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TRANSMITTAL OF *2005 ENERGY REPORT* RANGE OF NEED AND POLICY RECOMMENDATIONS TO THE CALIFORNIA PUBLIC UTILITIES COMMISSION

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Table of Contents

List of Tables

List of Figures

COMMISSION FINAL TRANSMITTAL OF *2005 ENERGY REPORT* RANGE OF NEED AND POLICY RECOMMENDATIONS TO THE CALIFORNIA PUBLIC UTILITIES COMMISSION

1. Executive Summary

Since the adoption of the *2003 Integrated Energy Policy Report* (*Energy Report*),[1] the California Energy Commission (Energy Commission) and California Public Utilities Commission (CPUC) have worked to ensure close coordination of the *2005 Energy Report* proceeding with the upcoming CPUC 2006 procurement proceeding. This *Transmittal of the 2005 Energy Report Range of Need and Policy Recommendations to the CPUC* (*Transmittal Report*) is the result of that cooperation. This report summarizes the key policy recommendations from the *2005 Energy Report*[2] that are most relevant to the procurement and related proceedings and the record on which those recommendations are based. This *Transmittal Report* also provides the CPUC with the data and analyses used by the Energy Commission to assess the demand forecasts and resource needs for the state's three largest investor-owned utilities (IOUs): San Diego Gas and Electric Company (SDG&E), Southern California Edison Company (SCE), and Pacific Gas and Electric Company (PG&E). The CPUC has stated its intention to use this information on the IOU demand forecasts and resource needs developed in the *2005 Energy Report* proceeding as the basis for its 2006 procurement proceeding.

The bulk of this report provides detailed documentation of the range of procurement need that the Energy Commission has identified for PG&E, SCE, and SDG&E for the 2006 procurement proceeding. The Energy Commission has developed these ranges of need based on publicly available information from the *2005 Energy Report* proceeding. The range of need adopted here is based on public summaries of the

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[1] *2003 Integrated Energy Policy Report (2003 Energy Report)*, California Energy Commission, publication 100-03-019, December, 2003.

[2] *Committee Draft 2005 Integrated Energy Policy Report (Draft Energy Report)*, California Energy Commission, CEC-100-2005-007-CTD, September, 2005.

resource plans submitted by the IOUs in early 2005 and the revised Energy Commission staff forecast published in September 2005.[3] The Energy Commission's focus in evaluating IOU procurement needs in this proceeding has been, to a large extent, on the need for adequate long-term planning. In part due to this emphasis and in part due to the fact that the resource plan information provided by the IOUs for the years 2006 through 2008 is not in the public record, the range of need presented in this report is only for the years 2009 through 2016. The revised staff demand forecast that the Energy Commission is adopting does include demand forecasts at the planning area, distribution service area, and bundled customer levels for 2006 through 2016. As stated in the *Energy Report*, "The Energy Commission generally finds the staff's detailed end-use models more reliable in the long-term and the utilities' econometric methodologies more useable in the near-term."[4] The CPUC is currently addressing use of Energy Commission staff's monthly peak demand forecast for the resource adequacy requirements in 2006. The Energy Commission expects that the CPUC will similarly review the forecast the Energy Commission is adopting for appropriate use in the near term (2007 and 2008) portion of the upcoming procurement proceeding.

The purpose of the range of need tables in this report is to assist in meeting future IOU bundled customer demand with the existing IOU controlled physical and contractual resources. The report presents a preliminary picture of the amount of resources the IOUs will need to procure to meet expected demand for the years 2009 through 2016, along with a road map for how to update the planning numbers during the 2006 procurement proceeding. The ranges presented here are necessarily preliminary, since they are based on resource plan data prepared by the IOUs in early

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[3] *California Energy Demand 2006-2016, Staff Energy Demand Forecast, Revised September 2005 (Revised Staff Forecast)*, California Energy Commission staff final report, CEC-400-2005-034SF-ED2.

[4] *2005 Integrated Energy Policy Report (Energy Report)*, California Energy Commission, CEC-100-2005-007-CMF, November, 2005, p. 41.

2005 that is now, to some degree, out of date. The Energy Commission has included in section 5.8 of this report recommendations on when and how this data should be updated.

In addition, the Energy Commission has reported on the amounts of "preferred resources" the IOUs should plan to acquire as they fill this need, consistent with the state's loading order for resource additions. The Energy Commission's underlying approach to identifying the amounts of preferred resources the IOUs should expect to include in their portfolios is to make use of the goals the state has established. For energy efficiency and demand response, the Energy Commission has taken as given the goals adopted in CPUC proceedings. For renewable resources, the Energy Commission recommended in the *2004 Energy Report Update* that the state should adopt long-term renewable energy development goals that go beyond the established goal of 20 percent by 2010. The Energy Commission has included in the range of need tables a preferred level of renewable resources going forward that reflect the IOUs' estimates of what would be needed to meet the *2004 Energy Report Update* goals. Any changes to the CPUC-adopted energy efficiency or demand response goals, as well as the establishment of distributed generation/combined heat and power targets, will result in future adjustments to these "preferred resource" amounts.

2. Background

2.1. 2005 Energy Report Proceeding

The Energy Commission is directed by statute to prepare an *Energy Report* every two years. This report must contain an overview of major energy trends and issues facing the state. In order to ensure consistency in the information underlying state energy policy and decisions, other state agencies and entities are directed to carry out their energy-related responsibilities using the information and analyses in the *Energy Report* (Pub. Resources Code, § 25302).

The *2005 Energy Report* proceeding began when the *Energy Report* Committee (Commissioner John L. Geesman, Presiding Member, and Commissioner James D.

Boyd, Associate Member) issued a Notice of Committee Hearing for an August 18, 2004 hearing on the scope of the *2005 Energy Report* proceeding. At the hearing, the Committee received comments and discussed the appropriate scope of issues for the *2005 Energy Report*. On September 3, 2004, the Committee issued a scoping order identifying a list of issues to be addressed in the *2005 Energy Report*.[5] The issues were grouped into the following major categories:

- California's Energy Demand, Supply, and Infrastructure.
  - Transportation Fuel Demand, Supply, and Infrastructure.
  - Electricity Demand, Supply, and Infrastructure.
  - Natural Gas Demand, Supply, and Infrastructure.
- Energy, Environmental, and Economic Sustainability.
- California-Baja California Border Issues.

In order to establish a comprehensive information base for decision making, the Committee directed certain market participants to provide a broad range of information related to electricity supply and retail price, electricity demand, natural gas supply and price, transmission issues, and environmental issues. In addition, Energy Commission staff, numerous other state agencies, market participants, and members of the public submitted papers, analyses, and comments. Prior to publication of the *Draft Energy Report* and *Committee Draft Strategic Transmission Investment Plan (Draft Strategic Plan)*,[6] the Committee held 53 public hearings and workshops and received more than 50 staff and consultant papers and reports, with extensive participation by more than 600 public and private entities and individuals. The evidentiary record compiled over the course of the *2005 Energy Report* proceeding exceeds 30,000 pages. Key reports relating to issues addressed in this *Transmittal Report* included:

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[5] *Committee Scoping Order*, Docket 04-IEP-1, September 3, 2004.

[6] *Committee Draft Strategic Transmission Investment Plan (Draft Strategic Plan)*, California Energy Commission, CEC-100-2005-006-CTD, September, 2005.

- *Assessment of California CHP Market and Policy Options for Increased Penetration.*
- *Investor-Owned Utility Resource Plan Summary Assessment.*
- *Resource Plan Aggregated Data Results.*
- *Preliminary Reference Case in Support of the 2005 Natural Gas Market Assessment.*
- *California Energy Demand 2006-2016 – Staff Energy Demand Forecast, Staff Draft Report.*
- *Energy Demand Forecast Methods Report.*
- *Electricity Demand Forecast Comparison Report.*
- *California and Western Electricity Supply Outlook Report.*
- *Implementing California's Loading Order for Electricity Resources.*
- *California Energy Demand 2006-2016 – Staff Energy Demand Forecast Revised September 2005.*
- *Upgrading California's Electric Transmission System: Issues and Actions for 2005 and Beyond.*
- *Revised Reference Case in Support of the 2005 Natural Gas Market Assessment.*

After consideration of all of the papers, reports, written comments, and discussions at hearings and workshops, the Committee published the *Draft Energy Report,* the *Draft Strategic Plan*, and the *Draft Transmittal Report*. The *Draft Energy Report* addressed specific energy issues associated with transportation fuels; electricity needs and procurement policies; electricity resources; transmission; natural gas; water/energy interaction; global climate change; and energy concerns in the California-Mexico border region. It also identified policy options and recommended strategies for achieving the state's energy goals. As discussed below, this *Transmittal Report* contains those assessments and recommendations that are specific to the load-serving entities (LSEs) that fall under the CPUC's jurisdiction, including the three largest IOUs: SDG&E, SCE, and PG&E.

The Committee held a public hearing on the *Draft Strategic Transmission Plan,* and six public hearings on the *Draft Energy Report* and received extensive written comments from more than 100 parties. The Committee considered these comments in preparing the final versions of the *Strategic Transmission Plan* and the *Energy Report*, which were published on November 7, 2005.

The Committee also held a public hearing and received written comments on the *Draft Transmittal Report*, as discussed below in Chapter 10. The written comments on the

Draft Transmittal Report are included in Appendix C, and the Energy Commission's responses are included in Appendix D. This *Transmittal Report* reflects the relevant changes to the other two documents and changes in response to comments received on the *Draft Transmittal Report*. All three reports were adopted by the full Energy Commission at a special business meeting on November 21, 2005.

2.2. Coordination with the CPUC

Early in the *2005 Energy Report* proceeding, the Energy Commission and the CPUC began discussions about integrating the *2005 Energy Report* with the CPUC's upcoming 2006 procurement proceeding. Michael R. Peevey, the President of the CPUC and the Assigned Commissioner for the CPUC Order Instituting Rulemaking (OIR) to Promote Policy and Program Coordination and Integration in Electric Utility Resource Planning (R. 04-04-003), issued an Assigned Commissioner's Ruling (ACR) in September 2004, stating that the *2005 Energy Report* process should serve as the "initiation of a new, integrated, statewide resource planning process."[7] In the ACR, President Peevey specifically identified the *2005 Energy Report* process as the appropriate forum to consider load forecasting, resources assessment, and scenario issues and to establish the appropriate range of resource portfolio expansion for LSEs in California. In fact, President Peevey was explicit that the CPUC would not, in its 2006 procurement proceeding, reevaluate the range of need established by the Energy Commission in the *2005 Energy Report* proceeding unless so required by law. Stakeholders interested in participating in the development of such analyses were directed to "do so in the context of the [Energy Commission's Integrated Energy Policy Report] process."[8]

[7] President Peevey ACR, R.04-04-003, September 16, 2004.

[8] *Id.* at p. 3.

On March 14, 2005, President Peevey issued a more detailed ACR as part of R.04-04-003.[9] This ACR explicitly placed parties on notice that they would not be allowed to relitigate the Energy Commission's determination of the appropriate level and range of resource needs for LSEs, absent new information or materially changed circumstances.[10] The March ACR identified the process the Energy Commission would follow in developing this determination and addressed the contents of this *Transmittal Report*. Specifically, the ACR stated that, after conducting public proceedings, including any hearings necessary pursuant to Public Utilities Code Section 1822, the Energy Commission would develop a report identifying the likely range of statewide and IOU-specific need, discussing issues relevant to these determinations, and responding to participant comments.[11] According to the ACR, the *Transmittal Report* would be based on the information and comments provided in the proceeding.[12] The ACR was served on all parties to R. 04-04-003 and to the umbrella proceedings.[13] The Committee issued an Order on the same day stating that the Order and the ACR had been fully coordinated between the two agencies.[14] The comment period and hearing on the *Draft Transmittal Report* provided another opportunity for parties to express their concerns or positions regarding the LSE need determinations to be used in the 2006 CPUC procurement proceeding.

The March 14, 2005 ACR also addressed the issue of intervenor compensation. The CPUC is required to implement a comprehensive compensation system for

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[9] President Peevey ACR, R.04-04-003, March 14, 2005.

[10] *Id*. at p. 6.

[11] *Id*. at p. 7.

[12] *Ibid.*

[13] These include: R. 01-0 8-028, R. 04-04-025, R. 03-10-003, I. 00-11-001, R. 04-01-026, R. 04-04-026, R. 04-03-017, R. 02-06-001, and R. 04-01-025.

[14] *Order Re: Coordination with CPUC's 2006 Procurement Proceeding*, Docket 04-IEP-1, March 14, 2005.

intervenors whose participation results in a "substantial contribution" to CPUC proceedings. The CPUC recognized that this requirement raises a question of whether participants in the *2005 Energy Report* proceeding, who make a substantial contribution to those portions of the *2005 Energy Report* proceeding that will be used in CPUC's 2006 procurement proceeding, are eligible for compensation. The CPUC decided that such compensation is appropriate. Accordingly, the ACR established a process by which participants in both proceedings could apply for and, if eligible, receive compensation. This process requires the Energy Commission to provide the CPUC with a written assessment of a claim of substantial contribution within 75 days of an intervenor request for compensation for participation in the *2005 Energy Report* proceeding. The Utility Reform Network (TURN), the Natural Resources Defense Council (NRDC), the Union of Concerned Scientists, the Green Power Institute, and Women's Energy Matters filed notices of intent to claim compensation for work conducted in the *2005 Energy Report* proceeding and participated in various parts of the proceeding.

2.3. Confidentiality

Confidentiality issues were a major source of discussion and debate in the *2005 Energy Report* proceeding, culminating in two IOU lawsuits against the Energy Commission to prevent the release of IOU-provided bundled customer annual peak demand forecasts and tables including aggregations of IOU-supplied resource plan data.[15] These suits underscore the level of contention regarding the Energy Commission's decision to conduct the Energy Report proceeding in an open and accessible forum and highlight differences in the way the Energy Commission and the CPUC undertake planning activities.

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[15] SCE filed the suit to prevent release of its bundled customer annual peak demand forecast. Energy Commission staff have agreed not to release the peak forecasts from PG&E and SDG&E based on an agreement among attorneys for the Energy Commission and the IOUs that the disputed data would remain confidential until any court action was resolved. The three IOUs filed a joint action relating to the aggregated data tables.

In recent years, the electric resource planning process at the CPUC has been shrouded by a significant degree of secrecy. Under the current CPUC process, CPUC staff and some non-market participants who have signed non-disclosure agreements are allowed to review the utility procurement plans and implementation activities through the use of non-disclosure agreements and protective orders. As a result, scrutiny of assumptions and debate over alternatives is severely truncated. This secretive process can only undermine public confidence in the regulatory decisions made in this environment. The Energy Commission firmly believes that significant benefits accrue from rigorous public scrutiny of data and planning assumptions and that responsible and effective electricity resource planning should not and cannot exclude the public.

Conversely, conducting policymaking by using information that is not publicly available hinders the Energy Commission's accountability to the public, to the Legislature, and to the Governor. When the Energy Commission cannot discuss the information that underlies its decisions, it loses the ability to be responsive to those who have a right to understand Energy Commission decisions. As a result, for decision-making purposes, the Energy Commission has not relied on information that is not available for public review and discussion at public workshops.

The Energy Commission notes that its approach is compelled by the Public Records Act (PRA), which is designed to safeguard the accountability of government to the public. Because it serves this important public interest by securing public access to government records, the PRA is construed broadly in favor of access and narrowly in terms of exemptions from disclosure. The Energy Commission is using the *2005 Energy Report* record to set important state energy policy, including how much and what kind of electrical generation and transmission are necessary for the state's future. There is a strong public interest in having the information underlying such policy decision-making accessible to the public and interested parties, rather than using a process that is not subject to public discussion or critique.

The Energy Commission's approach is also required by the Warren-Alquist Act (Pub. Resources Code § 25000 et seq.), which directs the Energy Commission to "gain the perspectives of the public and market participants" in developing the *Energy Report* (Pub. Resources Code, § 25306). This approach is also consistent with the State Constitution, which expressly states that the public has the right to access information concerning the conduct of the people's business and that statutes and regulations shall be broadly construed if they further the people's right of access and narrowly construed if they limit the right of access (California Constitution, article, I § 3, subd. (b)(1) and (2)).

Finally, the Energy Commission notes that disagreements between LSEs and the Energy Commission regarding claims for confidentiality have consumed a significant amount of scarce staff resources in this *2005 Energy Report* cycle.

As stated in the *Energy Report***:**

> The Energy Commission believes that public disclosure of demand forecasts and resource plans, in both energy and capacity terms, is critical to a sound, transparent planning process that is fundamentally responsive to the public it serves. Even greater disclosure is warranted for California IOUs because of their dominant size and the regulatory protection they enjoy as regulated monopolies. A more open environment is also consistent with the Public Records Act, which is designed to ensure the accountability of government to the public it serves. It is broadly worded in favor of open access, and its exceptions are very narrowly defined.
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> In its public comments, the League of Women Voters identified confidentiality as an issue that "may be the most critical one that our state needs to address if there is to be any rationality in a comprehensive integrated planning process." The League further noted that IOU claims of confidentiality include all information associated with the application of least-cost, best-fit criteria in the selection of bids and on details of contracts. Without that available information, the League concluded that "the public cannot have confidence in the decision process." The League expressed its respect for the confidentiality of proprietary information, but added that they do not support "failing to disclose information that is to be used in defining resource planning decisions, if that information is directly relevant to the public good."
>
> Some public interest groups don't recognize the impact the [procurement review group (PRG)] process has had on resource planning transparency. For example, TURN points out in its comments on the [renewable portfolio standard (RPS)] that the "program takes many complicated decision processes and makes them transparent by subjecting the evaluation methodologies used by the IOUs to

public review and CPUC approval." However, TURN's comments fail to note that only very general and opaque descriptions of least-cost, best-fit criteria and their application have been made public. No party, other than members of the PRGs, has any real understanding of how the principle of least-cost, best-fit is being used to shape the state's resource procurement. TURN does, however, identify what the Energy Commission believes is one of the primary downsides of inadequate public disclosure: "that IOUs would simply invent their methodologies, their own contract terms, and their own preferred solicitation protocols. Leaving it to the utilities to unilaterally decide these elements could have perverse results and undermine the goal of ensuring fair, transparent, and open competition…"

TURN's comments about all source procurement deepen the Energy Commission's apprehension about the PRG process. At a time when the CPUC has placed considerable emphasis on requiring that renewables be the "rebuttable presumption" for all IOU procurement, TURN, a primary participant in and defender of the PRGs, has come to a different conclusion: "Based on experience reviewing recent all source [request for offers (RFOs)], TURN believes that these solicitation are not likely to be effective vehicles for the selection of renewable resources. The metrics for comparing gas-fired resources with renewables are tricky, and the two sets of resources serve different purposes in IOU portfolios. Some of the benefits of fossil units (ramping, load following, ancillary services) are not available from renewables."

Tricky or not, the Energy Commission believes these metrics deserve vigorous public debate and that the process would be better informed were it accessible to a full range of stakeholders, including the press, and not limited to IOUs and "non-market participants." These are fundamental aspects of public policy, better served by an open and transparent process rather than by a small elite, no matter how well-motivated.

The Energy Commission is committed to rigorous public scrutiny of data and planning assumptions and believes that responsible and effective resource planning cannot exclude the public. The *2005 Energy Report* has elected to rely exclusively upon publicly disclosed information for the basis of its assessments, findings, and policy recommendations. The Energy Commission believes that resource planning and procurement in California should be open and transparent to the public it serves.[16]

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[16] *Energy Report*, pp. 55-56 (footnotes omitted).

Given the strong public policy favoring accessibility to information and transparency of the decision-making process, the Energy Commission will actively pursue steps to minimize conflicts about confidentiality in future *Energy Report* proceedings. The Energy Commission is participating in the CPUC's OIR to Implement Senate Bill No. 1488 (2004 Cal. Stats., Ch. 690 (Sept. 22, 2004)) Relating to Confidentiality of Information (R.05-06-040). The Energy Commission also opened a rulemaking (05-DATA-1) on October 19, 2005, to revise Energy Commission regulations regarding data collection and information disclosure for future *Energy Report* proceedings. The Energy Commission will vigorously defend its own determinations that certain information should be publicly available, and, if appropriate, seek long-term legislative solutions to ensure that state government has a consistent policy that allows the *Energy Report* process to be conducted without withholding information from participants, the Legislature, and the public.

3. General Procurement Policy Recommendations

The Energy Commission has included in the *2005 Energy Report* policy recommendations based on the analyses conducted during this proceeding. These recommendations cover a broad range of topics. In this portion of the *Transmittal Report*, the Energy Commission specifically identifies those *Energy Report* policy recommendations that should be implemented by the CPUC in the upcoming 2006 procurement proceeding.

The starting point for these recommendations is the loading order. The loading order was first identified in the *Energy Action Plan (EAP) I*[17] and the *2003 Energy Report*. It was subsequently endorsed by Governor Schwarzenegger and was recently re-

[17] *Energy Action Plan (EAP I)*, California Power Authority, California Public Utilities Commission, and California Energy Commission, April 2003. The *Energy Action Plan* is an implementation roadmap adopted by the state's key energy agencies for ensuring consistency in implementing the state's energy policies and objectives.

affirmed with the adoption of *EAP II*.[18] The loading order (efficiency, demand response, renewable power, distributed generation, clean and efficient fossil-fired generation) is the state's priority sequencing policy for preferred options that address increasing energy needs while considering the need to improve the transmission grid and distribution infrastructure.

In addition, the Energy Commission offers several recommendations based on its mandate to facilitate efficient and reliable energy markets (Pub. Resources Code, § 25301 (b)(5)). Specifically, the Energy Commission finds that several improvements to the CPUC's procurement process would help achieve this goal. Together, these policy recommendations should help ensure that the state's policy objectives are clearly and consistently promoted throughout the 2006 procurement proceeding.

3.1. Implementation of the Loading Order

3.1.1. Need for Long-Term Contracts

One important step in implementing the loading order will be an increased emphasis on the use of long-term contracts to meet utilities' needs. A careful review of the record developed during this proceeding demonstrates that policies encouraging long-term contracts would increase deployment of both new renewable and new conventional generation, provide a hedge against increasing natural gas prices, and increase environmental and reliability benefits associated with diminished reliance on the state's aging fleet of existing plants. As noted in the *Energy Report*, "the lack of long-term power contracts has stalled development and construction of more than 7,000 megawatts (MW) of permitted plants and sharply curtailed the number of new permit applications. Utilities need to invest now for the long-term to avoid a repeat of the

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[18] *Energy Action Plan II: Implementation Road Map for Energy Policies (EAP II)*, California Public Utilities Commission and California Energy Commission, September 2005.

catastrophic mistakes made during the 2000-2001 energy crisis that Californians are still paying for today."[19]

No regulatory barriers to long-term contracts currently exist. As noted by the CPUC in the July 7, 2005, hearing on electricity issues and policy options, IOUs are capable of entering into longer-term contracts.[20] Nonetheless, a majority of the capacity sought under current procurement is under medium- or short-term contracts.

Use of short-term contracts perpetuates reliance on aging and inefficient infrastructure and impedes construction of the backlogged new resources that have already received licenses. As noted in the *2004 Energy Report Update*, aging power plants currently play an important role in the state's electricity system, including "provid[ing] local reliability services…; contribut[ing] to regional and statewide reliability…; and help[ing] alleviate transmission system congestion…."[21] While these plants have provided needed resources during the last several years and will unavoidably play a role in the near term, the state cannot afford to rely indefinitely on power plants that are 30 years old and older. Instead, the state must begin an orderly process to retire them.[22]

The lack of long-term contracts also hinders the development of renewable resources. Ms. Julee Malinowski-Ball, representing Public Policy Advocates, stated at the May 9, 2005 hearing on renewable resource potential that long-term, fixed-price contracts are needed to promote the development of additional renewable resources. [23] In addition, there was a significant volume of testimony in this proceeding regarding

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[19] *Energy Report,* p. E-3.

[20] 7/7/05 RT, p. 40.

[21] *Integrated Energy Policy Report 2004 Update (2004 Energy Report Update)*, California Energy Commission, publication 100-04-006CM, November 2004, p. 6.

[22] When the Energy Commission speaks of "retiring" these aging power plants, it refers specifically to the aging steam boiler units included in the list in Appendix A. The orderly process for retiring the aging units may include replacing them with new generating units at or near the same site.

[23] 5/9/05 RT, p. 107.

the need for standardized contracts. A number of representatives of the renewable industry discussed the difficulty associated with negotiating individual terms for each renewable contract.[24] The Energy Commission recommends that the CPUC establish standard contract terms in order to decrease the delays associated with negotiating renewable resource contracts.

The Energy Commission also notes that the extensive record developed in its consideration of IOU appeals of the Executive Director's Notice of Intent to Release Aggregated Data supports the importance of long-term contracts as a means of reducing vulnerability to short-term fluctuations in the market.[25] In the context of evaluating the possible impacts of release of the aggregated data, staff witnesses considered the effects of long-term contracts. The testimony of the staff witnesses clearly demonstrated that long-term contracts reduce exposure to spot market price risks.[26] Staff pointed out that they also have other benefits by encouraging construction of new generation.

In its comments on the *Draft Transmittal Report*, Constellation expressed concern that execution of long-term power contracts by the IOUs "will perpetuate and prolong

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[24] See, for example, 5/9/05 RT, pp. 104, 105, 111, 122.

[25] Following the release of the Executive Director's Notice of Intent, the three IOUs appealed the proposed release of some of the aggregated data tables. The appeals were initially scheduled to be heard by the Energy Commission at its July 13, 2005 business meeting, with written testimony due by July 8. Following submission of the written testimony by Energy Commission staff and the three IOUs, the IOUs requested the ability to file rebuttal testimony. As a result, consideration of these appeals was postponed until August 24, 2005, with rebuttal testimony due on August 12. Staff, the IOUs, the Independent Energy Producers Association, and four energy service providers acting collectively, all filed rebuttal testimony. The Energy Commission allowed cross examination of the various witnesses during the August 24, 2005, business meeting. The Energy Commission then allowed parties to file post-hearing briefs by August 31, then voted to deny the appeals and uphold the Executive Director's Notice of Intent at the September 7, 2005, business meeting. The IOUs filed an appeal of that decision in Superior Court on October 17, 2005. All of the materials considered as part of this appeal are available on the Energy Commission's web site at: [http://www.energy.ca.gov/2005_energypolicy/documents/index.html#082405].

the existing hybrid market structure."[27] The Energy Commission notes that the state's energy agencies embraced the current hybrid electricity market in the first Energy Action Plan, adopted by the Energy Commission and CPUC in April and May, 2003, respectively.[28] The Energy Action Plan recognized "that California currently has a hybrid energy market and that state policies can capture the best features of a vigorous, competitive wholesale energy market and renewed, positive regulation." The Energy Commission believes that the challenge facing the state is how to best implement the hybrid market. The Energy Commission believes that long-term contracts are urgently needed to stimulate investment in new infrastructure in the context of the hybrid market. Avoiding a clear recommendation to that effect risks continued under-investment in new infrastructure.

In sum, the most important action the CPUC can take in the 2006 procurement proceeding is to compel the IOUs to enter into long-term contracts, particularly contracts with renewable facilities. Long-term contracts will encourage development of new conventional and renewable resources, both reducing reliance on aging, less efficient plants and providing important gas-price hedging advantages. The result will be a more reliable market, with environmental and economic benefits accruing to all utility customers.

3.1.2. Combined Heat and Power Resources

The *Energy Action Plan* priorities are well known. These priorities identify renewable and distributed generation (DG) resources as the preferred generation technologies for use in meeting electricity needs, after efficiency and demand

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[26] See, for example, Rebuttal Testimony of Energy Commission Staff, Attachment A.

[27] Constellation, November 8, 2005, p. 2. (See Appendix C for a copy of this comment letter, and Appendix D for the Energy Commission response.)

[28] *EAP I.*

response.[29] During the *2005 Energy Report* proceeding, the Committee devoted considerable effort to exploring options to encourage development of combined heat and power (CHP) resources.[30] As part of this effort, the Committee held a workshop on April 28, 2005, to explore CHP issues. Information presented at the workshop, as well as written comments filed in the *2005 Energy Report* docket, provides extensive arguments on why the state should increase its efforts to accelerate the development of these resources. In fact, the recently adopted *EAP II* specifically identifies support for CHP as an important part of the *Energy Action Plan*.[31]

The consultant study presented at the CHP workshop evaluated both base case and high deployment scenarios.[32] The base case scenario would result in total benefits over the 15-year forecast period of 400 trillion Btu in energy savings, resulting in approximately $1 billion in reduced facility operating costs and 23 million tons of reduction in CO_2 emissions.[33] Under the high deployment scenario, these benefits reach 1,900 trillion Btu in energy saving, $6 billion in reduced costs, and CO_2 reductions of 112 million tons. These are compelling figures and support significant additional emphasis on CHP resources as an important part of California's energy future.

At the Committee hearing on CHP, a number of entities provided presentations that addressed CHP issues. Several discussed the difficulties associated with interconnection for these facilities, focusing specifically on the CA ISO tariff. David Dyck of Valero Energy Corporation noted that compliance issues associated with the

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[29] *EAP II*, p. 2.

[30] CHP, also know as cogeneration, differs from other DG resources in that it tends to be installed in fairly large systems; in fact 90 percent of the installed CHP facilities in the state (representing approximately 9,000 MW) have a capacity of 20 MW or greater. (*Assessment of California CHP Market and Policy Options for Increased Penetration*, April, 2005, p. viii.)

[31] *EAP II*, pp. 7, 8.

[32] *Assessment of California CHP Market and Policy Options for Increased Penetration*, April, 2005, CEC-500-2005-060D.

[33] *Id*. at p. ix.

ISO tariff are very significant. While electricity generation is not Valero's primary business, it has the permits and space to add a second cogeneration unit, but is unable to move forward. PG&E won't purchase Valero's power unless it signs a master services agreement with the CA ISO.[34] Michael Alcantar of the Cogeneration Association of California/ Energy Producers and Users Coalition (CAC/EPUC) expressed similar concerns. He noted that the primary purpose of Watson Cogeneration, a 410 MW facility at the BP refinery in Carson, is to ensure that the refinery has process steam with electricity as a by-product. These cogeneration plants "are fundamentally steam plants, but from the CA ISO perspective you're a power plant."[35] Barry Lovell, representing Berry Petroleum, discussed its experiences exploring construction of two new cogeneration units during the 2000-2001 energy crisis that would have totaled 90 MW. He noted that they were required to sign with the CA ISO as a participating generator. "You end up signing a very simple 13-page document that basically says that you're going to comply with every [CA] ISO tariff that will ever be written. And many of them are confidential and you can't even see them. So for someone who's not in the power generation business, this is kind of a scary process."[36]

Others identified problems in contract negotiations.[37] Rod Aoki of CAC/EPUC testified at the July 25, 2005 Committee workshop on implementing California's loading order for electricity resources that California needs to ensure that existing CHP capacity be retained. "CHP contracts are expiring at a significant rate over the next five to seven years," 1,000 MW by 2008 and 1,800 MW by 2010. [38] Mr. Aoki also pointed out that the

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[34] 4/28/05 RT, pp. 34-36.

[35] 4/28/05 RT, p. 66.

[36] 4/28/05 RT, pp. 80-81.

[37] *Id*. at pp. 77, 81.

[38] 7/25/05 RT, p. 207.

benefits existing CHP facilities are providing will be lost if contract negotiations are not successful. He offered the example of an existing 300 MW facility in California that had been in negotiations for quite some time and whose current contract was set to expire on August 30, 2005. The facility owner was completely uncertain about what to do.[39] Other existing large CHP facilities are trying to make decisions on equipment upgrades and replacements. Greater certainty about long term contracts with the utilities to allow these upgrades and replacements take place.[40]

The Energy Commission recognizes that these facilities are quite different from traditional merchant plants and that the IOUs are reluctant to include them in their portfolios. However, the IOUs develop portfolios with a wide range of resources with different operational profiles. Given both the benefits that they offer, the Energy Commission believes it is in the state's interest to promote these resources. The CA ISO's recent identification of a need in excess of 25, 000 MW for generation located close to load strongly reinforces this conclusion.[41]

As a result, the *Energy Report* includes the following recommendations for encouraging the increased use of CHP resources to meet the state's energy needs:

- The CPUC and the Energy Commission should establish annual utility procurement targets for CHP facilities by the end of 2006.
- The CPUC should require investor-owned utilities to purchase electricity from CHP facilities at prevailing wholesale prices.
- The CPUC should explore regulatory incentives that reward utilities for promoting customer and utility-owned combined heat and power projects.
- The CPUC should require that investor-owned utilities provide CA ISO scheduling services for these facilities and be compensated for doing so.[42]

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[39] *Id.* at p. 208.

[40] *Id.* at pp. 209-210.

[41] *Local Capacity Technical Analysis: Overview of Study Report and Final Analysis,* California Independent System Operator, September 23, 2005.

[42] *Energy Report*, p. E-4.

These steps should help resolve many of the difficulties in negotiating contracts identified by the participants in the *2005 Energy Report* process. Finally, the CPUC should require IOUs to offer CA ISO scheduling services at cost to their CHP customers to reduce the barriers created by the CA ISO tariff. Implementation of these recommendations should help ensure that the state's objectives of promoting CHP and harnessing its significant financial and environmental benefits are achieved.

3.2. Portfolio Performance and Least-Cost, Best-Fit Criteria

The CPUC stated in its December 2004 resource procurement decision that it will rely upon a portfolio approach to balance obtaining adequate resources and procurement.[43] IOUs currently employ least-cost, best-fit criteria when selecting bids from their solicitations. These criteria ostensibly ensure that selected bids match the base load, peaking, and other physical characteristics of system needs. The Energy Commission has significant concerns with the current application of the least-cost, best-fit criteria. Utilities have developed individual methods to calculate or weigh these criteria including resource or market value, portfolio fit, credit, viability, transmission impact, debt equivalence, and non-price terms and conditions. As stated in the *Energy Report*:

> [The] descriptions provided by utilities about the use of least-cost, best-fit criteria are not universally transparent and require a high degree of subjective interpretation and judgment. The application of these criteria in bid selection is known only to utilities and individuals participating in PRGs.[44] [fn: In its 2005 Request for Offers for renewables, Southern California Edison reserved the right to conduct the solicitation without procurement review group concurrence, subject to CPUC approval. Since all discussions with procurement review groups are confidential, no one outside the procurement review group can discern whether legitimate issues were raised by members and dismissed by the utility or even the extent to which the details of the least-cost, best-fit criteria are disclosed within the group.]

[43] D.04-12-048, p. 28.

[44] *Energy Report*, p. 62.

A recent review by the Energy Commission of evaluation criteria indicated that there are significant shortcomings in the market value and portfolio fit criteria that are currently being used by utilities.[45] For example, the market valuation looks at the present value of an asset compared with a market price assumption, where portfolio fit criteria compare an asset to the utility's "short" or "long" positions. While these comparisons have value when looking at a single asset, they are less valid when examining a larger portfolio because the portfolio changes the market price assumption.

The *Energy Report* notes that:

> The state's energy objectives are broader than the IOU definition of least-cost, best-fit: they also include improving the security of a cost-effective supply under a range of uncertain but reasonably anticipated events, including:
>
> - Major disruptions in supply or extreme volatility in the price of a single fuel, such as natural gas.
> - Loss of access to or extended outage of a significant portion of a single technology type, such as nuclear.
> - Adverse hydro and/or extreme temperature conditions.
>
> The Energy Commission recommends the following to address concerns about portfolio fits and least-cost, best-fit criteria:
>
> - The CPUC, in collaboration with the Energy Commission, should pursue the additional development of portfolio approaches and risk assessment to create a more transparent and standardized method for determining what constitutes least-cost, best-fit. This would allow policy makers to better ensure that IOU resource selections reflect the state's interests in addressing future electricity risk and uncertainty.[46]

3.3. Greenhouse Gas Performance Standard

Governor Schwarzenegger has established aggressive greenhouse gas (GHG) emissions targets for California. For the state to meet these targets, electricity planning

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[45] *Upgrading California's Electric Transmission System: Issues and Actions for 2005 and Beyond*, July 2005, CEC-700-2005-018, attachment 3, *Risk, Portfolio Theory and Transmission Planning*.

[46] *Energy Report*, pp. 63-64.

and procurement will need to address greenhouse gas emissions. The CPUC has taken an important first step in this direction by addressing the potential financial risk IOUs face from future greenhouse gas policies by incorporating the "carbon adder" as part of the IOU evaluation of future procurement. Further steps are likely to be implemented in the future.

In the interim, California's utility procurement policy will affect achievement of its greenhouse gas reduction goals and may be a critical driver of "clean coal" technology development in the West. California has a critical interest in avoiding the severe consequences of climate change that have been identified for the state and compelling motivation to reduce greenhouse gasses. Without burdening interstate commerce or discriminating against particular technologies or fuels, the state should specify a greenhouse gas performance standard to be applied to all utility procurement, both in-state and out-of-state, both coal and non-coal.

The Committee held two days of workshops on August 17 and 18, 2005, seeking public comment on the technology, environmental and design permitting, and operational issues associated with state imports of electricity from coal-based generating plants in the Intermountain West region. The workshop included participation from representatives of the United States Department of Energy, the State of Wyoming, the Western Interstate Energy Board, the Western Governors' Association, industry, utilities, academic research institutes, and public interest groups. This workshop highlighted the advances being made in development of clean coal technologies. Many of the participants encouraged California to play an active role in the ongoing development of these advanced technologies, while acknowledging the need to address greenhouse gas emission issues.

While more specific recommendations will await the January 2006 report of Governor Schwarzenegger's Climate Action Team, the Energy Commission recommends that any greenhouse gas performance standard for utility procurement of long-term baseload resources be set so that greenhouse gas emissions are no higher than levels achieved by a new combined-cycle natural gas turbine. Additional consideration is needed before determining what role, if any, greenhouse gas emission offsets should play in complying with such a performance standard.

At its October 6, 2005 meeting, the CPUC responded to the *Draft Energy Report* and the letter from Energy Commission Chairman Joseph Desmond requesting input on the proposed greenhouse gas performance standard by adopting a resolution that, in part, directed its staff:

> … to investigate adoption by the PUC of a greenhouse gas emissions performance standard for IOU procurement that is no higher than the GHG emissions levels of a combined-cycle natural gas turbine for all procurement contracts that exceed three years in length and for all new IOU owned generation. In the case of coal-fired generation, the capacity to capture and store carbon dioxide safely and inexpensively is necessary to meeting the standard;
>
> … to investigate the integration of a GHG performance standard into the PUC's existing policies regarding GHG emissions including the environmental adder, the procurement incentives framework, as well as the work of the Governor's Climate Action Team and the [Energy Commission]. A critical step in this process will be to collect specific fuel type information for IOU procurement at a level of detail that will allow the State to ensure that the performance standard is met;
>
> … with the [Energy Commission], to investigate offset policies that are designed to ensure that the Governor's GHG goals are achieved. In addition, the PUC directs Staff to consider whether an offset policy would eliminate the important benefit of mitigating financial risk to California consumers of future GHG regulation and also significantly dampen the market signal for investment in new and improved technologies for clean generation. Finally, any offset policy must include a reliable and enforceable system of tracking emissions reductions.[47]

The Energy Commission looks forward to working with the CPUC to implement a greenhouse gas performance standard as part of the 2006 procurement proceeding.

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[47] California Public Utilities Commission, *Policy Statement on Greenhouse Gas Performance Standards*, October 6, 2005, pp. 2-3.

3.4. Transparency in Energy Planning and Procurement

As discussed previously in Section 2.3, the Energy Commission firmly believes that responsible and effective electricity resource planning should not and cannot exclude the public. The Energy Commission believes it is critically important to the integrity of the 2006 procurement proceeding that the CPUC refrain from relying on confidential data and confidentiality agreements that allow some participants but not others to review the information that is the basis of a CPUC decision. The *EAP II* also emphasizes the need for transparency in the energy planning process, stating that "We [the CPUC and the Energy Commission] pledge to remove the remaining barriers to transparency in the electricity resource procurement process in the State."[48] In addition, it says "We must streamline and make transparent all of our approval processes. . ."[49]

Two areas in which the confidentiality procedures of the CPUC are particularly troubling are in the determination of "least-cost, best-fit" and in the implementation of the renewable portfolio standard (RPS) program. Currently, determination of whether a particular resource meets least-cost, best-fit criteria is made entirely in secret, thus providing no information about how different attributes of projects are weighed against one another. Energy Commissioners, legislators, and members of the public have no way of knowing how least-cost, best-fit criteria are implemented for any given project. This severely undermines the credibility of these determinations; in fact, it is impossible to tell what criteria are used to approve resources procured by the IOUs. The Energy Commission has previously identified the significant benefits that accrue from the rigorous public scrutiny of data and planning assumptions and stated that when agencies cannot identify or discuss the information that underlies their decisions, they have lost the right to claim to be responsive to those who have a right to understand their decisions. The Energy Commission strongly encourages the CPUC to address this

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[48] *EAP II*, p. 2.

[49] *Id*. at p. 6.

now and to refrain from the use of procurement review groups, non-disclosure agreements, and other mechanisms that prohibit transparency in resource planning decisions.

The Energy Commission also notes that the process under which RPS procurement decisions are made is similarly shrouded in secrecy. As with least-cost, best-fit determinations, such decisions do not provide any information to the public, other agencies, or the Legislature about the criteria that that the utilities use or how these criteria are applied. The *Energy Report* noted the Energy Commission's concerns in this area:

> In the case of RPS procurement, for example, Energy Commissioners will ultimately make decisions about the expenditure of supplemental energy payments — awards of public funds — to renewable project developers. Under current confidentiality constraints, Commissioners are unable to review or scrutinize detailed information about IOU RPS solicitations, the application of least-cost, best-fit criteria, the terms and conditions of the full range of bids considered, and the contracts ultimately forwarded to the CPUC for approval. In this secretive environment, it is difficult for Commissioners to effectively ensure that public funds actually contribute to the state's RPS goals or constitute an appropriate expenditure of the state's limited subsidy funds for renewable resource development.[50]

The procurement of renewable resources is an important part of the state's energy policy goals and of the *Energy Action Plan*. It is critical that both the Energy Commission and the CPUC be able to demonstrate how they are implementing these objectives.

3.5. Departing Load

One key uncertainty facing the IOUs is the degree to which load may depart from their customer base to either new community choice aggregation providers or direct access providers. A number of the participants in the proceeding stated that

[50] *Energy Report*, p. 54.

because of concerns about this risk, IOUs are reluctant to enter into long-term contracts.[51] Multiple parties indicated that establishing the "coming and going rules" for future direct access is the best way to reduce any remaining uncertainty about future IOU loads. The CPUC's Office of Ratepayer Advocates (ORA), SCE, PG&E, SDG&E, and TURN generally agreed that there is more uncertainty about reentry rights than there is about the departure of loads to retail sellers other than the IOUs.[52] Since utilities are the providers of last resort, the conditions for returning to IOU service were seen as the most critical element of these rules.

ORA suggested its preference for reentry would be that once customers leave the utility, they should not be allowed to return. However, ORA did say it was open to solutions being pursued in other parts of the country to develop capacity markets and CA ISO back-stop strategies.[53] SCE and PG&E both indicated that, while at times their companies have considered the "once you're gone, you can't return" policy, they recognize that is not consistent with what their customers want.[54] SDG&E called for reasonable switching rules to address departing load uncertainty.[55] TURN expressed concerns about the ability to enforce such a rule in a situation where the IOU is the only entity that can serve the load.[56]

Because of the need to enter into long-term contracts and encourage construction of new facilities, the Energy Commission believes it is critically important that the CPUC establish a mechanism under which the IOUs are protected from costs associated with the long-term procurement of resources for load that may subsequently change

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[51] 7/7/05 RT, pp. 19, 91, 188, 189.

[52] Transcripts from the *Energy Report* Committee June 29, 2005 hearing on the IOU resource plans and the July 7, 2005 workshop on electricity policy issues.

[53] 6/29/05 RT, pp. 116-128.

