periods during which product will be available. Examples include:

7 x 16 (5,840 hours per year)
6 x 16 (Monday – Saturday, 6 a.m. – 10 p.m., excluding the 6 NERC holidays)
Q3, 7 x 8 (third quarter, 7 days a week), 1:00 p.m. to 8:00 p.m.
Mos. 5-10, max 50 hrs/mo, (May – October, up to 50 hours per month)
100 MW off-peak (year-round, all hours not covered by 6 x 16)

Describe any limitations on the LSE related to scheduling or dispatch for the contract products during the contract period. Identify any contingent or residual obligations related to availability of contract products. For example, if the contract product is used for year-ahead Resource Adequacy reporting, to what extent must these products be made available to CAISO?

Must-Take

If applicable, indicate must-take characteristics of the contract. Examples include:

Yes (for energy contract, all energy indicated jointly by MW and Availability)
Min 30,000 MWh monthly

Unit(s) Under Contract
Name or describe all individual power plants and/or generating units identified in the contract. If the supplier will provide energy from a portfolio of resources, identify each resource and proportion of energy that each is likely to contribute on an annual basis.

Capacity of the Unit(s)
For each powerplant identified in the contract, list the maximum qualifying capacity (preferred) or dependable capacity (for LSEs outside CAISO). List individual generating units whenever that distinction is relevant (for example, Contra Costa 6, NCPA I Units 1 and 2).

Availability of the Unit(s)
Describe any limitations on LSE scheduling or dispatch of the units during the contract period. If this is a unit-contingent contract, indicate what rights the *buyer* has to dispatch the unit(s).

Identify any contingent or residual obligations on the buyer related to availability of the unit(s). For example, if the generating units will be used for demonstrating year-ahead or month-ahead resource adequacy, to what extent must these units be made available to CAISO? Enter “same as availability of contract products,” if true.

Fuel Type
If the contract identifies a specific generating unit, identify the primary fuel used for generation. If dual fuels or hybrid fuels are used or likely to be used, identify the proportions expected to be used in meeting contract obligations.

Locational Attributes of Unit
If the contract identifies a specific generating unit, identify its location by state, control area, transmission zone, load pocket, and sub-pocket.

Unit Contingent / LD Contract
LSEs are asked to distinguish between supplies from specifically named generating units, and those supplies that are “portfolio” or “system power.” If delivery is contingent upon the availability of a specific unit or units, enter “unit contingent” and name the indicated power plant or unit(s).

If supplies are **required** to be delivered from a portfolio of physical assets under the control of the counterparty, enter “portfolio” and provide an appropriate description or reference.

If the contract states a **preference** for a particular unit when it is available and requires the seller to provide backup power from unspecified sources, enter “unit contingent with firming” and describe the obligation on the seller.

If the contract **allows** the seller to optimize economic dispatch, or does not specify the generating sources to be used, enter “system power.”

Firm

Yes / No. “Yes” indicates that seller can only fail to provide replacement power under *force majeure* provisions or in order to avoid involuntary load curtailments in another control area.

“No” indicates non-delivery may occur for other reasons, such as market conditions or transmission congestion. Contracts without firm delivery requirements typically include provisions for liquidated damages.

Expected Energy from Contract

Identify how much energy is expected to be supplied under terms of each contract for each year of the contract period. Use median (or 1-in-2 year) assumptions for any relevant variable.

Contract Pricing

Enter the mechanism used to determine energy payments under the contract. This may be a fixed price (“Fixed”), a tolling agreement, or otherwise indexed to a market fuel price. If a gas price index is used, please name it (for example, Malin, Topoc, or Citygate delivery points). For tolling agreements, specify the referenced heat rate. If the supply is an energy exchange agreement, describe the return requirements in the notes.

Transmission Contingent and Path

Please enter “contingent” if the seller was assumed to have control of transmission rights, or if the seller will be required to demonstrate such as a condition of the contract. If transmission will be provided by seller, specify typical paths.