[54] *Id.* at pp. 20-30; *Id.* at pp. 11-20.

[55] *Id.* at pp. 31-37.

[56] *Id.* at pp. 89-104.

service providers. The CPUC has already indicated that it is supportive of this concept, stating:

> In general we agree that the utilities should be allowed to recover their stranded costs from all customers, including an exit fee. Such an approach best meets the [CPUC's] goals of providing "the need for reasonable certainty of rate recovery" (as required under AB 57 and noted in the June 4th ACR) as well as best ensuring that California meets its energy needs.
>
> Requiring departing customers to assume a fair share of their costs is also consistent with the [CPUC's] policy of holding captive ratepayers harmless as required by state law.[57]

The Energy Commission strongly encourages the CPUC to begin the process of establishing rules to implement these goals as expeditiously as possible so that the risk of departing load can no longer be used to justify avoidance of long-term contracts. As stated in the *Energy Report:*

> The Energy Commission agrees with the CPUC's conclusion that establishing exit fees for departing load is the most equitable approach for meeting the goal for providing "the need for reasonable certainty for rate recovery" as well as ensuring that California meets its energy demand [fn: CPUC Decision 04-12-048, December 16, 2004, pp. 52 and 185]. The Energy Commission believes that the CPUC policy of establishing exit fees is sufficient to eliminate the lion's share of uncertainty about departing load, and is troubled that IOUs are using these concerns over departing load to avoid securing the significant long-term procurement California needs to meet California's growing electricity demand….
>
> Because the remaining uncertainty about departing load, especially return rights, is inhibiting investment in new generation, the Energy Commission makes the following recommendation:
>
> - The CPUC should begin immediately to establish appropriate coming and going rules for departing load. The CPUC should establish a schedule that would provide a sound set of departing load rules by the end of 2006.[58]

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[57] D.04-12-048, p. 52.

[58] *Energy Report*, pp. 58-59.

4. Procedural History on Demand Forecasts and Resource Plans

4.1. Demand Forecasts

As part of the *2005 Energy Report* process, all LSEs with annual peak demand greater than 200 MW were required to submit to the Energy Commission both retail price and electricity demand forecasts, along with supporting information.[59] LSEs with annual peak demand below 200 MW were deemed exempt for this proceeding. The Energy Commission Order required LSEs to submit their forecasts on Forms and Instructions (forms), which were published in draft form in September 2004, and discussed at workshops on September 20 (retail price) and September 21 (demand). The Energy Commission received the LSE forecasts in February 2005.

The adopted retail price forms directed all LSEs with a load of 200 MW or greater in 2003 or 2004 to file electricity revenue requirements for price forecast development, inputs, work papers, and related information by November 30, 2004.[60] The adopted forms also directed all LSEs with a load of 200 MW or greater in 2003 or 2004 to file the following information by November 24, 2004:

For IOUs:

Form 1.a: Total Electricity by Source and Revenue Requirement per Category, Bundled Customers.

Form 1.b: Electricity Sales and Revenue Requirements by Category, Bundled Customers by Customer Class.

Form 1.c: Electricity Sales and Revenue Requirements by Category, Bundled Customers by Rate Schedule.

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[59] *Order Adopting Demand Forecast and Price Information Forms and Instructions,* November 3, 2004.

[60] *General Instructions: Retail Electricity Price Forecast*, November 3, 2004.

For Publicly Owned Utilities:

Form 2.a: Total Electricity by Source and Revenue Requirement per Category.

Form 2.b: Electricity Sales and Revenue Requirements by Category by Customer Class.

Form 2.c: Electricity Sales and Revenue Requirements by Category by Rate Schedule.

For Energy Service Providers:

Form 3.a: Total Sales and Revenue Requirements by Category.

Form 3.b: Electricity Sales and Revenue Requirements by Category per Customer Class.

The following LSEs provided information on their revenue requirements:

IOUs:

- PG&E
- SCE
- SDG&E

Energy Service Providers:

- APS Energy Services
- Constellation NewEnergy
- Pilot Power Group
- Sempra Energy Solutions
- Strategic Energy

Publicly Owned Utilities:

- Anaheim Public Utilities Dept.
- City of Redding
- Glendale Public Service Department
- Imperial Irrigation District
- Los Angeles Dept. of Water & Power
- Modesto Irrigation District
- Pasadena Water & Power Dept.
- Riverside Utilities Dept.
- Roseville Electric Dept.
- Sacramento Municipal Utility District
- Silicon Valley Power
- Turlock Irrigation District

Energy Commission staff prepared its own forecast of electricity and natural gas demand for each of the planning areas in the state. These forecasts are based on sector specific energy consumption and peak demand models and used retail price forecasts compiled by Energy Commission staff using the revenue requirement information filed by the LSEs. Full documentation of the staff methods for preparing the demand forecast is provided in the *Energy Demand Forecast Methods Report*.[61]

The adopted demand forecast forms directed all load serving entities with a load of 200 MW or greater in 2003 or 2004 to file the following information by February 1, 2005[62]:

Form 1. Historic and Forecast Electricity Demand – annual sales and peak demand, private supply, and hourly loads

- Form 1.1 Retail Sales of Electricity by Sector.
- Form 1.2 Net Electricity for Generation Load (Including Departed Load).
- Form 1.3 Coincident Peak Demand by Sector.
- Form 1.4 Distribution Area Peak Demand.
- Form 1.5 Peak Demand Weather Scenarios.
- Form 1.6 Hourly Loads.
- Form 1.7 Local Private Supply by Sector.

Form 2. Forecast Input Assumptions - economic and demographic assumptions and electricity rate forecasts

- Form 2.1 State or National Economic and Demographic Inputs.
- Form 2.2 Planning Area Economic and Demographic Assumptions.
- Form 2.3 Electricity Rate Forecast and Natural Gas Price Forecast.
- Form 2.4 Customer Count and Other Forecasting Inputs.

Form 3. Demand Side Management (DSM) Program Impacts and Costs (Committed and Uncommitted), including demand response and distributed generation program impacts

- Form 3.1a Efficiency Program First Year Costs and Impacts by Sector.
- Form 3.1b Efficiency Program Costs by Cost Category.
- Form 3.2 Efficiency Program Cumulative Impacts.
- Form 3.3 Renewable & Distributed Generation Program Costs and Impacts.
- Form 3.4 Demand Response Program Costs and Impacts.

Form 4 Demand Forecast Methods And Models
Form 5 Demand-Side Program Methodology
Form 6 Uncertainty Analysis

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61 *Energy Demand Forecast Methods Report*, CEC-400-2005-036, June 2005.

62 Information on Forms 3 and 5 relating to uncommitted resources was due on March 1, 2005.

The following LSEs provided demand forecasts:

IOUs:
- PG&E
- SCE
- SDG&E

Energy Service Providers:
- APS Energy Services
- Constellation NewEnergy
- Pilot Power Group
- Sempra Energy Solutions
- Strategic Energy

Municipal utilities and irrigation districts:
- Anaheim Public Utilities Dept
- Burbank Water and Power
- City of Redding
- Glendale Public Service Department
- Imperial Irrigation District
- Los Angeles Dept, of Water & Power
- Modesto Irrigation District
- Pasadena Water & Power Dept
- Riverside Utilities Dept
- Roseville Electric Dept
- Sacramento Municipal Utility District
- Silicon Valley Power
- Turlock Irrigation District

The IOUs and energy service providers (ESPs) other than Pilot Power Group requested confidential treatment for much of the information provided. All three IOUs requested confidentiality for information on Forms 1.3, 1.4, 1.5, and 1.6. SCE also requested confidentiality for part of the information on Form 1.2, and SDG&E also requested confidentiality for the information in Form 2.3.[63] APS Energy Services, Constellation NewEnergy, Sempra Energy Solutions, and Strategic Energy all requested

[63] *California Energy Commission Order Denying Pacific Gas and Electric Company's Appeal of Executive Director Decision Denying Confidentiality*, docket 04-IEP-1D, April 13, 2005; *California Energy Commission Order Denying San Diego Gas and Electric Company's Appeal of Executive Director Decision Denying Confidentiality*, docket 04-IEP-1D, April 13, 2005; *California Energy Commission Order Denying Southern California Edison Company's Appeal of Executive Director Decision Denying Confidentiality*, docket 04-IEP-1D, April 13, 2005; *California Energy Commission Order Denying Constellation NewEnergy Inc.'s Appeal of Executive Director Decision Denying Confidentiality*, docket 04-IEP-1D, April 13, 2005; *California Energy Commission Order Denying APS Energy Services's Appeal of Executive Director Decision Denying Confidentiality*, docket 04-IEP-1D, April 13, 2005; *California Energy Commission Order Denying Strategic Energy LLC's Appeal of Executive Director Decision Denying Confidentiality*, docket 04-IEP-1D, April 13, 2005.

confidentiality for the information they provided on Forms 1.1, 1.3, 1.6, 2.3, and 2.4. Sempra also requested confidentiality for its information on Forms 1.4 and 1.5, and Strategic Energy requested confidentiality for Forms 4 and 6.

Based on Energy Commission regulations, the Executive Director granted an initial three-year term of confidentiality for IOU-supplied data on Form 1.5 demand forecast data, setting forth the peak demand resulting from "1-in-5," "1-in-10," and "1-in-20" temperature scenarios (those that can be expected to occur once in every five years, every 10 years, and every 20 years, respectively). The Executive Director also granted confidentiality for the hourly load forecast contained on Form 1.6, finding that the information can be used to calculate hourly "residual net short" forecasts, which would, by providing information about how much power the IOUs need at each hour during the year, give sellers and buyers a negotiating advantage.[64] However, the Executive Director concluded that remaining data were not entitled to confidential treatment because the annual net peak demand data on those forms are insufficient to arrive at the hourly "residual net short" forecasts.

The Executive Director granted an initial three-year term of confidentiality for the ESP-supplied data on Forms 1.6 and 2.4, along with IOU distribution service area allocation of ESP forecasts on Forms 1.1 and 1.3. The Executive Director denied confidentiality for the ESPs for data on Form 1.1 showing retail sales by customer class, data on Form 1.3 showing peak demand for all customers of the ESP, information on Form 4 regarding forecast methods, and information on Form 6 relating to uncertainties.[65]

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[64] While the Executive Director's determination stated that information about hourly loads could provide a competitive advantage to bidders, the Energy Commission itself has not addressed this issue.

[65] The denial of confidentiality for information on Forms 4 and 6 only relate to Sempra Energy Solutions. Pilot Power Group and Strategic Energy did not request confidentiality for the information they supplied on these two forms; APS and Constellation NewEnergy did not provide information on these forms.

The IOUs and ESPs appealed the determination that the load serving entities' forecasts of annual bundled customer peak demand were not confidential. The Energy Commission upheld the Executive Director's determinations at the April 13, 2005, business meeting. SCE filed a Petition for a Writ of Administrative Mandate in Sacramento Superior Court on June 9, 2005, seeking to set aside the Energy Commission's decision regarding the confidentiality of the annual peak demand.[66] No ESPs filed an appeal of the Energy Commission's decision.

Because the dispute over the confidentiality of the annual bundled customer peak forecasts provided by the IOUs has not yet been resolved, the Energy Commission is currently treating this information as confidential and has not considered the IOU-provided annual peak forecast in preparing the range of need. However, the dispute over the IOU-provided peak forecast does not affect the ability of the Energy Commission to publish its own staff-generated peak forecasts at either the planning area or bundled customer levels since these staff forecasts are prepared independently from the IOU-provided peak forecasts. Staff-generated peak forecasts are the basis of the demand forecast transmitted to the CPUC in this report.

The Energy Commission developed the electricity energy and peak demand forecasts for the state and for the three IOUs after consideration of separate forecasts prepared by Energy Commission staff and IOUs. These forecasts were presented at a June 30, 2005 workshop. Following discussion of the forecasts and key differences at the workshop and consideration of written comments, the *Energy Report* Committee directed staff to develop a revised set of forecasts that cover the range of likely demand for the state and for each of the IOUs. That revised forecast was published on September 26, 2005. Section 6 below discusses the different forecasts considered in June and the resulting revised forecast in more detail.

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[66] No action to resolve this appeal has yet occurred; thus, for the purposes of this *Energy Report* cycle, the peak demand forecasts prepared by the IOUs for their bundled customers are being treated as confidential.

4.2. Resource Plans

As part of the *2005 Energy Report* process, all LSEs with annual peak demand greater than 200 MW were required to submit to the Energy Commission a series of resource plans, along with supporting information. LSEs with annual peak demand below 200 MW were exempt from this requirement. Draft versions of the Forms and Instructions for these resource plans were published on December 10, 2004,[67] and discussed at a Committee workshop on December 21, 2004. Following this workshop, the Committee directed staff to publish revised forms that provided more information on the scenarios and uncertainty analyses being requested. The initial forms providing the reference case instructions were adopted by the Energy Commission on January 19, 2005, and the reference case filings were due March 1, 2005.[68] The supplemental instructions for the scenarios and uncertainty analyses were adopted March 2, 2005, and these filings were due on April 1, 2005.[69]

The adopted forms directed all load serving entities with a load of 200 MW or greater in 2003 or 2004 to file the following forms:

Form S-1: Capacity Resource Accounting Table.
Form S-2: Energy Balance Accounting Table.
Form S-3: Generic Renewable Capacity and Energy Locations.
Form S-4: Projected Qualifying Facility (QF) Energy and Costs.
Form S-5: Bilateral Contracts.

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[67] *Proposed Electricity Resource and Bulk Transmission Data Requests*, California Energy Commission staff report, 700-04-011, December 2004.

[68] *Forms and Instructions for the Electricity Resources and Bulk Transmission Data Submittal*, California Energy Commission, CEC-100-2005-002-CMF, January 2005; *Order Adopting Electricity Resource and Bulk Transmission Forms and Instructions*, California Energy Commission, January 19, 2005.

[69] *Supplemental Instructions and Errata to the Forms and Instructions for the Electricity Resources and Bulk Transmission Data Submittal*, California Energy Commission, CEC-100-2005-002-AD, March 2005; *Order Adopting Supplemental Electricity Resource and Bulk Transmission Forms and Instructions*, California Energy Commission, March 2, 2005.

On Form S-1, all LSEs were directed to provide a reference case estimating how much power, in megawatts, is needed to serve monthly peak retail customer load, plus reserves and other obligations, as well as identifying how much power will come from individual electricity supply resources classified in several categories. On Form S-2, the LSEs were 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. This capacity and energy information was required for all months of the forecast period, January 2006 through December 2016. With a few exceptions, such as hydroelectric resources and qualifying facility (QF) contracts, the LSEs were directed to provide these monthly values for individual power plants and individual contracts. Sample resource accounting tables showing the overall structure of Forms S-1 and S-2 are provided in Appendix A.

In addition to the reference case required of all LSEs, the IOUs were directed to provide a plan based on the accelerated renewables scenario recommended in the *2004 Energy Report Update*, which is aimed at PG&E and SDG&E achieving 33 percent renewable generation by 2020, and SCE, which has the greatest renewable potential in its service territory, achieving 35 percent by 2020.[70] In addition, if their reference case assumed a transmission project that upgrades the bulk transmission grid that has yet to receive regulatory approval, the IOUs were directed to provide a separate case without the transmission upgrade. SCE, whose reference case included completion of the Devers-Palo Verde No. 2 Project, and SDG&E, whose reference case included a 500-kV transmission project, both submitted cases without the upgrades. PG&E's reference case did not include a future major upgrade to the transmission system. The IOUs were also requested to provide their preferred resource plan in addition to the reference case. All three submitted such plans, though SCE and SDG&E indicated that these were alternate cases that did not necessarily represent the utility's preferred future. Finally, the

[70] *2004 Energy Report Update*, pp. 37-39.

reference case directed the IOUs to include certain assumptions about future departing load. The IOUs were invited to submit a case with different departing load assumptions if it would provide useful planning information. PG&E included a "core/non-core" case that assumed higher levels of departing load. Each of the three IOUs provided a total of four resource scenarios, as shown in Table 1. The first three cases are similar to all three IOUs, while the last is specific to each IOU.

Table 1: Resource Plan Scenarios Filed by the Investor-Owned Utilities

PG&E	SCE	SDG&E
♦ Reference case ♦ Accelerated renewables ♦ Preferred case ♦ Core/non-core	♦ Reference case ♦ Accelerated renewables ♦ Alternative case ♦ No transmission case	♦ Reference case ♦ Accelerated renewables ♦ Alternative case ♦ No transmission case

The following LSEs provided resource plans:

IOUs:
- PG&E
- SCE
- SDG&E

ESPs:
- APS Energy Services
- Constellation NewEnergy
- Pilot Power Group
- Sempra Energy Solutions
- Strategic Energy

Municipal utilities & irrigation districts:
- Anaheim Public Utilities Dept.
- Burbank Water and Power
- City of Redding
- Glendale Public Service Department
- Imperial Irrigation District
- Los Angeles Dept. of Water & Power
- Modesto Irrigation District
- Pasadena Water & Power Dept.
- Riverside Utilities Dept.
- Roseville Electric Dept.
- Sacramento Municipal Utility District
- Silicon Valley Power
- Turlock Irrigation District

The IOUs, the ESPs other than Pilot Power Group, and Imperial Irrigation District requested confidential treatment for much of the resource plan information they provided. Based on Energy Commission regulations, the Executive Director granted confidentiality for the information in Forms S-1, S-2, and S-3 for a period of three years (through the end of calendar year 2008),[71] and to the information in Forms S-4 and S-5 through the end of 2016 or to the end of the relevant contract period.[72] No appeals of these determinations were filed.

The Executive Director, pursuant to Energy Commission regulations on the treatment of confidential information (California Code of Regulations., title 20, section 2506), subsequently notified the IOUs and ESPs whose detailed resource plans had been designated confidential of his intent to release summary tables at a level of aggregation

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[71] As with the similar three-year confidentiality period applied to certain of the demand forms by the Executive Director, the question of the three-year confidentiality term allowed for Forms S-1, S-2, and S-3 was not raised to the Energy Commission.

[72] Letter from Energy Commission to PG&E (Exec. Direc. Determination) "Re: Application for Designation of Confidentiality for Electricity Supply and Uncertainties 2003-2016, Docket 04-IEP-1D," March 30, 2005; Letter from Energy Commission to SDG&E (Exec. Direc. Determination) "Re: Application for Designation of Confidentiality for Electricity Supply and Uncertainties 2003-2016, Docket 04-IEP-1D," March 30, 2005; Letter from Energy Commission to SCE (Exec. Direc. Determination) "Re: Application for Designation of Confidentiality for Electricity Supply and Uncertainties 2003-2016, Docket 04-IEP-1D," March 30, 2005; Letter from Energy Commission to APS Energy Services (Exec. Direc. Determination) "Re: Application for Designation of Confidentiality for Electricity Supply and Uncertainties 2003-2016, Docket 04-IEP-1D," May 26, 2005; Letter from Energy Commission to Constellation NewEnergy (Exec. Direc. Determination) "Re: Application for Designation of Confidentiality for Electricity Supply and Uncertainties 2003-2016, Docket 04-IEP-1D," April 28, 2005; Letter from Energy Commission to APS Energy Services (Exec. Direc. Determination) "Re: Application for Designation of Confidentiality for Electricity Supply and Uncertainties 2003-2016, Docket 04-IEP-1D," May 26, 2005; Letter from Energy Commission to Sempra Energy Solutions (Exec. Direc. Determination) "Re: Application for Designation of Confidentiality for Electricity Supply and Uncertainties 2003-2016, Docket 04-IEP-1D," April 27, 2005; Letter from Energy Commission to Strategic Energy (Exec. Direc. Determination) "Re: Application for Designation of Confidentiality for Electricity Supply and Uncertainties 2003-2016, Docket 04-IEP-1D," April 28, 2005.

that would "protect the confidentiality of any underlying data that is confidential."[73] The information that the Executive Director proposed to release in these tables would be collapsed from the original LSE filings in two dimensions. First would be the quarterly and annual aggregations of the monthly values initially submitted, with maximum values provided for capacity and a sum of the monthly values for energy. Second, the proposed aggregation would collapse the resource specific information such as individual power plants or individual contracts into general resource categories such as utility-controlled fossil resources or other bilateral contracts. These aggregation tables would be prepared for IOU bundled customers and separately for all customers in a larger "planning area" that includes ESPs and publicly owned utilities (POUs). The three IOUs separately appealed different portions of the proposal, and parties prepared and filed direct and rebuttal testimony. Following a hearing at the August 24, 2005, business meeting, the Energy Commission upheld the Executive Director's proposal at its September 7, 2005 business meeting.[74] On October 17, 2005, the three IOUs jointly filed a Petition for a Writ of Administrative Mandate in Sacramento Superior Court seeking to set aside the Energy Commission's decision.

In June, 2005, Energy Commission staff published those aggregated tables that none of the IOUs appealed.[75] This report was published in support of the June 29, 2005 committee hearing on the IOU resource plans. The following aggregated tables were published for each IOU for each of the four resource plan scenarios that were filed:

- Annual planning area capacity tables.
- Annual planning area energy tables.
- Annual bundled service customer energy tables.

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[73] *Energy Commission Executive Director Notice of Intent to Release Aggregated Data*, June 3, 2005, p. 1.

[74] *Commission Order Denying Appeals of San Diego Gas and Electric Company, Southern California Edison Company, and Pacific Gas and Electric Company of the Executive Director's Notice of Intent to Release Aggregated Data,* docket 04-IEP-1D, September 7, 2005.

[75] *Resource Plan Aggregated Data Result*, CEC-150-2005-001, June 2005.

The remaining tables (annual bundled service customer capacity and all quarterly tables) will not be published unless the dispute with the IOUs is settled in a manner that establishes that the information at that level of aggregation is not confidential.

5. Construction of the Range Of Need

In the March ACR, President Peevey noted that the Energy Commission would develop a transmittal report that would identify the likely range of statewide and IOU-specific need, discuss issues relevant to these determinations, respond to participant comments, and discuss how the Energy Commission reached its decisions.[76] President Peevey made clear the CPUC's intention to rely on determinations made in the *2005 Energy Report* proceeding regarding the range of need.

The Energy Commission has reviewed all of the publicly available demand forecast and resource plan information and the comments from the parties. Key Committee workshops and hearings and related staff reports considered in developing the range of need are shown in Table 2 below.

This section provides an overview of the method that the Energy Commission, after review of this record, used to construct the range of need. A more detailed discussion of specific issues raised in developing the range of need is included in the following sections.

[76] President Peevey ACR, R.04-04-003, March 14, 2005, p. 7.

Table 2: Key Hearings and Workshops

Hearing/ Workshop	Topic	Paper/ Report	Short title
Hearing June 29, 2005*	IOU Resource Plans	*Investor-Owned Utility Resource Plan Summary Assessment*	*RPSA Report*
		Resource Plan Aggregated Data Results (revised version published in November 2005)	*Aggregated Tables Report*
Hearing June 30, 2005*	Demand Forecasts	*California Energy Demand 2006-2016 - Staff Energy Demand Forecast, Staff Draft Report*	*Staff Draft Forecast*
		Energy Demand Forecast Methods Report	*Methods Report*
		Electricity Demand Forecast Comparison Report	*Comparison Report*
		California and Western Electricity Supply Outlook Report	*Western Supply Outlook*
Workshop July 7, 2005	Electricity Issues and Policy Options	*No staff papers or reports for this workshop*	
Workshop July 11, 2005	Energy Efficiency Electricity Policy Options and Issues	*No staff papers or reports for this workshop*	
Workshop July 25, 2005	Loading Order	*Implementing California's Loading Order for Electricity Resources*	*Loading Order Report*
Hearing July 26, 2005	California and Western Electricity Supply Outlook	*California and Western Electricity Supply Outlook Report*	*Western Outlook Report*
Hearing October 7, 2005*	Revised staff demand forecast (and *Draft Energy Report*)	*California Energy Demand 2006-2016 - Staff Energy Demand Forecast Revised September 2005*	*Revised Staff Forecast*

* - In the notices for these hearings, the Committee offered parties the opportunity to conduct cross examination on the use of models. No parties asked to conduct cross examination

5.1. Use of Revised Staff Demand Forecast

Following the June 30, 2005, hearing on demand forecasts, the Committee directed staff to prepare a revised forecast, which staff published in September, 2005.[77] This forecast includes a base case that incorporates various updates and corrections as specified by the Committee. The revised forecast report also presents high and low cases that incorporate the different assumptions about economic, demographic, and energy intensity trends that were key to the differences between the staff draft forecast and the forecasts filed by the LSEs. The differences between the staff draft forecast and the LSE forecasts and the Committee's direction for developing the forecast ranges are discussed in more detail in Section 6 below.

The Energy Commission is adopting the staff revised forecast as the starting point for determining the range of need. This forecast provides both annual peak and energy forecasts for the period 2006 through 2016 on planning area, service area, and bundled service customer levels. The IOU distribution service area includes both bundled and direct access customers, while the forecast planning areas for the IOUs generally correspond to the geographic areas that each IOU assesses in the transmission planning process, thus also including POUs. Staff prepared the forecasts at the planning area level. As described in the revised staff forecast report, the forecasts were then disaggregated to the service territory and bundled service customer level.[78] For both the energy and capacity forecasts for IOUs, the Energy Commission is using the bundled service customer disaggregation as the starting point for the range of need.

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[77] *California Energy Demand 2006-2016, Staff Energy Demand Forecast, Revised September 2005 (Revised Staff Forecast)*, California Energy Commission staff final report, CEC-400-2005-034SF-ED2.

[78] *Id.* at pp. 1-4.

The revised forecast includes a base case along with a high and low forecast. These three forecasts provide the variation that defines the range of need for each utility.

In its comments on the *Draft Transmittal Report*, SCE stated its belief that demand forecast models used by Energy Commission staff are "inherently flawed and should not be used as the basis for State forecasts."[79] SCE's comments also noted that its concerns about staff's forecasting methods dated to the common forecasting methodology proceedings in the 1980s and 1990s. The Energy Commission notes that, while SCE may have raised these types of detailed methodological concerns in previous decades, it failed to do so in the current *Energy Report* proceeding when the Committee held a hearing on June 30, 2005, on the *Draft Staff Forecast*, the *Methodology Report*, and the *Comparison Report.* SCE and other parties declined the opportunity to cross examine staff on its use of models at that hearing and subsequent hearings on October 7, 2005, on the *Revised Staff Forecast* and the *Draft Energy Report*, and on November 4, 2005, on the *Draft Transmittal Report*. The Energy Commission's decision to adopt the revised staff forecast in this proceeding is based on the substantial information developed in the record over the last year.

As discussed above, the forecasts incorporate efficiency and demand response programs for which funding has already been approved, such as the efficiency programs for 2006 through 2008. Efficiency and demand response programs for which program funding is not yet authorized should be considered as part of the future resource mix though they are not included within the demand forecasts. Alternative accounting practices followed by different parties yielded substantial confusion, such as SDG&E's inclusion of long-term (post-2008) energy efficiency program impacts in its demand forecast.

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[79] SCE, November 8, 2005, p. 4. (See Appendix C for a copy of this comment letter and Appendix D for the Energy Commission response.)

5.2. Treatment of Departing Load

In the *2005 Energy Report* proceeding, California's IOUs identified the risk of load departing to ESPs due to establishment of core/ non-core market rules, community choice aggregators (CCA), and POUs as their single greatest source of uncertainty in planning for and procuring future resources. Utilities argued that unless this issue is ultimately decided, they cannot engage in significant long-term procurement since they cannot accurately predict the amount of load they may lose. Their concern is that if a significant portion of their load migrates to a different supplier, they could end up over-procuring resources and incur the stranded costs of those resources. As discussed above, the *Energy Report* recommends that the CPUC promptly establish appropriate coming and going rules for departing load to address this uncertainty.

The resource plans filed by the IOUs in this proceeding made various assumptions about the level of departing load that they would face in the future. The resource plan forms and instructions directed IOUs to assume no additional migration between IOU and direct access services in the reference case and to assume a modest amount of community choice aggregation and POU departing load reaching between 4 percent and 10 percent by 2013.

The IOUs were also directed to report on the impact of other key uncertainties in addition to departing load. Uncertainties about resource portfolios include availability of large existing units (nuclear units and the Mojave coal-fired power plant); transmission upgrades; compliance options for meeting the RPS annual energy procurement obligations; and impact of a greenhouse gas adder on bid evaluation. The IOU responses generally recommend a mix of short-, mid-, and long-term contracts along with procurement flexibility as the preferred strategy.[80] Both SCE and SDG&E

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[80] The IOU responses are summarized in the *Revised Investor-Owned Utility Resources Plan Summary Assessment (RPSA Report)*, California Energy Commission staff report, CEC-700-2005-014, June 2005, pp. 95-101.

indicated that uncertainties would be reduced by the addition of their proposed bulk transmission connections to the Desert Southwest.

PG&E used the same planning area demand forecast in its four resource plan scenarios, which varied chiefly on the demand side by the amount of departing load. Compared with the reference case, PG&E's bundled service energy requirements were 12 percent lower in the preferred case (which it also used for its accelerated renewables case) and 17 percent lower in the core/non-core case in 2016.

SCE filed three resource cases to demonstrate the impact on future resource needs of Energy Commission-directed assumptions: the reference case both with and without the Palo Verde-Devers No. 2 transmission project and the accelerated renewables case. All cases used the same planning area base demand forecast, which assumed that load for Cerritos was departing. Compared with the reference case and accelerated renewables case, SCE's bundled service energy requirements were 9 percent higher in its alternate case in 2016 because that case assumes no community choice aggregator.

SDG&E filed three additional resource cases to demonstrate the impact on future resource needs of an Energy Commission-directed reference case: an alternative case without CCA departing load, an accelerated renewables case, and a no major transmission interconnection case. Planning area load forecasts were the same for all cases, with the alternative case having a 4 percent higher energy forecast for bundled service load due to lack of CCA departing load.

PG&E advocated using its preferred case, with its increased levels of departing load as the basis for resource acquisition rather than the more limited loss of load in the reference case. "PG&E has designed a portfolio to minimize the risk of stranded costs should PG&E experience substantial bundled-load departures in the future."[81] PG&E's approach is to reduce the risks of stranded costs. "Consistent with its long-term plan of

[81] PG&E April 1 filing, pp. 4-5.

July 2004, PG&E anticipates procuring long-term resources to meet its minimum expected future requirements to minimize the likelihood of incurring potential stranded costs. For levels of demand above this amount PG&E intends to procure shorter-term resources."[82] PG&E acknowledges the risk of under-procurement:

> Given the assumptions made on Demand Response, and CCA and non-core load migration there is a risk that procurement anticipated in the preferred portfolio may not be sufficient to meet actual requirements. Should there be less customer departure, higher load growth, or less Demand Response in the early years of the plan (up to 2010), PG&E would seek to contract with existing generation under short-term contracts to balance its requirements. Sustained loads above expected amounts after 2010 could be met by re-contracting with existing resources with expiring contracts or contracting with new resources. Conversely, if CCA or non-core departures are greater or if energy efficiency is more successful than assumed, short-term contracts would be allowed to expire when their terms are complete.[83]

PG&E recommends that the Energy Commission resist temptation to be overly prescriptive in its recommendations to the CPUC since procurement planning is an ongoing and dynamic process and resource plans need to be flexible to respond to changing conditions. Going forward, PG&E anticipates these changes: new resource adequacy requirements, CCA implementation rules, new legislation, a ballot measure on direct access and utility service, and future details on CA ISO market redesign.[84]

In their own cases, SCE and SDG&E preferred to have the flexibility to plan for no new departing load, though not a return to direct access. Generally, SCE warned that procurement based on resource plans with speculative assumptions entails reliability and price risks. SCE did not file a preferred plan because of the uncertainty associated with its customer base.

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[82] *Id.* at p. 12.

[83] *Id.* at p. 16.

[84] 6/29/05 TR, pp. 12-13.

> Since the CPUC is still determining the rules and processes for the formation of CCAs in R.03-10-003, there is currently insufficient information available to accurately assess which cities and counties may apply for CCA status. SCE does not currently have any conclusive evidence upon which it can make a reasoned assessment for planning purposes of the amount of departing load that may be experienced. Including speculative estimates for departing load in connection with CCAs and municipilization is risky for resource planning purposes. Insofar as any scenario is used to establish procurement limits, speculative assumptions concerning possible load migration could lead to reduced reliability and increased ratepayer costs.[85]

SDG&E took issue with departing load assumptions required in the various resource cases and requested that "In issuing the final [*Energy Report*], the [Energy] Commission should expressly recognize that certain forecasts contained in the Report do not necessarily constitute the forecasts that should be used for resource planning purposes."[86]

SDG&E explained its position in its April 1 filing:

> SDG&E believes it is not only prudent but mandatory for the local utility to plan for its entire existing load until a firm and binding commitment is made by a CCA and other required elements of the CPUC's CCA program have been fully implemented. This *resource planning assumption* does not mean that SDG&E opposes CCA or that SDG&E's Resource Plan cannot be adjusted should CCA load depart; rather, for *resource planning purposes* and to ensure that the utility continues to meet its obligation to serve and provide cost-effective, reliable electric service, at this time a no CCA departure assumption is the best course.[87]

In the June 29th hearing on the IOU resource filings, parties discussed the implications of departing load uncertainty on resource planning. Scott Cauchois, ORA, agreed it is difficult for the IOUs to predict what load will depart or return. He said that if one speculates that the CPUC will make the IOUs whole as promised, there's little risk to the IOU associated with load departing. ORA is more concerned with the

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[85] SCE April 1 filing, pp. 5-6.

[86] SDG&E, July 22 comments, pp. 1-2.

[87] SDG&E April 1 filing.

uncertainty of conditions under which existing and future departing load would return to IOU service compared with the potential problems of stranded costs. Would costs of serving the returning load be imposed on bundled customers or just the returning load? Because the conditions governing returning load are not established, IOUs can't really know now what risks they face. But their procurement can't ignore the possibility of load returning since they do have the obligation of being the provider of last resort.[88]

Stuart Hemphill, SCE, agreed that under-procurement due to uncertainty in returning load is more of a problem than over-procurement. "What happens in the retail structure defines how the wholesale structure will unfold, and how generation will be financed, and everything else."[89] SCE has presented proposals on coming and going rules in the CPUC record.[90]

Harold LaFlash of PG&E also agreed that stranded costs from over-procurement are a financial issue while under-procurement can make the lights go out. PG&E thinks the stranded cost and exit fee protections are very important, but they still are trying to be responsible about minimizing stranded costs.[91]

Steven Kelly, Independent Energy Producers Association (IEP), stated that the provider of last resort is really the CA ISO and that direct access load returning to IOU service is the same as the IOU under-scheduling in the CA ISO's markets. Hemphill responded that the CA ISO just determined it is other LSEs who are under-scheduling not the utilities.[92] All acknowledged that the resource adequacy protocols should fix the CA ISO's under-scheduling problem in the near term, which raised the question of whether resource adequacy rules are needed for a longer term than year-ahead. Kelly

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[88]6/29/05 TR, pp. 118-119.

[89] 6/29/05 TR, pp. 118 - 120.

[90] *Id.* at p. 131.

[91] 6/29/05 TR, pp. 120-121.

[92] 6/29/05 TR, pp. 122-123.

claimed: "Tradeable capacity markets will go a very long way . . . to relieve some of the concerns." Hemphill said that the industry doesn't necessarily need longer than one-year resource adequacy requirements or capacity markets if the coming and going rules of retail direct access are "appropriately" structured with new investment constraints in mind—"retail structure is the defining element for this industry in California."[93]

Similar themes were raised at the July 7th electricity policy workshop regarding the need to stabilize retail market rules. Robert Anderson of SD&GE said, "If we had core/non-core settled, we would have three- and four-year contracts signed."[94] SDG&E supported customer choice, but said that three things have to happen first: fix the flaws in the CA ISO/market structure, ensure adequate supply by implementing resource adequacy, and eliminate perverse price signals such as capped customer rates caused by Assembly Bill 1X (Chapter 4, Statutes of 2001, Keeley).[95]

Local Power comments for Women's Energy Matters asserted that the IOUs' resource plans don't reflect as much departing load as Local Power believes will occur, based on publicly available information. If IOU procurement is based on the reference case resource plans, the IOU will over procure, and the departing load will get stuck with the cost of the IOU stranded investment. Local Power claimed that 20 percent of California IOU load is in various stages of CCA.[96]

In its comments on the *Draft Transmittal Report*, Constellation stated that the "Departing load assumptions and the resultant resource procurements will negatively impact retail market development."[97] The Energy Commission is concerned that uncertainty over departing load continues to hinder long-term investment in new

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[93] *Id*. at p. 127.

[94] 7/7/05 TR, pp. 188-189.

[95] 7/7/05 TR, pp. TR pp. 128-132.

[96] Paul Fenn, Local Power comments for Women's Energy Matters, June 28, 2005, pp. 2, 3.

[97] Constellation, November 8, 2005, p. 7. (See Appendix C for a copy of this comment letter and Appendix D for the Energy Commission response.)

infrastructure. Constellation stated that procurement based on an assumption of no departing load, as developed in the *Transmittal Report*, will result in over-investment by the IOUs. The Energy Commission believes the much greater risk is that of under-investment resulting from no LSE taking responsibility for procuring resources for future demand because of uncertainty over who will be serving load in the future.

Based on the input received during the *2005 Energy Report* proceeding, the Energy Commission decided that the revised forecasts upon which resource plans should be based should not include any departing load. While this approach does leave some risk that the utilities may procure resources for a larger customer base than remains in place over time, the Energy Commission believes that once the CPUC establishes appropriate coming and going rules for departing load as it signaled it would do in D.04-012-004, the resulting financial risk to the IOUs and their ratepayers is acceptable. For the IOUs to procure based on an assumption that a significant portion of their customers will depart to other providers raises much greater reliability and adequacy risks and potential for under-procurement.

5.3. Demand Response and Energy Efficiency

Demand response and energy efficiency are the top resources in the loading order. The CPUC and Energy Commission are both dedicated to ensuring that these resources be developed to the maximum extent feasible. In constructing the range of need below, the Energy Commission has included in the demand forecasts the efficiency programs for the years 2006 through 2008, whose funding the CPUC has approved. Efficiency programs for 2009 and beyond, for which the CPUC has not yet approved funding, are not included in the demand forecast. Rather, these are included in the resource plans, with the expectation that the CPUC will approve future utility programs to assure that the level of efficiency procured is optimized. The current targets for efficiency are identified as part of the resource mix the IOUs will use to meet the identified need.

SDG&E expressed "serious concerns regarding the combination of the load forecast and uncommitted energy efficiency (EE) amounts used in the report for years

2009 – 2016…. [SDG&E] believes future EE efforts are already embedded in the Staff load forecast. However, the report also shows the full amount of future EE goals as a resource."[98] The Energy Commission understands that the goals as established in the CPUC energy efficiency proceeding did not have a clearly documented baseline demand forecast against which to measure, which may lead to problems when applying them to a specific demand forecast such as the revised staff forecast the Energy Commission is adopting. Resolving this issue is beyond the scope of this report and is more appropriately addressed in the CPUC energy efficiency proceeding. To the extent that the CPUC goals are adjusted in the future, these adjustments can and should be reflected in the tables.

The Energy Commission recommends a similar approach for demand response as for energy efficiency, with demand response programs incorporated into the future Energy Commission demand forecasts as funding is approved. Targets for future programs that have not yet been funded are identified as part of the resource mix the IOUs are expected to use to meet identified need.

The term "demand response" encompasses a variety of programs, including traditional direct control (interruptible) programs and new price-responsive demand programs. A key distinction is whether the program is dispatchable. Dispatchable programs such as direct control, interruptible tariffs, or demand bidding programs, have triggering conditions that are not under the control of and cannot be anticipated by the customer. Energy or peak load saved from dispatchable programs is treated as a resource and is therefore not accounted for in the demand forecast, whether resulting from an existing funded program or a speculative program conceived to satisfy overall demand response goals created by D.03-06-032. Nondispatchable programs are not activated using a predetermined threshold condition but rather allow the customer to

[98] SEU/SDG&E, November 8, 2005, p. 2. (See Appendix C for a copy of this comment letter and Appendix D for the Energy Commission response.)

make the economic choice whether to modify usage in response to ongoing price signals. Impacts from committed nondispatchable programs should be included in the demand forecast.

At this time all existing demand response programs are dispatchable programs that have some form of triggering condition. The utility or CA ISO can call on these resources because of high market prices or resource scarcity. The customer only has the opportunity to participate in the program when the program operator has called an event. Therefore, no demand response impacts are counted in the demand forecasts adopted in this proceeding. If appropriate demand response tariffs are instituted, then their impacts will be incorporated in future demand forecasts.

These existing interruptible programs are one of the resources that the IOUs can call on at times of peak demand when the supply/demand balance is tight. Consistent with the counting conventions being established in the CPUC's resource adequacy proceeding, the Energy Commission is including the capacity covered under these programs as a supply resource when calculating the capacity supply/demand balance in the need tables. The Energy Commission notes that, to date, there has been little progress made by the IOUs toward meeting the demand response goals. As stated in the *Energy Report*, the Energy Commission recommends:

- The CPUC and Energy Commission should closely monitor investor-owned utilities' energy efficiency programs to ensure that peak energy savings are captured in their respective efficiency portfolios….
- The CPUC and the Energy Commission must vigorously pursue actions to ensure that the state's demand response goals are met.[99]

5.4. Evaluation of Resource Plan Information

As previously indicated, the utility resource plans included detailed information on their existing and planned resource base. Each of the IOUs submitted four separate resource plan scenarios in early 2005. Three of the four scenarios were common to the

[99] *Energy Report*, p. E-6.

three IOUs: a reference case specified in the forms and instructions, a "preferred" or "alternate" case developed by the utility, and an accelerated renewables case. For PG&E, the fourth scenario was a core/non-core case. For SCE, the fourth assumed that the Devers-Palo Verde No. 2 line did not come into service. For SDG&E, the fourth assumed that the generic 500-kV transmission line included in the other cases did not come into service.

Two general comments are necessary to describe how resource plans have been evaluated. First, no monthly or quarterly data was made public, so the Energy Commission worked only with annual data. Second, differences among the scenarios on the demand side (for example, level of departing load assumed) are not considered because the Energy Commission has decided to use the revised staff forecast as the basis for the demand numbers in calculating the range of need.

In evaluating the resource plan energy data for calculation of the range of need, the Energy Commission used the tables of annual aggregated energy data for the IOU bundled service customers for the years 2009 through 2016, as published in November, 2005, in the revised *Aggregated Tables Report*, which included some minor corrections to the original tables.[100]

On the capacity side, the Energy Commission had to be selective due to confidentiality constraints. Two sources of public capacity data were included in the record. First, each of the IOUs provided a public table with a limited amount of information on the annual capacity of some key resources for the years 2009 through 2016 when they filed their resource plans in early 2005.[101] This information included the annual peak capacity of utility controlled fossil, nuclear, and hydro resources, along with the peak capacity for each of the Department of Water Resources (DWR) contracts

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[100] *Resource Plan Aggregated Data Results (Aggregated Tables Report)*, California Energy Commission revised staff report, CEC-150-2005-001-REV, November, 2005.

[101] The public tables filed by the three IOUs for capacity and energy resources were published in Appendix B of the *RPSA Report.*

assigned to that IOU. With the exception of the DWR contracts, no information on contractual resources was in these public tables.

Second, the *Resource Plan Aggregated Data Results* included planning area capacity tables for the years 2009 through 2016. For each of the IOUs, the aggregated planning area tables totaled the annual capacity values provided by that IOU, by any publicly owned utilities located within their portion of the CA ISO control area, and by a share of the ESP resources.[102] Because only the IOUs hold DWR contracts and QF contracts within their planning areas, the totals shown in the aggregated capacity tables for these two categories are specific to the IOU's bundled customers. For the three remaining categories of resources (renewables contracts, other bilateral contracts, and spot market/ short term purchases), these annual aggregated numbers, which include IOUs, ESPs, and POUs, were the only information in the public record on the capacity values at the time the *Draft Transmittal Report* was published. Because none of the POUs requested confidentiality for the level of data shown in the aggregated tables, the Energy Commission stated its intent to include in the final *Transmittal Report* tables showing the POU data that was included in the planning area capacity aggregation tables in these two categories and to subtract the POU shares from the planning area totals to produce a "distribution service area" version of the tables that shows the sum of the IOU data and appropriate shares of the ESP data. The Energy Commission specifically invited comment on this plan at the November 4, 2005, hearing on this *Draft Transmittal Report*. Because no parties commented on this plan at the hearing or in written comments, the Energy Commission is showing distribution service area level data for renewables contracts and other bilateral contracts in the tables in Appendix B.

Interruptible load programs provide another resource available to the IOUs in meeting extreme peak demand. The IOUs included in their resource plans the amount

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[102] The ESPs allocated their loads among the three IOUs in their demand forecast forms. These proportions were used to allocate their resources to the different IOUs planning areas.

of capacity available under existing interruptible load programs. These programs are considered part of the resource base for meeting the 15 percent planning reserve requirements under resource adequacy.

When the existing utility resource base, existing contracts, planned resources, and interruptible load programs are compared against the demand forecast on a year by year basis, an initial estimate is established of the amount of energy and capacity the utilities will need to acquire simply to meet projected demand. This supply/demand balance provides a starting point for the determination of need for each IOU. Because the resource numbers included here are based on plans developed by the IOUs in early 2005, as discussed below, these numbers will need to be updated during the CPUC's 2006 procurement proceeding.

This supply/demand balance does not exactly match the balance suggested in the structure of forms S-1 and S-2 and used in the aggregated data tables.[103] The forms included short-term and spot market purchases as part of the total existing and planned energy. With those purchases included, a total generic resource need was calculated on forms S-1 and S-2 by subtracting the total existing and planned resources from the firm peak energy or capacity requirement. In calculating future resources needs for this report, these short-term and spot purchases have not been included in the existing and planned resource mix. The equivalent of the supply/demand balance calculated here would be the sum of the short term and spot market purchases and the generic resource needs submitted to the Energy Commission in the resource plan filings.

In addition, the Energy Commission has also evaluated the public aggregations of the resource plan information provided by the LSEs, along with staff's assessment of the degree to which those plans comply with the state's policy guidance and the comments received on these topics. As discussed below, the Energy Commission has identified amounts of preferred resources (efficiency, demand response, and

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[103] *Aggregated Tables Report.*

renewables[104]) that the utilities should consider as the first step in meeting their resource needs. The IOUs should tailor their procurement of other resources on the assumption that at least these preferred levels of loading order resources will be achieved. The Energy Commission expects that direction to the utilities in obtaining these loading order resources will not necessarily come from the 2006 procurement proceeding itself, but from related proceedings such as R.01-08-028 on energy efficiency, R.02-06-001 on demand response, and R.04-04-025 on the RPS. Thus, the procurement direction given to the IOUs in the 2006 procurement proceeding needs to be designed to automatically adjust when other proceedings change the preference levels for loading order resources.

The Energy Commission notes that the CPUC included strong support for the loading order resources in its procurement decision last year:

> As stated above, following the "loading order" contained in the *EAP* is the first priority for IOU resource procurement, meaning that [energy efficiency] and demand-side resources should be employed first. When these opportunities are captured, renewable generation is to be procured to the fullest extent possible – whenever an IOU issues [a request for offers (RFO)] for generation resources, it must be prepared to defend its selection of fossil generation over renewable generation offers. In other words, selection of renewable generation is the rebuttable presumption guiding IOU generation procurement.[105]

Such policies as the "rebuttable presumption" in favor of procurement of new renewable resources included in the CPUC's D.04-12-048 or the establishment of higher energy efficiency goals in the future could result in higher levels of procurement of these resources and correspondingly lower levels of additional undesignated need.

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104 Distributed generation is also one of the preferred resources, but no targets have been set for the IOUs. As discussed above, the Energy Commission recommends that IOU-specific targets be established by the Energy Commission and CPUC by the end of 2006. Once those targets are established, the amounts should be included in the preferred resource totals.

105 D.04-12-048, p. 77.

5.5. Aging Power Plants

In the *Energy Report*, "the Energy Commission recommends that the state's utilities undertake long-term planning and procurement that will allow for the orderly retirement or repowering of the aging power plants in [the *2004 Energy Report Update*] study group by 2012."[106] This study group included only natural gas-fired power plants of 10 MW or greater that were built before 1980. Peaking plants were excluded, as were any plants known at the time to be scheduled for retirement in the near term. Power plants in this pool are listed in Appendix A, along with their capacities and average generation during the years 2002 through 2004. Excluding the plants in the study group that are owned by POUs, this pool includes 50 power plants.

Because most of these plants have been relied upon in recent years primarily to meet peak demand, the Energy Commission recommended in the *2004 Energy Report Update* that the state's utilities "work aggressively to implement demand response programs to attain the 2007 statewide goal of reducing peak demand by 5 percent."[107] To the extent that these plants can be replaced by demand response programs, efficiency programs, renewable resources, CHP, and an appropriate level of conventional power plants, the state will see significant benefits in terms of reliability, reduced reliance on natural gas, reduced greenhouse gas emissions, and other environmental benefits.

To facilitate the retirement of these aging power plants, the Energy Commission has apportioned these 50 plants to the three IOUs based on their physical location, along with their existing capacity and the average energy produced in 2002 through 2004. In order to ensure that sufficient investment takes place in the next round of procurement to provide for the orderly replacement of the retiring plants with new resources, the Energy Commission is reporting in the procurement need tables and

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[106] *Energy Report*, p. 178.

[107] *2004 Energy Report Update* p. xvi.

graphs the average energy generation for 2002 through 2004 and the amount of the existing capacity of these plants. Some time will be needed to bring any new generation on line to replace these plants. Therefore, to facilitate an orderly transition to the retirement of these plants by 2012, the Energy Commission is including a four-year ramp-up of this increment, starting with 25 percent of the utilities' share of energy or capacity in 2009, and increasing to 50 percent, 75 percent and the full share in 2010, 2011, and 2012, respectively.

The Energy Commission is reporting the aging plant replacement energy and capacity amounts in this manner to emphasize the need for IOU planning and procurement activities in the 2006 procurement cycle to accommodate the recommended replacement of all of these aging plants. Because continued reliance on these plants is not in the economic interest of IOU customers, it would be imprudent for the IOUs to contract with the aging units beyond that time.

5.6. Resource Needs

The tables and figures in Appendix B provide a preliminary evaluation of the procurement needs for the IOUs based on the revised staff demand forecast and the resource plan information prepared by the IOUs in early 2005. For energy, this need is simply the different between the total energy requirement and the total existing and planned energy resources. On the capacity side, the existing interruptible program capacity is included with the total existing and planned capacity, and all of these are subtracted from the firm peak requirement to calculate the supply/demand balance.

California has established a loading order for future resources needed to meet the state's electricity demand. As stated in *Energy Action Plan II*:

> The loading order identifies energy efficiency and demand response as the State's preferred means of meeting growing energy needs. After cost-effective efficiency and demand response, we rely on renewable sources of power and distributed generation, such as combined heat and power applications. To the extent efficiency, demand response, renewable resources, and distributed generation are unable to satisfy increasing energy and capacity needs, we support clean and efficient fossil-fired generation. Concurrently, the bulk electricity transmission grid and distribution facility infrastructure must be

improved to support growing demand centers and the interconnection of new generation, both on the utility and customer side of the meter.[108]

The CPUC and the Energy Commission share a commitment to implementing the loading order. To aid this process, the Energy Commission has included identification of preferred resources on the tables showing the range of need. For energy needs, these preferred resources include uncommitted energy efficiency programs, renewable resources, and distributed generation such as combined heat and power. For capacity needs, these preferred resources include uncommitted energy efficiency programs, uncommitted dispatchable demand response, renewable resources, and distributed generation such as combined heat and power.

The Energy Commission directed the IOUs to assume in their reference case resources plans that the efficiency targets for both peak demand and energy established by the CPUC in D.04-09-060 would be met. While the targets for each IOU represented the cumulative savings expected from IOU efficiency programs starting in 2004, the IOUs were directed to include the committed savings from those programs whose funding had at the time been approved (that is, 2004 and 2005 programs) in their retail load and sales forecasts.[109] These reference case efficiency totals reported by the IOUs are the basis for the energy efficiency numbers in the preferred resource category of the need tables. Because the CPUC has now approved funding for the energy efficiency programs for 2006 through 2008 and the resulting savings are incorporated into the revised staff forecast, the numbers reported by the utilities in their resource plan filings have been reduced by the amount of the savings through 2008. In addition, PG&E included programs for 2009, 2010, and 2011 in its demand forecast rather than as uncommitted energy efficiency. Inclusion of these future public-goods charge programs

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[108] *EAP II.*

[109] *Forms and Instructions for the Electricity Resources and Bulk Transmission Data Submittal*, California Energy Commission, CEC-100-2005-002-CMF, January 2005, p. 11.

resulted in an additional 527 GWh of annual energy savings and 98 MW of annual capacity savings in the total.

The demand response targets for capacity are calculated based on achieving the 5 percent demand response goal for 2007 and beyond, measured against the full demand in each IOU's distribution service area as directed by D.03-06-032.

Among the resource plan scenarios the Energy Commission directed the IOUs to file was one reflecting the accelerated targets recommended by the Energy Commission in the *2004 Energy Report Update*, which aim at PG&E and SDG&E achieving 33 percent renewables by 2020, and SCE, which has the greatest renewable potential in its service territory, achieving 35 percent by 2020.[110] The IOUs all filed this scenario, while generally questioning the feasibility and advisability of attempting to reach the accelerated targets. The Energy Commission recognizes that the CPUC currently lacks statutory authority to require the IOUs to procure more than 20 percent of their demand from renewable resources. While the CPUC cannot require the utilities to go beyond 20 percent, the CPUC can work to ensure that they do not prematurely buy non-renewable resources beyond 2010 to a degree that would preclude renewables beyond 20 percent.

The Energy Commission is including in the preferred resource category the amount of renewable energy and capacity identified by the IOUs as necessary to meet the accelerated targets. The Energy Commission recognizes that these scenarios were not based on the revised staff demand forecasts and that the trajectory of that level of future purchases would not be 33 percent of demand in 2020 when using the revised staff forecast. Nonetheless, the primary purpose of identifying a preferred level of renewable resources on the need tables is to avoid procuring so much in additional undesignated resources that renewable purchases to meet future targets are precluded. Therefore, the Energy Commission considers the generic renewable resources identified by the IOUs in their accelerated renewables cases to be a useful benchmark. The Energy

[110] *2004 Energy Report Update*, pp. 37-39.

Commission described this approach in the *Draft Transmittal Report* and invited comments on this approach and any recommendations for alternate approaches to determining the amount of preferred renewables to include in the need tables. No parties commented on this approach.

The difference between the preferred resource targets and the total need shown in the tables is the target amount that the IOUs should be planning to procure through procurement activities for undesignated needs, with the understanding that the resource plan information will need to be brought up to date during the CPUC's 2006 procurement proceeding. The Energy Commission emphasizes that these activities should not preclude additional energy efficiency, demand response, renewable projects, and distributed generation beyond the targets identified in the preferred resource category. The Energy Commission views those targets as the floor and not the ceiling for acquisition of efficiency, demand response, renewable resources, and distributed generation. Further, the Energy Commission is not specifying how undesignated resource needs should be acquired. The Energy Commission believes it is appropriate that the 2006 procurement proceeding determine how resources are acquired.

5.7. Sample Range of Need

The following tables illustrate the calculation of the range of need, using numbers for PG&E for the year 2012 as an illustration. Tables and figures showing each year and the low, base, and high demand cases are presented for each IOU in Appendix B.

The calculation of the energy need is illustrated in Table 3 and of the capacity need in Table 4. Both tables use the base forecast and PG&E's resource status for 2012 as an example. The revised staff forecast includes low and high cases as well as the base case. The difference in demand among these cases provides the variation within the range of need, while the existing and planned utility resources are the same in the three cases.

For the capacity tables, IOU-specific numbers for renewables contracts and other bilateral contracts are not currently in the public record. The tables that were included in this draft report showed the planning area values that were included in the aggregated tables.[111] These numbers included data from the IOU, from ESPs in proportion to the load they serve in that service territory, and any POUs that are located within that IOUs portion of the CA ISO control area. None of the POUs within the CA ISO control area requested confidentiality for their resource plan filings. As stated in the *Draft Transmittal Report*, the Energy Commission has included in this final version of the report the data on renewables contracts and other bilateral contracts for those utilities. By subtracting those public values from the previously published planning area totals, the Energy Commission is now showing the distribution service area level capacity data for these resources.

[111] *Aggregated Tables Report*.

Table 3: Energy Range of Need Calculation Example

PG&E Energy for 2012, revised staff forecast base case (GWh)

		Base case	Source/explanation
	ENERGY DEMAND (GWh)		
a)	Net Energy for Bundled Customer Load	89,069	Staff revised forecast
b)	Firm Sales Obligations	413	Aggregated data tables (3)
c)	**TOTAL ENERGY REQUIREMENT**	**89,482**	***Sum of a) and b)***
	EXISTING & PLANNED RESOURCES		
	Utility-Controlled Physical Resources		
d)	Nuclear	16,797	Aggregated data tables (3)
e)	Fossil (2)	173	Aggregated data tables (3)
f)	Total Hydro Energy Supply	15,061	Aggregated data tables (3)
g)	**Total Utility-Controlled Physical Resources**	**32,030**	**Sum of d) through e)**
	Existing and Planned Contractual Resources		
h)	Total Energy Supply from DWR Contracts	1,190	Aggregated data tables (3)
i)	Total Energy Supply from QF Contracts	19,769	Aggregated data tables (3)
j)	Total Existing & Planned Renewable Contracts	528	Aggregated data tables (3)
k)	Total Energy from Other Bilateral Contracts	1,063	Aggregated data tables (3)
l)	**Total Contractual Resources**	**22,550**	**Sum of h) through k)**
m)	**TOTAL EXISTING & PLANNED ENERGY RESOURCES**	**54,580**	**Sum of g) and l)**
n)	**TOTAL PROCUREMENT NEED**	**34,902**	***Difference of c) and m)***
	ADDITIONAL PREFERRED RESOURCES		
o)	Uncommitted Energy Efficiency	4,204	Uncommitted energy efficiency reported by IOU, adjusted for inclusion of committed 2006-2008 programs being included in demand forecast (5)
p)	Renewables	7,890	Generic renewables reported by IOU for accelerated renewables case, reported in aggregated data tables
q)	Distributed Generation/ CHP	*Target to be developed by Energy Commission and CPUC in 2006*	
r)	**TOTAL ADDITIONAL PREFERRED RESOURCES (1)**	**12,094**	***Sum of o) through q)***

Table 3: Energy Range of Need Calculation Example (continued)

s)	**ADDITIONAL NON-DESIGNATED NEED (1)**	**22,808**	***Difference of n) and r)***
t)	**Aging Plant Replacement**	**7,969**	average annual generation from the aging plants located in the service territory of that IOU for the years 2002 through 2004(4)

Notes:

(1) - The total additional preferred resources will increase and the additional non-designated need will decrease when DG/CHP targets are established in 2006, since a portion of the undesignated need will be designated to DG/CHP.

(2) - In its reference case, PG&E did not include any energy values for the Humboldt Bay replacement project, though it included 150 MW of capacity. The Energy Commission is including the fossil resource energy values that PG&E filed with its preferred, accelerated renewables, and core/non-core cases.

(3) - Data from aggregated data tables are based on IOU filings for the reference case, except as noted. These data are based on the LSE resource plans that were prepared in early 2005, and so do not reflect any changes, such as new contracts, that have occurred during 2005. These data will need to be updated as part of the CPUC's 2006 procurement proceeding. (Source: *Resource Plan Aggregated Data Results (Aggregated Tables Report)*, California Energy Commission Revised Staff Report, CEC-150-2005-001-REV, November, 2005.)

(4) - The aging plant replacement ramps up to the full share in 2012. For 2009, the value is 25 percent of the full share, for 2010 it is 50 percent, and for 2011 it is 75 percent.

(5) These values are calculated from Tables 2-3, 2-9, and 2-13 in the *RPSA Report* and IOU comments on that report. Because the demand forecast includes programs through 2008, the first-year GWh savings through 2008 are subtracted from the cumulative totals from line 1.

Table 4: Capacity Range of Need Calculation Example

PG&E Capacity for 2012, base case demand forecast (MW)

		base case	Source/explanation
	PEAK DEMAND (MW)		
a)	Peak Service Area Demand (base case) (1)	20,256	Staff revised forecast
b)	Peak Bundled Customer Demand (base case)	18,872	Staff revised forecast
c)	Reserve Margin (at 15 percent)	2,831	15 percent of b)
d)	Firm Sales Obligations	0	Aggregated data tables (4)
e)	**Firm Peak Requirement**	**21,703**	***Sum of b) through c)***
	EXISTING & PLANNED CAPACITY		
	Utility-Controlled Physical Resources		
f)	Nuclear	2,214	IOU public capacity tables (4)
g)	Fossil	150	IOU public capacity tables (4)
h)	Total Dependable Hydro Capacity	4,734	Aggregated data tables (4)
i)	**Total Utility-Controlled Physical Resources**	**7,098**	**Sum of f) through h)**
	Contractual Resources		
j)	DWR Contracts	263	IOU public capacity tables (4)
k)	QF Contracts	2,517	IOU public capacity tables (4)
l)	Renewable Contracts (2)	103	Aggregated data tables (4)
m)	Other Bilateral Contracts (2)	1,268	Aggregated data tables (4)
n)	**Total Contractual Resources**	**4,151**	**Sum of j) through m)**
o)	**TOTAL EXISTING & PLANNED CAPACITY**	**11,248**	***Sum of i) and n)***
p)	**Existing Interruptible/ Emergency Programs and Dispatchable Demand Response**	**374**	IOU public capacity tables (4)
q)	**TOTAL PROCUREMENT NEED**	***10,080***	***Difference of e) and total of o) and p)***
	ADDITIONAL PREFERRED RESOURCES		
r)	Uncommitted Energy Efficiency	1,095	Uncommitted energy efficiency reported by IOU (7)
s)	Uncommitted Dispatchable Demand Response (8)	1,165	CPUC target of 5% of service territory load shown in a)
t)	Renewables	1,017	Generic renewables reported by IOU for accelerated renewables case, reported in aggregated data tables (6)
u)	Distributed Generation/ CHP	*Target to be developed by Energy Commission and CPUC in 2006*	
v)	**TOTAL ADDITONAL PREFERRED RESOURCES (3)**	**3,277**	***Sum of r) through u)***

Table 4: Capacity Range of Need Calculation Example (continued)

w)	**ADDITIONAL UNDESIGNATED NEED (3)**	**6,804**	***Difference of q) and v)***
x)	**Aging Plant Replacement**	**4,900**	capacity of the aging plants located in the service territory of that IOU (5)

Notes:

(1) - Peak distribution service area demand is used for calculation of the uncommitted dispatchable demand response targets.

(2) - Distribution service area data are presented here because the IOU bundled customer data are confidential.

(3) - Total additional preferred resource will increase and the additional undesignated need will decrease when DG/CHP targets are established in 2006, since some undesignated need will be designated to DG/CHP.

(4) - Data from aggregated data tables or IOU public capacity tables are based on IOU filings for the reference case, except as noted. (Source: *Resource Plan Aggregated Data Results (Aggregated Tables Report)*, California Energy Commission Revised Staff Report, CEC-150-2005-001-REV, November, 2005.)

(5) - The aging plant replacement ramps up to the full share in 2012. For 2009, the value is 25 percent of the full share, for 2010 it is 50 percent, and for 2011 it is 75 percent.

(6) - These values may include contractual resources held by the publicly owned utilities in the PG&E planning area or by ESPs.

(7) - These values are calculated from Tables 2-4, 2-10, and 2-15 in the *RPSA Report* and utility comments on the report. Because the demand forecast includes programs through 2008, the MW savings for 2008 are subtracted from the cumulative totals from line 1. These calculated values have then been increased by 15 percent to compensate for the true impact of demand-side programs on required reserves when they are implemented and reduce customer demand. The energy efficiency goals adopted by the CPUC that these values are based on are for all customers in the IOU's distribution service territory.

(8) - The value reflects the full goal of 5% of distribution service area demand to be achieved by 2007 and beyond. These calculated values have been increased by 15 percent to compensate for the true impact of demand-side programs on required reserves when they are implemented and reduce customer peak demand. The estimated impacts of the programs authorized under R.02-06-001, Critical Peal Pricing tariffs authorized by the CPUC pursuant to the applications filed in summer 2005, the portion of the DWR Demand Reserves Partnership allocated to each IOU, and other mechanisms that are eligible to satisfy the goals are included here. The difference between the goal and the sum of authorized program impacts is the amount remaining to be achieved from new or expanded programs and tariffs.

5.8. Future Adjustments to the Range of Need

The Energy Commission recognizes that some of the information used in constructing the range of need shown in the tables in this report will be out of date by the conclusion of the CPUC's 2006 procurement proceeding (LTPP). The Energy Commission offers the following guidelines for when and how adjustments to the numbers would be appropriate.

In terms of the demand forecasts, the Energy Commission believes that the revised staff forecast provides the appropriate basis for the 2006 LTPP. A biennial proceeding focused upon the long-term cannot be a good source of short term demand forecasts that are updated frequently for recent historic data and near-term expectations. Such near-term demand forecasts are appropriate for many operating activities. The Energy Commission does not anticipate any conditions in which an update of the staff revised forecast for the years 2008 and beyond would be appropriate for long-term planning purposes before the *2007 Energy Report* is completed. The short-term demand forecasts that all LSEs will be using each year as part of compliance with resource adequacy requirements should be established through other proceedings. Thus, updates for the 2006 and 2007 load forecasts reported here for purposes other than long-term planning are acceptable to the extent the CPUC determines this is appropriate.

On the resource side, the Energy Commission notes that the IOUs have begun to fill the resource needs identified in their filings. For example, PG&E has signed a capacity and dispatchable energy contract with Duke Energy for the 650-MW Morro Bay Power Plant from 2005-2007, initiated a long-term request for offers (RFO) for 1,200 MW in 2008 and an additional 1,000 MW in 2010, and proposed to construct and operate the 530-MW Contra Costa 8 unit, which may defer a portion of the long-term RFO; SCE has signed renewables contracts for about 640 MW, including a 500-MW peaking solar thermal energy project; and SDG&E has signed a contract with a 300-MW peaking solar project.

The Energy Commission recommends that the CPUC direct the utilities to update their utility-controlled and contractual resource status by filing in the 2006 LTPP a listing of all contracts and other projects committed to, and all contracts terminated or owned resources retired, since January 1, 2005. This filing should clearly indicate whether these projects were included in the reference case resource plan filed at the Energy Commission during the *2005 Energy Report* proceeding. The energy and capacity values of those projects can then be added to the appropriate existing and planned resource line and, if it is a preferred resource, subtracted from the appropriate preferred resource line of the range of need tables and the resulting totals recalculated. The Energy Commission does not anticipate that any other changes to the existing and planned resource base would be appropriate.

In terms of energy efficiency and demand response, the tables are based on the Energy Commission's understanding of the implications of the adopted *EAP II* loading order preferences. If the CPUC formally adopts goals for any of these preferred resources in the future, these numbers should be adjusted as appropriate. For renewables, this line is the "generic renewables" that would need to be procured in the future as reported by the IOU for the accelerated renewables case. Any adjustments to either the target or the existing and planned resource base should be reflected in this line. No numbers have been included for distributed generation and combined heat and power resources. The *Energy Report* notes that 5,400 MW by 2020 is a realistic goal and recommends that "by the end of 2006, the Energy Commission and CPUC should collaboratively translate this goal into annual IOU procurement targets."[112] Once these yearly targets are set, they should be incorporated into the need tables. The Energy Commission does not anticipate any other changes to the preferred resource numbers until they are reviewed again in the *2007 Energy Report* proceeding.

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[112] *Energy Report*, p. 78.

6. Electricity Energy and Peak Demand Forecasts

6.1. Energy Commission Draft Staff Demand Forecast

The *Staff Draft Forecast* was published on June 14, 2005.[113] Table 5 summarizes the key statewide results of the June staff forecast. The staff and LSE forecasts are described in more detail in the sections below on the individual planning areas.

Table 5: Staff Draft Forecast of Statewide Electricity Demand

	Consumption (GWh)		Peak (MW)
1990	229,367		46,907
2000	262,985		53,758
2003	264,824		55,303
2008	285,867		60,878
2013	304,355		65,144
2016	314,471		67,569
Annual Average Growth Rates			
1990-2000	1.38%		1.37%
2000-2003	0.23%		0.95%
2003-2008	1.54%		1.94%
2003-2013	1.40%		1.65%
Historic values are shaded			

Source: *California Energy Demand 2006-2016 - Staff Energy Demand Forecast (Staff Draft Forecast)*, California Energy Commission staff draft report, CEC-400-2005-034-SD, June 2005.

In addition to the June staff demand forecast, Energy Commission staff prepared a separate report comparing the staff forecast to forecasts provided by the LSEs.[114] This

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[113] *California Energy Demand 2006-2016 – Staff Energy Demand Forecast (Staff Draft Forecast)*, California Energy Commission staff draft report, CEC-400-2005-034-SD, June 2005. As discussed below, the draft staff forecast is not the forecast used for calculation of the range of need. The draft staff forecast and the LSE forecasts were evaluated by the parties at the June 30, 2005 hearing. Based on that hearing, the Committee directed staff to prepare a revised forecast, which is the basis of the range of need.

[114] *Electricity Demand Forecast Comparison Report (Comparison Report),* California Energy Commission staff report, CEC-400-2005-037, June 2005.

report compared the electricity demand forecasts filed by the LSEs in February, 2005, with the staff draft forecast of annual electricity use and peak demand at both the total level and at the sectoral level where possible. The staff draft forecast was presented at a planning area level. For the comparison report, the forecasts from the different load serving entities were aggregated, with the forecasts provided by each IOU being combined with the portion of the forecast load for ESP customers using that IOU's distribution system and with the load for the publicly owned utilities within the IOU's portion of the transmission system.[115] While the IOU bundled customer annual peak demand is being treated as confidential pending completion of SCE's lawsuit against the Energy Commission, the LSEs agreed that the aggregated planning area annual peak demand could be made public.

The comparison report identified and explained differences between forecasts to provide a basis for Energy Commission decisions on what forecast or range of forecasts to adopt in the *2005 Energy Report* proceeding.[116] The sections below on the individual planning areas explain the key differences between staff's forecast and the LSE forecasts.

Some parties requested confidentiality for some of the demand forecast data submitted. While the Energy Commission has determined that the basic annual peak demand forecast should be public for all LSEs, SCE appealed that determination to Sacramento Superior Court on June 10, 2005. To maintain confidentiality of the data until the legal process is complete, staff uses certain aggregation conventions in the comparison report. Sales data submitted by ESPs are aggregated with staff estimates of

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115 The specific utilities included in each planning area is shown in Table 1-1 of the *Staff Draft Forecast*, with additional information on the aggregation included at the start of the chapter on each IOU's planning area.

116 *Comparison Report*, p. 1.

non-filing ESPs and publicly owned utilities. For SCE, SDG&E, and PG&E, peak data are reported only at the planning area level.[117]

Staff's draft forecast and the comparison of this forecast with the aggregated forecasts supplied by the LSEs were the subject of a hearing on June 30, 2005. Because the staff forecast was expected to be a key input from the *2005 Energy Report* feeding into the CPUC's 2006 procurement proceeding, the Committee offered parties an opportunity for cross examination on the use of models in preparing the forecast, consistent with Section 1822 of the Public Utilities Code. No parties requested the opportunity for cross examination.

Following the hearing and review of written comments, the Committee directed staff to prepare a revised forecast that would include high and low cases in addition to a base case. The details of these comments, the Committee's direction to staff, and the resulting revised forecast are described in the section below on the Committee direction and the revised staff forecast. Staff published the revised forecast in September 2005.[118] The original LSE forecasts did not fall within the range across the three cases of the revised forecast, as discussed in more detail below. The SDG&E and SCE forecasts are both higher than the high case in the revised forecast; the PG&E forecast is below the low case.

6.2. Differences between Staff and LSE Forecasts

At the June 30 hearing, participants identified several key uncertainties driving the differences between staff and utility forecasts, including trends in commercial and industrial energy use, residential demographic trends, and currency of data. In addition, staff and utility forecasts use different types of models. These differences and

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[117] *Id.* at pp. 1-2.

[118] *California Energy Demand 2006-2016 - Staff Energy Demand Forecast, Revised September 2005 (Revised Staff Forecast)*, California Energy Commission staff final report, CEC-400-2005-034-SF-ED2, September, 2005.

the Committee's direction for resolving them are reviewed below and discussed in more detail in the IOU-specific sections that follow.

6.2.1. Model Assumptions

The draft staff forecast and the LSE forecasts differed in a number of key economic, demographic, and energy intensity assumptions. The Committee determined that these assumptions were all reasonably defensible and directed staff to develop a range of forecasts based on the different perspectives. Specific differences are discussed below, and their application in the revised forecasts are summarized.

Demographic projections are a key driver of residential demand. Staff used the Department of Finance population projections, PG&E used Economy.com, and SCE and SDG&E used Global Insight. Global Insight's population growth rate is lower than both the Economy.com forecast and the Department of Finance forecast (which are very close to one another), but it projects faster growth in the number of households, calculated as population divided by persons per household (PPH). Nationally, persons per household are projected to continue to decline as the population ages. On average, California's trend has been the opposite, with increasing persons per household.[119]

Three persons-per-household options were presented at the hearing. The Global Insight and Economy.com forecasts assume that California will reverse its historic trend and revert to the national average of declining persons per household. Thus, the IOU forecasts assume declining persons per household and increasing numbers of households. Staff assumes continued increasing persons per household.[120] Local groups like San Diego Association of Governments (SANDAG) project constant persons per household.[121]

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[119] 6/30/05 TR, pp. 30, 31, 90.

[120] *Id.* at p. 90.

[121] *Id.* at p. 19; June 30 workshop Energy Commission staff presentation "Forecast Overview," slide 18.

Both staff and the IOUs use economic projections developed by outside forecast services. The county level economic projections of Economy.com allow staff forecasts to better account for different economic trends within the state. For example, recent history has shown that Southern California is growing faster than Northern California.[122] PG&E also used Economy.com, while SCE and SDG&E used Global Insight. The Global Insight personal income forecast is much higher than the forecast staff derived from Economy.com. PG&E believes that the staff's economic input assumptions are reasonable.[123] SCE and SDG&E prefer their own.[124]

To capture these different perspectives, the high case assumes higher personal income and constant PPH, and the low case uses declining PPH and the older, lower personal income.

In the commercial sector, staff forecasted decreasing electricity use per square foot, reflecting the effects of building and appliance standards and slowing growth in office equipment demand. Some participants thought this reversal of recent trends unlikely and expected use per square foot to continue to increase.[125] PG&E thought that decreasing use per square foot was reasonable, given that the large build-up of office equipment inventory seen in the late 1990s was no longer occurring and that appliance energy efficiency improvements are expected to continue.[126] Staff's base case uses the original assumptions, while the high case assumes constant use per square foot.

Staff's industrial forecast was higher than that of the IOUs, reflecting only a slow decline in energy intensity.[127] Staff developed a revised forecast in which the forecasted

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[122] 6/30/05 TR, pp. 12-13.

[123] 6/30/05 TR, p. 50.

[124] 6/30/05 TR, pp. 65, 75 and SDG&E July 28 comment letter.

[125] 6/30/05 TR, pp. 20-23 and 6/30/05 TR, p.78.

[126] 6/30/05 TR, pp. at 54-55.

[127] 6/30/05 TR, pp. 71, 72 and June 30 workshop SCE presentation, slide 7.

energy intensity trend is more consistent with historic trends. The high case uses the draft forecast assumptions, while the base and low cases assume a faster decline use per unit of production.

6.2.2. Baseline Data Uncertainty

An increased percentage of consumption reported to the Energy Commission under the quarterly fuel and energy reporting (QFER) requirements is reported as "unclassified."[128] This can lead to a misallocation of a portion of demand among industrial and commercial customers. Ten percent of non-residential consumption, 18,000 GWh, is currently not assigned to an end-use type in the QFER reporting.[129] Staff has assigned this unclassified load to the industrial or commercial sectors in proportion to the classified load, which may not accurately reflect sectoral differences. This creates great calibration problems in getting the sector starting points right and ripples through the forecast because different sectors have different capacity factors and growth rates. For example, SCE identified this as a key difference between its forecast and staff's.[130] The revised forecasts use the historic sector data submitted by SCE for calibration, which reduces the problem for this forecast. However, the Energy Commission still needs more accurate detailed historic data from the IOUs for future forecasts and demand analysis.

6.2.3. Treatment of Energy Efficiency and Demand Response

The staff draft forecast and the various LSE demand forecasts and resource plans used different conventions for treating energy efficiency and demand response programs. The forms and instructions for both the demand forecasts and resource plans specified that LSEs should include the effects of energy efficiency and demand response programs that had been approved in the demand forecast, while targets based on future

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128 *Staff Revised Forecast*, pp. 2-16.

129 6/30/05 TR, p. 21.

130 6/30/05 TR, pp. 63-65.

programs that had not yet been funded should be included on the resource side.[131] The staff draft demand forecast followed this convention, but the IOU forecasts did not. SDG&E's demand forecast incorporated future efficiency programs throughout the forecast period. PG&E's forecast includes the effects of historic levels of public goods charge funding. SCE's forecast did not include post-2008 effects, but it also did not include effects of some 2006-2008 programs. However, those effects were documented in its submittal as uncommitted. At the June workshop, SCE presented a forecast which included both 2006-2008 effects and post-2008 effects.

The staff forecast incorporates the effects of planned energy efficiency programs through 2008 and adopted building and appliance standards. Estimated savings by program are obtained directly from utilities and public agencies. All building and appliance standards are modeled within the sector forecast models. The impacts from many demand-side management (DSM) programs are estimated directly within the market sector end-use models. Use of the basic forecasting models to quantify standards and program savings depends on determining a certain set of characteristics for each program that describe how it will function including customer type affected, program measures end-use classifications, and compliance levels if the program is nominally mandatory. Energy impacts from some programs are quantified outside the sector models. Adjustments are made to distinguish between program-induced and non-programmatic, or market, effects. The final results are aggregated by sector and planning area and provided to the summary model where they are used to evaluate the appropriate sector forecasts. At the aggregate, the utility and program estimates are used to gauge the impacts included within the end-use models.

As discussed above, SDG&E expressed concern that the revised staff forecast already incorporates future energy efficiency that is separately included as

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[131] *General Instructions for Demand Forecast Submittals*, California Energy Commission, November 3, 2004, p. 5; Forms and Instructions for the Electricity Resources and Bulk Transmission Data Submittal, California Energy Commission, CEC-100-2005-002-CF, January 2005, p.7.

uncommitted energy efficiency on the resource side.[132] The Energy Commission understands that the goals as established in the CPUC energy efficiency proceeding did not have a clearly documented baseline demand forecast against which to measure, which may lead to problems when applying them to a specific demand forecast such as the revised staff forecast the Energy Commission is adopting. To the extent that this issue may mean that the efficiency goals should be adjusted to reflect a specific baseline, it is more appropriately addressed in the CPUC energy efficiency proceeding.

6.2.4. Model Differences

Staff uses end-use forecasting models for the residential, commercial, and industrial sectors; econometric models for the agricultural and water pumping sectors; and trend analysis for the remaining small sectors.[133] PG&E, SCE, and SDG&E use econometric models, which are designed for and better at near-term forecasting. SCE's biggest concern about staff's end-use models is the number of assumptions that have to be made.[134]

One evaluation problem that arises from use of different models is that it is difficult to compare input assumptions. Different models affect which input assumptions are the most critical, especially whether the residential sector driver is population or number of households. Parties acknowledged this difficulty and made some attempts at the hearing to comment on the drivers used by staff.

While all parties agree that the econometric models provide better near-term forecasts, the Energy Commission has determined that staff's end-use forecasting models provide a more appropriate basis for the forecasts needed for the procurement proceeding.

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[132] SEU/SDG&E, November 8, 2005, p. 2. (See Appendix C for a copy of this comment letter and Appendix D for the Energy Commission response.)

[133] 6/30/05 TR, p. 9.

[134] 6/30/05 TR, p. 76.

6.3. PG&E Forecast

As shown in Table 6, the staff draft forecast and the aggregated LSE forecasts for PG&E's planning area[135] are very close, the peak within 0.5 percent in 2010 and 2 percent in 2016 and the energy within 1.2 percent in 2010 and 4 percent in 2016. Staff's draft forecast is higher than PG&E's except for peak demand for the years to 2010. Over the 2003-2016 planning horizon, growth rates are consistently within 0.2 percent, even though the forecasts are based on differing modeling techniques.[136] PG&E doesn't see any real difference between its and staff's planning area forecasts.[137] PG&E believes that the staff's economic input assumptions are reasonable.[138] Staff uses an end-use forecast; PG&E uses an econometric model.[139] No party expressed concerns about using two different forecasting methods, though IOUs generally felt econometric forecasting was more accurate in the short term.

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[135] In each of the three areas, the IOU serves roughly 80 to 90 percent of the total load. Therefore, in discussing the aggregated LSE forecasts for the different planning areas, the Energy Commission will typically refer to them as the IOU's forecast.

[136] 6/30/05 TR, p. 40 and slides 29, 30.

[137] 6/30/05 TR, p. 45.

[138] *Id.* at pp. 50, 53.

[139] 6/30/05 TR, p. 42.

Table 6: Comparison of Staff Draft Forecast with the Aggregated LSE Forecasts for PG&E Planning Area

	Consumption (GWh)				Peak (MW)		
	Aggregated Forecasts	Staff Draft Forecast	Percent Difference		Aggregated Forecasts	Staff Draft Forecast	Percent Difference
2000	96,844	96,822	-0.02%		20,698	20,698	0.00%
2003	94,114	95,638	1.62%		20,464	20,464	0.00%
2008	102,677	103,180	0.49%		22,537	22,331	-0.91%
2010	104,812	106,074	1.20%		23,069	22,975	-0.41%
2013	108,015	110,769	2.55%		23,909	24,040	0.55%
2016	110,401	114,614	3.82%		24,538	24,964	1.74%
Annual Average Growth Rates							
2000-2003	-0.95%	-0.41%			-0.38%	-0.38%	
2003-2008	1.76%	1.53%			1.95%	1.76%	
2003-2013	1.39%	1.48%			1.57%	1.62%	
2003-2016	1.61%	1.83%			1.83%	2.01%	
Historic values are shaded							

Source: *Electricity Demand Forecast Comparison Report (Comparison Report),* California Energy Commission staff report, CEC-400-2005-037, June 2005.

Two PG&E-specific issues were raised at the June 30 hearing: treatment of post-2008 energy efficiency and calibration of the energy forecast. No additional issues were raised in written comments.

The post-2008 energy efficiency issue is a resource accounting issue.[140] Staff used the PG&E method in the *2003 Energy Report* proceeding, but changed now that the CPUC's energy efficiency proceeding separated the targets into a committed 2006-2008 portion and an uncommitted post-2008 portion, which will be revisited later.[141]

As discussed above, the Energy Commission believes it is more prudent to treat post-2008 energy efficiency as a resource option rather than subtracting it from the load forecast. This approach acknowledges that post-2008 targets are subject to future energy agency regulation. Post-2008 energy efficiency will be the top of the loading order in the

[140] 6/30/05 TR, p. 46.

[141] 6/30/05 TR, p. 49.

supply/demand balance assessments. The Committee directed staff to use this approach in preparing the revised forecasts.

Also as discussed above, the calibration problem primarily results from reporting of unclassified electricity consumption in the Energy Commission's QFER data collection system. On the calibration issue, Aslin reported at the June 29 hearing that "Staff and PG&E have worked out a common understanding of peak use in the historic year of 2003 (used to calibrate growth rates), but still have some work to do on the energy side. This is very important, because both projections should start from the same 'reality'."[142] Staff agreed that this was necessary.

The Committee directed staff to reach agreement with PG&E on historic calibration, which staff did in the revised forecast by using the consumption data provided by PG&E. While this issue was resolved for the current forecast cycle, additional work will be required to ensure that the problem is appropriately addressed in future cycles.

6.4. SCE Forecast

Table 7 shows the staff draft forecast and the aggregated LSE forecasts for SCE's planning area. SCE's forecast is less than 2 percent higher for both energy and peak through 2010. The difference in the forecasts increases after 2010, to 9.5 percent for energy and 6 percent for peak by 2016.[143] At the hearing, SCE presented a revised forecast that included post-2008 energy efficiency programs from its February submittal.[144] While this had the effect of narrowing the difference between the original SCE forecast (which is included in the aggregated forecast shown in Table 7) and the staff draft forecast, it is not consistent with the approach staff used in the draft forecast.

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142 6/30/05 TR, p. 52.

143 6/30/05 TR, p. 60, June 30 workshop, Energy Commission staff presentation "SCE Planning Area Forecast," slide 31.

144 6/30/05 TR, p. 65.

SCE's forecast is higher due to its higher economic forecast, a different distribution of retail sales between a more robust commercial sector and a flatter industrial sector, and definitions and methodologies.[145]

Table 7: Comparison of Staff Draft Forecast with the Aggregated LSE Forecasts for the SCE Planning Area

	Consumption (GWh)				Peak (MW)		
	Aggregated Forecasts	Draft Staff Forecast	% Difference		Aggregated Forecasts	Draft Staff Forecast	% Difference
1990	n/a	78,271			n/a	17,564	
2000	92,469	92,543	0.08%		20,369	19,465	-4.44%
2003	89,534	90,045	0.57%		20,261	19,907	-1.75%
2008	98,837	98,088	-0.76%		22,543	22,468	-0.33%
2010	102,689	100,821	-1.82%		23,419	23,156	-1.12%
2013	110,800	104,670	-5.53%		25,064	24,108	-3.82%
2016	119,984	108,500	-9.57%		26,786	25,066	-6.42%
Annual Average Growth Rates							
1990-2000	n/a	1.69%			n/a	1.03%	
2000-2003	-1.07%	-0.91%			-0.18%	0.75%	
2003-2008	2.00%	1.73%			2.16%	2.45%	
2003-2013	1.65%	1.16%			1.65%	1.48%	
2003-2016	2.28%	1.44%			2.17%	1.79%	
Historic values are shaded							

Source: *Electricity Demand Forecast Comparison Report (Comparison Report),* California Energy Commission staff report, CEC-400-2005-037, June 2005.

SCE uses an econometric method, starting with Global Insight county-level economic data and adjusting the data as necessary.[146] SCE's forecast is primarily developed for procurement, so it focuses on getting the latest, most accurate near-term data for two to five years out.[147] SCE attributes its higher forecast to more robust

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145 SCE slide 2; 6/30/05 TR, p. 67.

146 6/30/05 TR, p. 65.

147 *Id.* at p. 75.

economic growth, higher wages, and higher employment in the southland than does the economic forecast used by staff.[148]

SCE notes a large difference in the historical period between the SCE and Energy Commission count of households. The difference disappears by 2016, when the forecast is identical.[149] SCE forecasts fewer persons per household, leading to growth in total households and forecasts growth in use per household.[150]

SCE's commercial forecast is higher than staff's due to higher short-term floorspace additions and continuing increases in use per square foot.[151] SCE had not reviewed staff's data on the impact of standards on commercial use per square foot but expressed concerns about it.[152] SCE has a flat industrial sector compared with staff's growing one. It believes that California manufacturers can't compete with offshore companies.[153]

SCE agrees with staff that its load factor will be declining due to a change in sector mix.[154] SCE and staff start at different historic load factors, which is important because SCE uses load factor as an input.

In total, the 2016 difference between staff's forecast and the forecast SCE presented at the hearing (as opposed to its February submittal that is included in the aggregated forecast in Table 7) is approximately 3 percent in peak, or equivalent to a one to two degree difference in temperature on the peak day.[155] However, SCE's

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[148] June 30 workshop SCE presentation, slide 5 and June 30 TR at p. 69.