If seller was not and will not be required to demonstrate control of capacity and transmission rights as a condition of the contract, enter “No.”

Delivery Points

Name the point(s) at which energy can be delivered (*for example*, NP15, Malin, Lugo substation). If multiple points, indicate whether buyer or seller has option.

Scheduling Coordinator

For each contract, specify which party will serve as scheduling coordinator.

Termination and Extension Rights

LSEs should indicate which party or parties have the right to unilaterally terminate or extend the contract (for reasons other than non-performance of the other party).

For termination rights, indicate the possible termination dates, notification requirements, and allowable circumstances. For example, “Seller may terminate on January 1 of each year beginning 1/1/2011 with 90 days prior notice.”

For extension rights, indicate the possible extension dates, length of extension, notification requirements, and allowable circumstances. For example, “From 7/1/2010 until 1/1/2010, buyer may extend contract for six months with 30 days prior notice, provided that energy purchases have exceeded 80,000 MWh in each of the three preceding calendar quarters.”

Performance Requirements

Indicate circumstances under which buyer can terminate contract for non-performance. For example, “Buyer may terminate contract for non-performance if wind energy delivered at the busbar fails to meet at least 80% of specified targets for each of three consecutive quarters. Thirty days notice is required.”

Notes

Include any clarifying or explanatory statements required or considered appropriate.

Publicly Owned Utility Resource Adequacy

Summary and Context

AB 380 (Nuñez), Chapter 367, Statutes of 2005, created Public Utilities Code Section 9620. It requires local Publicly Owned Utilities (POUs) to undertake and accomplish certain resource adequacy (RA) protocols. AB 380 assigned the Energy Commission with responsibilities to oversee these activities, and to periodically report to the legislature via the biennial *Energy Report*. To accomplish this requirement, the Energy Commission is authorized to collect resource adequacy data from individual POUs.

A detailed process to collect such data, implementing this aspect of AB 380, has been included in proposed new regulations. These regulations will not be adopted on a timeline that facilitates early collection of information about resource adequacy for the summer months of 2007. To collect near-term information that is relevant to the summer 2007 electricity outlook, Energy Commission staff has embarked on a collaborative project with POUs in advance of formal rule-making. This cooperative and voluntary project is designed to quickly collect information from all POUs early in 2007, with review and evaluation of these filings taking place in the spring of 2007. The scope and timing of this project is designed to keep these new reporting burdens on POUs down to essentials (especially for the small POUs), and to accomplish staff assessments in this area prior to other *2007 Energy Report* workloads.

The narrative information requests described in this section on POU Resource Adequacy apply only to medium and large POUs. The parallel collaborative project with small POUs is asking for the same narrative information about POU planning and procurement protocols, all of which are aimed at ensuring resource adequacy.

The parallel collaborative project with small POUs is also asking those LSEs to provide monthly load and supply forecasts for 2007 only, using Form S-1 and Form S-5. These forms identify peak-hour power requirements, including a planning reserve margin, and the resources that will be used to serve end use customers, along with any firm export requirements. The medium and large POUs will already be providing this quantitative information for 2007 as part of their 10-year resource plans.

The proposed Energy Commission data regulations will exempt “small” load-serving entities (LSEs) from most of the data reporting requirements associated with the biennial energy report. Small LSEs will be exempt from filing 10-year resource plans that show supply and demand balances (using Forms S-1, S-2, and S-5). This exemption, however, depends on an expectation that small LSEs will provide year-ahead data and narratives about resource adequacy.

By November 2, 2006, all small POUs who operate in CAISO provided CAISO with their “year-ahead” filings that show how forecasted loads will be met during the five months of May through September 2007. These Resource Adequacy Plans are commonly called “IRRP” filings, which stands for “Interim Reliability Requirements

Program." The IRRP filings by POUs were a new CAISO requirement after FERC approved changes to the CAISO tariff in May 2006. For the parallel collaborative project with small POUs, these IRRP filings will be considered adequate for the summer 2007 outlook assessment by Energy Commission staff, with one small caveat. The small POUs in CAISO are being asked to identify the effective contractual end date of listed resources, which in most cases will extend beyond the September 2007 "RR Capacity Effective End Date" shown on the IRRP filings.