[149] June 30 workshop SCE presentation, slide 4.

[150] *Id.* at slide 34, 6/30/05 TR, pp. 61-62.

[151] June 30 workshop Energy Commission staff presentation, "SCE Planning Area Forecast," slide 42; 6/30/05 TR, pp. 63, 64.

[152] 6/30/05 TR, p. 78.

[153] *Id.* at pp. 71, 72; June 30 workshop SCE presentation, slide 7.

[154] 6/30/05 TR, p. 73.

[155] *Ibid.*

inclusion of post-2008 energy efficiency reductions masked part of the difference in forecasts. When compared using common energy efficiency assumptions, the difference is 9.5 percent for energy and 6 percent for peak by 2016.[156]

At the hearing, no parties questioned SCE or staff, apart from the questions asked by the Committee. No party filed post-hearing comments on the demand forecast for SCE. As noted above, the Committee directed staff to use different economic and demographic assumptions in order to develop the low, base, and high cases in the revised forecast and to include only funded energy efficiency programs (through 2008) in the revised forecast.

6.5. SDG&E Forecast

As shown in Table 8, the aggregated LSE forecast for SDG&E's planning area is higher than the staff draft forecast. For the energy forecast, the SDG&E forecast is 1 percent higher by 2008 and almost 4 percent higher by 2016. In terms of the peak forecast, the differences are more than 2.5 percent in 2008 and more than 5 percent in 2016.[157] SDG&E assumes faster growth in the number of households and faster income growth. At the hearing, SDG&E pointed out that the differences between forecasts of approximately three years' growth at the end of the forecast period understate the true differences since staff does not include post-2008 energy efficiency and SDG&E does. SDG&E's economic assumptions are similar to SCE's, so it has very similar issues with staff's forecast. The difference between forecasts is as much as eight years' growth at the end.[158] Staff concurs that when the forecasts are compared using common energy efficiency assumptions, the forecasts are 12 percent different in 2016.

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[156] 6/30/05 TR, p. 60; Commission staff presentation "SCE Planning Area Forecast," slide 30.

[157] June 30 workshop Energy Commission staff presentation, "SDG&E Planning Area Forecast," slide 30; 6/30/05 TR, p. 88.

[158] 6/30/05 TR, pp. 91-92.

Table 8: Comparison of Staff Draft Forecast with the Aggregated LSE Forecasts for the SDG&E Planning Area

	Consumption (GWh)				Peak (MW)		
	Aggregated Forecasts*	Draft Staff Forecast	% Difference		Aggregated Forecasts*	Draft Staff Forecast	% Difference
1990	n/a	14,460			n/a	2,961	
2000	18,424	18,928	2.74%		3,485	3,472	-0.37%
2003	18,385	18,398	0.07%		3,902	3,921	0.48%
2008	20,626	20,405	-1.07%		4,468	4,350	-2.64%
2010	21,406	21,042	-1.70%		4,639	4,486	-3.30%
2013	22,575	21,981	-2.63%		4,889	4,686	-4.15%
2016	23,840	22,893	-3.97%		5,148	4,879	-5.22%
Annual Average Growth Rates							
1990-2000	n/a	2.73%			n/a	1.60%	
2000-2003	-0.07%	-0.94%			3.84%	4.14%	
2003-2008	2.33%	2.09%			2.75%	2.10%	
2003-2016	2.02%	1.70%			2.15%	1.70%	
Historic values are shaded							

* - The SDG&E forecast included energy efficiency programs throughout the forecast period, so the values after 2008 are lower than they would be if the draft staff forecast method of only including the 2006-2008 energy efficiency programs had been used.

Source: *Electricity Demand Forecast Comparison Report (Comparison Report),* California Energy Commission staff report, CEC-400-2005-037, June 2005.

Two-thirds of the difference between staff and SDG&E is in residential demand. SDG&E assumes faster growth in the number of households, implying declining persons per household and faster income growth, because Global Insight has a higher economic forecast than Economy.com. For SDG&E, the key difference is in the number of households, not use per household.[159]

The difference in population and PPH is attributable to different sources. SDG&E believes that the data from the Department of Finance (DOF) and Economy.com used by staff is the low end of the plausible range, while staff's sources are toward the higher end. Staff's forecast is consistent with the University of California at Los Angeles recent forecast and with the forthcoming SANDAG forecast.[160]

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[159] 6/30/05 TR, p. 93.

[160] *Id.* at p. 92.

SDG&E did not have an opinion about commercial use per square foot floor space trends.[161]

Staff and SDG&E also had a starting point problem. The staff's draft forecast for 2006 was nearly the same as SDG&E's 2005 starting point. The staff was a year's growth off on its starting point. Staff's last historic year was 2003. If staff had used 2004 actual data, much of the 1.5 percent calibration problem might disappear.[162] This view was reiterated in the July 22 follow-up comments that said the Energy Commission needs to adjust the peak starting point to account for normal weather and revise its short-term outlook.

SDG&E stated that staff's weather-sensitive residential load is understated by more than 50 percent. This is significant because it is a fast-growing segment of load. The adjustment could add one year of growth to the peak forecast. SDG&E stated that it has load study information that supports its view.[163] SDG&E also recommended that staff continue to make progress on adding more weather stations, including considerations of humidity and minimum temperatures.[164]

The Committee directed staff to resolve these issues with SDG&E. The revised forecast has adjusted its base peak forecast upward to account for a return to normal weather. The adjustment of peak to account for normal weather lowers the load factor slightly. This served to increase the peak estimates for all forecast years. The revised forecast also uses revised sector load shapes that increase weather-sensitive load and decrease base load for the SDG&E region. The revised forecast did not reflect other model changes suggested by SDG&E because it has not yet provided adequate documentation to assess the viability of the model results and claims laid out in its

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161 *Id*. at p. 99.

162 *Id*. at pp. 94-95.

163 *Id*. at pp. 96-98.

164 *Id*. at p. 99, SDG&E July 22 comment.

comments. Staff is directed to work with SDG&E to jointly improve weather-sensitive modeling.

No parties had questions for SDG&E or staff on their forecasts. SDG&E filed a follow-up comment letter on July 28 that addressed the issues discussed above.

6.6. Committee Direction and Revised Staff Forecast

The fundamental issue facing the Energy Commission is developing a plausible range of energy and peak demand that IOUs may face in the next decade for their bundled service customers. This can be broken down into specific estimates of general economic and demographic trends; energy intensity trends in each of the sectors; accuracy of historic end-use and trend data; potential impacts of regulatory decisions on departing load; and means of addressing the uncertainty inherent in all these factors.

The Committee had a clear and complete record on energy forecasts and parties agreed on the source of differences. Small differences compound over time, so that they could translate into several years' growth when compared using common assumptions. The Committee chose not to adopt a forecast presented at the hearings, but directed staff to produce a revised forecast using Committee-directed assumptions reflecting positions presented in testimony and hearings.

In response to the testimony and hearings, the Committee directed staff to revise some of the historic data used for the forecast. Some utilities pointed out that some of the historical data used by staff was inconsistent with their own data. In these cases staff replaced historical consumption and peak data with the values reported on the demand forms submitted to the Energy Commission by each LSE. The draft forecast also used 2003 consumption as the last historical year. This contributed to starting point differences between the staff and utility forecasts using more recent data. To address these concerns, all the revised forecasts incorporate 2004 electricity and natural gas consumption, peak demand, and weather data.

The base case forecast also uses a new higher forecast of per capita income produced by Economy.com in June 2005, with updated population estimates. Since the June 2005 forecast the Department of Finance re-estimated interim population and PPH size by county for January 2001 through 2005.[165] These revised estimates were factored into the new base case population and persons per household forecasts.

The Committee directed staff to vary key economic and demographic assumptions to develop a reasonable range of possible outcomes. Table 9 summarizes the changes from the draft staff forecast to the base, low, and high cases in the revised staff forecast. The residential high case incorporates assumptions similar to that of the IOU forecasts, using the new, higher real personal income and assuming constant PPH through the forecast period, resulting in more households. The low forecast uses the new PPH forecast with the older per capita income projection.

Table 9: Composition of Revised Forecasts

	Industrial	Mining	Commercial	Residential
Base	Decreased kwh per output	Increased kwh per output	No 2005 lighting standards, no 98 office lighting standards; no misc./office equipment growth	New income, New persons per household
Low	Decreased kwh per output	Increased kwh per output	No 2005 lighting standards; no misc./office equipment growth	June income, New persons per household
High	Jun-05 Forecast	Increased kwh per output	No lighting standards effects; higher misc. (2%). and office equipment growth (1%)	New income, Constant persons per household

For the commercial sector, the Committee directed staff to develop a high case with increasing-to-flat use per square foot. To accomplish this, impacts of the new 2005 nonresidential lighting standards were removed from the model, and growth of demand in the miscellaneous and office equipment end uses was accelerated by 1 to 2

165 State of California, Department of Finance, E-5 City/County Population and Housing Estimates , Revised 2001-2004,with 2000 DRU Benchmark. May 2005.

percent per year. For the low case, growth of office and miscellaneous equipment was set at zero, and some lighting standards effects not included in the base case were added back in.

In response to comments that the industrial forecast seemed unreasonably high given marketplace conditions in California, the Committee directed staff to develop a revised industrial forecast for the low case. Staff reviewed the historical use per output for each industry group. Staff evaluated the trends in energy use per output for each industrial group and revised the energy intensity growth rates to produce a forecast more consistent with historical trends. For manufacturing industries, this entailed a faster decline in use per dollar of value of shipments over the forecast period. This higher forecast is used for the low and base case forecast, while the original staff forecast, calibrated to 2004 data, is used in the high case. The oil and gas extraction industry, however, has become more electricity intensive in recent years. In the revised mining sector forecast, used for all cases, this trend is projected to continue.

As discussed above, the effects of energy efficiency programs through 2008, which have had their funding approved, are incorporated into the demand forecast, while post-2008 programs are listed on the resource side.

Also as discussed above, the Energy Commission has determined that departing load uncertainty is a resource uncertainty that is best addressed through appropriate exit fees and coming-and-going rules. The Energy Commission will not insert a level of departing load into the forecasts. The revised forecasts assume direct load growth at half the sector growth rate of the planning area forecast.

The revised staff forecast, based on the Committee's direction, was published on September 27, 2005.[166] Table 10 summarizes statewide annual energy and capacity and compares these three cases to the draft staff forecast. Tables 11 through 13 summarize the low, medium and high forecasts at the bundled customer level for the three IOUs.

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166 *Revised Staff Forecast.*

Comparisons between the revised staff energy forecasts and the IOU-submitted forecasts are discussed in the next section.

Table 10: Statewide Electricity Demand: Comparison of Draft and Revised Staff Forecasts

Consumption (GWh)

	Draft Staff Forecast	Revised Staff Forecast			Percent Difference Base/ Staff Draft	Percent Difference High/ Low
		Low	Base	High		
1990	229,367	229,375	229,375	229,375	0.00%	0.00%
2000	262,985	265,021	265,021	265,021	0.77%	0.00%
2004	272,386	270,927	270,927	270,927	-0.54%	0.00%
2008	285,867	285,317	286,813	289,002	0.33%	1.29%
2013	304,355	302,059	304,400	310,869	0.01%	2.92%
2016	314,471	310,716	313,397	323,372	-0.34%	4.07%
Annual Average Growth Rates						
1990-2000	1.38%	1.45%	1.45%	1.45%		
2000-2004	0.88%	0.55%	0.55%	0.55%		
2004-2008	1.21%	1.30%	1.43%	1.63%		
2004-2016	1.20%	1.15%	1.22%	1.49%		

Peak (MW)

	Draft Staff Forecast	Revised Staff Forecast			Percent Difference Base/ Staff Draft	Percent Difference High/ Low
		Low	Base	High		
1990	46,907	47,431	47,431	47,431	1.12%	0.00%
2000	53,758	54,028	54,028	54,028	0.50%	0.00%
2004	56,339	56,435	56,435	56,435	0.17%	0.00%
2008	60,878	60,640	61,042	61,528	0.27%	1.46%
2013	65,144	64,515	65,144	66,525	0.00%	3.11%
2016	67,569	66,656	67,379	69,473	-0.28%	4.23%
Annual Average Growth Rates						
1990-2000	1.37%	1.31%	1.31%	1.31%		
2000-2004	1.18%	1.10%	1.10%	1.10%		
2004-2008	1.96%	1.81%	1.98%	2.18%		
2004-2016	1.53%	1.40%	1.49%	1.75%		

Historic values are shaded

Source: *California Energy Demand 2006-2016 - Staff Energy Demand Forecast, Revised September 2005 (Revised Staff Forecast)*, California Energy Commission Staff Final Report, CEC-400-2005-034-SF-ED2, September, 2005.

Table 11: PG&E Bundled Customer Electricity Demand

	Consumption (GWh)				Peak (MW)			
	Low	Base	High	Percent Difference High/Low	Low	Base	High	Percent Difference High/Low
1999	77,932	77,932	77,932	0.0%	17,297	17,297	17,297	0.0%
2000	81,149	81,149	81,149	0.0%	17,681	17,681	17,681	0.0%
2001	81,002	81,002	81,002	0.0%	16,371	16,371	16,371	0.0%
2002	76,549	76,549	76,549	0.0%	16,437	16,437	16,437	0.0%
2003	77,343	77,343	77,343	0.0%	16,328	16,328	16,328	0.0%
2004	78,821	78,821	78,821	0.0%	16,390	16,390	16,390	0.0%
2005								
2006	81,450	81,720	82,179	0.9%	17,250	17,316	17,416	1.0%
2007	82,655	82,957	83,682	1.2%	17,504	17,577	17,734	1.3%
2008	83,739	84,064	85,107	1.6%	17,728	17,807	18,029	1.7%
2009	84,825	85,180	86,621	2.1%	17,959	18,044	18,344	2.1%
2010	86,071	86,449	88,237	2.5%	18,221	18,311	18,682	2.5%
2011	87,456	87,852	90,023	2.9%	18,520	18,615	19,062	2.9%
2012	88,652	89,066	91,600	3.3%	18,773	18,872	19,394	3.3%
2013	89,961	90,393	93,374	3.8%	19,055	19,158	19,768	3.7%
2014	90,972	91,424	94,894	4.3%	19,276	19,383	20,088	4.2%
2015	91,998	92,469	96,452	4.8%	19,518	19,631	20,434	4.7%
2016	93,008	93,501	97,959	5.3%	19,760	19,877	20,775	5.1%

Annual Average Growth Rate

2006-2016	1.2%	1.3%	1.7%		1.3%	1.3%	1.7%	

Historic values are shaded

Source: *California Energy Demand 2006-2016 - Staff Energy Demand Forecast, Revised September 2005 (Revised Staff Forecast)*, California Energy Commission Staff Final Report, CEC-400-2005-034-SF-ED2, September, 2005.

Table 12: SCE Bundled Customer Electricity Demand

	Consumption (GWh)				Peak (MW)			
	Low	Base	High	Percent Difference High/Low	Low	Base	High	Percent Difference High/Low
1999	74,106	74,106	74,106	0.0%	17,033	17,033	17,033	0.0%
2000	81,667	81,667	81,667	0.0%	17,918	17,563	17,918	0.0%
2001	79,934	79,934	79,934	0.0%	16,009	16,009	16,009	0.0%
2002	73,115	73,115	73,115	0.0%	15,299	15,313	15,299	0.0%
2003	75,419	75,419	75,419	0.0%	16,497	16,521	16,497	0.0%
2004	78,064	78,064	78,064	0.0%	17,108	17,318	17,108	0.0%
2005								
2006	80,663	81,078	81,302	0.8%	18,340	18,456	18,506	0.9%
2007	81,729	82,205	82,591	1.1%	18,612	18,745	18,829	1.2%
2008	82,850	83,377	83,957	1.3%	18,886	19,033	19,156	1.4%
2009	84,003	84,589	85,421	1.7%	19,171	19,335	19,506	1.7%
2010	85,067	85,703	86,758	2.0%	19,434	19,612	19,827	2.0%
2011	86,141	86,822	88,092	2.3%	19,697	19,888	20,146	2.3%
2012	87,319	88,045	89,554	2.6%	19,981	20,184	20,490	2.5%
2013	88,365	89,132	90,901	2.9%	20,237	20,452	20,808	2.8%
2014	89,444	90,258	92,385	3.3%	20,504	20,733	21,155	3.2%
2015	90,516	91,342	93,815	3.6%	20,773	21,005	21,492	3.5%
2016	91,423	92,254	95,048	4.0%	21,009	21,243	21,791	3.7%

Annual Average Growth Rate

2006-2016	1.3%	1.3%	1.6%		1.4%	1.4%	1.6%	

Historic values are shaded

Source: *California Energy Demand 2006-2016 - Staff Energy Demand Forecast, Revised September 2005 (Revised Staff Forecast)*, California Energy Commission Staff Final Report, CEC-400-2005-034-SF-ED2, September, 2005.

Table 13: SDG&E Bundled Customer Electricity Demand

	Consumption (GWh)				Peak (MW)			
	Low	Base	High	Percent Difference High/Low	Low	Base	High	Percent Difference High/Low
1999	13,621	13,621	13,621	0.0%	3,361	3,361	3,361	0.0%
2000	14,382	14,382	14,382	0.0%	3,177	3,177	3,177	0.0%
2001	16,063	16,063	16,063	0.0%	2,875	2,875	2,875	0.0%
2002	15,315	15,315	15,315	0.0%	3,168	3,168	3,168	0.0%
2003	16,112	16,112	16,112	0.0%	3,351	3,351	3,351	0.0%
2004	16,985	16,985	16,985	0.0%	3,543	3,543	3,543	0.0%
2005								
2006	17,541	17,661	17,717	1.0%	3,696	3,720	3,732	1.0%
2007	17,823	17,954	18,043	1.2%	3,754	3,781	3,800	1.2%
2008	18,173	18,314	18,438	1.5%	3,827	3,856	3,882	1.4%
2009	18,477	18,627	18,792	1.7%	3,890	3,921	3,956	1.7%
2010	18,771	18,930	19,135	1.9%	3,951	3,984	4,027	1.9%
2011	19,063	19,228	19,476	2.2%	4,011	4,046	4,098	2.2%
2012	19,357	19,529	19,822	2.4%	4,073	4,109	4,171	2.4%
2013	19,649	19,825	20,167	2.6%	4,134	4,171	4,243	2.6%
2014	19,936	20,117	20,513	2.9%	4,194	4,232	4,315	2.9%
2015	20,225	20,400	20,849	3.1%	4,254	4,290	4,385	3.1%
2016	20,507	20,679	21,185	3.3%	4,312	4,348	4,454	3.3%

Annual Average Growth Rates

2006-2016	1.6%	1.6%	1.8%		1.6%	1.6%	1.8%	

Historic values are shaded

Source: *California Energy Demand 2006-2016 - Staff Energy Demand Forecast, Revised September 2005 (Revised Staff Forecast)*, California Energy Commission Staff Final Report, CEC-400-2005-034-SF-ED2, September, 2005.

6.6.1. Comparison of Staff Revised Forecast to IOU Forecasts

As mentioned previously, the forecasts provided by the IOUs for electricity sales fall outside the range of the revised staff forecast, with the PG&E forecast lower than the low case in revised staff forecast and the SCE and SDG&E forecasts higher than the high case.[167] These differences are discussed below.

The Energy Commission is adopting the revised staff forecasts, since staff's end-use modeling methods are more appropriate for long-term planning purposes.

6.6.1.1. PG&E

While the revised staff forecast and PG&E forecast are very similar in the early years, PG&E's forecast is 3 percent lower than staff's low case by 2014. The key differences are with conservation assumptions. First, because of the econometric methods used by PG&E, it considers the effects of historic levels of energy efficiency program funding, incorporated in its forecast beyond 2008. In addition, PG&E assumes persistence of behavioral conservation from the energy crisis, while staff does not. Therefore the staff forecast projects increasing residential use per household, while PG&E projects flat to decreasing use per household.[168]

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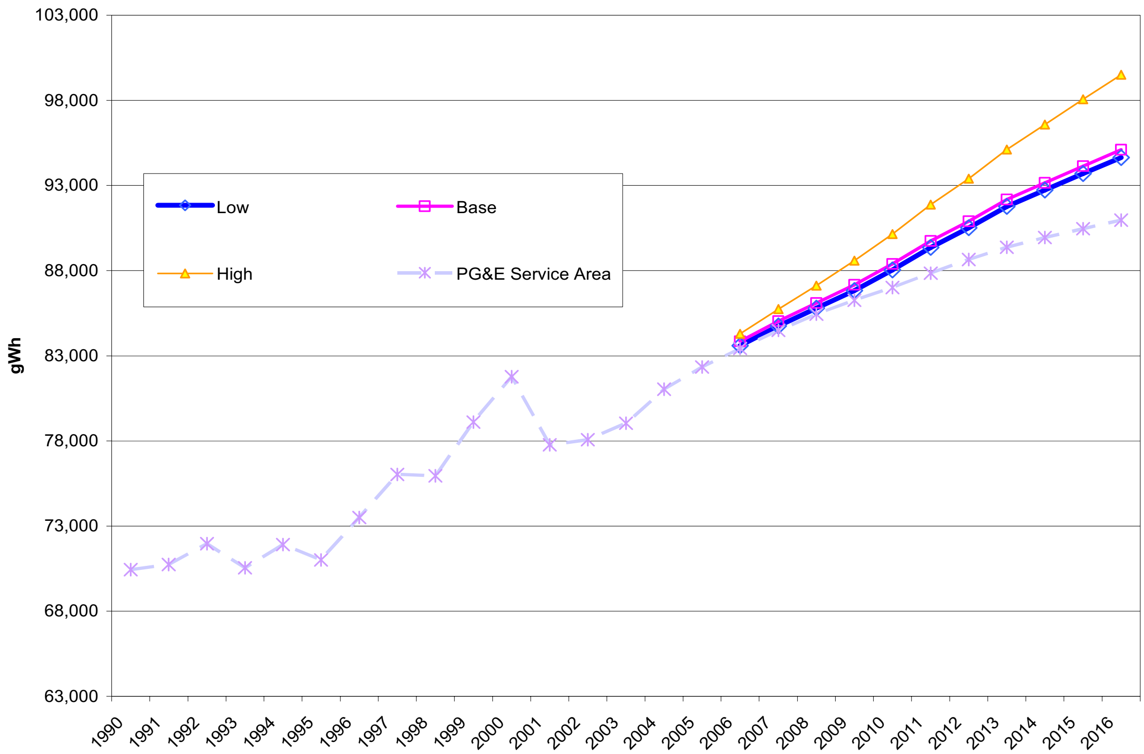
[167] No direct comparison can be made between the annual bundled customer peak in the IOU-supplied forecasts and the revised staff forecasts. The IOU annual peak numbers are being treated as confidential while the court case filed by SCE seeking to overturn the Energy Commission's determination that this data was not confidential is pending.

[168] *Comparison Report*, Figure 2-5.

Figure 1: PG&E Service Area Electricity Sales Forecasts

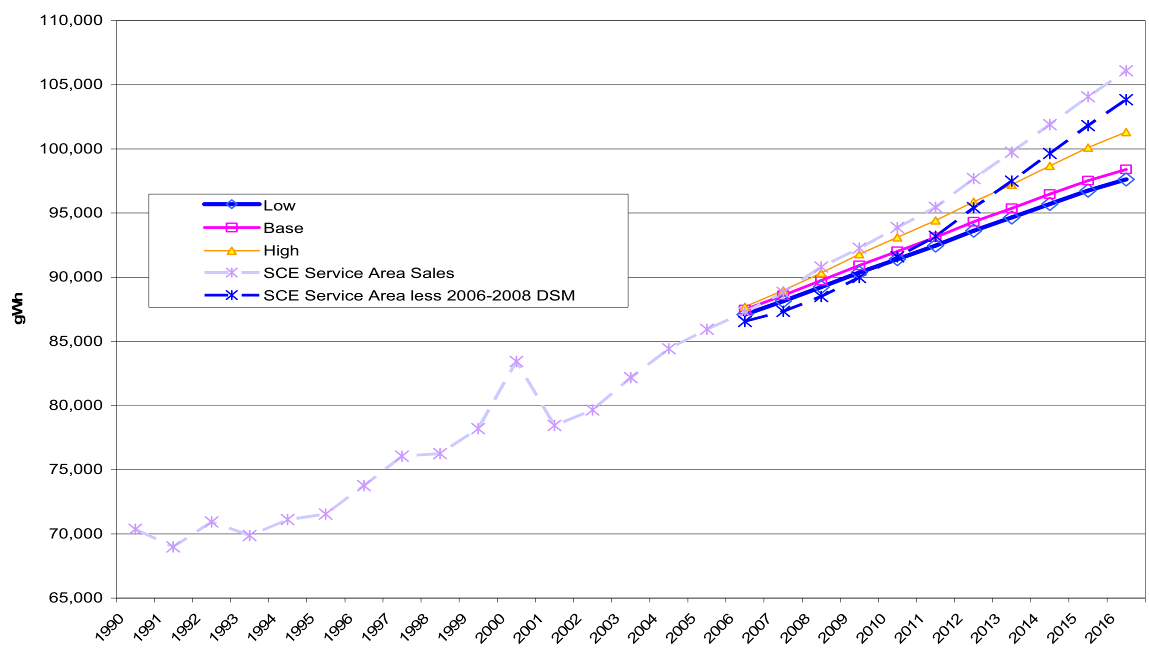


6.6.1.2. SCE

The forecast submitted by SCE is 5 percent higher than staff's high case in 2013. However, this forecast did not include effects of some programs to be funded in 2006-2008 that SCE treated as uncommitted at the time it submitted its forecast. Using SCE data submitted on the DSM forms, staff estimated an adjusted forecast that includes these effects. This adjusted forecast is lower than the staff low forecast initially, but one percent higher than the high by the end of the forecast period. As in the June forecast comparison, assumptions about trends in commercial sector energy use drive the differences. In the staff's high forecast, accelerated office equipment growth and the reduced effects from building and appliance standards produce constant commercial electricity use per square foot (as opposed to declining use in the base case), while the SCE forecast assumes increasing use per square foot.[169]

While use per square foot has been increasing in recent years, this trend has reflected the rapid penetration of computers and related equipment. Staff's perspective is that the future rate of new penetration is likely to slow and will be offset as older electronic equipment is replaced with more energy efficient models.

Figure 2: SCE Service Area Electricity Sales Forecasts



6.6.1.3. SDG&E

SDG&E submitted a forecast including the effects of energy efficiency programs from 2008 through 2016, which for this proceeding are considered uncommitted. This forecast is very similar to staff's high forecast, within 0.5 percent until the last two forecast years.

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169 *Comparison Report*, Figure 3-12.

However, adding the uncommitted effects back to the forecast produces a "no uncommitted" forecast that is 5 percent higher than staff's high case by 2013, and almost 10 percent higher by 2016. SDG&E 's documentation does not describe in detail how conservation and standards are accounted for, but some of the difference between the staff high case and the SDG&E "no uncommitted" forecast may reflect differences in how energy efficiency impacts are accounted for. Savings that SDG&E attributes to future DSM programs may to some extent be already accounted for in the Energy Commission models as part of the effects of building decay, equipment replacement, price effects, and building and appliance standards.

However, this cannot explain all the difference; staff's high case has removed many of the effects of commercial building standards, and SDG&E's own econometric forecast methods would also tend to incorporate the effects of historic levels of program activity into the forecast. The growth of use per capita in SDG&E's "no uncommitted" forecast, shown in Figure 4, is comparable to the rapid growth during the technology boom of the late 1990s. While the Energy Commission has seen similar increases in 2003 and 2004, these likely reflect the rebound from the energy crisis and the effects of the recent construction boom. While more such cyclical phenomena (either positive or negative) may occur in the future, such trends are generally short lived and not sustained over the period indicated in the SDG&E "no uncommitted" forecast.

Figure 3: SDG&E Service Area Electricity Sales Forecasts

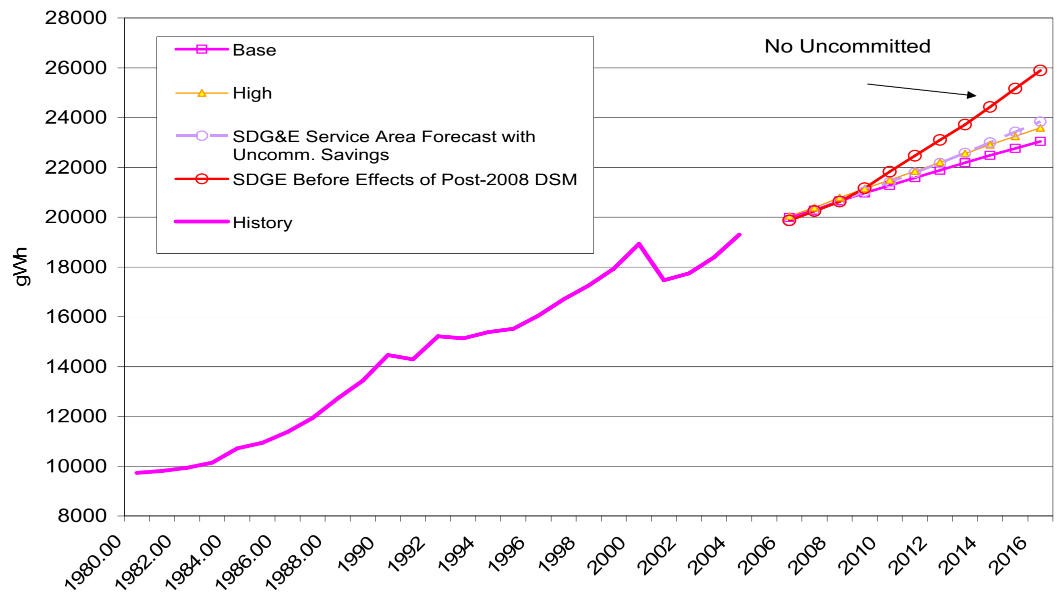
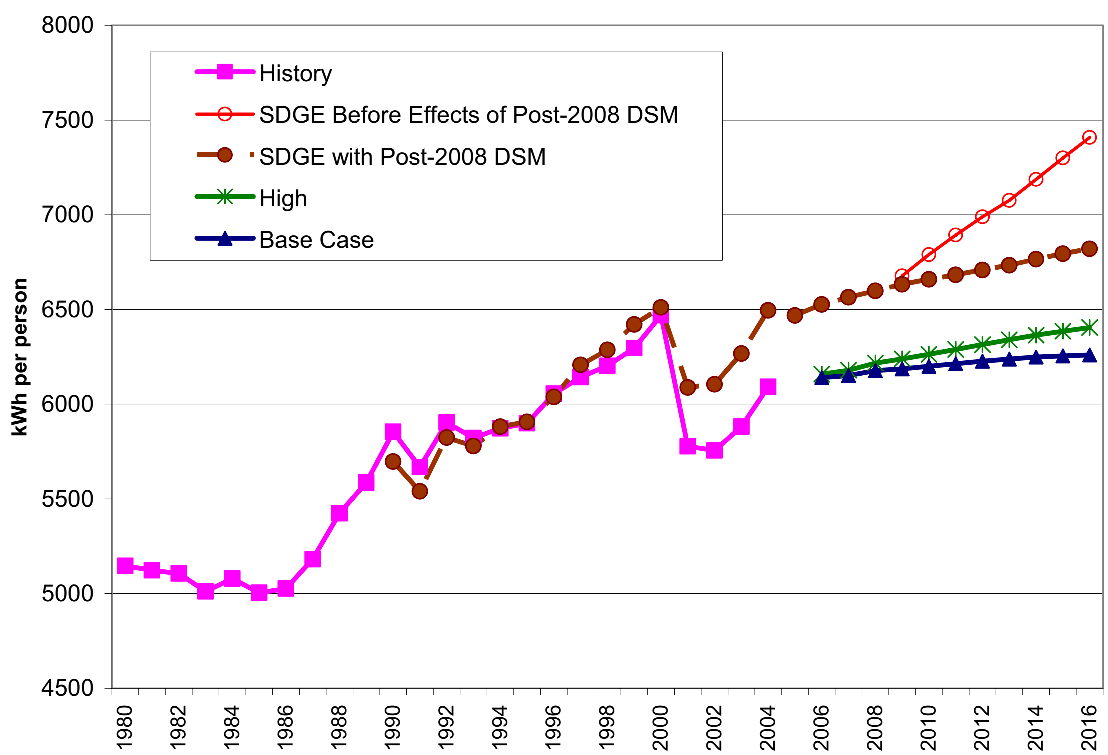


Figure 4: SDG&E Service Area Electricity Consumption per Capita



7. Resource Plans and Range of Need

For each of the three IOUs, the following sections summarize staff's review of key elements of the resource plans and supporting information filed by the IOUs, and then present the range of need.

7.1. PG&E Resource Plan and Range of Need

7.1.1. Preferred Resources

7.1.1.1. Energy Efficiency

PG&E's resource plans include an energy efficiency program that it asserts will meet CPUC targets in D.04-09-060. PG&E stated that its portfolios were constructed in a bottoms-up manner consistent with the *Energy Action Plan* loading order, with energy efficiency targets included first. The energy efficiency programs have an aggressive ramp-up, a focus on programs that meet peak power needs in the near term, and aggressive cost-effective energy savings starting in 2007.[170] PG&E also stated its commitment to achieving its long-term targets and is actively developing programs to achieve this level of energy efficiency."[171]

While PG&E appears to be committed to achieving considerable peak savings, its novel program strategy in the 2006-2008 period will bear close watching to confirm that it can deliver the savings it anticipates. PG&E is to be commended for trying a completely redesigned customer-oriented and market-based approach for achieving energy efficiency.

The Energy Commission is including the uncommitted portion of the current CPUC-adopted energy efficiency targets within the preferred resource category in the range of need tables.

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[170] *RPSA Report*, p. 23, 24.

[171] PG&E, July 22 Comments. p. 2.

7.1.1.2. Demand Response

PG&E used its 5 percent targets to set the same demand response forecast in all its resource plan scenarios. Since the demand response programs serve all system level load customers, the projections did not vary with differing assumptions about departing load.[172] Staff agrees that PG&E's description of its plan is reasonable, but notes that SCE and SDG&E chose to also provide an alternative forecast to illustrate their own internal estimates of available demand response. PG&E did not provide such an estimate.

The Energy Commission is showing the current CPUC target of 5 percent of service territory load in 2007 and beyond as the amount of preferred demand response resources in the need tables. The Energy Commission recognizes that the CPUC may decide to revise those targets in its demand response proceeding and expects that the values in the need tables will be appropriately adjusted if new targets are adopted.

7.1.1.3. Renewables

All PG&E's resource portfolios include a minimum of 20 percent renewable energy by 2010.[173] The company built a renewable portfolio in its preferred plan, which reaches 23 percent by 2013, and used that same case in the reference case, with its higher load, which reaches 20 percent by 2010 and retains that percentage through 2016. Its accelerated renewables case is built from its preferred case and reaches 28 percent by 2016.[174]

PG&E states that its proposed renewable resources are based on their likely availability and value to the system, though actual procurement of renewable generation will occur based on the least-cost best-fit analysis of bids received through its proposed RPS Procurement Plan and accompanying RFO for Renewable Resources.

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[172] PG&E, July 22 Comments, p. 3.

[173] PG&E, April 1 filing, p. 4.

[174] *RPSA Report*, pp.52-53.

In describing its supply resource options, PG&E states that it relied primarily on renewable resource information published by the Energy Commission as part of its *2004 Energy Report Update*.[175]

Staff found the renewable development assumptions used in these plans to be plausible after comparing the plans by technology and location with the remaining technical potential in the Energy Commission's *2003 Renewable Resources Development Report*.[176]

While PG&E states that the amount of renewable resources located and available in the NP 15 transmission zone is sufficient to meet the 20 percent renewable procurement target, PG&E believes it will likely need to procure renewable resources from other areas to achieve a 33 percent target. This would require additional transmission and/or the use of renewable energy credits. PG&E believes it may be more efficient, environmentally beneficial, and less expensive to ratepayers to allow the use of renewable energy credits instead of building additional transmission.[177]

PG&E developed a resource portfolio to reach 33 percent by 2020 but states that:

> Based on information currently available this portfolio is theoretically possible, but PG&E is concerned that this portfolio will be extremely difficult to realize and the costs of achieving a 33 percent renewable portfolio are very likely to be substantially understated. PG&E believes the total cost of the Accelerated Renewable portfolio is much greater than the costs presented here reflect. PG&E assumed the resource potential and costs for renewable development are based on CEC-developed technical potential information. This cannot however, provide sufficiently detailed information regarding the type and location of the renewables that will ultimately constitute PG&E's portfolio, and as a result specific cost estimates have not been developed.[178]

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175 *RPSA Report*, p. 52

176 *RPSA Report*, p. 53

177 *RPSA Report*, p. 56

178 Energy Commission Integrated Energy Policy Report PG&E Electric Resource Supply & Transmission Plan, April 26, 2005, page 13.

For example, PG&E reported that, in addition to the generation costs reported in Attachment E, Table 2, "to achieve the 20 percent renewable resources level in all scenarios, it will incur approximately $170-$230 million in incremental transmission costs (other than interconnection) which will increase the transmission component of its rates."[179]

The Energy Commission has decided to use the generic renewable energy and capacity values developed by PG&E for the accelerated renewables case within the preferred renewables identified in the range of need table. The Energy Commission recognizes that this scenario was based on a different demand forecast, so the resulting trajectory of that level of future purchases would not be 33 percent of demand in 2020. Nonetheless, the primary purpose of identifying a preferred level of renewable resources on the need tables is to avoid procuring so much in non-preferred resources that renewable purchases to meet future targets are precluded. Therefore, the Energy Commission considers the generic renewable resources identified by PG&E in its accelerated renewables case, which all parties agreed would be technically achievable (though at uncertain costs), provide a useful benchmark. The Energy Commission invites comments on this approach and recommendations on alternative approaches for determining the amount of preferred renewables to identify in the need tables.

7.1.1.4. Distributed Generation

In its assessment of PG&E's resource plan filings, staff could not determine what assumptions PG&E used regarding future DG. Staff proposed that an extrapolation of 2002-2004 actual installations, 2.5 MW per year, should be used.[180] In its July 22, 2005, comments, PG&E clarified that it used the same data source and the same assumption of 2.5 MW per year that staff recommended.[181]

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[179] PG&E, April 26, p. 13.

[180] *RPSA Report,* pp. 66-67.

[181] PG&E July 22 Comments, pp. 3-4.

In the *Energy Report,* the Energy Commission recommends that "by the end of 2006, the Energy Commission and CPUC should collaboratively translate this goal [of 5,400 MW of CHP statewide by 2020] into annual IOU procurement targets."[182] Once these goals are established, the CPUC should incorporate them into the preferred resource category on the need tables.

7.1.2. Energy Resource Needs

The preliminary energy range of need for PG&E is shown in Appendix B Figure B-1; in Tables B-1, B-2, and B-3 for the base, low and high revised staff forecasts, respectively; and is described in the sections below. The resource information shown in the appendix is based on resource plan information prepared by PG&E in early 2005, and will need to be updated as part of the CPUC's 2006 procurement proceeding.

The tables and graphs in Appendix B also show the average annual energy for the years 2002 through 2004 provided by the aging power plants in PG&E's planning area, with a transition to the full amount from 2009 to 2012. The Energy Commission recommends that these plants be replaced by 2012, and it would be imprudent for PG&E to contract with these aging units beyond 2012.

7.1.2.1. Utility Controlled Resources

PG&E's resource plans included the annual energy for utility controlled nuclear, fossil, and hydroelectric resources. For nuclear resources, PG&E's plans assume relatively flat levels of generation throughout the forecast period and a slow decline in generation from hydro resources, with the 2016 hydro generation at approximately 80 percent of the 2009 value. For fossil resources, PG&E did not include any generation in its reference case for 2009 and beyond, though it included 150 MW of capacity based on the planned replacement of the Humboldt Bay Power Plant. The other three resource plans filed by PG&E showed between 170 and 180 GWh of fossil generation between 2009 and 2016, which would correspond to a capacity factor of approximately 15

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182 *Energy Report*, p. 78.

percent for 150 MW of capacity.[183] Overall, PG&E's reported utility-controlled resources total between 30,000 and 33,000 GWh for the years 2009 through 2016.

7.1.2.2. Contractual Resources

PG&E's resource plans show a significant drop in contractual resources throughout the forecast period, with the largest drop between 2009 and 2010 due to the decline of energy supply from DWR contracts from more than 21,000 GWh in 2009 to just more than 3,000 GWh in 2010. This total declines to about 1,000 GWh in 2012 and disappears in 2013.

PG&E projected that energy resources from QF contracts would remain relatively constant throughout the period, with the energy supply from these contracts between 19,000 and 20,000 GWh. Energy supplies from existing renewable contracts and other bilateral contracts decline throughout the planning period, from a combined total of slightly more than 4,000 GWh in 2009 to less than 500 GWh in 2016, presumably reflecting expiration of such contracts.

While the aggregated data tables counted short-term and spot market purchases as part of the total existing and planned resources, the Energy Commission has chosen to consider these purchases as part of the need to be filled by PG&E.

7.1.2.3. Energy Range of Need

The balance of energy demand versus existing and planned resources reported in the resource plans in early 2005 for PG&E show relatively modest energy needs across the three demand forecasts of 10 to 12 percent of the total energy requirement in 2009, to 45 to 50 percent by 2016.

In addition to developing the total range of procurement need, the Energy Commission is reporting on the amount of preferred resources that the utilities should plan to obtain, consistent with the loading order. The Energy Commission recognizes

[183] *Aggregated Tables Report*. The PG&E reference case public tables showed more than 3,500 GWh for fossil generation, which is not consistent with the 150 MW of reported capacity.

that procurement activity by PG&E and ongoing and future proceedings at the CPUC may result in adjustments to these numbers, but recommends that the authority the CPUC grants for open source procurement be adjusted to ensure that these preferred resources are not crowded out in the future.

The uncommitted energy efficiency savings included in the preferred resources are based on the estimates provided by PG&E based on the targets established by the CPUC in D.04-09-060, adjusted to account for the inclusion of committed energy efficiency programs through 2008 that are included in the revised demand forecast. These savings ramp up from approximately 1,000 GWh in 2009 to 9,000 GWh in 2016.

As discussed above, the Energy Commission is including in the preferred resources category renewable resources consistent with the accelerated goal of 33 percent renewables by 2020 that the Energy Commission recommended for PG&E in the *2004 Energy Report Update*. While the CPUC cannot under current law require RPS procurement beyond 20 percent, the Energy Commission places great weight on the rebuttable presumption for renewable resources in any RFO seeking generation resources established by the CPUC in D.04-12-048, despite PG&E's lack of specificity about how it intends to implement this policy directive.

As directed by the Energy Commission, PG&E filed an accelerated renewables resource plan scenario aiming at 33 percent renewable resources by 2020. While the trajectory in this resource plan is not based on the revised staff demand forecast, it is the most detailed information in the record on the possible path that PG&E could follow to meet the accelerated targets. Therefore, the Energy Commission is using the generic renewable energy needs identified by PG&E in this resource plan scenario as a placeholder to ensure that PG&E will be able to purchase adequate renewables to meet the enhanced goals, should they be enacted into law. The Energy Commission invites comments on this approach and other recommendations on alternate approaches for determining the amount of preferred renewables to identify in the need tables.

These preferred resources represent between 60 and 75 percent of the procurement energy needs identified for PG&E in 2009. With the expiration of many

DWR contracts greatly increasing the total need in 2010, the portion of total need represented by the preferred resources drops to just over 30 percent in the three cases in 2010, slowly increasing to between 40 and 50 percent by 2016.

Though targets have not yet been established, the Energy Commission recommends that the CPUC and Energy Commission establish targets for distributed generation and combined heat and power resources by the end of 2006. When these targets are established, these need tables should be updated to reflect the targets, resulting in an increase in the preferred resources and a reduction in the level of undesignated need.

7.1.3. Capacity Resource Needs

The preliminary capacity range of need for PG&E is shown in Appendix B Figure B-2; in Tables B-4, B-5, and B-6 for the base, low and high revised staff forecasts, respectively; and is described in the sections below. The resource information shown in the appendix is based on resource plan information prepared by PG&E in early 2005, and will need to be updated as part of the CPUC's 2006 procurement proceeding.

The tables and graphs in Appendix B also show the capacity of the aging power plants in PG&E's planning area, with a transition to the full amount from 2009 to 2012. The Energy Commission recommends that these plants be replaced by 2012, and it would be imprudent for PG&E to contract with these aging units beyond 2012.

7.1.3.1. Utility-Controlled Resources

PG&E's resource plans included public tables providing the annual capacity for utility-controlled nuclear, fossil, and hydroelectric resources for the years 2009 through 2016.[184] These tables show a nearly constant level of capacity available from these existing and planned resources, with the only change a 67 MW reduction in hydroelectric capacity starting in 2014. The Energy Commission includes these resources in its calculation of the range of need.

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[184] The public tables filed by PG&E were published in Appendix B of the *RPSA Report.*

7.1.3.2. Contractual Resources

For contractual resources, the public capacity tables in PG&E's resource plans only included the DWR contracts. The aggregated PG&E planning area capacity tables also show totals for QF contracts (no QF contracts are held by other LSEs in PG&E's planning area, so this total is also PG&E-specific), renewable contracts, and other bilateral contracts.[185]

The DWR contracts assigned to PG&E decline rapidly starting in 2009, with total capacity declining from 4,392 MW in 2009 to 263 MW in 2012. No DWR contracts remain in place after 2014. PG&E projected QF capacity to remain relatively constant throughout the period, with the 2009 QF capacity of 2,559 MW declining only to 2,472 MW in 2016. These IOU-specific contractual resources consistently represent more than 65 percent of the capacity of the contractual resources for each year in the capacity tables for PG&E's planning area.

The capacity tables in the *Draft Transmittal Report* showed capacity from existing renewable contracts and other bilateral contracts only at the planning area level due to confidentiality constraints. The Energy Commission stated its plan to publish in the final version the POU data included in these totals, and to subtract those numbers from the planning area total to show a distribution service area total for each IOU. No parties objected to this plan, so the Appendix B tables in this version of the report show distribution service areas. Table 13 shows the calculation of the service area values for PG&E.

185 *Aggregated Tables Report*.

Table 13: PG&E Planning and Service Area Contract Data

Other Bilateral Contracts	2009	2010	2011	2012	2013	2014	2015	2016
PG&E planning area	**1,522**	**1,536**	**1,525**	**1,538**	**873**	**888**	**880**	**800**
Modesto Irrigation District	211	211	188	188	188	188	164	68
Silicon Valley Power	0	0	0	0	0	0	0	0
Turlock Irrigation District	82	83	83	83	82	82	81	81
PG&E service area	**1,229**	**1,241**	**1,254**	**1,268**	**603**	**619**	**635**	**651**

Renewable Contracts	2009	2010	2011	2012	2013	2014	2015	2016
PG&E planning area	**169**	**170**	**171**	**172**	**174**	**96**	**97**	**96**
Modesto Irrigation District	38	38	38	38	38	26	26	26
Silicon Valley Power	7	7	7	6	6	6	6	6
Turlock Irrigation District	25	25	25	25	25	25	25	25
PG&E service area	**98**	**100**	**101**	**103**	**104**	**39**	**41**	**40**

The aggregated tables show declining capacity from existing renewable contracts and other bilateral contracts through the planning period, going from a combined total of 1,327 MW in 2009 to 691 MW in 2016. Due to confidentiality constraints, these values include a share of contracts held by ESPs.

While the aggregated data tables counted short-term and spot market purchases as part of the total existing and planned capacity, the Energy Commission has chosen to consider these purchases as part of the need to be filled by PG&E.

7.1.3.3. Capacity Range of Need

As described in more detail above, the procurement need for each forecast was calculated by subtracting the identified resources and existing interruptibles capacity reported in the resource plans in early 2005 from the forecast demand. The total peak capacity procurement need for PG&E for 2009 is approximately 25 percent of its total firm peak requirement, increasing to just over 50 percent by 2013 and increasing slightly through the remainder of the planning period.

Consistent with the loading order, this need is to be filled first with future programs designed to meet the CPUC’s energy efficiency and demand response targets, by renewable resources, and then by distributed generation and combined heat and power resources. The preferred resource goals are shown in the tables.[186] For renewables, the goals shown are based on the accelerated target that goes beyond the 20 percent RPS in statute requirement.

Additional undesignated need beyond those levels should be filled through procurement, with the CPUC's rebuttable presumption as part of the open source procurement, through distributed generation resources, and through an appropriate level of short-term and spot market sales and purchases.

These preferred resources represent approximately 40 percent of PG&E's total peak procurement need identified for PG&E in 2009, declining to near 30 percent in 2012, then increasing slowly to approximately 40 percent at the end of the forecast period.

Though targets have not yet been established, the Energy Commission recommends that the CPUC and Energy Commission establish targets for distributed generation and combined heat and power resources by the end of 2006. When these targets are established, these need tables should be updated to reflect the targets, resulting in an increase in the preferred resources.

7.2. SCE Resource Plan and Range of Need

7.2.1. Preferred Resources

7.2.1.1. Energy Efficiency

SCE provided two different forecasts of energy efficiency in its submittals. The first is the reference case required by the Energy Commission. SCE expressed concern that the required efficiency goals are not reliably achievable and, therefore, submitted

[186] The demand response goal for 2007 and beyond is 5 percent of the peak demand in the IOU distribution service area.

an alternative resource plan with an energy efficiency forecast based on its 2004 long-term procurement plan.[187]

In its comments, SCE reports that it has "included the required levels of energy efficiency and demand response in its Reference Case."[188] SCE expresses doubt about meeting the adopted goals beyond 2011. "There is significant uncertainty, however, concerning whether these levels of EE and DR can be attained within the current cost-effectiveness guidelines."[189] SCE believes there is no analysis to support levels of efficiency beyond what it terms "maximum achievable potential." SCE further comments that "directing SCE to implement a procurement plan based on the levels of EE and DR assumed by the Energy Commission could unnecessarily and unreasonably expose ratepayers to significant reliability and cost risk."[190] These same points are reiterated in SCE's comments on the June 29 *Resource Plan Summary Assessment Report* workshop.

In developing the efficiency goals, staff considered various limiting factors including constraints to ramping up program funding and the trend in market saturations for various measures. The statewide goal reflected the lower end of the range for economic potential presented in the Xenergy potential report.[191] Staff translated the statewide goals into utility-specific targets by applying a baseline ratio of IOU savings per dollar of expenditure to each IOU's share of relative program funding.

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[187] Comments of SCE to the scenarios filed with the California Energy Commission for the *2005 Integrated Energy Policy Report*, April 1, 2005, p.2.

[188] *Id.* at p. 6.

[189] *Ibid.*

[190] *Id.* at p. 7.

[191] *RPSA Report*, p. 14. See also *California's Secret Energy Surplus: The Potential for Energy Efficiency Programs in California*, prepared by Xenergy for the Energy Foundation and the Hewlitt Foundation, September 2002 [http://www.ef.org/documents/Secret_Surplus.pdf].

Recognizing the uncertainty and disagreement over the underlying assumptions used to calculate the maximum achievable savings potential, the adopted CPUC decision adjusted the goals to "reasonably bound the savings goals trajectory at either end of the forecast period, based on the best study information available to date."[192] Staff believes this adjustment took both market realism and judgment about future cost-effective efficiency potential into account.

SCE proposed an alternate case to the goals based on its 2004 long-term procurement plan using utility-specific analysis of its "maximum reliably achievable potential" for energy efficiency. This is the level that SCE believes is "the appropriate level to include for procurement planning purposes."[193] The major reason for the difference in projected savings in this case is a steep decline in the annual increments of uncommitted savings, coupled with the end of committed savings in 2011. SCE believes that the marketplace for some energy efficient technologies will become saturated in the later years of the forecasting period. Additional savings will require newer technologies for the marketplace. SCE's alternate case will fall below the adopted goals (adjusted to generation level) by approximately 1,448 GWh and 289 MW in 2013.[194]

SCE disagreed with staff's assumption that it is likely that public goods charge funding will be available after 2011.[195] It notes that public goods charge funding of energy efficiency ends on January 1, 2012, by statute. "At this time, neither SCE nor the CEC has any basis for assuming that will be modified. Consequently, SCE must assume that public goods charge funding will terminate at the end of calendar year 2011. From a reporting perspective SCE has merely transferred PGC funded program activities into

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[192] D.04-09-050, p.26

[193] SCE, April 7, 2005, p.7.

[194] *RPSA Report*, p. 35 and Table 2-16.

[195] *RPSA Report*, p.30.

the "uncommitted" or unfunded category in accordance with CEC's definitions of committed and uncommitted".[196]

Staff questioned SCE's assumption that it will be possible to add 970 new GWh in the first year of a new program cycle.[197] SCE responded by reporting a similar ramp-up between its 2003 program year and its current 2004-2005 program years. SCE also reported exceeding 2004 goals and expects to exceed its 2005 goals. Additional energy efficiency activities aimed at reducing peak demand by 37.5 MW were authorized for the summer of 2005. Further, on June 1, 2005, SCE filed Application 05-06-015 requesting funding for a portfolio of programs targeted at exceeding the 970 new GWh referenced in this forecast.[198] Staff based its original conclusion on 28 years of historic data. Staff acknowledges that SCE has reported 984 GWh of savings for 2004, up from 499 GWh in 2003. These savings, however, have not yet been verified.

In its June 1 filing to the CPUC, SCE put together a highly diverse portfolio of programs for 2006-2008; only one program accounts for more than 10 percent of the portfolio savings. Over the three-year period, SCE projects 4,071 GWh in savings, 130 percent of CPUC goals, and 784 MW, or about 108 percent of the peak savings goal. All the IOU peer review groups, however, expressed concern that without more emphasis on developing new programs, promoting comprehensive savings, and minimizing lost opportunities, meeting the 2009-2013 goals would be difficult.

The Energy Commission believes that SCE's long-term planning and procurement should be based on the targets established at the CPUC that consider statutory directives. On September 29, 2005, Governor Schwarzenegger signed into law Senate Bill 1037 (Chapter 366, Statutes of 2005, Kehoe) that clearly directs a primary focus on energy efficiency. While some of the concerns raised by SCE may be valid,

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[196] SCE June 25 workshop comments, p.6.

[197] *RPSA Report*, p.30.

[198] SCE June 25 workshop comments, p.6.

these issues should be addressed through monitoring and evaluating approved efficiency programs, and through future efficiency proceedings at the CPUC that will establish funding for programs for 2009 and later years and adjust efficiency targets as appropriate.

The Energy Commission is including the uncommitted portion of the current CPUC-adopted energy efficiency targets within the preferred resource category in the range of need tables.

7.2.1.2. Demand Response

SCE "generally agrees with the [RPSA] Report's conclusions with respect to demand response" but criticizes the report for failing "to address the impact of the fundamental disconnect between the CPUC's definition of its quantitative goals for demand response and the ability of current portfolios of price responsive programs to meet such goals during the 2006-2008 program cycle."[199]

SCE's comments, drawn from its Application 05-06-008 to the CPUC, raise a number of issues regarding the goals, including the need to pursue a "portfolio approach" of both price-sensitive and reliability demand response programs, the need to make the goals reflective of the proportion of customers to whom those program options were available (and thus which programs could be counted toward the goals), and the definition of demand response.

From a resource planning perspective, it makes sense to continue to distinguish between emergency "reliability" demand response programs and price-sensitive demand response programs that are counted toward demand response goals. The "portfolio approach" recommendation would only shift resources from one line of the table to another. Since the purpose of aggressive demand response goals was to

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199 SCE's written comments to California Energy Commission's *Investor-Owned Utility Resource Plan Summary Assessment* report, July 22, 2005, p. 8.

encourage the addition of new, price-responsive programs and tariffs, using preexisting reliability resources to count toward those goals is inconsistent with its original intent.

The original DR goals were intended to include all customer groups, including those that did not have interval meters in 2003. D.03-06-032 and D.03-06-036 both anticipated that the goals would provide incentives for the IOUs to expedite both the development of price-responsive DR for large customers and the installation of interval meters for small customers. SCE's proposals to alter the goals to reflect slower progress than originally envisioned are properly being addressed through its Application 05-06-008 at the CPUC. The Energy Commission is including the current goals in the preferred resource category, with the understanding that this amount should be adjusted if the CPUC decides to revise the goals.

7.2.1.3. Renewables

SCE's four resource plan scenarios include three different levels of renewable resources, all of which include a minimum of 20 percent renewable energy by 2010. It built the same renewable portfolio in its reference case and no transmission case, which reaches 20 percent by 2007 and maintains that percentage through 2016. SCE's alternate case achieves about the same percentages as the reference case, but its renewables portfolio must include more than 120 percent of the amount of eligible renewable energy by 2016. This happens because the alternate case has different assumptions than the reference case: lower existing renewable QF generation and higher retail sales (because of lower assumptions about community choice aggregation load and energy efficiency resources). SCE's accelerated renewable case makes the same assumptions as the reference case for existing renewable QFs and retail sales, but its renewables portfolio over the period 2006 through 2016 must include close to three and one-half times the amount of eligible renewable energy to meet the higher goal of 31 percent by 2016.[200]

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[200] SCE, April 1 filing, p. 3; *RPSA Report*, p. 47.

SCE states that its renewable resource assumptions to meet the 20 percent by 2010 goal are reasonable, but actual resources procured will be "the least cost best fit option[s] available during the planning period."[201] Staff found the renewable development assumptions used in these plans to be plausible after comparing the plans by technology and location to the remaining technical potential in the *2003 Renewable Resources Development Report*.[202]

The Energy Commission's 2016 target of 31 percent for SCE's accelerated renewables case requires SCE "to procure an additional 9,000 GWh of renewable power annually above what is currently required by statute and planned for by SCE." SCE's accelerated renewable case assumes 1,900 MW more eligible renewable capacity than in the reference case, plus some associated new transmission lines and upgrades.[203] Staff found the renewable development assumptions used in this case also to be plausible, based on technological potential.

SCE estimated the costs of the accelerated renewables case to be $1.2 billion more than the reference case (net present value of 2006-2016; in 2006 dollars, a 10.5 percent discount rate). SCE also expressed this cost increase as an "inflation-adjusted average of annual scenario costs per megawatt-hour" of $2.10 per MWh in 2006 dollars.[204] In its comments on the *RPSA Report*, which characterized SCE's cost estimates as "admittedly incomplete," SCE defended its cost estimate as providing "sufficient data and components essential to be able to make a comparison between the provided scenarios."[205]

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201 SCE, April 1 filing, p. 9.

202 *RPSA Report*, pp. 47-48. See also *Renewable Resources Development Report*, California Energy Commission, publication 500-03-080F, November, 2003.

203 SCE, April 1 filing, p. 13.

204 SCE, April 1 filing, p. 15.

205 SCE written comments to California Energy Commission's *Investor-Owned Utility Resource Plan Summary Assessment* report, July 22, 2005, p.18.

The Energy Commission has decided to use the generic renewable energy and capacity values developed by SCE for the accelerated renewables case as the preferred renewables identified in the range of need tables. The Energy Commission recognizes that this scenario was based on a different demand forecast, so the resulting trajectory of that level of future purchases would not be 35 percent of demand in 2020. Nonetheless, the primary purpose of identifying a preferred level of renewable resources on the need tables is to avoid procuring so much in non-preferred resources that renewable purchases to meet future targets are precluded. Therefore, the Energy Commission considers the generic renewable resources identified by SCE in its accelerated renewables case, which all parties agreed would be technically achievable (though at uncertain costs), provide a useful benchmark. The Energy Commission invites comments on this approach and recommendations on alternate approaches for determining the amount of preferred renewables to identify in the need tables.

7.2.1.4. Distributed Generation

In its assessment, staff could not determine what SCE's assumptions were regarding future DG. In its July 22 comments, SCE clarified its forecast:

> SCE believes the CEC forecast for industrial local private supply may be high. There is an ongoing shift from manufacturing to non-manufacturing activity in the local economy. Based on this shift, the SCE forecast includes a slow but steady decline in industrial energy use. The CEC forecast shows a slow but steady increase in industrial energy use. The difference in industrial outlooks probably accounts for the difference in the industrial private supply between the two forecasts.[206]

In the *Energy Report,* the Energy Commission recommends that "by the end of 2006, the Energy Commission and CPUC should collaboratively translate this goal [of 5,400 MW of CHP statewide by 2020] into annual IOU procurement targets."[207] Once these goals are established, the CPUC should incorporate them into the preferred

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[206] *Id*. at pp. 21-22.

[207] *Energy Report*, p. 78.

resource category on the need tables and correspondingly reduce the amount of undesignated need.

7.2.2. Energy Resource Needs

The preliminary energy range of need for SCE is shown in Appendix B Figure B-3; in Tables B-7, B-8, and B-9 for the base, low, and high revised staff forecasts, respectively; and is described in the sections below. The resource information shown in the appendix is based on resource plan information prepared by SCE in early 2005, and will need to be updated as part of the CPUC's 2006 procurement proceeding.

The tables and graphs in Appendix B also show the average annual energy for the years 2002 through 2004 provided by aging power plants in SCE's planning area, with a transition to the full amount from 2009 to 2012. The Energy Commission recommends that these plants be replaced by 2012, and it would be imprudent for SCE to contract with these aging units beyond 2012.

7.2.2.1. Utility-Controlled Resources

SCE's resource plans included the annual energy for utility-controlled nuclear, fossil, and hydroelectric resources. For these resources, SCE's plans assume relatively flat levels of generation throughout the forecast period. SCE's reported utility-controlled resources total between 30,000 and 33,000 GWh for the years 2009 through 2016.

7.2.2.2. Contractual Resources

SCE's resource plans show a significant drop in contractual resources throughout the forecast period, with the largest drop between 2011 and 2012 as the almost 20,000 GWh of DWR contracts reported for 2009 and 2010 decline to less than 17,000 GWh in 2011 and to zero in 2012.

SCE projected energy resources from QF and renewables contracts to remain relatively constant, with the energy supply from these contracts approximately 25,000 GWh for QF contracts and slightly less than 3,000 GWh for renewables contracts throughout the period. Energy supplies from other existing bilateral contracts decline during the planning period, going from more than 6,000 GWh in 2009 and 2010 to 1,750 GWh in 2011, and approximately 1,400 GWh for 2012 through 2016.

While the aggregated data tables counted short-term and spot market purchases as part of the total existing and planned resources, the Energy Commission has chosen to consider these purchases as part of the need to be filled by SCE.

7.2.2.3. Energy Range of Need

The balance of energy demand versus existing and planned resources for SCE reported in the resource plans in early 2005 show relatively modest energy needs across the three demand forecasts of 5 percent or less of the total energy requirement in 2009 and 2010, increasing to just over 35 percent by 2016.

In addition to developing the total range of need, the Energy Commission is reporting on the amount of preferred resources that the utilities should plan to obtain, consistent with the loading order. The Energy Commission recognizes that ongoing and future proceedings at the CPUC may result in adjustments to these numbers, but recommends that the authority the CPUC grants for open source procurement be adjusted to ensure that these preferred resources are not crowded out in the future.

The uncommitted energy efficiency savings included in the preferred resources are based on the estimates provided by SCE and based on the targets established by the CPUC in D.04-09-060, adjusted to account for the inclusion of committed energy efficiency programs through 2008 in the revised demand forecast. These savings ramp up from less than 900 GWh in 2009 to almost 9,000 GWh in 2016.

As discussed above, the Energy Commission includes in the preferred resources category renewable resources consistent with the accelerated goal of 35 percent renewables by 2020 that the Energy Commission recommended for SCE in the *2004 Energy Report Update*. While the CPUC cannot under current law require RPS procurement beyond 20 percent, the Energy Commission places great weight on the rebuttable presumption for renewable resources in any RFO seeking generation resources established by the CPUC in D.04-12-048, despite SCE's lack of specificity about how it intends to implement this policy directive.

As directed by the Energy Commission, SCE filed an accelerated renewables resource plan scenario aiming at 35 percent renewable resources by 2020. While the trajectory in this resource plan is not based on the revised staff demand forecast, it is the most detailed information in the record on the possible path that SCE could follow to meet the accelerated targets. Therefore, the Energy Commission is using the generic renewable energy needs identified by SCE in its resource plan as a placeholder to ensure that SCE will be able to purchase adequate renewables to meet the enhanced goals should they be enacted into law. The Energy Commission invites comments on this approach and recommendations on alternate approaches for determining the amount of preferred renewables in the need tables.

For SCE, these preferred resources represent more than the total need for 2009 and 2010, and slightly less than the total need in 2011 as the DWR contracts begin to go away. SCE's total need increases significantly between 2009 and 2012 because of the major expiration of DWR contracts by 2012. The share of total need represented by preferred resources declines to less than 40 percent by 2012 for all three demand forecast cases. The share then slowly increase to between 55 and 60 percent by 2016.

Though targets have not yet been established, the Energy Commission recommends that the CPUC and Energy Commission establish targets for distributed generation and combined heat and power resources by the end of 2006. When these targets are established, these need tables should be updated to reflect the targets, resulting in an increase in the preferred resources.

7.2.3. Capacity Resource Needs

The preliminary capacity range of need for SCE is shown in Appendix B Figure B-4; in Tables B-10, B-11, and B-12 for the base, low and high revised staff forecasts, respectively; and is described in the sections below. The resource information shown in the appendix is based on resource plan information prepared by SCE in early 2005, and will need to be updated as part of the CPUC's 2006 procurement proceeding.

The tables and graphs in Appendix B also show the capacity of the aging power plants in SCE's planning area, with a transition to the full amount from 2009 to 2012.

The Energy Commission recommends that these plants be replaced by 2012, and it would be imprudent for SCE to contract with these aging units beyond 2012.

7.2.3.1. Utility-Controlled Resources

SCE's resource plans include public tables providing the annual capacity for utility-controlled nuclear, fossil, and hydroelectric resources for the years 2009 through 2016.[208] These tables show a nearly constant level of capacity available from these existing and planned resources, the only change being an 11 MW reduction in fossil capacity by 2016. The Energy Commission is including these resources in its calculation of the range of need.

7.2.3.2. Contractual Resources

For contractual resources, the public capacity tables in SCE's resource plans only included the DWR contracts. The aggregated SCE planning area capacity tables also show totals for QF contracts (which are not held by other LSEs within SCE's planning area, so this total is also SCE-specific), renewable contracts, and other bilateral contracts.

The DWR contracts assigned to SCE decline rapidly starting in 2009, with total capacity declining from 3,217 MW in 2009 and 2010 to 2,415 MW in 2011, and disappearing entirely in 2012. SCE projected QF capacity to remain constant throughout the period at 3,211 MW. These IOU-specific contractual resources represent more than 80 percent of the capacity of the contractual resources in the capacity tables for SCE's planning area in 2009 through 2011, and approximately 70 percent in the remainder of the forecast period.

The capacity tables in the *Draft Transmittal Report* showed capacity from existing renewable contracts and other bilateral contracts only at the planning area level due to confidentiality constraints. The Energy Commission stated its plan to publish in the final version the POU data included in these totals, and to subtract those numbers from the planning area total to show a distribution service area total for each IOU. No parties

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[208] The public tables filed by SCE were published in Appendix B of the *RPSA Report*.

objected to this plan, so the Appendix B tables in this version of the report are distribution service area. Table 14 shows the calculation of the service area values for SCE.

Table 14: SCE Planning and Service Area Contract Data

Other Bilateral Contracts	2009	2010	2011	2012	2013	2014	2015	2016
SCE planning area	**1,261**	**1,230**	**1,174**	**1,179**	**1,202**	**1,222**	**1,233**	**1,260**
Anaheim	0	0	0	0	0	0	0	0
Pasadena	132	132	132	132	132	132	117	117
Riverside	188	136	60	60	60	60	60	60
SCE service area	**941**	**962**	**982**	**987**	**1,010**	**1,030**	**1,056**	**1,083**

Renewable Contracts	2009	2010	2011	2012	2013	2014	2015	2016
SCE planning area	**405**	**412**	**415**	**417**	**425**	**428**	**436**	**444**
Anaheim	44	49	49	49	54	54	59	64
Pasadena	7	7	7	7	7	7	7	7
Riverside	0	0	0	0	0	0	0	0
SCE service area	**354**	**356**	**359**	**361**	**364**	**367**	**370**	**373**

The aggregated tables show relatively steady capacity from renewable contracts and other bilateral contracts through the planning period, going from a combined total of 1,295 MW in 2009 to 1,456 MW in 2016. Due to confidentiality constraints, these values include a share of contracts held by ESPs.

While the aggregated data tables counted short-term and spot market purchases as part of the total existing and planned capacity, the Energy Commission has chosen to consider these purchases as part of the need to be filled by SCE.

7.2.3.3. Capacity Range of Need

As described in more detail above, the procurement need for each forecast was calculated by subtracting the identified resources and existing interruptibles capacity reported in the resource plans in early 2005 from the forecast demand. SCE's peak procurement need for 2009 is almost 40 percent of its total firm peak requirement, increasing to approximately 55 percent by 2012 and remaining level through the remainder of the planning period.

Consistent with the loading order, this need is to be filled first by future programs designed to meet the CPUC's energy efficiency and demand response targets. These goals are shown in the tables.[209] For renewables, the goals shown are based on the accelerated target that goes beyond the 20 percent RPS requirement in statute.

Additional undesignated need beyond those levels should be filled through procurement, with the CPUC's "rebuttable presumption" as part of the open source procurement, through distributed generation resources, and through an appropriate level of short-term and spot market sales and purchases. These preferred resources represent just over 25 percent of SCE's peak procurement need in 2009, increasing to approximatelyl 40 percent in 2016.

Though targets have not yet been established, the Energy Commission recommends that the CPUC and Energy Commission establish targets for distributed generation and combined heat and power resources by the end of 2006. When these targets are established, these need tables should be updated to reflect the targets, resulting in an increase in the preferred resources.

7.3. SDG&E Resource Plan and Range of Need

7.3.1. Preferred Resources

7.3.1.1. Energy Efficiency

SDG&E believes that the goals authorized by the CPUC in D.04-09-060 for 2006 through 2008 are aggressive but achievable. For the years beyond 2009, however, it believes the CPUC's stated goals will be difficult to attain. D.04-09-060 acknowledges that the adopted trajectory of GWh savings goals for SDG&E is 118 percent of the cumulative maximum achievable potential that was identified in background analysis.

[209] The demand response goal for 2007 and beyond is 5 percent of the peak demand in the service territory.

SDG&E expects that before 2009, the CPUC will reevaluate these goals, and that this reevaluation will likely result in more realistic and achievable goals for SDG&E.[210] However, SDG&E did not present a lower level of energy efficiency savings in any of its cases.

With regard to the feasibility of the 2006-2008 energy efficiency savings, the preliminary savings estimates exceed target levels. Results for 2003 and 2004 show that SDG&E did not meet its goals for GWh in those years but did meet the MW goal in 2004. A review of the proposed energy efficiency programs by the peer review group (CPUC, Energy Commission, ORA, and others) stated that the near-term goals are attainable, but that the longer-term goals would be much harder to reach. A consultant report revealed potential problems in ramping up programs to target funding levels, lack of contractors and vendors to support the programs, and the role of participants outside the direct control of SDG&E.[211]

IEP recommended that the numbers passed on to the CPUC for procurement be based on realistic, achievable inputs and not on stretch goals.[212]

SDG&E faces a more acute version of the same issue for all three IOUs. SDG&E's housing development is taking place in inland regions leading to much greater air conditioning needs than in the past. In light of this, SDG&E should be targeting energy efficiency programs that achieve peak impacts.

The 2006-2008 energy efficiency targets were included in the demand forecast, and all parties agreed they were aggressive but achievable. Parties agree that SDG&E's post-2009 goals are somewhat unrealistic and will be revisited and revised in the next CPUC proceeding when new cost-effectiveness and program performance information is available. While the CPUC has acknowledged that the post-2009 goals for SDG&E are

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[210] SDG&E April 1 filing, p.8,9 and June 29 transcript at p. 32.

[211] *RPSA Report*, p.23.

[212] Kelly, June 29 TR at 58.

118 percent of maximum achievable potential that was identified in background analysis, the CPUC has not yet revised those goals. As discussed above, the Energy Commission anticipates that the CPUC will adjust the range of need to reflect any changes in the energy efficiency goals. Therefore, in this *Transmittal Report*, the Energy Commission is using the currently adopted goals for SDG&E within the preferred resources.

As discussed above, SDG&E's comments on the *Draft Transmittal Report* expressed "serious concerns regarding the combination of the load forecast and uncommitted energy efficiency (EE) amounts used in the report for years 2009 – 2016…. [SDG&E] believes future EE efforts are already embedded in the Staff load forecast. However, the report also shows the full amount of future EE goals as a resource."[213] The Energy Commission understands that the goals as established in the CPUC energy efficiency proceeding did not have a clearly documented baseline demand forecast against which to measure, which may lead to problems when applying them to a specific demand forecast such as the revised staff forecast the Energy Commission is adopting. Resolving this issue is beyond the scope of this report, and is more appropriately addressed in the CPUC energy efficiency proceeding. To the extent that the CPUC goals are adjusted in the future, these adjustments can and should be reflected in the tables.

7.3.1.2. Demand Response

In its Reference Case, SDG&E includes the annual load reduction targets set forth by the CPUC in D.03-06-032. These targets are designed to achieve load reductions from day-ahead programs equal to 4 percent of annual system peak load by 2006 and 5 percent of annual system peak load in 2007 and beyond. SDG&E removed these targets from its alternative scenario and has included only the load reductions from those

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[213] SEU/SDG&E, November 8, 2005, p. 2. (See Appendix C for a copy of this comment letter, and Appendix D for the Energy Commission response.)

programs with approved funding. Since programs have been modified over the past several years and since the Advanced Metering/Dynamic Pricing proceeding is engaged in redesigning programs, SDG&E did not feel it had either a track record or funding authorization to forecast achievable programs over the long term.[214] This results in about 200 MW less peak reduction by 2012 in the planning area, with program acceleration so that similar 400 MW reductions are reached by 2016.[215]

The Energy Commission is showing the current CPUC target of 5 percent of service territory load in 2007 and beyond as the amount of preferred demand response resources in the need tables. The Energy Commission recognizes that the CPUC may decide to revise those targets in its demand response proceeding and expects that the values in the need tables will be adjusted appropriately if new targets are adopted.

In its comments on the *Draft Transmittal Report*, SDG&E noted an error in the demand response portion of the SDG&E capacity tables in Appendix B of the *Draft Transmittal Report*. Those tables showed no resources in the "existing interruptible/emergency programs" category, based on the information provided by SDG&E in their resource plans in early 2005. SDG&E's comments clarify that at the time of those filings, "SDG&E had 6 MW of committed interruptible programs and 30 MW of committed dispatchable demand response programs."[216] These had been included in their submittal as uncommitted rather than committed. The Appendix B totals have now been updated to include those 36 MW, and the category title has been renamed "existing interruptible/ emergency programs and dispatchable demand response." SDG&E further notes that it currently has 86 MW of committed interruptible and dispatchable demand response programs. The Energy Commission expects that these totals will be updated as appropriate during the CPUC's 2006 procurement proceeding.

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[214] SDG&E April 1 filing, p.9.

[215] Aggregated Data Tables 27 and 29.

[216] SEU/SDG&E, November 8, 2005, p. 3.

7.3.1.3. Renewable Energy

In SDG&E's April 1 filing, renewable energy targets are met in three of the four scenarios, with SDG&E failing to meet the required 20 percent of retail sales by 2010 in its no major transmission scenario. All other scenarios assume the development of a major transmission line to either SCE territory or the Imperial Valley. The reference case meets the 20 percent requirement by 2010 and holds that percent constant throughout the forecast period. The accelerated renewables case meets the target of 28 percent by 2016 but states that several factors would determine if this is feasible, including the availability, portfolio fit and cost of renewable energy; whether new transmission lines are built; and whether or not SDG&E can procure and count renewable energy credits for meeting this target.[217]

Staff noted that in the reference case and the alternative case, SDG&E assumes a doubling of renewable energy in its portfolio mix between 2009 and 2010 in order to meet the 20 percent target.[218] This is implausible without some major change such as a new transmission line or use of renewable energy credits. SDG&E states that these cases both assume the addition of a major transmission line and additional renewable projects that will take time to develop.

Staff found the renewable development assumptions used in these plans to be plausible by comparing the plans by technology and location with the remaining technical potential in the *2003 Renewable Resources Development Report*.[219] SDG&E demonstrated it plans to meet RPS requirements, but will probably need either major new transmission or renewable energy trading credits to attain the 2010 goal on time. SDG&E plans to submit a bulk transmission line to the CPUC in 2006. The Energy

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[217] SDG&E, April 1 filing, p. 3

[218] *RPSA Report*, p. 57.

[219] *RPSA Report*, p. 59. See also *Renewable Resources Development Report*, California Energy Commission, publication 500-03-080F, November, 2003.

Commission supports the value of a new bulk line, as discussed below and in the *Draft Strategic Plan*. Renewable credits are also under active consideration.

The Energy Commission has decided to use the generic renewable energy and capacity values developed by SDG&E for the accelerated renewables case within the preferred renewables identified in the range of need table. The Energy Commission recognizes that this scenario was based on a different demand forecast, so the resulting trajectory of that level of future purchases would not be 33 percent of demand in 2020. Nonetheless, the primary purpose of identifying a preferred level of renewable resources on the need tables is to avoid procuring so much in non-preferred resources that renewable purchases to meet future targets are precluded. Therefore, the Energy Commission considers the generic renewable resources identified by SDG&E in its accelerated renewables case, which all parties agreed would be technically achievable (though at uncertain costs), provide a useful benchmark. The Energy Commission invites comments on this approach and recommendations on alternate approaches for determining the amount of preferred renewables to identify in the need tables.

7.3.1.4. Distributed Generation

Staff's assessment of SDG&E's DG additions revealed that future DG additions were significantly less than historical monthly average additions of 1.2 MW from 2001-2004. This average was calculated using interconnection data from 2001-2004.[220]

SDG&E states that an analysis of historical interconnection data would be necessary to determine whether using data from this time period is appropriate for forecasting future DG additions. DG additions during and after the energy crisis and the addition of a few large projects could skew the monthly average and may not be indicative of future DG additions.[221]

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[220] *RPSA Report,* p.78.

[221] SDG&E July 22 comments p. 9.

In the *Energy Report*, the Energy Commission recommends that "by the end of 2006, the Energy Commission and CPUC should collaboratively translate this goal [of 5,400 MW of CHP statewide by 2020] into annual IOU procurement targets."[222] Once these goals are established, the CPUC should incorporate them into the preferred resource category on the need tables and make a corresponding change in the undesignated need portion of these tables.

7.3.2. Energy Resource Needs

The preliminary energy range of need for SDG&E is shown in Appendix B Figure B-5; in Tables B-13, B-14, and B-15 for the base, low and high revised staff forecasts, respectively; and is described in the sections below. The resource information shown in the appendix is based on resource plan information prepared by SDG&E in early 2005, and will need to be updated as part of the CPUC's 2006 procurement proceeding.

The tables and graphs in Appendix B also show the average annual energy for the years 2002 through 2004 provided by the aging power plants in SDG&E's planning area, with a transition to the full amount from 2009 to 2012. The Energy Commission recommends that these plants be replaced by 2012, and it would be imprudent for SDG&E to contract with these aging units beyond 2012.

7.3.2.1. Utility-Controlled Resources

SDG&E's resource plans include the annual energy for utility-controlled nuclear, fossil, and hydroelectric resources. For nuclear resources, SDG&E proposes to revise its 20 percent ownership portion, 430 MW, of the San Onofre Nuclear Generation Station (SONGS).[223] SDG&E has opted not to participate in the proposed replacement of the SONGS steam generators and is awaiting a CPUC decision in A.04-02-026. SDG&E assumes in its reference case that the CPUC will allow SDG&E to not participate and

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222 *Energy Report*, p. 78.

223 SDG&E, April 1, p. 2

reduce its ownership share to 14 percent of SONGS. If the replacements go forward on SCE's proposed schedule, these changes will occur in 2009 for Unit 2 and 2010 for Unit 3. The result is a drop in nuclear energy in the resource plan from more than 3,100 GWh in 2009 to approximately 2,500 GWh through the remainder of the planning period. The CPUC is expected to rule on SONGS before completion of the 2006 long term procurement proceeding, and any changes necessary to this portion of the need table should be made based on that ruling.

SDG&E's plans assume relatively flat levels of hydro and fossil generation throughout the forecast period. SDG&E shows small negative hydro energy resources of approximately 15 GWh throughout the forecast period. SDG&E relies on hydro pumped storage that, on average through the year, results in energy expenditures while offering advantages in terms of available capacity during peak times. The fossil energy resources total approximately 4,000 GWh throughout the forecast period. Overall, SDG&E's reported utility-controlled resources start at 7,100 GWh in 2009, and then range between 6,200 and 6,700 GWh for the years through 2016.

7.3.2.2. Contractual Resources

SDG&E's resource plans show a significant drop in contractual resources throughout the forecast period, with the largest drop between 2010 and 2011 due to the expiration of more than 1,500 GWh of DWR contracts. SDG&E projects energy resources from QF contracts to remain relatively constant throughout the period, with the energy supply from these contracts slightly more than 1,700 GWh. Energy supplies from renewable contracts and other bilateral contracts decline throughout the planning period, going from a combined total of slightly more than 6,000 GWh in 2009 to approximately 2,500 GWh in 2016.

While the aggregated data tables counted short-term and spot market purchases as part of the total existing and planned resources, the Energy Commission has chosen to consider these purchases as part of the need to be filled by SDG&E.

7.3.2.3. Energy Range of Need

The balance of energy demand and existing and planned resources reported in the resource plans in early 2005 for SDG&E show relatively modest energy needs across the three demand forecasts of approximately 10 percent of the total energy requirement in 2009 to almost half by 2016. In addition to developing the total range of need, the Energy Commission is reporting the amount of preferred resources that the utilities should plan to obtain consistent with the loading order. The Energy Commission recognizes that ongoing and future proceedings at the CPUC may result in adjustments to these numbers, but recommends that the authority the CPUC grants for open source procurement be adjusted to ensure that these preferred resources are not crowded out in the future.

The uncommitted energy efficiency savings included in the preferred resources are based on the estimates provided by SDG&E based on the targets established by the CPUC in D.04-09-060, adjusted to account for the inclusion of committed energy efficiency programs through 2008 in the revised demand forecast. These savings ramp up from approximately 140 GWh in 2009 to more than 2,000 GWh in 2016.

As discussed above, the Energy Commission is including in the preferred resources category renewable resources consistent with the accelerated goal of 33 percent renewables by 2020 that the Energy Commission recommended for SDG&E in the *2004 Energy Report Update*. While the CPUC cannot under current law require RPS procurement beyond 20 percent, the Energy Commission places great weight on the rebuttable presumption for renewable resources in any RFO seeking generation resources established by the CPUC in D.04-12-048, despite SDG&E's lack of specificity about how it intends to implement this policy directive.

As directed by the Energy Commission, SDG&E filed an accelerated renewables resource plan scenario aiming at 33 percent renewable resources by 2020. While the trajectory in this resource plan is not based on the revised staff demand forecast, it is the most detailed information in the record on the possible path that SDG&E could follow to meet the accelerated targets. Therefore, the Energy Commission is using the generic renewable energy needs identified by SDG&E in this resource plan as a placeholder to ensure SDG&E will be able to purchase adequate renewables to meet the enhanced goals, should they be enacted into law. The Energy Commission invites comments on this approach and recommendations on alternate approaches for determining the amount of preferred renewables to identify in the need tables.

These preferred resources represent between 30 and 40 percent of the total energy needs identified for SDG&E in 2009. Because SDG&E's accelerated renewables resource plan included a major jump in renewable resources in 2010 on the assumption that additional transmission would become available, the preferred resources represent approximately 75 percent of the total need in 2010. The portion of total need represented by the preferred resources then drops to near 55 percent by 2012, and then increases slowly to approximately 65 percent by 2016.

Though targets have not yet been established, the Energy Commission recommends that the CPUC and Energy Commission establish targets for distributed generation and combined heat and power resources by the end of 2006. When these targets are established, these need tables should be updated to reflect the targets, resulting in an increase in the preferred resources and a decrease in the undesignated need portion of the tables.

7.3.3. Capacity Resource Needs

The preliminary capacity range of need for SDG&E is shown in Appendix B Figure B-6; in Tables B-16, B-17, and B-18 for the base, low and high revised staff forecasts, respectively; and is described in the sections below. The resource information shown in the appendix is based on resource plan information prepared by SDG&E in early 2005, and will need to be updated as part of the CPUC's 2006 procurement proceeding.

The tables and graphs in Appendix B also show the capacity of the aging power plants in SDG&E's planning area, with a transition to the full amount from 2009 to 2012. The Energy Commission recommends that these plants be replaced by 2012, and it would be imprudent for SDG&E to contract with these aging units beyond 2012.

7.3.3.1. Utility-Controlled Resources

SDG&E's resource plans included public tables providing the annual capacity for utility-controlled nuclear, fossil, and hydroelectric resources for the years 2009 through 2016.[224] These tables show a nearly constant level of capacity available from these existing and planned resources, the only change being a 66 MW reduction in nuclear capacity starting in 2010, based on SDG&E's reduced ownership share in SONGS. The Energy Commission is including these resources in its calculation of the range of need.

7.3.3.2. Contractual Resources

For contractual resources, the public capacity tables in SDG&E's resource plans only included the DWR contracts. The aggregated SDG&E planning area capacity tables also show totals for QF contracts (which are not held other LSEs in the SDG&E planning area, so this total is also SDG&E-specific), renewable contracts, and other bilateral contracts.

The DWR contracts decline rapidly after 2011, with a total capacity declining to 2,103 MW for 2009 and 2010, declining to 718 MW in 2011 and 26 MW in 2012 and 2013. No DWR contracts assigned to SDG&E remain in place after 2013. SDG&E projected QF capacity to remain constant throughout the period at 221 MW. These IOU-specific contractual resources represent more than 70 percent of the capacity of the contractual resources in the capacity tables for SDG&E's planning area in 2009 and 2010, declining to just over half in 2011 and to just over 20 percent for the remainder of the period.

The aggregated tables show a small decline in capacity from renewable contracts and other bilateral contracts through the planning period, going from a combined total of 840 MW in 2009 to 766 MW in 2016. Due to confidentiality constraints, these values include a share of contracts held by ESPs. There are no POUs in SDG&E's planning area, so no adjustments were made to this part of these tables from the *Draft Transmittal Report*..

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[224] The public tables filed by SDG&E were published in Appendix B of the *RPSA Report.*

While the aggregated data tables counted short-term and spot market purchases as part of the total existing and planned capacity, the Committee has chosen to consider these purchases as part of the need to be filled by SDG&E.

7.3.3.3. Capacity Range of Need

As described in more detail above, the procurement need for each forecast was calculated by subtracting the identified resources and existing interruptibles capacity reported in the resource plans in early 2005 from the forecast demand. SDG&E's peak procurement need for 2009 is less than 10 percent of their total firm peak requirement, increasing to approximately 55 percent by 2012 and increasing slightly to 60 percent by the end of the planning period.

Consistent with the loading order, this need is to be filled first by future programs designed to meet the CPUC's energy efficiency and demand response targets. These goals are shown in the tables.[225] For renewables, the goals shown are based on the accelerated target that goes beyond the 20 percent RPS requirement in statute.

Additional undesignated need beyond those levels should be filled through procurement, with the CPUC's rebuttable presumption as part of the open source procurement, through distributed generation resources, and through an appropriate level of short-term and spot market sales and purchases.