In the parallel collaborative project, all small California POUs that operate *outside* the CAISO control area are being asked to complete Form S-1 for the months of 2007, and Form S-5 for those contractual resources listed on Form S-1.

Background and Previous Data Collection

Resource adequacy activities have been underway in California since the CAISO's initial proposal surfaced as part of its Market Design 2002 (MD02) in early 2002. A broader proposal from FERC surfaced in 2003, which ignited strong opposition from western and south-eastern states and from congressional representatives. FERC agreed to allow states to establish resource adequacy requirements.

The CPUC established key dimensions of a resource adequacy program for investor-owned utilities (IOUs) and electric service providers (ESPs) under its jurisdiction in D.04-01-050, D.04-10-035, D.05-10-042, D.06-06-064, and D.06-07-031. The CAISO established some elements of these requirements as tariff requirements for POUs within its control area, established through its IRRP which was approved by FERC order dated May 12, 2006.

Because there were some questions about the CPUC's authority to establish RA requirements for ESPs, legislative proposals concerning RA surfaced in 2005. AB 380 was adopted, confirming CPUC jurisdiction over all LSEs (including ESPs) that operate in IOU distribution service areas. A companion provision established an oversight role for the Energy Commission regarding POU resource adequacy activities.

Once AB 380 was signed into law in 2005, the previous collaborative efforts between Energy Commission staff and the California Municipal Utilities Association (CMUA) have been beneficial in facilitating Energy Commission staff data requests to POUs. Staff has twice requested some or all POUs to provide load forecast information in the first six months of 2006.[4]

[4] In February 2006, the Executive Director sent a formal data request to each of the 12 POUs >200 MW peak demand that had provided information in the 2005 IEPR requesting updates of loads and resources for 2006. All 12 responded, and these data were used informally as part of the Summer 2006 Outlook, giving greater confidence that resources existed to cover peak loads, plus planning reserves. In June 2006, staff worked with CMUA to obtain summer 2007 peak-load forecasts from all POUs in the CAISO control area. These data were used to segregate CAISO LCR estimates into those portions that

Beginning in February 2006, resource adequacy requirements became functional for the IOUs and ESPs in the CAISO control area. Filing requirements applying to POUs were approved in May 2006, and the first month-ahead filings by POUs became due almost immediately. All types of LSEs in CAISO must now meet the same basic month-ahead and year-ahead filing requirements, including the same counting conventions for qualifying capacity. However, POUs retain some discretion under the CAISO IRRP tariff, appropriately, for establishing their own planning reserve margin, and for adopting other planning protocols and procurement standards by which resource adequacy can be judged. Consequently, there is still a diversity of approaches to resource adequacy among different classes of LSEs in the CAISO control area.

Scope and Purpose

This request to POUs aims to elicit narrative information about their strategies and plans to remain resource adequate. From these filings, the Energy Commission will report on elements that have become standard and explicit, along with elements that are significantly diverse or implicit.

All POUs, without regard to the control areas in which they serve load, are directed by AB 380 to "…prudently plan for and procure resources that are adequate to meet its planning reserve margin and peak demand and operating reserves, sufficient to provide reliable electric service to its customers." This statute recognizes that locally managed public utilities have some variability and discretion about what constitutes reliable and affordable electric service for their local customers. This relatively autonomous responsibility includes decisions about what planning strategies and procurement options are appropriate for implementing a desired level of customer service. Several large and small POUs in California are located in seven different control areas outside of the CAISO control area[5].