These preferred resources exceed SDG&E's total peak need identified for SDG&E in 2009 and 2010. Preferred resources then generally remain in the range of 40 to 50 percent of total peak need from 2011 through 2016.

Though targets have not yet been established, the Energy Commission recommends that the CPUC and Energy Commission establish targets for distributed generation and combined heat and power resources by the end of 2006. When these targets are established, these need tables should be updated to reflect the targets,

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[225] The demand response goal for 2007 and beyond is 5 percent of the peak demand in the service territory.

resulting in an increase in the preferred resources and a decrease in the undesignated need values.

8. Natural Gas Demand, Supply, Prices, Infrastructure Needs, and Policies

The Committee assessed natural gas demand, supply, price, and infrastructure issues. These issues will significantly affect California's energy future; as a result, related policy choices will be an important tool in meeting future energy challenges.

8.1. Preliminary Staff Assessment

In order to assist in the Committee's consideration of these issues, the Energy Commission staff prepared a natural gas demand forecast, using the North American Regional Gas – MarketBuilder model (NARG-MB).[226] The results indicate that natural gas demand in California is expected to grow at a rate of 0.7 percent per year, from 6.5 billion cubic feet per day (cfd) in 2006 to slightly under 7 billion cfd in 2016.[227] Demand in the commercial and residential sectors will grow at 2 percent and 1.4 percent respectively during the next decade, but this growth will be offset by declining demand and slower growth in gas consumption by industrial users and power generators.[228] Because the market from which California obtains its natural gas extends across the entire continent, the staff assessment also included projections for natural gas consumption and growth rates throughout North America.[229]

Generally speaking, natural gas consumption is expected to rise annually by 1.7 percent in the United States over the forecast period, with most of the increase due to

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[226] *Preliminary Reference Case in Support of the 2005 Natural Gas Market Assessment*, Energy Commission Staff, June, 2005, p. 1

[227] *Id*. at p. xi

[228] *Id*. at p. 7

[229] *Id*. at p. x

growth in the power generation sector in the eastern portion of the United States.[230] Total consumption will likely increase from slightly less than 60 billion cfd to approximately 70 billion cfd by 2016.[231]

Energy Commission staff also conducted an assessment of natural gas supply, using information from the National Petroleum Council, which recently evaluated the North American gas market, as well as the United States Geological Survey, the Mineral Management Service, and other industry and governmental groups. This assessment addressed gas supplies available to North American markets generally (increasing from approximately 80 billion cfd in 2006 to slightly more than 90 billion cfd in 2016), and projected gas supplies by basin to California (increasing from 5.4 billion cfd in 2006 to 5.9 billion cfd in 2016). The report also included an assumption that the liquefied natural gas (LNG) portion of North American natural gas supply would increase by 8.7 percent during the forecast period.[232]

With respect to prices, Energy Commission staff expects a general initial increase in wellhead prices, followed by price decreases several years into the forecast period, due to the introduction of new supplies. However, by the end of the forecast period, prices would be above current levels.[233] End-use prices in California generally mirror this trend, with prices being highest for SDG&E customers and lowest for PG&E customers, although the gap will narrow over time.[234]

In evaluating infrastructure, Energy Commission staff addressed interstate and intrastate pipeline capacity and adequacy issues, but did not explicitly examine what

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[230] *Id*. at p. 5

[231] *Ibid*.

[232] *Id*. at p. 27

[233] *Id*. at p. 41

[234] *Id*. at p. 43

infrastructure would be associated with additional LNG facilities.[235] Staff noted that there have been several major pipeline expansions during the past four years, resulting in an increase in receiving capacity from 6,901 million cfd in 2001, to 7,970 million cfd in 2004.[236] Given these expansions, and assuming that an LNG facility is built on the West Coast, staff concluded that interstate pipeline capacity is sufficient to meet California's natural gas needs on an annual basis.[237] However, staff indicated that interstate capacity is not sufficient to meet daily needs, and that either cold weather or interstate pipeline disruptions can result in shortfalls. At those times, the state must rely on its fairly significant storage capacity to meet demand.[238]

Staff also assessed the delivery capacity of the natural gas pipelines – the ability of the pipelines to actually deliver natural gas to California customers – and concluded that interstate pipeline actual flows into California will generally increase, and that expansion of the TGN (Transportadora de Gas Natural) Pipeline that connects Baja California to the San Diego region would be cost-effective if the LNG projects in Baja California are built.

With respect to natural gas policy issues, staff stated that it does not have immediate concerns about reliability.[239] However, staff notes that consumers will likely pay a higher price for natural gas. Staff identified several policy options, including investments in energy efficiency, development of supplemental supplies, and ensuring that needed infrastructure is identified in a timely manner.[240] Staff also pointed out that

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[235] *Id*. at p. 33

[236] *Id*. at p. 34

[237] *Ibid*.

[238] *Id*. at p. 35

[239] *Id*. at p. 49

[240] *Id*. at p. 53

reducing peak electrical demand will reduce a small summer peak in natural gas demand because of the use of natural gas in California's electrical generating system.[241]

8.2. Utility Assessments

In addition to the staff assessment, the three IOUs offered assessments of natural gas issues.[242] With respect to forecasted demand, PG&E reported that its 10-year forecast for the residential sector was within 1 percent of the staff forecast.[243] There were some minor data issues, but they did not have a significant effect on the forecasts. On the non-residential side, PG&E's forecast differed significantly from staff's.[244] PG&E's forecast projects some growth in the early years of the forecast, but then shows stagnation and declining demand in the later years. PG&E attributes this to high natural gas prices and lack of growth in manufacturing; the only sector that PG&E believes will experience growth is oil refining; all others will not.[245] PG&E also notes that both consumption per customer and total number of customers are declining in those sectors.[246] Staff's forecast on the other hand, shows annual average growth rates of 1 percent.[247]

Sempra provided natural gas forecasts for both the Southern California Gas Company (SCG) and SDG&E service area. For SCG, Sempra's forecast for growth rates

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[241] *Id*. at p. 54

[242] There are three IOUs offering natural gas services to California customers – PG&E, SDG&E, and Southern California Gas Company (SCG). SCG and SDG&E share the same parent company -- Sempra Energy Utilities (Sempra) – and filed joint comments and made joint presentations on natural gas issues.

[243] 7/14/05 RT, p.70

[244] 7/14/05 RT, p. 74.

[245] *Id*. at pp. 75-76

[246] *Id*. at p. 77

[247] PG&E's Comments on CEC's Draft Gas Demand Forecast, Slide 5; Preliminary Reference Case in Support of the 2005 Natural Gas Market Assessment, Energy Commission Staff, June, 2005, p. 11

in the residential sector is similar to staff's, with the differences attributable to differing assumptions about long-term energy efficiency savings. Sempra included savings mandated by the CPUC for a 10-year period, whereas Energy Commission staff only included savings from programs that are currently funded.[248] The difference in growth rate assumptions is approximately 0.1 percent per year.[249] On the non-residential side, the staff and Sempra forecasts differ more than on the residential side, but the difference is primarily due to the differing assumptions about energy efficiency savings over time discussed above.[250] However, here the difference in growth rate assumptions is 1.9 percent per year.[251] Finally, the staff forecast for demand growth in the electrical generation market segment is higher than Sempra's.[252]

For SDG&E, the two residential forecasts use similar growth rates, but the staff forecast shows a higher level of demand[253]. On the non-residential side, staff assumed an annual growth rate 1.3 percent higher than that assumed by Sempra, due primarily to the inclusion by Sempra of longer-term energy efficiency savings that staff did not include.[254] Finally, there are significant differences in the growth rate assumptions for the electrical generation sector, with staff showing an annual growth rate of 4.6 percent, compared to Sempra's assumption of 1.7 percent.[255]

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[248] 7/14/05 RT, pp. 83-84

[249] July 14 hearing, Sempra presentation, "Comments of Southern California Gas Company and San Diego Gas and Electric Company on the CEC Staff's Preliminary Natural Gas Assessment and Policy Issues Report", slide 3

[250] July 14 hearing, Sempra Presentation, slide 4.

[251] *Ibid*.

[252] July 14 hearing, Sempra Presentation, slide 5.

[253] July 14 hearing, Sempra Presentation, slide 7.

[254] *Id*. at slide 8

[255] *Id*. at slide 9

PG&E also presented comments on natural gas supply and infrastructure needs. PG&E is concerned because it believes that natural gas prices will continue to increase.[256] As a result, PG&E supports implementation of energy efficiency programs and development of renewable resources to moderate the effect of these price increases.[257] PG&E also sees a benefit from increased supplies and believes the most promising new supplies are LNG and natural gas delivered via an Alaska pipeline.[258] Finally, PG&E believes that new infrastructure -- both storage and pipelines -- is needed, primarily to connect to new supplies of LNG entering the state.[259]

Sempra's comments on natural gas supply and price issues focused on the need to develop new supplies, especially LNG. Sempra is concerned about price volatility and the effect of high prices on certain industrial sectors. Sempra believes that to address these problems, the state should support the development of new supplies and actively promote LNG deliveries. Sempra also explained that it believes shippers should pay the costs of expanding "backbone" receipt facilities, unless benefits exceed costs, in which case the costs should be rolled into system rates. Finally, Sempra expressed support for the natural gas policy recommendations included in the *2003 Energy Report*.

8.3. Western States Petroleum Association (WSPA)

WSPA did not file written comments on natural gas issues, but did make an oral presentation at the July 14, 2005 hearing on staff's preliminary natural gas assessment and natural gas policy issues. In its comments, WSPA recommended that the Committee focus on reliability issues and stated that WSPA's policy is to support expanded natural gas exploration, development and production, maintenance of

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[256] 7/14/05 RT, p. 267

[257] PG&E's Comments on Committee Hearing on the Staff's Preliminary Natural Gas Assessment and Policy Issues, Robert Howard, slide 3

[258] *Id*. at slide 5

[259] 7/14/05 RT, pp. 267-268

existing infrastructure and development of new infrastructure, and development of LNG facilities. WSPA stated that it believes natural gas demand may be greater than identified in the staff assessment.[260]

8.4. Committee Discussion

Based on the presentations at the July 14, 2005 hearing and comments received on the preliminary staff forecast, the Committee directed staff to make several changes in the assumptions underlying the natural gas price and supply forecast. The major changes were the demand elasticity parameters for California markets, the ability for LNG receiving facilities in the U.S. to expand beyond 2010 if they are economical to do so, and delaying the entry of natural gas supplies from the Alaskan and MacKenzie pipelines. The revised forecast was published in September 2005.[261]

The demand projections resulting from the NARG-MB model results differed slightly from the demand projections developed in the Demand Analysis Office of the Energy Commission due to differing economic-demographic factors such as the population growth in the state. The input parameters in the NARG-MB model were changed to be consistent with assumptions used by other Energy Commission offices, reflecting the Department of Finance population growth rate estimates for California (as opposed to the DOE/EIA assumptions for the entire United States).

The preliminary reference case assumed that no LNG facility would expand above its current capacity, plus any additional capacity under construction, beyond the year 2010. This assumption was changed to include any economically viable expansion of LNG facilities beyond the year 2010. Further, based on more recently available market information, the time of availability of the MacKenzie pipeline and the Alaskan pipeline from Arctic resources was delayed. It was assumed that the MacKenzie

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[260] 7/14/05 RT, p. 90

[261] *Revised Reference Case in Support of the 2005 Natural Gas Market Assessment*, Energy Commission Staff Report, CEC-600-2005-026-REV, September 2005.

pipeline would be constructed and be in operation in 2013, while the Alaskan pipeline would be available by the year 2016.

The Committee directed staff to make the above changes and provide the updated results at the hearing on the natural gas chapter of the *Draft Energy Report* that was held on October 7, 2005. At the hearing, PG&E filed testimony saying the staff generated price forecast for the Henry Hub estimates or the Lower 48 wellhead prices were reasonable compared to other private forecasts reviewed by PG&E. However, it commented that the natural gas end-use or retail prices in the PG&E service area were higher than its estimations. Based on PG&E comments, staff made further changes to the reference case. Changes included modifying the distribution costs in the pricing chain to be fixed at the tariff rate. The results of the revised reference case are discussed below.

8.4.1. Natural Gas Demand

Revisions to the preliminary reference case after the July 14 hearing resulted in some changes to natural gas demand in California. Total natural gas demand in California was projected to grow at a rate of 0.7 percent per year, from about 6.2 billion cfd in 2006 to 6.6 billion cfd in 2016 in the reference case.[262] The changes made in response to comments received at the October 7 hearing did not significantly change the growth rate so it stayed at 0.7 percent per year. Strong growth in the residential and commercial sectors will be offset by declining industrial gas demand and slower growth in gas consumption by power generators than has been observed in recent years. Overall, the natural gas demand growth in the state is expected to be lower than the demand growth in the rest of the nation.

8.4.2. Natural Gas Supply

The September assessment addressed gas supplies available to North American markets generally, (increasing from approximately 80 billion cfd in 2006 to slightly more than 94 billion cfd in 2016.[263] The report included an assessment of natural gas supplies that California receives from various basins in the North American continent including the Western Canadian Sedimentary basin (principally, the province of Alberta, Canada), Rocky Mountain basins, and the Southwestern basins. By 2016, Southwest supplies continue to be the larger resources, satisfying 43 percent of California's market. Canadian and Rocky Mountain basins shares drop slightly to about 17 and 25 percent, respectively. California production, which has been declining over the past four years, will continue at 15 percent over the forecast period . LNG's share from the new Baja California projects in the state's total consumption will amount to about 4 percent by 2016. The report also included an assumption that the LNG portion of North American natural gas supply would expand based on economic competition and increase to 22 percent during the forecast period.[264]

Since 2001, natural gas supplies in the North American continent have been observed to follow a different trend than during the previous decade. Even though the number of drilling rigs has kept pace with price and demand, total quantity of gas produced has been shy of meeting the demanded quantities. Hence the lower 48 states have had to increasingly rely either on Canadian imports or on LNG from a variety of foreign sources. Canadian use of natural gas also has grown, and basins in the Canadian producing provinces are facing similar difficulties as their US counterparts; it is anticipated in the long run that the production in Canada is not going to be sufficient to meet both Canada's own domestic needs and its export requirements to the US. This will likely lead to an increased reliance on and need to bring in natural gas as LNG from other available foreign sources.

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[262] *Ibid.*

[263] *Ibid.*

[264] *Id*. at p. 27.

Changes to assumptions after the October 7 hearing focused on transportation costs and hence did not significantly affect the production trends. The final reference case also shows supply trends as discussed above.

8.4.3. Natural Gas Prices

Since the energy crisis of 2001, natural gas prices that were anticipated to revert to the trends of the previous 10 to 15 years have instead consistently remained high. Global crude oil markets, a decreasing rate in finding new natural gas supplies, and events related to weather — most recently Hurricanes Katrina and Rita — have continued to put pressure on natural gas prices across the nation. Generally, when hurricanes impact the industry, producers and pipelines recover and resume normal operations within one to three months. However, the repeated and harsh impacts of this season's two major hurricanes have dramatically increased natural gas prices, with price and supply effects possibly lasting for more than six months. These trends will likely continue to place upward pressure on natural gas prices. It is the industry's anticipation that the prices may not back down from the high levels seen today for a significant period of time.

The Energy Commission staff forecast does not consider such unanticipated events in its price projections. The staff model is based on market fundamentals that normally drive the supply-demand balance in a well functioning market; this model and other similar ones have a long history of providing reasonably accurate forecasts. Yet, clearly, today's market prices are substantially higher than the staff's forecasted prices.

In the past five years, numerous events have driven prices away from a fundamental forecast of future prices. In addition to the hurricanes, price manipulation documented in the Enron scandal and the misreporting of the natural gas price indices are examples of events that make comparing the staff forecast — or any other forecast — with natural gas market prices increasingly problematic. Existing equilibrium model forecasts relied on by Energy Commission staff and others cannot adequately capture such events in advance with any accuracy, but such events do have a very real effect on market prices. The Energy Commission notes that a fundamentals forecast may underrepresent future market prices.

The Center for Energy Efficiency and Renewable Technologies (CEERT) noted in its comments that current natural gas prices reflect large scarcity rents above the marginal costs of production that consumers are paying. It further notes that equilibrium models like the Energy Commission staff NARG model fail to capture this discrepancy.[265] While recognizing the difficulty in projecting what the scarcity price of natural gas will be in the future, CEERT points to this failure as a major shortcoming in staff's current approach to forecasting natural gas prices.

Despite the high prices being paid for gas over the last few years, U.S. production has not increased. Ass CEERT points out, this is not because the gas industry has not tried. In fact, the number of wells drilled per year has followed producer prices fairly well. CEERT further notes that if U.S. production hasn't increased at today's high prices, it is unlikely to increase in the foreseeable future, especially if LNG supplies reduce current well-head prices, as staff assumed in its assessment. The Commission noted that CEERT made a similar critique of staff's forecast in the *2003 Energy Report* process. While the Energy Commission shares concerns about this dilemma, it also notes that some parties provided comments that the Energy Commission's price forecast is too low, while others criticized it as too high.

The Energy Commission will adopt the staff's forecast for the *2005 Energy Report* with the caveat that it should be augmented for its first two years by NYMEX prices. The Energy Commission should further investigate alternative forecasting methods in the *2007 Energy Report* cycle to better assess future natural gas prices. While the *Draft Transmittal Report* specifically invited parties to comment on the augmenting the staff

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[265] October 7 afternoon hearing, Center for Energy Efficiency and Renewable Technologies presentation; 10/7/05 afternoon RT, pp.87-107.

natural gas forecast with NYMEX prices for the first two years, no comments were received on this step.

9. Transmission Project Recommendations

9.1. Procedural History

In 2002 and 2003, the Legislature added new electricity resource and transmission planning responsibilities to the Energy Commission's *Energy Report* process. In 2002 the Legislature also assigned new responsibilities to the CPUC concerning IOU procurement. More recently, the CA ISO has new management and in recognition of the seriousness of the state's growing transmission problems, is proposing to revamp its transmission and grid planning processes. These agencies must work hand-in-hand with the Legislature to produce a proactive and forward-looking transmission planning and permitting process for California.

Senate Bill 1565 (SB 1565, Bowen, Chapter 692, Statutes of 2004) added Public Resources Code Section 25324:

> The [Energy Commission], in consultation with the Public Utilities Commission, the California Independent System Operator, transmission owners, users, and consumers, shall adopt a strategic plan for the state's electric transmission grid using existing resources. The strategic plan shall identify and recommend actions required to implement investments needed to ensure reliability, relieve congestion, and meet future growth in load and generation, including, but not limited to, renewable resources, energy efficiency, and other demand reduction measures. The plan shall be included in the integrated energy policy report adopted on November 1, 2005, pursuant to subdivision (a) of Section 25302.

To meet this directive, as well as to receive input on critical transmission-related issues for inclusion in the *2005 Energy Report*, the Committee held multiple workshops. Committee workshops that focused on operational issues associated with integrating renewables were conducted on February 3 and May 10, 2005; the April 11, 2005 workshop focused on geothermal issues; and the May 9, 2005 workshop focused on renewable resource potential in California and interstate renewable resources. In addition, the May 19, 2005 Committee workshop focused on corridor planning and strategic transmission planning issues.

The *Transmission Staff Report*,[266] published on July 20, 2005, was the culmination of staff's compilation of information from these *Energy Report* Committee workshops, as well as the LSE transmission plans filed in response to the *Forms and Instructions for the Electricity Resources and Bulk Transmission Data Submittal*[267]. The *Transmission Staff Report* represents a comprehensive assessment of the status of transmission planning and permitting; transmission system problems and project updates; long-term corridor needs; and transmission issues associated with renewables integration; based on the Committee workshop record. The report also documents the Energy Commission staff's efforts to identify and evaluate the actions and strategies necessary to develop the foundation for the state's first *Strategic Transmission Investment Plan* (*Strategic Plan*).

The *Transmission Staff Report* focused on five areas:

- Transmission policy status (Chapter 2).
- Transmission problems and project update (Chapter 3).
- Transmission corridor planning and development (Chapter 4).
- The impact of transmission on renewable development (Chapter 5).
- Transmission policy options (Chapter 6).

A Committee hearing on Strategic Transmission Planning Issues and the *Transmission Staff Report* was held on July 28, 2005 to seek public comment on issues relating to the *Transmission Staff Report*, the strategic transmission planning process, and to review new contractor work completed after publication of the *Transmission Staff Report*. Interested parties were encouraged to present their views either in advance of the hearing, orally at the hearing, or in writing after the hearing. Reply comments were

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266 California Energy Commission, *Upgrading California's Electric Transmission System: Issues and Action for 2005 and Beyond*, July 2005. CEC 700-2005-018.

267 California Energy Commission, *Forms and Instructions for the Electricity Resources and Bulk Transmission Data Submittal*, January 2005. CEC 100-2005-002-CMF.

requested by August 4, 2005. Hearing transcripts were posted on the Energy Commission website on August 4, 2005.[268] Final contractor reports, presentation slides, and written comments are available online.

The notice for the hearing was posted July 14, 2005. The agenda, presentations and roundtable discussion questions were posted July 27, 2005 on the Energy Commission website. The hearing was conducted in coordination with the ACR issued by CPUC President Peevey in Rulemaking 04-04-003 on March 14, 2005. The ACR noted that the Integrated Energy Policy Report Committee would conduct public proceedings, including any hearings necessary pursuant to Public Utilities Code (PUC) section 1822, in its consideration of information used to determine the likely range of the specific needs of statewide load serving entities. Consistent with this requirement, the notice offered parties the opportunity to cross examine on issues relating to strategic transmission planning and on the *Transmission Staff Report*. Both of these topics support the creation of the state's first *Strategic Plan* as required by Public Resources Code section 25324. No parties requested the opportunity to cross examine on these topics.

The following parties provided technical information or comments relevant to the hearing issues: Lawrence Berkeley National Laboratory (LBNL)/Consortium for Electric Reliability Technology Solutions (CERTS); Navigant Consulting; Pinnacle Consulting LLC; the Energy Commission; SDG&E; Imperial Irrigation District (IID); SCE; Los Angeles Department of Water and Power (LADWP); PG&E; TURN, Flynn RCI, and the CA ISO.

The discussion below summarizes staff's review of transmission projects and the comments of the various parties relating to these projects, focusing on the five projects the Energy Commission is recommending in the *Strategic Plan* and the *Energy Report*.

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[268] Transcripts: July 28, 2005 Re: Strategic Transmission Planning Issues and Transmission Staff Report Hearing. Docket No. 04-IEP-01F.

9.2. Evaluation of Transmission Projects

The July 28, 2005 hearing included a request for feedback on the *Transmission Staff Report*. Staff posed the following questions to solicit comments on the report:

- Did the staff accurately capture parties' input?
- Are there other relevant points?
- Did staff draw appropriate conclusions?
- Did staff identify appropriate policy options?

Also at that hearing, staff introduced the PRC section 25324 directive and suggested the following criteria for including specific transmission projects in the Strategic Plan:

- The project could be on line by 2010.
- The project is in need of siting approval.
- The project meets the PRC Section 25324 guidelines.
- The project is consistent with *2003* and *2004 Energy Report* recommendations.

Based on these criteria, the staff proposed nine projects for consideration in the Strategic Plan, using the 21 projects in Chapter 3 and Appendix F of the *Transmission Staff Report* as the starting point.[269] The following nine projects passed the first two screening criteria noted above of being able to be on line by 2010 and being in need of siting approval:

- Trans-Bay DC Cable Project (project #3[270])
- Metcalf-Moss Landing 230 kV Reinforcement (project #4)
- San Diego 500 kV Project (project #7)
- Lake Elsinore Advanced Pumped Storage (LEAPS) Project (project #8)
- South of Lugo Congestion Management (project #11)
- Path 26 Upgrades (project #12)

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[269] July 28 hearing, California Energy Commission staff presentation, "Upgrading California's Electric Transmission System: Issues and Actions for 2005 and Beyond," slide no. 14, posted July 28, 2005, [http://www.energy.ca.gov/2005_energypolicy/documents/2005-07-28_hearing/presentations/2005-07-28_GRAU_JUDY.PDF].

[270] Project numbering is consistent with the conventions used in Chapter 3 and Appendix F of the *Transmission Staff Report*.

- ♦ Palo Verde-Devers No. 2 (project #15)
- ♦ Tehachapi Segment #1 and #2 (parts of project #16)
- ♦ Imperial Valley Transmission Upgrades (project #17)

The 12 projects which did not pass the first two screening criteria are noted below, along with staff's reasoning:

- ♦ Jefferson-Martin 230 kV Line (project #1) [CPCN granted in August 2004]
- ♦ San Francisco/Peninsula Long-term (2011+) Upgrades (project #2) [beyond 2010]
- ♦ Greater Fresno Area Projects (project #5) [beyond 2010]
- ♦ Sacramento Area Voltage Support Project (project #6) [Received Final Environmental Impact Statement and Record of Decision in January 2004]
- ♦ Otay Mesa Power Plant Transmission Project (project #9) [CPCN granted in June 2005]
- ♦ Miguel-Mission No. 2 230 kV Project (project #10) [CPCN granted in July 2004]
- ♦ Blythe Area Transmission Proposals (project #13) [both the Blythe II Power Plant Project and the Blythe Energy project Transmission Line are currently in the Energy Commission's Application For Certification process; therefore it is procedurally inappropriate for the Energy Commission to comment on these projects at this time]
- ♦ Short-term STEP Upgrades (project #14) [CA ISO approval received in June 2004]
- ♦ Frontier Project (project #18) [conceptual project beyond 2010]
- ♦ Northern Lights Transmission Project (project #19) [conceptual project beyond 2010]
- ♦ Southwest Intertie Project (project #20) [out of state project for which most of the permitting has been completed]
- ♦ East of River 9000+ Project (project #21) [out of state project for which most of the permitting has been completed]

The July 28, 2005 hearing included a request for feedback on the development of the state's first *Strategic Plan*. Staff posed the following questions:

- ♦ Do the projects presented in Chapter 3 and Appendix F of the Transmission Staff Report provide an appropriate foundation from which to develop the Strategic Plan?
- ♦ Which of the projects in Chapter 3 and Appendix F should be considered for inclusion in the Strategic Plan, and why?
- ♦ Are there other projects that should be considered?

SDG&E noted that transmission must be built in order to relieve congestion, noting that the next major transmission line will be needed around the year 2010.[271] Even with the addition of new generation plants coming on line in 2006 and 2008, the San Diego region does not have sufficient local generation to satisfy peak load requirements.[272] As a result, SDG&E must look at another transmission line into the area, and it is likely that the next 500 kV line, needed for reliability, will be from the east.[273] However, extensive land ownership east of San Diego includes Indian reservations, military bases, national forests, and other public lands that further complicate permitting, making it imperative that SDG&E have the ability to cross state or federal land in order to bring new transmission into San Diego.[274]

In addition, SDG&E noted the need for a transmission link to the north at some point in time. Such a line could provide benefits to the state more so than to San Diego.[275] A link to the north could provide a conduit for economical generation from Arizona as well as for renewables from the Imperial Valley region.[276] SDG&E noted that proponents of the Lake Elsinore Advanced Pumped Storage (LEAPS) Project, which consists of both pumped hydro storage as well as transmission facilities, approached SDG&E several years ago with a proposal to connect it to SCE territory.[277] At the time, SDG&E did not believe the project was either economically or technically feasible, especially given the significant amount of federal land it must traverse and the

[271] 7/28/05 RT, p. 90.

[272] *Id.* at p. 88.

[273] *Id.* at pp. 88 to 92.

[274] *Id.* at p. 93.

[275] *Id.* at p. 94.

[276] *Id.* at pp. 94 to 97.

[277] *Id.* at p. 98.

fact that SDG&E has to pursue other alternatives before it can pursue federal land. Legislation that would provide access through the federal land would help the situation, but there are topographic and climate factors that present challenges.[278]

IID noted that the Transmission Staff Report accurately captured the Southern California transmission system and upgrade plans.[279] It noted that its transmission access is very limited and will not meet its future needs.[280] IID noted that its service area has some of the best geothermal resources in the state, as well as the potential for other green resources. IID believes that its philosophy of actively engaging its neighbors in planning joint transmission projects is essential for a robust transmission system.[281]

LADWP noted its commitment to remaining involved in the Tehachapi and Salton Sea area transmission planning groups.[282] Its Owens Gorge 230 kV line runs very near the Tehachapi area. LADWP believes the line will serve quite a lot of its renewable generation requirements going forward: the existing line can carry 450 MW, and 160 MW of that is available for a potential tie-in to renewable resources there.[283]

PG&E offered some clarifications and updates to transmission projects in its service area. It noted that the Jefferson-Martin 230 kV line (project #1 in the Transmission Staff Report) is making good progress and is on track to be operational in the first half of 2006, at which point the Hunters Point Power Plant can be shut down. Project #2 (San Francisco/Peninsula Long-Term [2011+] Upgrades) and Project #3 (Trans-Bay DC Cable Project) could be the same project, depending on cost and need:

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[278] *Id.* at pp. 98 to 99.

[279] 7/28/05 RT, p. 102

[280] *Id.* at pp. 102 to 103.

[281] *Id.* at pp. 103 to 105.

[282] 7/28/05 RT, p. 161

[283] *Id.* at pp. 161 to 162.

the stakeholders and the CA ISO are still evaluating alternatives. The Henrietta-Gregg reconductoring projects, which is part of the Greater Fresno Area Projects (project #5), has recently received CPUC approval and PG&E plans to be in construction in 2006. PG&E supports the RPS target and schedule for the Tehachapi Area Renewable Interconnection (project #16), and it will work to make sure that the most cost-efficient solution is there to support the statewide goal. PG&E is still working on studies to determine if an interconnection from Tehachapi north to the PG&E network is needed. The identified problem is north of PG&E's Midway Substation, as Path 15 would reach its limit in the south to north direction before Path 26 would. The recent Path 26 upgrade to 4,000 MW (project #12) is only in the north to south direction.[284]

The following parties submitted written comments after the July 28, 2005 hearing: the League of California Cities/California State Association of Counties/Regional Council of Rural Counties, the California Department of Water Resources State Water Project, LADWP, and Vulcan Power Company[285]. With respect to the issue of which specific transmission projects should be included in the Strategic Plan, only LADWP and Vulcan Power Company provided comments. LADWP notes that SCE's economic analysis of Palo Verde-Devers No. 2 (PVD2) focuses on the increased revenue to SCE from existing transmission contracts (ETCs) and the increased revenue to the CA ISO by wheeling through or out of the CA ISO grid. LADWP states that increased revenue for both SCE and the CA ISO at the expense of ETCs and wheel-throughs does not necessarily achieve the objectives of least cost, market efficiency, and

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[284] 7/28/05 RT, p. 182-184.

[285] Reports, the hearing transcript, presentations and comments relating to this hearing are available on the Energy Commission's website at: [http://www.energy.ca.gov/2005_energypolicy/documents/index.html#072805].

See also the *2005 Energy Report* Docket Log for Docket no. 04-IEP-1F at [http://www.energy.ca.gov/dockets/04-IEP-1F.html].

resource flexibility; cost savings for one group at the expense of another should not be the goal of an overarching transmission plan.

Vulcan Power Company believes that the *Transmission Staff Report* focused too narrowly on the geothermal potential in the Imperial Valley without mentioning potential transmission upgrades that would benefit geothermal development outside the Imperial Valley, such as Northern California and across the border in Oregon and Nevada. Vulcan noted that it has submitted prior testimony in which it made recommendations for cost-effective transmission projects that could undergo expedited permitting processes because they involve upgrades to existing facilities and do not require the construction of additional transmission lines. Three of the most cost-effective recommendations include upgrades to the North of Cottonwood facilities, North of Round Mountain facilities, and North of Lugo facilities.

The *Draft Strategic Plan* was published on September 9, 2005.[286] The *Draft Strategic Plan* recommended four projects as important components: the SDG&E Sunrise Powerlink Project, the Imperial Valley Transmission Upgrades Project, the Palo Verde-Devers No. 2 Project, and the Antelope Transmission Project (part of the Tehachapi Area Transmission Projects.) A fifth project, the Trans-Bay DC Cable, received conditional support pending the outcome of CA ISO Board of Governors action.

A Committee hearing was held on September 23, 2005 to seek public comment on the *Draft Strategic Plan* as part of the *2005 Energy Report* proceeding. Interested parties were encouraged to present their views either in advance of the hearing, orally at the hearing, or in writing after the hearing. Reply comments were requested by October 14, 2005. Hearing transcripts were posted on the Energy Commission website

[286] California Energy Commission, *Committee Draft Strategic Transmission Investment Plan*, September 2005. CEC 100-2005-006CTD.

on October 3, 2005.[287] Presentations and the transcript of the hearing are available online at [http://www.energy.ca.gov/2005_energypolicy/documents/index.html#092305].

The notice for the hearing on the *Draft Strategic Plan* was posted on the Energy Commission website on September 9, 2005. The agenda was posted on September 19, 2005, while staff presentations were posted on September 22, 2005. The hearing was conducted in coordination with the ACR issued by CPUC President Peevey in Rulemaking 04-04-003 on March 14, 2005. The ACR noted that the Integrated Energy Policy Report Committee would conduct public proceedings, including any hearings necessary pursuant to Public Utilities Code (PUC) section 1822, in its consideration of information used to determine the likely range of the specific needs of statewide load serving entities. Consistent with this requirement, the notice offered parties the opportunity to cross examine on issues relating to the *Draft Strategic Plan*. No parties requested the opportunity to cross examine on this topic.

At the September 23, 2005 Hearing, Commissioner Geesman noted that the CA ISO Board approved the Trans-Bay Cable project shortly after the *Draft Strategic Plan* was published and asked Energy Commission staff if this would "elevate this project into that group of four priority projects that we are recommending go forward."[288] Staff agreed and asked parties to provide comments on this addition either at the hearing or in writing.[289]

SDG&E agreed with the *Draft Strategic Plan's* support for the Sunrise Powerlink Project. It noted that it expects to file its application for a CPCN for the need for the project "within the next couple of months."[290] It plans to file its environmental

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[287] Transcripts: September 23, 2005 Re: Committee Draft 2005 Strategic Transmission Investment Plan Hearing. Docket No. 04-IEP-01K.

[288] 9/23/05 RT, p. 16.

[289] 9/23/05 RT, p. 16.

[290] 9/23/05 RT, p. 17-18.

assessment at the end of the second calendar quarter of 2006.[291] SDG&E advocates working collaboratively with the state's consultants to prepare that assessment jointly, as a means to save both time and money, with the objective of receiving a need determination by the third calendar quarter of 2006 and a CPCN by the end of 2006.[292] In addition, SDG&E plans to bring together state, federal, and local agencies, business and consumer groups, environmental communities, and "traditional opponents" as another means to expedite the project.[293]

SDG&E noted that it has signed contracts for renewable resources at the eastern end of the line in the Imperial Valley which could total up to 900 MW.[294] Furthermore, SDG&E stated that "With what we have under contract, we could be close to 16 percent renewables before or by 2010, and what we are still trying to negotiate could easily exceed that 20 percent target by 2010. The one thing that is going to hamper us is the inability to get it to use without transmission."[295] The project would also mitigate "a large percentage" of forecasted RMR costs.[296]

ORA noted that it believes that it is the only party that submitted testimony on the Tehachapi Phase 1 (Antelope Transmission Project) application for a CPCN. ORA recommended support for the line. ORA notes that "We did raise a couple of issues regarding the rate making treatment Edison has proposed, and we are working with Edison about settling those issues to avoid the need for hearings, just to be able to expedite the whole process."[297]

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[291] *Id.* at p. 18.

[292] *Id.* at pp. 18 to 21.

[293] *Id.* at p. 22.

[294] *Id.* at p. 23.

[295] 9/23/05 RT, p. 26.

[296] *Id.* at pp. 25-26.

[297] 9/23/05 RT, p. 32.

Commissioner Geesman noted that the *Draft Strategic Plan* speaks in terms of approving that project as required by law within its twelve month time period. Given ORA's expectation that that process will be expedited, Commissioner Geesman asked if his understanding is correct that the publication date for the final CEQA documents has slipped to March 2006. The ORA representative agreed to check on that.[298]

Commissioner Geesman asked PG&E to provide written comments on PG&E's going-forward position on the Trans-Bay Cable Project and its willingness to facilitate the completion of the project. PG&E noted that "We will do our part to whatever needs to be interconnected, so, we will see how they proceed, and let's hope that San Francisco gets the reliability it needs through all the projects that are out there."[299]

The following parties submitted specific written comments on the transmission project assessments contained in the *Draft Strategic Plan* after the September 23, 2005 hearing: The Hydro Company, Inc., Southern California Edison, and Pacific Gas & Electric (PG&E). The Hydro Company, Inc. noted several significant milestones that were recently achieved with the LEAPS Project, clarified the responsible party for the project's licensing process, and clarified its perception of the relationship between the LEAPS Project and the potential northern interconnection portion of the Sunrise Powerlink Project. Southern California Edison expressed concern that the *Draft Strategic Plan* did not sufficiently address the ongoing congestion on Path 26 and suggested that accelerating Phase 4 of the Tehachapi transmission proposal could help mitigate Path 26 congestion. PG&E noted that it would continue to work with TransBay Cable LLC to complete the CA ISO-required studies necessary for the interconnection of the TransBay Cable Project with the CA ISO-controlled grid at PG&E's Pittsburg and Potrero substations.

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[298] *Id.* at pp. 38-39.

[299] 9/23/05 RT, p. 56-58.

The *Strategic Plan* was published on November 7, 2005, and was adopted by the Energy Commission on November 21, 2005.[300] The record of the *Strategic Plan* incorporates all information, comments, filings, staff reports, consultant reports, and studies contained in the record of the 2003 *Energy Report*, the *2004 Energy Report Update*, and the *2005 Energy Report*. This information is available on the Energy Commission's website: [http://www.energy.ca.gov/2005_energypolicy/index.html].

Chapter 4 of the *Strategic Plan* describes the transmission project investments for consideration. It first discusses the evaluation criteria used to screen the projects. Based on the record developed for the *Transmission Staff Report* and the July 28, 2005 hearing, seven projects were deemed the appropriate starting point.[301] The *Strategic Plan* summarizes the conclusions reached for these projects.

SDG&E Sunrise Powerlink 500 kV Project
(Project 1, *Strategic Plan*, p. 65)

> The proposed 500 kV Sunrise Powerlink Project would provide significant near-term system reliability benefits to California, reduce system congestion and resultant congestion costs, and provide an interconnection to renewable resources located in the Imperial Valley and lower-cost out-of-state generation.

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[300] California Energy Commission *Strategic Transmission Investment Plan*, November 2005. CEC 100-2005-006-CMF.

[301] The *Strategic Plan* notes that seven projects passed the screening criteria (p. 62). Figure 4 on page 63 shows the seven projects. The seven projects in Figure 4 differ from the nine projects described at the July 28, 2005 Hearing in the following areas:

- The San Diego 500 kV Project (referred to as project #7 in the Transmission Staff Report) has been renamed by SDG&E as the Sunrise Powerlink 500 KV Project.
- The Tehachapi Area Transmission Projects and Path 26 Upgrades (referred to as project #16 and #12, respectively, in the Transmission Staff Report) have been combined into one project with two parts (6a and 6b) in the *Draft Strategic Plan*.
- The Metcalf-Moss Landing 230 kV Reinforcement Project (project #4 in the *Transmission Staff Report*) has been removed from consideration because it is a reconductoring rather than a new line and its permitting requirements are uncertain at this time.

Without the proposed project, it is unlikely that SDG&E will be able to meet the state's RPS goals, ensure system reliability, or reduce RMR and congestion costs. Therefore, the Energy Commission believes the proposed project offers significant benefits and recommends that the project be moved forward expeditiously so that the residents of San Diego and all of California can begin realizing these benefits by 2010.

LEAPS 500 kV Transmission Project
(Project 2, *Strategic Plan*, pp. 68-69)

The LEAPS transmission project would deliver pumped storage hydro power to the grid, reduce congestion and improve reliability in the San Diego area. The transmission component of LEAPS could complement the Sunrise Powerlink 500 kV project as a potential northern interconnection to the SCE service territory. This would require continued coordination between the project sponsors and SDG&E. Furthermore, the transmission component of LEAPS could strengthen the CA ISO grid by providing a 500 kV interconnection between the SDG&E and SCE service territories. As noted above, the state's existing 500 kV bulk transmission "backbone" runs from the Oregon border through the SCE service territory but does not connect with the San Diego area. San Diego's system currently connects to the rest of California via 230 kV lines running north through San Onofre Nuclear Generating Station and 500 kV lines running east to Imperial Valley. A northern 500 kV interconnection would improve the reliability of California's transmission system and increase the state's overall ability to import lower-cost power from Arizona, Mexico and the Desert Southwest. In its April 2, 2004, Motion to Intervene at the FERC, the CA ISO noted that "The transmission line proposed in association with the Lake Elsinore Pumped Storage Project would allow the San Diego area to import substantially more power from surrounding areas and would greatly enhance electric system reliability."

The Nevada Hydro Company, Inc. has made significant licensing progress with federal agencies. According to The Nevada Hydro Company, Inc., the U.S. Forest Service (USFS) has agreed to (i) be a cooperating agency for purposes of carrying out the requirements of the National Environmental Policy Act (NEPA), (ii) produce a single environmental impact statement (EIS) for the project that will address the needs of both the USFS and the FERC, and (iii) stated their willingness to issue appropriate permits and has submitted preliminary licensing conditions to the FERC. The FERC-authored Draft EIS is expected in November 2005, while the Final EIS and Record of Decision are expected in April 2006.-

However, the proposed LEAPS project has unresolved concerns, including:

- Incomplete economic studies.

- Incomplete transmission system impact studies, which could identify further environmental impacts.
- Because the proposed transmission component of LEAPS would travel through the Cleveland National Forest and portions of Department of Defense and other public lands, the project would be subject to the requirements of the USFS, the Environmental Protection Agency, and the Bureau of Land Management (BLM).

The transmission component of LEAPS may offer substantial benefits to California and is worthy of further monitoring and future consideration. However, pending completion of system and economic studies, as well as FERC approval, the Energy Commission believes the project does not warrant a recommendation at this time. The Energy Commission recommends monitoring and future consideration of the project in the *2007 Energy Report* cycle.

Imperial Valley Transmission Upgrades Project
(Project 3, *Strategic Plan*, p. 72)

An Imperial Valley upgrade project would provide access to valuable renewable resources needed to meet future load growth, support California's RPS goals and provide significant near-term reliability benefits to California. Therefore, the Energy Commission believes Phase 1 of the Imperial Valley Study Group's proposed plan, including a 500 kV link to SDG&E, would provide significant benefits to California and recommends that Phase 1 move forward expeditiously. Further transmission development in the Imperial Valley region should be carefully coordinated in order to avoid duplication, and to develop a transmission plan that serves the needs of both California and the West.

South of Lugo Vincent-Mira Loma 500 kV Project
(Project 4, *Strategic Plan*, p. 73)

The proposed project is currently in the planning stage and neither project costs nor significant issues associated with the project have been identified. In addition, the proposed project would require CA ISO Board of Governors approval and a CPCN by the CPUC. However, any planning and permitting delays could mean that the Vincent to Mira Loma 500 kV line would not be operational in time to prevent violation of reliability standards south of Lugo starting in 2009 or 2010.

The proposed Vincent-Mira Loma 500 kV Project may offer substantial benefits to California and is worthy of further monitoring and future consideration. However, due to the lack of specific project details and studies, the project does not warrant recommendations for action at this time. To warrant future consideration in the *2007 Energy Report* cycle, additional project documentation of benefits is necessary.

Palo Verde-Devers No. 2 500 kV Project
(Project 5, *Strategic Plan*, p. 78)

The proposed PVD2 Project would provide significant near-term benefits by reducing congestion on lines connecting California and Arizona and providing access to lower cost out-of-state generation to meet California's growing electricity needs. The proposed project would also provide strategic benefits to California ratepayers, including valuable insurance against abnormal system conditions and power outages, increased operating flexibility for California grid operators, reduced market power for generators, and reduced need for other infrastructure in California. Therefore, the Energy Commission believes the proposed project offers significant benefits and recommends that the project be moved forward expeditiously so that California can begin realizing these benefits by 2010.

Tehachapi Area/Path 26 Transmission Projects
(Project 6, *Strategic Plan*, p. 85)

The conceptual Tehachapi Transmission Plan would increase access to over 4,500 MW of renewable resources needed to serve California's growing electricity needs. The Energy Commission supports the conceptual Tehachapi Transmission Plan developed by the TSG because it could provide access to 4,500 MW of renewable generation and will assist California utilities in meeting RPS goals by 2010. The Energy Commission believes the Antelope Transmission Project proposed by SCE is crucial to the development of wind resources in the Tehachapi region and will offer significant benefits to California. Therefore, the Energy Commission recommends the project be moved forward expeditiously so that California can begin realizing benefits by 2010.

Trans-Bay DC Cable
(Project 7, *Strategic Plan*, p. 86-87)

Since this project is not under the jurisdiction of the CPUC, TBC requested approval of their finance proposal from FERC. FERC approved the TBC Operating Memorandum for the $300 million project on July 22, 2005. The CA ISO has recently completed its technical review of the project for the San Francisco Peninsula study group and recommended the Trans-Bay Cable as its preferred alternative for meeting the long-term reliability needs of the San Francisco Peninsula. While TBC supports the completion of the project in 2009, the CA ISO study indicates economic benefits from the project would not be realized until 2012.

The Committee Draft Strategic Plan, posted in early September 2005, noted that the Trans-Bay DC Cable required the CA ISO Board of Governors' (Board) approval, and if approved, the project could be operational by 2009. Because of the pending Board approval, the Energy Commission recommended both monitoring and future consideration of the project.

The CA ISO Board approved the Trans-Bay Cable Project at its meeting on September 8, 2005. In the letter to the CA ISO Board recommending approval for the project, the CA ISO staff noted the following:

> This Project is needed for reliability and is being recommended to mitigate violation of reliability planning standards beginning in 2012, but is being recommended for early operation. The Project, as currently structured, is planned to be in-service by 2009… [T]he ISO performed technical and economic analyses to assess the reliability benefits and the cost to the ISO ratepayers for advancing the in-service date by three years to 2009. ISO's technical analysis concluded that installation of this project in 2009 would significantly improve reliability of the San Francisco Peninsula electrical system… This Project, with a 2009 in-service date, will significantly reduce expected Locational Capacity Requirements and the need for Special Protection Schemes that are currently in place to shed firm load for critical double contingency disturbances for San Francisco Peninsula. Further, ISO's economic analysis concluded that while the Project does have identified benefits, the present value of the revenue requirements of the benefits and costs over the three-year advancement results in a net cost to the ISO ratepayers of $26 million. This "net cost" is viewed as an assurance cost against intangible benefits such as immediate increased reliability to the San Francisco Peninsula Area, unforeseen load forecast errors and consideration of unknowns such as project siting, schedule, cost risks, and economic benefits. Overall, ISO Management considers this assurance cost acceptable in return for the certainty that the Project will be there when it is needed.

At the September 23, 2005, *Energy Report* Committee Hearing on the Committee Draft Strategic Plan, Commissioner Geesman requested that PG&E provide a written statement explaining its position on the Trans-Bay Cable Project in its written comments on the Draft Strategic Plan. To that end, PG&E noted that, "In light of the ISO Board's decision to approve the [Trans-Bay Cable] Project, and as required by our tariff, PG&E will continue to work with the proponent TransBay Cable LLC to complete the ISO-required studies necessary to effect the interconnection of the [Trans-Bay Cable] Project to the ISO-controlled grid at PG&E's Pittsburg and Potrero substations."

The Energy Commission agrees with the CA ISO's assessment that the advanced in-service date provides insurance benefits that outweigh the net cost to CA ISO ratepayers. Therefore, the Energy Commission recommends that the Trans-Bay DC Cable Project move forward expeditiously in order for the San Francisco Peninsula and the CA ISO control area to realize these reliability benefits.

9.3. Final Project Recommendations

Consistent with the above discussion, the transmission projects described below will provide significant near-term benefits to California through improvements to system reliability, reduced congestion, and/or interconnection to renewable resources. The Energy Commission recommends investment in the following five projects.

9.3.1. PVD2 500 kV Project

The proposed PVD2 500 kV Project would provide significant near-term benefits by reducing congestion on lines connecting California and Arizona and providing access to lower-cost out-of-state generation. The proposed project would also provide strategic benefits to California ratepayers, including valuable insurance against abnormal system conditions and power outages. It would increase operating flexibility for California grid operators, reduce market power for generators, and reduce the need for additional infrastructure in California. The PVD2 Project is therefore a major component of California's Strategic Plan. The Energy Commission strongly believes that the proposed project offers significant benefits and recommends that the project be moved forward expeditiously so that California can begin realizing these benefits by 2010.

9.3.2. Sunrise Powerlink 500 kV Project

The proposed 500 kV Sunrise Powerlink Project would provide significant near-term system reliability benefits to California, reduce system congestion and its resultant costs, and provide an interconnection to both renewable resources located in the Imperial Valley and lower-cost out-of-state generation. Without this proposed project, it is unlikely that SDG&E will be able to meet the state's RPS goals, ensure system reliability, or reduce RMR and congestion costs. The Energy Commission therefore believes that the proposed project offers significant benefits and recommends that it move forward expeditiously so that the residents of San Diego and all of California can begin to realize these benefits by 2010.

9.3.3. Tehachapi Transmission Plan, Phase One: Antelope Transmission Project

The Energy Commission strongly believes that the Antelope Transmission Project, proposed by SCE, is crucial to the development of wind resources in the Tehachapi region and will offer significant benefits to California. As such, the proposed project is considered a major component of California's Strategic Plan. The Energy Commission therefore recommends the project be moved forward expeditiously so that California can begin realizing benefits by 2010.

9.3.4. Imperial Valley Transmission Upgrade Project

An Imperial Valley upgrade project would provide access to valuable renewable resources needed to meet future load growth, support California's RPS goals and provide significant near-term reliability benefits to California. The Energy Commission therefore believes that Phase 1 of the Imperial Valley Study Group's proposed plan, including a 500 kV link to SDG&E, would provide significant benefits to California and recommends that Phase 1 move forward expeditiously. Further transmission development in the Imperial Valley region should be carefully coordinated to avoid duplication and to create a transmission system that serves the needs of both California and the West.

9.3.5 Trans-Bay DC Cable Project

Although the Trans-Bay DC Cable Project is not needed for reliability purposes until after 2011, the CA ISO has approved the project for early operation in 2009, consistent with Trans-Bay Cable LLC's plans. The Energy Commission agrees with the CA ISO's assessment that the advanced in-service date provides insurance benefits that outweigh the net cost to CA ISO ratepayers. Therefore, the Energy Commission recommends that the Trans-Bay DC Cable Project move forward expeditiously so that the San Francisco Peninsula and the CA ISO control area can realize these reliability benefits.

9.4. CPUC Actions to Implement Investments

The CPUC should take action to ensure that the CPCN permitting processes for the DPV2 and Tehachapi Phase I projects are effective and completed in the 12 months required by law. The CPUC should take action to ensure that long-term strategic benefits are fully addressed in CPUC permitting assessments of project benefits for transmission projects deemed vital to the state in the Energy Commission's Strategic Plan.

The CPUC should assign great weight in its permitting process to the project need assessments submitted by the CA ISO.

Although the CPUC's permitting responsibilities in the Imperial Valley Transmission Upgrades and Trans-Bay Cable projects are limited[302], the CPUC should ensure that it fulfills its Public Utilities Code Section 762 responsibilities in a timely manner.

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302 The PG&E Pittsburg and Potrero Substation modifications required for the Trans-Bay Cable Project are likely exempt from the CPCN and Permit To Construct (PTC) requirements pursuant to General Order (GO) 131-D Section III. Similarly, any SDG&E and/or SCE substation modifications required for the Imperial Valley Transmission Upgrade Project will likely be exempt from GO 131-D Section III. However, Public Utilities Code Section 762 may require the CPUC to make and serve an order directing that such improvements be made after

Footnote continued on next page

10. Public Comment on the *Committee Draft Transmittal Report*

The *Draft Transmittal Report* was published on October 25, 2005, and the Committee held a hearing on the draft on November 4, 2005, at the Energy Commission in Sacramento. In the notice for this hearing, the Committee offered parties the opportunity to conduct cross-examination on the use of models as they relate to matters being transmitted to the CPUC for their use in future proceedings. No parties requested cross examination.

In addition to a presentation by Energy Commission staff, representatives of the CPUC, the Natural Resources Defense Council, the Independent Energy Producers Association, SCE, SDG&E, and PG&E spoke at the hearing. At the hearing, Les Guliasi of PG&E recommended that further discussion between the parties and Energy Commission staff relating to the range of need as presented in the *Draft Transmittal Report* and by Energy Commission staff at the hearings would be useful.[303] The Committee encouraged staff and other interested parties to conduct such dialogue as would be useful, but to do so in a timely fashion. As a result, Energy Commission staff held a conference call to which all parties who participated in the hearings were invited to participate on Monday, November 7, 2005. Representatives of the CPUC, the Natural Resources Defense Council, SCE, SDG&E, and PG&E all participated in the conference call.

Written comments were filed on November 8, 2005, by the Natural Resources Defense Council, SCE, Sempra Energy Utilities on behalf of SDG&E and Southern California Gas Company, PG&E, Duke Energy North America, Constellation Energy Commodities Group and Constellation NewEnergy (Constellation), and the Cogeneration Association of California and the Energy Producers and Users Coalition (CAC/EPUC). These written comments have been included in this *Transmittal Report* as

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consideration of such factors as community values, recreational and park areas, historical and aesthetic values, and influence on the environment.

Appendix C, and the Energy Commission's responses to these written comments have been provided in Appendix D.

In the *Draft Transmittal Report,* the Committee *invited* specific comment on a number of issues: the amount of renewable resources included in the preferred resource category; the treatment of existing demand response programs; the plan to publish distribution service area capacity tables in the final *Transmittal Report*; and the use of NYMEX prices for near-term natural gas prices. With the exception of comments from SDG&E on their existing demand response programs, no parties commented on these issues. The SDG&E tables have been corrected to reflect the existing demand response programs as of the time the resource plans were filed in early 2005, and the distribution service area capacity tables have been included in Appendix B as proposed by the D*raft Transmittal Report.* No other changes have been made from the *Draft Transmittal Report* on these specific issues.

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[303] 11/4/05 RT, pp. 61-63.

Appendix A

Aging Power Plant Study Group

Appendix A: Aging Power Plant Study Group

Planning Area	Plant	Unit	Capacity (MW)	Average Generation 2002-2004 (GWH)
PG&E (1)	Contra Costa	6	340	359
		7	340	777
	Hunters Point	4	163	471
	Morro Bay	1	163	11
		2	163	33
		3	338	294
		4	338	420
	Moss Landing	6	739	1,074
		7	739	1,083
	Pittsburg	5	325	675
		6	325	503
		7	720	1,504
	Potrero	3	207	765
PG&E Total			**4,900**	**7,969**

(1) - The study group included the Humboldt Bay power plant, located within PG&E's planning area and owned by PG&E. Because the resource plans provided by PG&E included energy and capacity from the planned replacement of these older units, they have not been included in this list or in the aging plant replacement totals for PG&E shown in the Appendix B tables.

SDG&E	Encina	1	107	146
		2	104	186
		3	110	263
		4	293	1,022
		5	315	1,158
	South Bay	1	147	491
		2	150	534
		3	171	454
		4	222	129
SDG&E Total			**1,619**	**4,383**

Appendix A: Aging Power Plant Study Group (continued)

Planning Area	Plant	Unit	Capacity (MW)	Average Generation 2002-2004 (GWH)
SCE	Alamitos	1	175	122
		2	175	134
		3	320	946
		4	320	636
		5	480	1,124
		6	480	621
	Coolwater	1	65	37
		2	81	50
		3	241	620
		4	241	525
	El Segundo	3	335	681
		4	335	729
	Etiwanda	3	320	253
		4	320	185
	Huntington Beach	1	215	689
		2	215	723
	Long Beach	8	303	-
		9	227	-
	Mandalay	1	215	367
		2	215	445
	Ormond Beach	1	750	1,101
		2	750	1,101
	Redondo Beach	5	175	83
		6	175	34
		7	480	741
		8	480	604
SCE Total			**8,088**	**12,551**
Grand Total			**14,712**	**25,237**

Appendix B

Tables Showing Range of Procurement Need

Appendix B: Tables Showing Range of Procurement Need

Tables B-1 through B-18 show the range of procurement need for both energy and capacity for PG&E, SCE, and SDG&E based on the three cases (low, base, and high) in the staff revised demand forecast. Tables B-19 and B-20 illustrate the sources and relationships of the various lines in the range of procurement need tables, and are repeated from the body of the report (Tables 3 and 4) for the reader's convenience. Figures B-1 through B-8 illustrate the range of procurement need for the three IOUs individually and jointly.

The following text is section 5.8 in the body of this report, and is reproduced here to remind the reader of how the Energy Commission expects the data presented in Appendix B to be used in the CPUC's 2006 procurement proceeding, including consideration of which data is expected to need to be updated next year.

5.8 Future Adjustments to the Range of Need

The Energy Commission recognizes that some of the information used in constructing the range of need shown in the tables in this report will be out of date by the conclusion of the CPUC's 2006 procurement proceeding (LTPP). The Energy Commission offers the following guidelines for when and how adjustments to the numbers would be appropriate.

In terms of the demand forecasts, the Energy Commission believes that the revised staff forecast provides the appropriate basis for the 2006 LTPP. A biennial proceeding focused upon the long-term cannot be a good source of short term demand forecasts that are updated frequently for recent historic data and near-term expectations. Such near-term demand forecasts are appropriate for many operating activities. The Energy Commission does not anticipate any conditions in which an update of the staff revised forecast for the years 2008 and beyond would be appropriate for long-term planning purposes before the *2007 Energy Report* is completed. The short-term demand forecasts that all LSEs will be using each year as part of compliance with resource adequacy requirements should be established through other proceedings. Thus, updates for the 2006 and 2007 load forecasts reported here for purposes other than long-term planning are acceptable to the extent the CPUC determines this is appropriate.

On the resource side, the Energy Commission notes that the IOUs have begun to fill the resource needs identified in their filings. For example, PG&E has signed a capacity and dispatchable energy contract with Duke Energy for the 650-MW Morro Bay Power Plant from 2005-2007, initiated a long-term request for offers (RFO) for 1,200 MW in 2008 and an additional 1,000 MW in 2010, and proposed to construct and operate the 530-MW Contra Costa 8 unit, which may defer a portion of the long-term RFO; SCE has signed renewables contracts for about 640 MW, including a 500-MW peaking solar thermal energy project; and SDG&E has signed a contract with a 300-MW peaking solar project.

The Energy Commission recommends that the CPUC direct the utilities to update their utility-controlled and contractual resource status by filing in the 2006 LTPP a listing of all contracts and other projects committed to, and all contracts terminated or owned resources retired, since January 1, 2005. This filing should clearly indicate whether these projects were included in the reference case resource plan filed at the Energy Commission during the *2005 Energy Report* proceeding. The energy and capacity values of those projects can then be added to the appropriate existing and planned resource line and, if it is a preferred resource, subtracted from the appropriate preferred resource line of the range of need tables and the resulting totals recalculated. The Energy Commission does not anticipate that any other changes to the existing and planned resource base would be appropriate.

In terms of energy efficiency and demand response, the tables are based on the Energy Commission's understanding of the implications of the adopted *EAP II* loading order preferences. If the CPUC formally adopts goals for any of these preferred resources in the future, these numbers should be adjusted as appropriate. For renewables, this line is the "generic renewables" that would need to be procured in the future as reported by the IOU for the accelerated renewables case. Any adjustments to either the target or the existing and planned resource base should be reflected in this line. No numbers have been included for distributed generation and combined heat and power resources. The *Energy Report* notes that 5,400 MW by 2020 is a realistic goal and recommends that "by the end of 2006, the Energy Commission and CPUC should collaboratively translate this goal into annual IOU procurement targets."[1] Once these yearly targets are set, they should be incorporated into the need tables. The Energy Commission does not anticipate any other changes to the preferred resource numbers until they are reviewed again in the *2007 Energy Report* proceeding.

[1] *Energy Report*, p. 78.

Table B-1
Annual Aggregated Energy Resource Accounting Table
PG&E Energy Procurement Need, Low Demand Case

revised: 21-Nov-05

ENERGY DEMAND (GWh)								
	2009	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
Net Energy for Bundled Customer Load (low case)	84,825	86,071	87,456	88,652	89,961	90,972	91,998	93,008
Firm Sales Obligations	413	413	413	413	413	413	413	413
TOTAL ENERGY REQUIREMENT	***85,238***	***86,484***	***87,869***	***89,065***	***90,374***	***91,385***	***92,411***	***93,421***
EXISTING & PLANNED RESOURCES (1)								
Utility-Controlled Physical Resources								
Nuclear	15,573	17,546	17,597	16,797	17,584	17,551	16,746	17,624
Fossil (5)	177	178	171	173	171	174	174	180
Total Hydro Energy Supply	15,983	15,290	15,023	15,061	14,174	13,534	13,347	12,471
Total Utility-Controlled Physical Resources	**31,733**	**33,014**	**32,790**	**32,030**	**31,929**	**31,259**	**30,267**	**30,275**
Existing and Planned Contractual Resources								
Total Energy Supply from DWR Contracts	21,203	3,079	2,482	1,190	0	0	0	0
Total Energy Supply from QF Contracts	19,727	19,939	19,873	19,769	19,708	19,592	19,463	19,387
Total Existing & Planned Renewable Contracts	519	526	528	528	527	300	66	31
Total Energy Supply from Other Bilateral Contracts	3,585	3,670	2,076	1,063	516	518	429	413
Total Contractual Resources	**45,034**	**27,214**	**24,959**	**22,550**	**20,750**	**20,410**	**19,958**	**19,831**
TOTAL EXISTING & PLANNED ENERGY RESOURCES (1)	***76,766***	***60,228***	***57,749***	***54,580***	***52,679***	***51,669***	***50,225***	***50,106***
TOTAL PROCUREMENT NEED	***8,472***	***26,256***	***30,120***	***34,485***	***37,695***	***39,717***	***42,186***	***43,315***
ADDITIONAL PREFERRED RESOURCES								
Uncommitted Energy Efficiency (2)	1,057	2,119	3,123	4,204	5,380	6,650	7,903	9,136
Renewables	5,423	6,481	6,961	7,890	8,259	9,267	10,513	11,306
Distributed Generation/ CHP	to be developed in 2006 by Energy Commission and CPUC							
TOTAL ADDITIONAL PREFERRED RESOURCES (3)	**6,480**	**8,600**	**10,084**	**12,094**	**13,639**	**15,917**	**18,416**	**20,442**
ADDITIONAL NON-DESIGNATED NEED (3)	**1,992**	**17,656**	**20,036**	**22,391**	**24,056**	**23,800**	**23,770**	**22,873**
Aging Plant Replacement (4)	**1,992**	**3,985**	**5,977**	**7,969**	**7,969**	**7,969**	**7,969**	**7,969**

(1) - Existing and planned resource totals are as of early 2005, when the LSEs prepared their resource plan submissions for the 2005 Energy Report proceeding.

(2) - Energy efficiency goals were established by the CPUC for the IOUs based on all customers in their service territory. Future savings from uncommitted energy efficiency programs are likely to come both from IOU bundled-service customers and ESP direct access customers.

(3) - The total preferred resources will increase and the open source need will decrease when DG/CHP targets are established in 2006.

(6) - The numbers for aging plant replacement reflect the amount of energy the IOUs should be including in their resource plans to account for the recommended retirement of the aging plants by 2012.

(5) - In its reference case, PG&E did not include any energy values for the Humboldt Bay replacement project, though it included 150 MW of capacity. The Energy Commission is including the fossil resource energy values that PG&E filed with its preferred, accelerated renewables, and core/non-core cases.

Table B-2
Annual Aggregated Energy Resource Accounting Table
PG&E Energy Procurement Need, Base Demand Case

revised: 21-Nov-05

ENERGY DEMAND (GWh)								
	2009	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
Net Energy for Bundled Customer Load (base case)	85,182	86,451	87,855	89,069	90,395	91,426	92,471	93,504
Firm Sales Obligations	413	413	413	413	413	413	413	413
TOTAL ENERGY REQUIREMENT	***85,595***	***86,864***	***88,268***	***89,482***	***90,808***	***91,839***	***92,884***	***93,917***
EXISTING & PLANNED RESOURCES (1)								
Utility-Controlled Physical Resources								
Nuclear	15,573	17,546	17,597	16,797	17,584	17,551	16,746	17,624
Fossil (5)	177	178	171	173	171	174	174	180
Total Hydro Energy Supply	15,983	15,290	15,023	15,061	14,174	13,534	13,347	12,471
Total Utility-Controlled Physical Resources	**31,733**	**33,014**	**32,790**	**32,030**	**31,929**	**31,259**	**30,267**	**30,275**
Existing and Planned Contractual Resources								
Total Energy Supply from DWR Contracts	21,203	3,079	2,482	1,190	0	0	0	0
Total Energy Supply from QF Contracts	19,727	19,939	19,873	19,769	19,708	19,592	19,463	19,387
Total Existing & Planned Renewable Contracts	519	526	528	528	527	300	66	31
Total Energy Supply from Other Bilateral Contracts	3,585	3,670	2,076	1,063	516	518	429	413
Total Contractual Resources	**45,034**	**27,214**	**24,959**	**22,550**	**20,750**	**20,410**	**19,958**	**19,831**
TOTAL EXISTING & PLANNED ENERGY RESOURCES (1)	***76,766***	***60,228***	***57,749***	***54,580***	***52,679***	***51,669***	***50,225***	***50,106***
TOTAL PROCUREMENT NEED	***8,829***	***26,636***	***30,519***	***34,902***	***38,129***	***40,171***	***42,659***	***43,810***
ADDITIONAL PREFERRED RESOURCES								
Uncommitted Energy Efficiency (2)	1,057	2,119	3,123	4,204	5,380	6,650	7,903	9,136
Renewables	5,423	6,481	6,961	7,890	8,259	9,267	10,513	11,306
Distributed Generation/ CHP	to be developed in 2006 by Energy Commission and CPUC							
TOTAL ADDITIONAL PREFERRED RESOURCES (3)	**6,480**	**8,600**	**10,084**	**12,094**	**13,639**	**15,917**	**18,416**	**20,442**
ADDITIONAL NON-DESIGNATED NEED (3)	**2,349**	**18,036**	**20,435**	**22,808**	**24,490**	**24,254**	**24,243**	**23,368**
Aging Plant Replacement (4)	**1,992**	**3,985**	**5,977**	**7,969**	**7,969**	**7,969**	**7,969**	**7,969**

(1) - Existing and planned resource totals are as of early 2005, when the LSEs prepared their resource plan submissions for the 2005 Energy Report proceeding.
(2) - Energy efficiency goals were established by the CPUC for the IOUs based on all customers in their service territory. Future savings from uncommitted energy efficiency programs are likely to come both from IOU bundled-service customers and ESP direct access customers.
(3) - The total preferred resources will increase and the open source need will decrease when DG/CHP targets are established in 2006.
(6) - The numbers for aging plant replacement reflect the amount of energy the IOUs should be including in their resource plans to account for the recommended retirement of the aging plants by 2012.
(4) - In its reference case, PG&E did not include any energy values for the Humboldt Bay replacement project, though it included 150 MW of capacity. The Energy Commission is including the fossil resource energy values that PG&E filed with its preferred, accelerated renewables, and core/non-core cases.

Table B-3
Annual Aggregated Energy Resource Accounting Table
PG&E Energy Procurement Need, High Demand Case

revised: 21-Nov-05

ENERGY DEMAND (GWh)								
	2009	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
Net Energy for Bundled Customer Load (high case)	86,621	88,237	90,023	91,600	93,374	94,894	96,452	97,959
Firm Sales Obligations	413	413	413	413	413	413	413	413
TOTAL ENERGY REQUIREMENT	***87,034***	***88,650***	***90,436***	***92,013***	***93,787***	***95,307***	***96,865***	***98,372***
EXISTING & PLANNED RESOURCES (1)								
Utility-Controlled Physical Resources								
Nuclear	15,573	17,546	17,597	16,797	17,584	17,551	16,746	17,624
Fossil (5)	177	178	171	173	171	174	174	180
Total Hydro Energy Supply	15,983	15,290	15,023	15,061	14,174	13,534	13,347	12,471
Total Utility-Controlled Physical Resources	**31,733**	**33,014**	**32,790**	**32,030**	**31,929**	**31,259**	**30,267**	**30,275**
Existing and Planned Contractual Resources								
Total Energy Supply from DWR Contracts	21,203	3,079	2,482	1,190	0	0	0	0
Total Energy Supply from QF Contracts	19,727	19,939	19,873	19,769	19,708	19,592	19,463	19,387
Total Existing & Planned Renewable Contracts	519	526	528	528	527	300	66	31
Total Energy Supply from Other Bilateral Contracts	3,585	3,670	2,076	1,063	516	518	429	413
Total Contractual Resources	**45,034**	**27,214**	**24,959**	**22,550**	**20,750**	**20,410**	**19,958**	**19,831**
TOTAL EXISTING & PLANNED ENERGY RESOURCES (1)	***76,766***	***60,228***	***57,749***	***54,580***	***52,679***	***51,669***	***50,225***	***50,106***
TOTAL PROCUREMENT NEED	***10,268***	***28,422***	***32,688***	***37,434***	***41,108***	***43,639***	***46,640***	***48,266***
ADDITIONAL PREFERRED RESOURCES								
Uncommitted Energy Efficiency (2)	1,057	2,119	3,123	4,204	5,380	6,650	7,903	9,136
Renewables	5,423	6,481	6,961	7,890	8,259	9,267	10,513	11,306
Distributed Generation/ CHP	to be developed in 2006 by Energy Commission and CPUC							
TOTAL ADDITIONAL PREFERRED RESOURCES (3)	**6,480**	**8,600**	**10,084**	**12,094**	**13,639**	**15,917**	**18,416**	**20,442**
ADDITIONAL NON-DESIGNATED NEED (3)	**3,788**	**19,822**	**22,604**	**25,340**	**27,469**	**27,722**	**28,224**	**27,824**
Aging Plant Replacement (4)	**1,992**	**3,985**	**5,977**	**7,969**	**7,969**	**7,969**	**7,969**	**7,969**

(1) - Existing and planned resource totals are as of early 2005, when the LSEs prepared their resource plan submissions for the 2005 Energy Report proceeding.

(2) - Energy efficiency goals were established by the CPUC for the IOUs based on all customers in their service territory. Future savings from uncommitted energy efficiency programs are likely to come both from IOU bundled-service customers and ESP direct access customers.

(3) - The total preferred resources will increase and the open source need will decrease when DG/CHP targets are established in 2006.

(6) - The numbers for aging plant replacement reflect the amount of energy the IOUs should be including in their resource plans to account for the recommended retirement of the aging plants by 2012.

(4) - In its reference case, PG&E did not include any energy values for the Humboldt Bay replacement project, though it included 150 MW of capacity. The Energy Commission is including the fossil resource energy values that PG&E filed with its preferred, accelerated renewables, and core/non-core cases.

Table B-4
Annual Aggregated Capacity Resource Accounting Table
PG&E Capacity Procurement Need, Low Demand Case

revised: 21-Nov-05

PEAK DEMAND (MW)								
	2009	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
Peak Service Area Demand (low case) (1)	19,311	19,583	19,893	20,156	20,448	20,676	20,923	21,169
Peak Bundled Customer Demand (low case)	17,959	18,221	18,520	18,773	19,055	19,276	19,518	19,760
Reserve Margin (15% of Bundled Customer Demand)	2,694	2,733	2,778	2,816	2,858	2,891	2,928	2,964
Firm Sales Obligations	0	0	0	0	0	0	0	0
FIRM PEAK REQUIREMENT	***20,653***	***20,954***	***21,298***	***21,589***	***21,913***	***22,167***	***22,446***	***22,724***
EXISTING & PLANNED CAPACITY (2)								
Utility-Controlled Physical Resources								
Nuclear	2,214	2,214	2,214	2,214	2,214	2,214	2,214	2,214
Fossil	150	150	150	150	150	150	150	150
Total Dependable Hydro Capacity	4,734	4,734	4,734	4,734	4,734	4,667	4,667	4,667
Total Utility-Controlled Physical Resources	**7,098**	**7,098**	**7,098**	**7,098**	**7,098**	**7,031**	**7,031**	**7,031**
Existing and Planned Contractual Resources								
DWR Contracts	4,392	2,392	1,597	263	90	90	0	0
QF Contracts	2,559	2,536	2,532	2,517	2,508	2,495	2,478	2,472
Renewable Contracts (3)	98	100	101	103	104	39	41	40
Other Bilateral Contracts (3)	1,229	1,241	1,254	1,268	603	619	635	651
Total Contractual Resources	**8,278**	**6,269**	**5,484**	**4,151**	**3,306**	**3,243**	**3,154**	**3,163**
TOTAL EXISTING & PLANNED CAPACITY (2)	***15,376***	***13,367***	***12,582***	***11,248***	***10,404***	***10,274***	***10,184***	***10,193***
Existing Interruptible/ Emergency Programs	**374**	**374**	**374**	**374**	**374**	**374**	**374**	**374**
TOTAL PROCUREMENT NEED	***4,903***	***7,213***	***8,342***	***9,966***	***11,135***	***11,520***	***11,887***	***12,157***
ADDITIONAL PREFERRED RESOURCES								
Uncommitted Energy Efficiency (4)	260	532	796	1,095	1,489	1,765	2,044	2,379
Uncommitted Dispatchable Demand Response (4)	1,110	1,126	1,144	1,159	1,176	1,189	1,203	1,217
Renewables	679	790	916	1,017	1,115	1,245	1,412	1,505
Distributed Generation/ CHP	to be developed in 2006 by Energy Commission and CPUC							
TOTAL ADDITIONAL PREFERRED RESOURCES (5)	**2,049**	**2,448**	**2,856**	**3,271**	**3,780**	**4,199**	**4,659**	**5,102**
ADDITIONAL NON-DESIGNATED NEED (5)	**2,853**	**4,765**	**5,487**	**6,696**	**7,355**	**7,321**	**7,229**	**7,055**
Aging Plant Replacement (6)	**1,225**	**2,450**	**3,675**	**4,900**	**4,900**	**4,900**	**4,900**	**4,900**

(1) - Peak service area demand is used for calculation of the uncommitteed dispatchable demand reponse targets.

(2) - Existing and planned capacity data are as of early 2005, when the LSE's prepared their resource plan submissions for the Energy Report proceeding.

(3) - Distribution service area data are presented here because the IOU-specific data are confidential.

(4) - Future demand side resources have been increased by 15% to account for their affect on the reserve margin. In addition, the uncommitted energy efficiency and demand response goals reflected here are based on service area load. Future savings from these programs are likely to come both from IOU bundled-service customers and ESP direct access customers.

(5) - Total preferred resource will increase and the open source need will decrease when DG/CHP targets are established in 2006.

(6) - The numbers for aging plant replacement reflect the amount of capacity the IOUs should be including in their resource plans to account for the recommended retirement of the aging plants by 2012.

Table B-5
Annual Aggregated Capacity Resource Accounting Table
PG&E Capacity Procurement Need, Base Demand Case

revised: 21-Nov-05

PEAK DEMAND (MW)								
	2009	2010	2011	2012	2013	2014	2015	2016
Peak Service Area Demand (base case) (1)	19,397	19,675	19,989	20,256	20,552	20,785	21,037	21,288
Peak Bundled Customer Demand (base case)	18,044	18,311	18,614	18,872	19,158	19,383	19,631	19,877
Reserve Margin (15% of Bundled Customer Demand)	2,707	2,747	2,792	2,831	2,874	2,907	2,945	2,982
Firm Sales Obligations	0	0	0	0	0	0	0	0
FIRM PEAK REQUIREMENT	***20,751***	***21,058***	***21,406***	***21,703***	***22,032***	***22,290***	***22,576***	***22,859***
EXISTING & PLANNED CAPACITY (2)								
Utility-Controlled Physical Resources								
Nuclear	2,214	2,214	2,214	2,214	2,214	2,214	2,214	2,214
Fossil	150	150	150	150	150	150	150	150
Total Dependable Hydro Capacity	4,734	4,734	4,734	4,734	4,734	4,667	4,667	4,667
Total Utility-Controlled Physical Resources	**7,098**	**7,098**	**7,098**	**7,098**	**7,098**	**7,031**	**7,031**	**7,031**
Existing and Planned Contractual Resources								
DWR Contracts	4,392	2,392	1,597	263	90	90	0	0
QF Contracts	2,559	2,536	2,532	2,517	2,508	2,495	2,478	2,472
Renewable Contracts (3)	98	100	101	103	104	39	41	40
Other Bilateral Contracts (3)	1,229	1,241	1,254	1,268	603	619	635	651
Total Contractual Resources	**8,278**	**6,269**	**5,484**	**4,151**	**3,306**	**3,243**	**3,154**	**3,163**
TOTAL EXISTING & PLANNED CAPACITY (2)	***15,376***	***13,367***	***12,582***	***11,248***	***10,404***	***10,274***	***10,184***	***10,193***
Existing Interruptible/ Emergency Programs	**374**	**374**	**374**	**374**	**374**	**374**	**374**	**374**
TOTAL PROCUREMENT NEED	***5,001***	***7,317***	***8,450***	***10,080***	***11,254***	***11,643***	***12,017***	***12,291***
ADDITIONAL PREFERRED RESOURCES								
Uncommitted Energy Efficiency (4)	260	532	796	1,095	1,489	1,765	2,044	2,379
Uncommitted Dispatchable Demand Response (4)	1,115	1,131	1,149	1,165	1,182	1,195	1,210	1,224
Renewables	679	790	916	1,017	1,115	1,245	1,412	1,505
Distributed Generation/ CHP	to be developed in 2006 by Energy Commission and CPUC							
TOTAL ADDITIONAL PREFERRED RESOURCES (5)	**2,054**	**2,454**	**2,861**	**3,277**	**3,786**	**4,205**	**4,665**	**5,108**
ADDITIONAL NON-DESIGNATED NEED (5)	**2,946**	**4,863**	**5,589**	**6,804**	**7,468**	**7,437**	**7,352**	**7,183**
Aging Plant Replacement (6)	**1,225**	**2,450**	**3,675**	**4,900**	**4,900**	**4,900**	**4,900**	**4,900**

(1) - Peak service area demand is used for calculation of the uncommitteed dispatchable demand reponse targets.

(2) - Existing and planned capacity data are as of early 2005, when the LSE's prepared their resource plan submissions for the Energy Report proceeding.

(3) - Distribution service area data are presented here because the IOU-specific data are confidential.

(4) - Future demand side resources have been increased by 15% to account for their affect on the reserve margin. In addition, the uncommitted energy efficiency and demand response goals reflected here are based on service area load. Future savings from these programs are likely to come both from IOU bundled-service customers and ESP direct access customers.

(5) - Total preferred resource will increase and the open source need will decrease when DG/CHP targets are established in 2006.

(6) - The numbers for aging plant replacement reflect the amount of capacity the IOUs should be including in their resource plans to account for the recommended retirement of the aging plants by 2012.

Table B-6
Annual Aggregated Capacity Resource Accounting Table
PG&E Capacity Procurement Need, High Demand Case

revised: 21-Nov-05

PEAK DEMAND (MW)								
	2009	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
Peak Service Area Demand (high case) (1)	19,709	20,060	20,455	20,800	21,189	21,521	21,878	22,227
Peak Bundled Customer Demand (high case)	18,344	18,682	19,062	19,394	19,768	20,088	20,434	20,755
Reserve Margin (15% of Bundled Customer Demand)	2,752	2,802	2,859	2,909	2,965	3,013	3,065	3,113
Firm Sales Obligations	0	0	0	0	0	0	0	0
FIRM PEAK REQUIREMENT	***21,096***	***21,484***	***21,921***	***22,303***	***22,733***	***23,101***	***23,499***	***23,868***
EXISTING & PLANNED CAPACITY (2)								
Utility-Controlled Physical Resources								
Nuclear	2,214	2,214	2,214	2,214	2,214	2,214	2,214	2,214
Fossil	150	150	150	150	150	150	150	150
Total Dependable Hydro Capacity	4,734	4,734	4,734	4,734	4,734	4,667	4,667	4,667
Total Utility-Controlled Physical Resources	**7,098**	**7,098**	**7,098**	**7,098**	**7,098**	**7,031**	**7,031**	**7,031**
Existing and Planned Contractual Resources								
DWR Contracts	4,392	2,392	1,597	263	90	90	0	0
QF Contracts	2,559	2,536	2,532	2,517	2,508	2,495	2,478	2,472
Renewable Contracts (3)	98	100	101	103	104	39	41	40
Other Bilateral Contracts (3)	1,229	1,241	1,254	1,268	603	619	635	651
Total Contractual Resources	**8,278**	**6,269**	**5,484**	**4,151**	**3,306**	**3,243**	**3,154**	**3,163**
TOTAL EXISTING & PLANNED CAPACITY (2)	***15,376***	***13,367***	***12,582***	***11,248***	***10,404***	***10,274***	***10,184***	***10,193***
Existing Interruptible/ Emergency Programs	**374**	**374**	**374**	**374**	**374**	**374**	**374**	**374**
TOTAL PROCUREMENT NEED	***5,346***	***7,743***	***8,965***	***10,681***	***11,955***	***12,453***	***12,941***	***13,301***
ADDITIONAL PREFERRED RESOURCES								
Uncommitted Energy Efficiency (4)	260	532	796	1,095	1,489	1,765	2,044	2,379
Uncommitted Dispatchable Demand Response (4)	1,133	1,153	1,176	1,196	1,218	1,237	1,258	1,278
Renewables	679	790	916	1,017	1,115	1,245	1,412	1,505
Distributed Generation/ CHP	to be developed in 2006 by Energy Commission and CPUC							
TOTAL ADDITIONAL PREFERRED RESOURCES (5)	**2,072**	**2,476**	**2,888**	**3,308**	**3,823**	**4,248**	**4,714**	**5,162**
ADDITIONAL NON-DESIGNATED NEED (5)	**3,273**	**5,267**	**6,078**	**7,373**	**8,133**	**8,206**	**8,227**	**8,138**
Aging Plant Replacement (6)	**1,225**	**2,450**	**3,675**	**4,900**	**4,900**	**4,900**	**4,900**	**4,900**

(1) - Peak service area demand is used for calculation of the uncommitteed dispatchable demand reponse targets.

(2) - Existing and planned capacity data are as of early 2005, when the LSE's prepared their resource plan submissions for the Energy Report proceeding.

(3) - Distribution service area data are presented here because the IOU-specific data are confidential.

(4) - Future demand side resources have been increased by 15% to account for their affect on the reserve margin. In addition, the uncommitted energy efficiency and demand response goals reflected here are based on service area load. Future savings from these programs are likely to come both from IOU bundled-service customers and ESP direct access customers.

(5) - Total preferred resource will increase and the open source need will decrease when DG/CHP targets are established in 2006.

(6) - The numbers for aging plant replacement reflect the amount of capacity the IOUs should be including in their resource plans to account for the recommended retirement of the aging plants by 2012.

Table B-7
Annual Aggregated Energy Resource Accounting Table
SCE Energy Procurement Need, Low Demand Case

revised: 15-Nov-05

ENERGY DEMAND (GWh)								
	2009	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
Net Energy for Bundled Customer Load (low case)	84,003	85,067	86,141	87,319	88,365	89,444	90,516	91,423
Firm Sales Obligations	2,144	2,144	2,144	2,151	2,144	2,144	2,144	2,151
TOTAL ENERGY REQUIREMENT	***86,147***	***87,211***	***88,286***	***89,470***	***90,509***	***91,589***	***92,661***	***93,574***
EXISTING & PLANNED RESOURCES (1)								
Utility-Controlled Physical Resources								
Nuclear	9,671	9,095	10,063	10,610	10,280	9,534	9,859	9,414
Fossil	16,234	15,862	17,596	17,469	17,520	17,509	17,280	17,293
Total Hydro Energy Supply	4,679	4,675	4,705	4,597	4,591	4,602	4,625	4,642
Total Utility-Controlled Physical Resources	**30,584**	**29,632**	**32,364**	**32,675**	**32,391**	**31,645**	**31,764**	**31,349**
Existing and Planned Contractual Resources								
Total Energy Supply from DWR Contracts	19,946	19,946	16,755	0	0	0	0	0
Total Energy Supply from QF Contracts	25,033	24,993	24,956	24,987	24,892	24,864	24,838	24,879
Total Existing & Planned Renewable Contracts	2,841	2,841	2,841	2,848	2,841	2,841	2,841	2,848
Total Energy Supply from Other Bilateral Contracts	6,352	6,419	1,754	1,406	1,406	1,388	1,383	1,383
Total Contractual Resources	**54,172**	**54,198**	**46,306**	**29,241**	**29,139**	**29,093**	**29,062**	**29,110**
TOTAL EXISTING & PLANNED ENERGY RESOURCES (1)	***84,756***	***83,830***	***78,670***	***61,916***	***61,529***	***60,738***	***60,826***	***60,459***
TOTAL PROCUREMENT NEED	***1,392***	***3,381***	***9,616***	***27,554***	***28,980***	***30,851***	***31,835***	***33,115***
ADDITIONAL PREFERRED RESOURCES								
Uncommitted Energy Efficiency (2)	866	1,783	2,708	3,956	5,191	6,426	7,660	8,895
Renewables	4,630	5,613	6,401	7,042	8,774	9,054	10,158	11,257
Distributed Generation/ CHP	to be developed in 2006 by Energy Commission and CPUC							
TOTAL ADDITIONAL PREFERRED RESOURCES (3)	**5,496**	**7,396**	**9,109**	**10,998**	**13,965**	**15,480**	**17,818**	**20,152**
ADDITIONAL NON-DESIGNATED NEED (3)	**-4,104**	**-4,015**	**507**	**16,556**	**15,015**	**15,371**	**14,017**	**12,963**
Aging Plant Replacement (4)	**3,138**	**6,276**	**9,413**	**12,551**	**12,551**	**12,551**	**12,551**	**12,551**

(1) - Existing and planned resource totals are as of early 2005, when the LSEs prepared their resource plan submissions for the 2005 Energy Report proceeding.
(2) - Energy efficiency goals were established by the CPUC for the IOUs based on all customers in their service territory. Future savings from uncommitted energy efficiency programs are likely to come both from IOU bundled-service customers and ESP direct access customers.
(3) - The total preferred resources will increase and the open source need will decrease when DG/CHP targets are established in 2006.
(6) - The numbers for aging plant replacement reflect the amount of energy the IOUs should be including in their resource plans to account for the recommended retirement of the aging plants by 2012.