Medium size LSEs (annual peak greater than 200 MW) and large LSEs (greater than 1,000 MW) are being asked to provide 10-year resource plans in a format only slightly revised from that used for the *2005 Energy Report*. These resource plans are designed to include the same information categories used in the Resource Adequacy Plan IRRP filings to CAISO. Thus, the 10-year resource plan filings of medium and large POUs will be compatible with the year-ahead resource adequacy filings of small POUs for all first-year projections. In effect, these first-year projections can be "added up" to provide a statewide summary of POU loads and resources for 2007.

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were CPUC-jurisdictional versus other, and as part of the methodology to allocate total import capability among all CAISO LSEs for 2007.

[5] These seven other control areas and their associated publicly owned utilities are SMUD (SMUD, Roseville, Redding, Modesto Irrigation District, and some WAPA loads), Turlock (Turlock and Merced irrigation districts), LADWP (LADWP, Burbank and Glendale), Imperial Irrigation District, PacifiCorp (Surprise Valley), Sierra Pacific (Truckee Donner PUD), and Nevada Power (Needles).

Assessments and evaluations of the information collected from POUs will involve:

- Review of the near term supply/demand balances for each POU, for the aggregated supply/demand balances of all POUs, and for each POU-centric control area;
- Review of the various planning reserve margins, procurement targets, and other criteria that each POU has set for itself to assure future resource adequacy;
- Review of the requirements on each POU that derive from its location within the CAISO control area or within another control area that has different requirements; and
- Review of the options and flexible arrangements that may be available to each POU for maintaining reliability under adverse or unexpected contingencies.

Perhaps the most useful results from these reviews will be an identification of the most important and most common planning and procurement criteria used by POUs to have adequate resources for their end-use customers. A summary of these assessments will be included, as a section or as an appendix, in the *2007 Energy Report*. These four "information-oriented" tasks will be the basis of a more nuanced assessment of POU resource adequacy activities. More specifically, this assessment will examine how explicit and detailed POU plans are for the seamless transition from load forecasting to procurement to scheduling and finally to the operating day. The assessment will also examine how some uncertainties and risks are accepted and managed, while other risks may be considered unacceptable (with plans to diminish or eliminate the risk).

Requests for Narrative Information

Medium and large POUs are asked to provide a detailed description of all resource adequacy and long-term reliability requirements that control area operators or planning entities have identified as applicable to the LSE. This especially includes locally adopted standards and ordinances meant to ensure adequate electricity resources are available to the utility. A standard to have "adequate" resources must be qualified, specified, and somehow limited by practical considerations, since absolute supply adequacy for all contingencies is not physically possible. Similarly, an extremely high standard of resource adequacy may not be deemed prudent or affordable.

Narrative descriptions about POU resource adequacy obligations and standards should include all the following:

(A) Terms of existing tariffs and agreements that identify the specific nature of resource adequacy requirements that an LSE must satisfy;

(B) Planning reserve margins for capacity or energy, and any other elements of standardized evaluations that address the balance between forecasted loads and available resources,

(C) Operating reserve requirements established by the Western Electricity Coordinating Council, control areas, and other authorities as they affect and determine resource adequacy obligations;

(D) Any unit commitment and dispatch obligations imposed by control area operators or other entities operating interconnected electric transmission systems, and a description of how the LSE meets these obligations with generation it owns or controls;

(E) Deliverability restrictions, dispatchability provisions, or transmission contingencies that affect the LSE's ability to rely upon specific resources, and a description of how these limitations might affect reliability of service; and

(F) The strategy that the LSE intends to pursue to achieve, and once accomplished maintain, the level of resource adequacy it has determined to be appropriate for its customers.

POUs within the same control area are encouraged to consult and coordinate with each other and to consult with control area operators on all relevant topics.

In the narrative filings by POUs on this topic, links to web-published documents may be provided where the requested information is already available. The filings should identify particular sections or pages that address the obligations and standards listed above.

More specific questions about resource adequacy may be directed to Mike Jaske at mjaske@energy.state.ca.us or (916) 654-4777.