Table B-8
Annual Aggregated Energy Resource Accounting Table
SCE Energy Procurement Need, Base Demand Case

revised: 15-Nov-05

ENERGY DEMAND (GWh)								
	2009	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
Net Energy for Bundled Customer Load (base case)	84,589	85,703	86,822	88,045	89,132	90,258	91,342	92,254
Firm Sales Obligations	2,144	2,144	2,144	2,151	2,144	2,144	2,144	2,151
TOTAL ENERGY REQUIREMENT	***86,733***	***87,847***	***88,967***	***90,196***	***91,276***	***92,403***	***93,486***	***94,405***
EXISTING & PLANNED RESOURCES (1)								
Utility-Controlled Physical Resources								
Nuclear	9,671	9,095	10,063	10,610	10,280	9,534	9,859	9,414
Fossil	16,234	15,862	17,596	17,469	17,520	17,509	17,280	17,293
Total Hydro Energy Supply	4,679	4,675	4,705	4,597	4,591	4,602	4,625	4,642
Total Utility-Controlled Physical Resources	**30,584**	**29,632**	**32,364**	**32,675**	**32,391**	**31,645**	**31,764**	**31,349**
Existing and Planned Contractual Resources								
Total Energy Supply from DWR Contracts	19,946	19,946	16,755	0	0	0	0	0
Total Energy Supply from QF Contracts	25,033	24,993	24,956	24,987	24,892	24,864	24,838	24,879
Total Existing & Planned Renewable Contracts	2,841	2,841	2,841	2,848	2,841	2,841	2,841	2,848
Total Energy Supply from Other Bilateral Contracts	6,352	6,419	1,754	1,406	1,406	1,388	1,383	1,383
Total Contractual Resources	**54,172**	**54,198**	**46,306**	**29,241**	**29,139**	**29,093**	**29,062**	**29,110**
TOTAL EXISTING & PLANNED ENERGY RESOURCES (1)	***84,756***	***83,830***	***78,670***	***61,916***	***61,529***	***60,738***	***60,826***	***60,459***
TOTAL PROCUREMENT NEED	***1,978***	***4,018***	***10,297***	***28,280***	***29,747***	***31,665***	***32,660***	***33,946***
ADDITIONAL PREFERRED RESOURCES								
Uncommitted Energy Efficiency (2)	866	1,783	2,708	3,956	5,191	6,426	7,660	8,895
Renewables	4,630	5,613	6,401	7,042	8,774	9,054	10,158	11,257
Distributed Generation/ CHP	to be developed in 2006 by Energy Commission and CPUC							
TOTAL ADDITIONAL PREFERRED RESOURCES (3)	**5,496**	**7,396**	**9,109**	**10,998**	**13,965**	**15,480**	**17,818**	**20,152**
ADDITIONAL NON-DESIGNATED NEED (3)	**-3,518**	**-3,378**	**1,188**	**17,282**	**15,782**	**16,185**	**14,842**	**13,794**
Aging Plant Replacement (4)	**3,138**	**6,276**	**9,413**	**12,551**	**12,551**	**12,551**	**12,551**	**12,551**

(1) - Existing and planned resource totals are as of early 2005, when the LSEs prepared their resource plan submissions for the 2005 Energy Report proceeding.
(2) - Energy efficiency goals were established by the CPUC for the IOUs based on all customers in their service territory. Future savings from uncommitted energy efficiency programs are likely to come both from IOU bundled-service customers and ESP direct access customers.
(3) - The total preferred resources will increase and the open source need will decrease when DG/CHP targets are established in 2006.
(6) - The numbers for aging plant replacement reflect the amount of energy the IOUs should be including in their resource plans to account for the recommended retirement of the aging plants by 2012.

Table B-9
Annual Aggregated Energy Resource Accounting Table
SCE Energy Procurement Need, High Demand Case

revised: 15-Nov-05

ENERGY DEMAND (GWh)								
	2009	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
Net Energy for Bundled Customer Load (high case)	85,421	86,758	88,092	89,554	90,901	92,385	93,815	95,048
Firm Sales Obligations	2,144	2,144	2,144	2,151	2,144	2,144	2,144	2,151
TOTAL ENERGY REQUIREMENT	***87,566***	***88,902***	***90,237***	***91,705***	***93,046***	***94,530***	***95,959***	***97,199***
EXISTING & PLANNED RESOURCES (1)								
Utility-Controlled Physical Resources								
Nuclear	9,671	9,095	10,063	10,610	10,280	9,534	9,859	9,414
Fossil	16,234	15,862	17,596	17,469	17,520	17,509	17,280	17,293
Total Hydro Energy Supply	4,679	4,675	4,705	4,597	4,591	4,602	4,625	4,642
Total Utility-Controlled Physical Resources	**30,584**	**29,632**	**32,364**	**32,675**	**32,391**	**31,645**	**31,764**	**31,349**
Existing and Planned Contractual Resources								
Total Energy Supply from DWR Contracts	19,946	19,946	16,755	0	0	0	0	0
Total Energy Supply from QF Contracts	25,033	24,993	24,956	24,987	24,892	24,864	24,838	24,879
Total Existing & Planned Renewable Contracts	2,841	2,841	2,841	2,848	2,841	2,841	2,841	2,848
Total Energy Supply from Other Bilateral Contracts	6,352	6,419	1,754	1,406	1,406	1,388	1,383	1,383
Total Contractual Resources	**54,172**	**54,198**	**46,306**	**29,241**	**29,139**	**29,093**	**29,062**	**29,110**
TOTAL EXISTING & PLANNED ENERGY RESOURCES (1)	***84,756***	***83,830***	***78,670***	***61,916***	***61,529***	***60,738***	***60,826***	***60,459***
TOTAL PROCUREMENT NEED	***2,810***	***5,072***	***11,567***	***29,789***	***31,517***	***33,792***	***35,133***	***36,739***
ADDITIONAL PREFERRED RESOURCES								
Uncommitted Energy Efficiency (2)	866	1,783	2,708	3,956	5,191	6,426	7,660	8,895
Renewables	4,630	5,613	6,401	7,042	8,774	9,054	10,158	11,257
Distributed Generation/ CHP	to be developed in 2006 by Energy Commission and CPUC							
TOTAL ADDITIONAL PREFERRED RESOURCES (3)	**5,496**	**7,396**	**9,109**	**10,998**	**13,965**	**15,480**	**17,818**	**20,152**
ADDITIONAL NON-DESIGNATED NEED (3)	**-2,686**	**-2,324**	**2,458**	**18,791**	**17,552**	**18,312**	**17,315**	**16,587**
Aging Plant Replacement (4)	**3,138**	**6,276**	**9,413**	**12,551**	**12,551**	**12,551**	**12,551**	**12,551**

(1) - Existing and planned resource totals are as of early 2005, when the LSEs prepared their resource plan submissions for the 2005 Energy Report proceeding.
(2) - Energy efficiency goals were established by the CPUC for the IOUs based on all customers in their service territory. Future savings from uncommitted energy efficiency programs are likely to come both from IOU bundled-service customers and ESP direct access customers.
(3) - The total preferred resources will increase and the open source need will decrease when DG/CHP targets are established in 2006.
(6) - The numbers for aging plant replacement reflect the amount of energy the IOUs should be including in their resource plans to account for the recommended retirement of the aging plants by 2012.

Table B-10
Annual Aggregated Capacity Resource Accounting Table
SCE Capacity Procurement Need, Low Demand Case

revised: 15-Nov-05

PEAK DEMAND (MW)								
	2009	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
Peak Service Area Demand (low case) (1)	21,168	21,441	21,714	22,009	22,275	22,555	22,834	23,077
Peak Bundled Customer Demand (low case)	19,171	19,434	19,697	19,981	20,237	20,504	20,773	21,009
Reserve Margin (15% of Bundled Customer Demand)	2,876	2,915	2,955	2,997	3,036	3,076	3,116	3,151
Firm Sales Obligations	255	255	255	255	255	255	255	255
FIRM PEAK REQUIREMENT	***22,302***	***22,605***	***22,907***	***23,234***	***23,528***	***23,835***	***24,144***	***24,416***
EXISTING & PLANNED CAPACITY (2)								
Utility-Controlled Physical Resources								
Nuclear	2,289	2,289	2,289	2,289	2,289	2,289	2,289	2,289
Fossil	1,648	1,645	1,643	1,641	1,638	1,637	1,637	1,637
Total Dependable Hydro Capacity	1,069	1,069	1,069	1,069	1,069	1,069	1,069	1,069
Total Utility-Controlled Physical Resources	**5,006**	**5,003**	**5,001**	**4,999**	**4,996**	**4,995**	**4,995**	**4,995**
Existing and Planned Contractual Resources								
DWR Contracts	3,217	3,217	2,415	0	0	0	0	0
QF Contracts	3,211	3,211	3,211	3,211	3,211	3,211	3,211	3,211
Renewable Contracts (3)	354	356	359	361	364	367	370	373
Other Bilateral Contracts (3)	941	962	982	987	1,010	1,030	1,056	1,083
Total Contractual Resources	**7,724**	**7,746**	**6,968**	**4,559**	**4,585**	**4,608**	**4,637**	**4,667**
TOTAL EXISTING & PLANNED CAPACITY (2)	***12,729***	***12,750***	***11,969***	***9,558***	***9,582***	***9,603***	***9,632***	***9,662***
Existing Interruptible/ Emergency Programs	**1,037**	**1,037**	**1,037**	**1,037**	**1,037**	**1,037**	**1,037**	**1,037**
TOTAL PROCUREMENT NEED	***8,536***	***8,818***	***9,901***	***12,639***	***12,909***	***13,195***	***13,475***	***13,716***
ADDITIONAL PREFERRED RESOURCES								
Uncommitted Energy Efficiency (4)	225	452	680	980	1,279	1,578	1,877	2,177
Uncommitted Dispatchable Demand Response (4)	1,217	1,233	1,249	1,266	1,281	1,297	1,313	1,327
Renewables	962	1,183	1,293	1,375	1,621	1,656	1,912	2,048
Distributed Generation/ CHP	to be developed in 2006 by Energy Commission and CPUC							
TOTAL ADDITIONAL PREFERRED RESOURCES (5)	**2,405**	**2,868**	**3,221**	**3,620**	**4,181**	**4,531**	**5,102**	**5,552**
ADDITIONAL NON-DESIGNATED NEED (5)	**6,131**	**5,950**	**6,680**	**9,018**	**8,729**	**8,664**	**8,373**	**8,164**
Aging Plant Replacement (6)	**2,022**	**4,044**	**6,066**	**8,088**	**8,088**	**8,088**	**8,088**	**8,088**

(1) - Peak service area demand is used for calculation of the uncommitteed dispatchable demand reponse targets.

(2) - Existing and planned capacity data are as of early 2005, when the LSE's prepared their resource plan submissions for the Energy Report proceeding.

(3) - Distribution service area data are presented here because the IOU-specific data are confidential.

(4) - Future demand side resources have been increased by 15% to account for their affect on the reserve margin. In addition, the uncommitted energy efficiency and demand response goals reflected here are based on service area load. Future savings from these programs are likely to come both from IOU bundled-service customers and ESP direct access customers.

(5) - Total preferred resource will increase and the open source need will decrease when DG/CHP targets are established in 2006.

(6) - The numbers for aging plant replacement reflect the amount of capacity the IOUs should be including in their resource plans to account for the recommended retirement of the aging plants by 2012.

Table B-11
Annual Aggregated Capacity Resource Accounting Table
SCE Capacity Procurement Need, Base Demand Case

revised: 15-Nov-05

PEAK DEMAND (MW)								
	2009	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
Peak Service Area Demand (base case) (1)	21,334	21,621	21,906	22,215	22,493	22,786	23,068	23,313
Peak Bundled Customer Demand (base case)	19,335	19,612	19,888	20,184	20,452	20,733	21,005	21,243
Reserve Margin (15% of Bundled Customer Demand)	2,900	2,942	2,983	3,028	3,068	3,110	3,151	3,186
Firm Sales Obligations	255	255	255	255	255	255	255	255
FIRM PEAK REQUIREMENT	***22,491***	***22,809***	***23,127***	***23,467***	***23,775***	***24,098***	***24,411***	***24,685***
EXISTING & PLANNED CAPACITY (2)								
Utility-Controlled Physical Resources								
Nuclear	2,289	2,289	2,289	2,289	2,289	2,289	2,289	2,289
Fossil	1,648	1,645	1,643	1,641	1,638	1,637	1,637	1,637
Total Dependable Hydro Capacity	1,069	1,069	1,069	1,069	1,069	1,069	1,069	1,069
Total Utility-Controlled Physical Resources	**5,006**	**5,003**	**5,001**	**4,999**	**4,996**	**4,995**	**4,995**	**4,995**
Existing and Planned Contractual Resources								
DWR Contracts	3,217	3,217	2,415	0	0	0	0	0
QF Contracts	3,211	3,211	3,211	3,211	3,211	3,211	3,211	3,211
Renewable Contracts (3)	354	356	359	361	364	367	370	373
Other Bilateral Contracts (3)	941	962	982	987	1,010	1,030	1,056	1,083
Total Contractual Resources	**7,724**	**7,746**	**6,968**	**4,559**	**4,585**	**4,608**	**4,637**	**4,667**
TOTAL EXISTING & PLANNED CAPACITY (2)	***12,729***	***12,750***	***11,969***	***9,558***	***9,582***	***9,603***	***9,632***	***9,662***
Existing Interruptible/ Emergency Programs	**1,037**	**1,037**	**1,037**	**1,037**	**1,037**	**1,037**	**1,037**	**1,037**
TOTAL PROCUREMENT NEED	***8,724***	***9,023***	***10,121***	***12,872***	***13,157***	***13,458***	***13,742***	***13,985***
ADDITIONAL PREFERRED RESOURCES								
Uncommitted Energy Efficiency (4)	225	452	680	980	1,279	1,578	1,877	2,177
Uncommitted Dispatchable Demand Response (4)	1,227	1,243	1,260	1,277	1,293	1,310	1,326	1,341
Renewables	962	1,183	1,293	1,375	1,621	1,656	1,912	2,048
Distributed Generation/ CHP	to be developed in 2006 by Energy Commission and CPUC							
TOTAL ADDITIONAL PREFERRED RESOURCES (5)	**2,414**	**2,878**	**3,232**	**3,632**	**4,193**	**4,544**	**5,115**	**5,565**
ADDITIONAL NON-DESIGNATED NEED (5)	**6,310**	**6,144**	**6,889**	**9,240**	**8,964**	**8,914**	**8,627**	**8,420**
Aging Plant Replacement (6)	**2,022**	**4,044**	**6,066**	**8,088**	**8,088**	**8,088**	**8,088**	**8,088**

(1) - Peak service area demand is used for calculation of the uncommitteed dispatchable demand reponse targets.

(2) - Existing and planned capacity data are as of early 2005, when the LSE's prepared their resource plan submissions for the Energy Report proceeding.

(3) - Distribution service area data are presented here because the IOU-specific data are confidential.

(4) - Future demand side resources have been increased by 15% to account for their affect on the reserve margin. In addition, the uncommitted energy efficiency and demand response goals reflected here are based on service area load. Future savings from these programs are likely to come both from IOU bundled-service customers and ESP direct access customers.

(5) - Total preferred resource will increase and the open source need will decrease when DG/CHP targets are established in 2006.

(6) - The numbers for aging plant replacement reflect the amount of capacity the IOUs should be including in their resource plans to account for the recommended retirement of the aging plants by 2012.

Table B-12
Annual Aggregated Capacity Resource Accounting Table
SCE Capacity Procurement Need, High Demand Case

revised: 15-Nov-05

PEAK DEMAND (MW)								
	2009	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
Peak Service Area Demand (high case) (1)	21,518	21,853	22,185	22,545	22,878	23,243	23,596	23,908
Peak Bundled Customer Demand (high case)	19,506	19,827	20,146	20,490	20,808	21,155	21,492	21,791
Reserve Margin (15% of Bundled Customer Demand)	2,926	2,974	3,022	3,074	3,121	3,173	3,224	3,269
Firm Sales Obligations	255	255	255	255	255	255	255	255
FIRM PEAK REQUIREMENT	***22,687***	***23,057***	***23,423***	***23,819***	***24,185***	***24,584***	***24,971***	***25,315***
EXISTING & PLANNED CAPACITY (2)								
Utility-Controlled Physical Resources								
Nuclear	2,289	2,289	2,289	2,289	2,289	2,289	2,289	2,289
Fossil	1,648	1,645	1,643	1,641	1,638	1,637	1,637	1,637
Total Dependable Hydro Capacity	1,069	1,069	1,069	1,069	1,069	1,069	1,069	1,069
Total Utility-Controlled Physical Resources	**5,006**	**5,003**	**5,001**	**4,999**	**4,996**	**4,995**	**4,995**	**4,995**
Existing and Planned Contractual Resources								
DWR Contracts	3,217	3,217	2,415	0	0	0	0	0
QF Contracts	3,211	3,211	3,211	3,211	3,211	3,211	3,211	3,211
Renewable Contracts (3)	354	356	359	361	364	367	370	373
Other Bilateral Contracts (3)	941	962	982	987	1,010	1,030	1,056	1,083
Total Contractual Resources	**7,724**	**7,746**	**6,968**	**4,559**	**4,585**	**4,608**	**4,637**	**4,667**
TOTAL EXISTING & PLANNED CAPACITY (2)	***12,729***	***12,750***	***11,969***	***9,558***	***9,582***	***9,603***	***9,632***	***9,662***
Existing Interruptible/ Emergency Programs	**1,037**	**1,037**	**1,037**	**1,037**	**1,037**	**1,037**	**1,037**	**1,037**
TOTAL PROCUREMENT NEED	***8,921***	***9,270***	***10,418***	***13,224***	***13,566***	***13,943***	***14,302***	***14,616***
ADDITIONAL PREFERRED RESOURCES								
Uncommitted Energy Efficiency (4)	225	452	680	980	1,279	1,578	1,877	2,177
Uncommitted Dispatchable Demand Response (4)	1,237	1,257	1,276	1,296	1,315	1,336	1,357	1,375
Renewables	962	1,183	1,293	1,375	1,621	1,656	1,912	2,048
Distributed Generation/ CHP	to be developed in 2006 by Energy Commission and CPUC							
TOTAL ADDITIONAL PREFERRED RESOURCES (5)	**2,425**	**2,891**	**3,248**	**3,651**	**4,215**	**4,570**	**5,146**	**5,600**
ADDITIONAL NON-DESIGNATED NEED (5)	**6,496**	**6,378**	**7,169**	**9,573**	**9,351**	**9,373**	**9,156**	**9,016**
Aging Plant Replacement (6)	**2,022**	**4,044**	**6,066**	**8,088**	**8,088**	**8,088**	**8,088**	**8,088**

(1) - Peak service area demand is used for calculation of the uncommitteed dispatchable demand reponse targets.

(2) - Existing and planned capacity data are as of early 2005, when the LSE's prepared their resource plan submissions for the Energy Report proceeding.

(3) - Distribution service area data are presented here because the IOU-specific data are confidential.

(4) - Future demand side resources have been increased by 15% to account for their affect on the reserve margin. In addition, the uncommitted energy efficiency and demand response goals reflected here are based on service area load. Future savings from these programs are likely to come both from IOU bundled-service customers and ESP direct access customers.

(5) - Total preferred resource will increase and the open source need will decrease when DG/CHP targets are established in 2006.

(6) - The numbers for aging plant replacement reflect the amount of capacity the IOUs should be including in their resource plans to account for the recommended retirement of the aging plants by 2012.

Table B-13
Annual Aggregated Energy Resource Accounting Table
SDG&E Energy Procurement Need, Low Demand Case

revised: 15-Nov-05

ENERGY DEMAND (GWh)	2009	2010	2011	2012	2013	2014	2015	2016
Net Energy for Bundled Customer Load (low case)	18,472	18,765	19,057	19,351	19,642	19,928	20,217	20,500
Firm Sales Obligations								
TOTAL ENERGY REQUIREMENT	***18,472***	***18,765***	***19,057***	***19,351***	***19,642***	***19,928***	***20,217***	***20,500***
EXISTING & PLANNED RESOURCES (1)								
Utility-Controlled Physical Resources								
Nuclear	3,164	2,338	2,554	2,563	2,387	2,715	2,394	2,561
Fossil	4,003	3,956	3,869	3,931	3,962	3,993	4,016	4,087
Total Hydro Energy Supply	-17	-15	-15	-15	-16	-16	-15	-14
Total Utility-Controlled Physical Resources	**7,150**	**6,279**	**6,408**	**6,479**	**6,333**	**6,692**	**6,395**	**6,635**
Existing and Planned Contractual Resources								
Total Energy Supply from DWR Contracts	1,590	1,589	0	0	0	0	0	0
Total Energy Supply from QF Contracts	1,718	1,718	1,716	1,716	1,714	1,713	1,718	1,721
Total Existing & Planned Renewable Contracts	1,009	1,004	978	971	908	879	873	875
Total Energy Supply from Other Bilateral Contracts	5,167	4,638	4,185	3,008	2,207	1,457	1,375	1,664
Total Contractual Resources	**9,485**	**8,948**	**6,879**	**5,696**	**4,829**	**4,050**	**3,966**	**4,259**
TOTAL EXISTING & PLANNED ENERGY RESOURCES (1)	***16,635***	***15,227***	***13,286***	***12,175***	***11,162***	***10,742***	***10,361***	***10,894***
TOTAL PROCUREMENT NEED	***1,837***	***3,538***	***5,771***	***7,176***	***8,480***	***9,186***	***9,856***	***9,606***
ADDITIONAL PREFERRED RESOURCES								
Uncommitted Energy Efficiency (2)	141	419	687	929	1,148	1,431	1,741	2,066
Renewables	574	2,453	2,710	2,920	3,236	3,672	4,075	4,460
Distributed Generation/ CHP	to be developed in 2006 by Energy Commission and CPUC							
TOTAL ADDITIONAL PREFERRED RESOURCES (3)	**715**	**2,872**	**3,397**	**3,849**	**4,384**	**5,103**	**5,816**	**6,526**
ADDITIONAL NON-DESIGNATED NEED (3)	**1,122**	**666**	**2,374**	**3,327**	**4,096**	**4,083**	**4,040**	**3,080**
Aging Plant Replacement (4)	**1,096**	**2,192**	**3,287**	**4,383**	**4,383**	**4,383**	**4,383**	**4,383**

(1) - Existing and planned resource totals are as of early 2005, when the LSEs prepared their resource plan submissions for the 2005 Energy Report proceeding.
(2) - Energy efficiency goals were established by the CPUC for the IOUs based on all customers in their service territory. Future savings from uncommitted energy efficiency programs are likely to come both from IOU bundled-service customers and ESP direct access customers.
(3) - The total preferred resources will increase and the open source need will decrease when DG/CHP targets are established in 2006.
(6) - The numbers for aging plant replacement reflect the amount of energy the IOUs should be including in their resource plans to account for the recommended retirement of the aging plants by 2012.

Table B-14
Annual Aggregated Energy Resource Accounting Table
SDG&E Energy Procurement Need, Base Demand Case

revised: 15-Nov-05

ENERGY DEMAND (GWh)								
	2009	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
Net Energy for Bundled Customer Load (base case)	18,627	18,930	19,228	19,529	19,825	20,117	20,400	20,679
Firm Sales Obligations								
TOTAL ENERGY REQUIREMENT	***18,627***	***18,930***	***19,228***	***19,529***	***19,825***	***20,117***	***20,400***	***20,679***
EXISTING & PLANNED RESOURCES (1)								
Utility-Controlled Physical Resources								
Nuclear	3,164	2,338	2,554	2,563	2,387	2,715	2,394	2,561
Fossil	4,003	3,956	3,869	3,931	3,962	3,993	4,016	4,087
Total Hydro Energy Supply	-17	-15	-15	-15	-16	-16	-15	-14
Total Utility-Controlled Physical Resources	**7,150**	**6,279**	**6,408**	**6,479**	**6,333**	**6,692**	**6,395**	**6,635**
Existing and Planned Contractual Resources								
Total Energy Supply from DWR Contracts	1,590	1,589	0	0	0	0	0	0
Total Energy Supply from QF Contracts	1,718	1,718	1,716	1,716	1,714	1,713	1,718	1,721
Total Existing & Planned Renewable Contracts	1,009	1,004	978	971	908	879	873	875
Total Energy Supply from Other Bilateral Contracts	5,167	4,638	4,185	3,008	2,207	1,457	1,375	1,664
Total Contractual Resources	**9,485**	**8,948**	**6,879**	**5,696**	**4,829**	**4,050**	**3,966**	**4,259**
TOTAL EXISTING & PLANNED ENERGY RESOURCES (1)	***16,635***	***15,227***	***13,286***	***12,175***	***11,162***	***10,742***	***10,361***	***10,894***
TOTAL PROCUREMENT NEED	***1,993***	***3,702***	***5,942***	***7,354***	***8,663***	***9,375***	***10,039***	***9,785***
ADDITIONAL PREFERRED RESOURCES								
Uncommitted Energy Efficiency (2)	141	419	687	929	1,148	1,431	1,741	2,066
Renewables	574	2,453	2,710	2,920	3,236	3,672	4,075	4,460
Distributed Generation/ CHP	to be developed in 2006 by Energy Commission and CPUC							
TOTAL ADDITIONAL PREFERRED RESOURCES (3)	**715**	**2,872**	**3,397**	**3,849**	**4,384**	**5,103**	**5,816**	**6,526**
ADDITIONAL NON-DESIGNATED NEED (3)	**1,278**	**830**	**2,545**	**3,505**	**4,279**	**4,272**	**4,223**	**3,259**
Aging Plant Replacement (4)	**1,096**	**2,192**	**3,287**	**4,383**	**4,383**	**4,383**	**4,383**	**4,383**

(1) - Existing and planned resource totals are as of early 2005, when the LSEs prepared their resource plan submissions for the 2005 Energy Report proceeding.
(2) - Energy efficiency goals were established by the CPUC for the IOUs based on all customers in their service territory. Future savings from uncommitted energy efficiency programs are likely to come both from IOU bundled-service customers and ESP direct access customers.
(3) - The total preferred resources will increase and the open source need will decrease when DG/CHP targets are established in 2006.
(6) - The numbers for aging plant replacement reflect the amount of energy the IOUs should be including in their resource plans to account for the recommended retirement of the aging plants by 2012.

Table B-15
Annual Aggregated Energy Resource Accounting Table
SDG&E Energy Procurement Need, High Demand Case

revised: 15-Nov-05

ENERGY DEMAND (GWh)								
	2009	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
Net Energy for Bundled Customer Load (high case)	18,792	19,135	19,476	19,822	20,167	20,513	20,849	21,185
Firm Sales Obligations								
TOTAL ENERGY REQUIREMENT	***18,792***	***19,135***	***19,476***	***19,822***	***20,167***	***20,513***	***20,849***	***21,185***
EXISTING & PLANNED RESOURCES (1)								
Utility-Controlled Physical Resources								
Nuclear	3,164	2,338	2,554	2,563	2,387	2,715	2,394	2,561
Fossil	4,003	3,956	3,869	3,931	3,962	3,993	4,016	4,087
Total Hydro Energy Supply	-17	-15	-15	-15	-16	-16	-15	-14
Total Utility-Controlled Physical Resources	**7,150**	**6,279**	**6,408**	**6,479**	**6,333**	**6,692**	**6,395**	**6,635**
Existing and Planned Contractual Resources								
Total Energy Supply from DWR Contracts	1,590	1,589	0	0	0	0	0	0
Total Energy Supply from QF Contracts	1,718	1,718	1,716	1,716	1,714	1,713	1,718	1,721
Total Existing & Planned Renewable Contracts	1,009	1,004	978	971	908	879	873	875
Total Energy Supply from Other Bilateral Contracts	5,167	4,638	4,185	3,008	2,207	1,457	1,375	1,664
Total Contractual Resources	**9,485**	**8,948**	**6,879**	**5,696**	**4,829**	**4,050**	**3,966**	**4,259**
TOTAL EXISTING & PLANNED ENERGY RESOURCES (1)	***16,635***	***15,227***	***13,286***	***12,175***	***11,162***	***10,742***	***10,361***	***10,894***
TOTAL PROCUREMENT NEED	***2,157***	***3,908***	***6,190***	***7,647***	***9,005***	***9,771***	***10,489***	***10,291***
ADDITIONAL PREFERRED RESOURCES								
Uncommitted Energy Efficiency (2)	141	419	687	929	1,148	1,431	1,741	2,066
Renewables	574	2,453	2,710	2,920	3,236	3,672	4,075	4,460
Distributed Generation/ CHP	to be developed in 2006 by Energy Commission and CPUC							
TOTAL ADDITIONAL PREFERRED RESOURCES (3)	**715**	**2,872**	**3,397**	**3,849**	**4,384**	**5,103**	**5,816**	**6,526**
ADDITIONAL NON-DESIGNATED NEED (3)	**1,442**	**1,036**	**2,793**	**3,798**	**4,621**	**4,668**	**4,673**	**3,765**
Aging Plant Replacement (4)	**1,096**	**2,192**	**3,287**	**4,383**	**4,383**	**4,383**	**4,383**	**4,383**

(1) - Existing and planned resource totals are as of early 2005, when the LSEs prepared their resource plan submissions for the 2005 Energy Report proceeding.
(2) - Energy efficiency goals were established by the CPUC for the IOUs based on all customers in their service territory. Future savings from uncommitted energy efficiency programs are likely to come both from IOU bundled-service customers and ESP direct access customers.
(3) - The total preferred resources will increase and the open source need will decrease when DG/CHP targets are established in 2006.
(6) - The numbers for aging plant replacement reflect the amount of energy the IOUs should be including in their resource plans to account for the recommended retirement of the aging plants by 2012.

Table B-16
Annual Aggregated Capacity Resource Accounting Table
SDG&E Capacity Procurement Need, Low Demand Case

revised: 15-Nov-05

PEAK DEMAND (MW)								
	2009	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
Peak Service Area Demand (low case) (1)	4,488	4,553	4,617	4,682	4,746	4,809	4,872	4,933
Peak Bundled Customer Demand (low case)	3,890	3,951	4,011	4,073	4,134	4,194	4,254	4,312
Reserve Margin (15% of Bundled Customer Demand)	584	593	602	611	620	629	638	647
Firm Sales Obligations	0	0	0	0	0	0	0	0
FIRM PEAK REQUIREMENT	***4,474***	***4,544***	***4,613***	***4,684***	***4,754***	***4,823***	***4,892***	***4,959***
EXISTING & PLANNED CAPACITY (2)								
Utility-Controlled Physical Resources								
Nuclear	377	311	311	311	311	311	311	311
Fossil	588	588	588	588	588	588	588	588
Total Dependable Hydro Capacity	40	40	40	40	40	40	40	40
Total Utility-Controlled Physical Resources	**1,005**	**938**	**938**	**938**	**938**	**938**	**938**	**938**
Existing and Planned Contractual Resources								
DWR Contracts	2,103	2,103	718	26	26	0	0	0
QF Contracts	221	221	221	221	221	221	221	221
Renewable Contracts (3)	120	120	116	116	107	105	104	105
Other Bilateral Contracts (3)	720	724	727	731	735	651	656	661
Total Contractual Resources	**3,164**	**3,167**	**1,782**	**1,094**	**1,089**	**977**	**981**	**986**
TOTAL EXISTING & PLANNED CAPACITY (2)	***4,168***	***4,106***	***2,720***	***2,032***	***2,027***	***1,915***	***1,919***	***1,925***
Existing Interruptible/ Emergency Programs	**36**	**36**	**36**	**36**	**36**	**36**	**36**	**36**
TOTAL PROCUREMENT NEED	***269***	***402***	***1,857***	***2,616***	***2,691***	***2,872***	***2,937***	***2,998***
ADDITIONAL PREFERRED RESOURCES								
Uncommitted Energy Efficiency (4)	55	118	175	225	278	345	417	486
Uncommitted Dispatchable Demand Response (4)	258	262	265	269	273	277	280	284
Renewables	66	428	546	567	601	647	689	728
Distributed Generation/ CHP	to be developed in 2006 by Energy Commission and CPUC							
TOTAL ADDITIONAL PREFERRED RESOURCES (5)	**379**	**808**	**986**	**1,062**	**1,152**	**1,269**	**1,387**	**1,498**
ADDITIONAL NON-DESIGNATED NEED (5)	**-110**	**-406**	**870**	**1,554**	**1,539**	**1,603**	**1,550**	**1,500**
Aging Plant Replacement (6)	**405**	**810**	**1,214**	**1,619**	**1,619**	**1,619**	**1,619**	**1,619**

(1) - Peak service area demand is used for calculation of the uncommitteed dispatchable demand reponse targets.

(2) - Existing and planned capacity data are as of early 2005, when the LSE's prepared their resource plan submissions for the Energy Report proceeding.

(3) - Distribution service area data are presented here because the IOU-specific data are confidential.

(4) - Future demand side resources have been increased by 15% to account for their affect on the reserve margin. In addition, the uncommitted energy efficiency and demand response goals reflected here are based on service area load. Future savings from these programs are likely to come both from IOU bundled-service customers and ESP direct access customers.

(5) - Total preferred resource will increase and the open source need will decrease when DG/CHP targets are established in 2006.

(6) - The numbers for aging plant replacement reflect the amount of capacity the IOUs should be including in their resource plans to account for the recommended retirement of the aging plants by 2012.

Table B-17
Annual Aggregated Capacity Resource Accounting Table
SDG&E Capacity Procurement Need, Base Demand Case

revised: 15-Nov-05

PEAK DEMAND (MW)								
	2009	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
Peak Service Area Demand (base case) (1)	4,520	4,586	4,652	4,718	4,784	4,848	4,909	4,970
Peak Bundled Customer Demand (base case)	3,921	3,984	4,046	4,109	4,171	4,232	4,290	4,348
Reserve Margin (15% of Bundled Customer Demand)	588	598	607	616	626	635	644	652
Firm Sales Obligations	0	0	0	0	0	0	0	0
FIRM PEAK REQUIREMENT	***4,509***	***4,582***	***4,653***	***4,725***	***4,797***	***4,867***	***4,934***	***5,000***
EXISTING & PLANNED CAPACITY (2)								
Utility-Controlled Physical Resources								
Nuclear	377	311	311	311	311	311	311	311
Fossil	588	588	588	588	588	588	588	588
Total Dependable Hydro Capacity	40	40	40	40	40	40	40	40
Total Utility-Controlled Physical Resources	**1,005**	**938**	**938**	**938**	**938**	**938**	**938**	**938**
Existing and Planned Contractual Resources								
DWR Contracts	2,103	2,103	718	26	26	0	0	0
QF Contracts	221	221	221	221	221	221	221	221
Renewable Contracts (3)	120	120	116	116	107	105	104	105
Other Bilateral Contracts (3)	720	724	727	731	735	651	656	661
Total Contractual Resources	**3,164**	**3,167**	**1,782**	**1,094**	**1,089**	**977**	**981**	**986**
TOTAL EXISTING & PLANNED CAPACITY (2)	***4,168***	***4,106***	***2,720***	***2,032***	***2,027***	***1,915***	***1,919***	***1,925***
Existing Interruptible/ Emergency Programs	**36**	**36**	**36**	**36**	**36**	**36**	**36**	**36**
TOTAL PROCUREMENT NEED	***305***	***440***	***1,897***	***2,657***	***2,733***	***2,915***	***2,978***	***3,040***
ADDITIONAL PREFERRED RESOURCES								
Uncommitted Energy Efficiency (4)	55	118	175	225	278	345	417	486
Uncommitted Dispatchable Demand Response (4)	260	264	267	271	275	279	282	286
Renewables	66	428	546	567	601	647	689	728
Distributed Generation/ CHP	to be developed in 2006 by Energy Commission and CPUC							
TOTAL ADDITIONAL PREFERRED RESOURCES (5)	**381**	**810**	**988**	**1,064**	**1,154**	**1,271**	**1,389**	**1,500**
ADDITIONAL NON-DESIGNATED NEED (5)	**-76**	**-370**	**909**	**1,593**	**1,579**	**1,645**	**1,589**	**1,539**
Aging Plant Replacement (6)	**405**	**810**	**1,214**	**1,619**	**1,619**	**1,619**	**1,619**	**1,619**

(1) - Peak service area demand is used for calculation of the uncommitteed dispatchable demand reponse targets.

(2) - Existing and planned capacity data are as of early 2005, when the LSE's prepared their resource plan submissions for the Energy Report proceeding.

(3) - Distribution service area data are presented here because the IOU-specific data are confidential.

(4) - Future demand side resources have been increased by 15% to account for their affect on the reserve margin. In addition, the uncommitted energy efficiency and demand response goals reflected here are based on service area load. Future savings from these programs are likely to come both from IOU bundled-service customers and ESP direct access customers.

(5) - Total preferred resource will increase and the open source need will decrease when DG/CHP targets are established in 2006.

(6) - The numbers for aging plant replacement reflect the amount of capacity the IOUs should be including in their resource plans to account for the recommended retirement of the aging plants by 2012.

Table B-18
Annual Aggregated Capacity Resource Accounting Table
SDG&E Capacity Procurement Need, High Demand Case

revised: 15-Nov-05

PEAK DEMAND (MW)								
	2009	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
Peak Service Area Demand (high case) (1)	4,558	4,635	4,710	4,787	4,864	4,940	5,015	5,088
Peak Bundled Customer Demand (high case)	3,960	4,032	4,104	4,178	4,251	4,324	4,395	4,466
Reserve Margin (15% of Bundled Customer Demand)	594	605	616	627	638	649	659	670
Firm Sales Obligations	0	0	0	0	0	0	0	0
FIRM PEAK REQUIREMENT	***4,554***	***4,637***	***4,720***	***4,805***	***4,889***	***4,973***	***5,054***	***5,136***
EXISTING & PLANNED CAPACITY (2)								
Utility-Controlled Physical Resources								
Nuclear	377	311	311	311	311	311	311	311
Fossil	588	588	588	588	588	588	588	588
Total Dependable Hydro Capacity	40	40	40	40	40	40	40	40
Total Utility-Controlled Physical Resources	**1,005**	**938**	**938**	**938**	**938**	**938**	**938**	**938**
Existing and Planned Contractual Resources								
DWR Contracts	2,103	2,103	718	26	26	0	0	0
QF Contracts	221	221	221	221	221	221	221	221
Renewable Contracts (3)	120	120	116	116	107	105	104	105
Other Bilateral Contracts (3)	720	724	727	731	735	651	656	661
Total Contractual Resources	**3,164**	**3,167**	**1,782**	**1,094**	**1,089**	**977**	**981**	**986**
TOTAL EXISTING & PLANNED CAPACITY (2)	***4,168***	***4,106***	***2,720***	***2,032***	***2,027***	***1,915***	***1,919***	***1,925***
Existing Interruptible/ Emergency Programs	**36**	**36**	**36**	**36**	**36**	**36**	**36**	**36**
TOTAL PROCUREMENT NEED	***350***	***495***	***1,964***	***2,737***	***2,825***	***3,021***	***3,099***	***3,175***
ADDITIONAL PREFERRED RESOURCES								
Uncommitted Energy Efficiency (4)	55	118	175	225	278	345	417	486
Uncommitted Dispatchable Demand Response (4)	262	266	271	275	280	284	288	293
Renewables	66	428	546	567	601	647	689	728
Distributed Generation/ CHP	to be developed in 2006 by Energy Commission and CPUC							
TOTAL ADDITIONAL PREFERRED RESOURCES (5)	**383**	**813**	**992**	**1,068**	**1,159**	**1,276**	**1,395**	**1,507**
ADDITIONAL NON-DESIGNATED NEED (5)	**-34**	**-318**	**972**	**1,669**	**1,666**	**1,745**	**1,704**	**1,668**
Aging Plant Replacement (6)	**405**	**810**	**1,214**	**1,619**	**1,619**	**1,619**	**1,619**	**1,619**

(1) - Peak service area demand is used for calculation of the uncommitteed dispatchable demand reponse targets.

(2) - Existing and planned capacity data are as of early 2005, when the LSE's prepared their resource plan submissions for the Energy Report proceeding.

(3) - Distribution service area data are presented here because the IOU-specific data are confidential.

(4) - Future demand side resources have been increased by 15% to account for their affect on the reserve margin. In addition, the uncommitted energy efficiency and demand response goals reflected here are based on service area load. Future savings from these programs are likely to come both from IOU bundled-service customers and ESP direct access customers.

(5) - Total preferred resource will increase and the open source need will decrease when DG/CHP targets are established in 2006.

(6) - The numbers for aging plant replacement reflect the amount of capacity the IOUs should be including in their resource plans to account for the recommended retirement of the aging plants by 2012.

Table B-19: Energy Range of Need Calculation Example

PG&E Energy for 2012, revised staff forecast base case (GWh)

		Base case	Source/explanation
	ENERGY DEMAND (GWh)		
a)	Net Energy for Bundled Customer Load	89,069	Staff revised forecast
b)	Firm Sales Obligations	413	Aggregated data tables (3)
c)	**TOTAL ENERGY REQUIREMENT**	**89,482**	***Sum of a) and b)***
	EXISTING & PLANNED RESOURCES		
	Utility-Controlled Physical Resources		
d)	Nuclear	16,797	Aggregated data tables (3)
e)	Fossil (2)	173	Aggregated data tables (3)
f)	Total Hydro Energy Supply	15,061	Aggregated data tables (3)
g)	**Total Utility-Controlled Physical Resources**	**32,030**	**Sum of d) through e)**
	Existing and Planned Contractual Resources		
h)	Total Energy Supply from DWR Contracts	1,190	Aggregated data tables (3)
i)	Total Energy Supply from QF Contracts	19,769	Aggregated data tables (3)
j)	Total Existing & Planned Renewable Contracts	528	Aggregated data tables (3)
k)	Total Energy from Other Bilateral Contracts	1,063	Aggregated data tables (3)
l)	**Total Contractual Resources**	**22,550**	**Sum of h) through k)**
m)	**TOTAL EXISTING & PLANNED ENERGY RESOURCES**	**54,580**	***Sum of g) and l)***
n)	**TOTAL PROCUREMENT NEED**	**34,902**	***Difference of c) and m)***
	ADDITIONAL PREFERRED RESOURCES		
o)	Uncommitted Energy Efficiency	4,204	Uncommitted energy efficiency reported by IOU, adjusted for inclusion of committed 2006-2008 programs being included in demand forecast (5)
p)	Renewables	7,890	Generic renewables reported by IOU for accelerated renewables case, reported in aggregated data tables
q)	Distributed Generation/ CHP	*Target to be developed by Energy Commission and CPUC in 2006*	
r)	**TOTAL ADDITIONAL PREFERRED RESOURCES (1)**	**12,094**	***Sum of o) through q)***

Table B-19: Energy Range of Need Calculation Example (continued)

s)	**ADDITIONAL NON-DESIGNATED NEED (1)**	**22,808**	***Difference of n) and r)***
t)	**Aging Plant Replacement**	**7,969**	average annual generation from the aging plants located in the service territory of that IOU for the years 2002 through 2004(4)

Notes:

(1) - The total additional preferred resources will increase and the additional non-designated need will decrease when DG/CHP targets are established in 2006, since a portion of the undesignated need will be designated to DG/CHP.

(2) - In its reference case, PG&E did not include any energy values for the Humboldt Bay replacement project, though it included 150 MW of capacity. The Energy Commission is including the fossil resource energy values that PG&E filed with its preferred, accelerated renewables, and core/non-core cases.

(3) - Data from aggregated data tables are based on IOU filings for the reference case, except as noted. These data are based on the LSE resource plans that were prepared in early 2005, and so do not reflect any changes, such as new contracts, that have occurred during 2005. These data will need to be updated as part of the CPUC's 2006 procurement proceeding. (Source: *Resource Plan Aggregated Data Results (Aggregated Tables Report)*, California Energy Commission Revised Staff Report, CEC-150-2005-001-REV, November, 2005.)

(4) - The aging plant replacement ramps up to the full share in 2012. For 2009, the value is 25 percent of the full share, for 2010 it is 50 percent, and for 2011 it is 75 percent.

(5) These values are calculated from Tables 2-3, 2-9, and 2-13 in the *RPSA Report* and IOU comments on that report. Because the demand forecast includes programs through 2008, the first-year GWh savings through 2008 are subtracted from the cumulative totals from line 1.

Table B-20: Capacity Range of Need Calculation Example

PG&E Capacity for 2012, base case demand forecast (MW)

		base case	Source/explanation
	PEAK DEMAND (MW)		
a)	Peak Service Area Demand (base case) (1)	20,256	Staff revised forecast
b)	Peak Bundled Customer Demand (base case)	18,872	Staff revised forecast
c)	Reserve Margin (at 15 percent)	2,831	15 percent of b)
d)	Firm Sales Obligations	0	Aggregated data tables (4)
e)	**Firm Peak Requirement**	**21,703**	***Sum of b) through c)***
	EXISTING & PLANNED CAPACITY		
	Utility-Controlled Physical Resources		
f)	Nuclear	2,214	IOU public capacity tables (4)
g)	Fossil	150	IOU public capacity tables (4)
h)	Total Dependable Hydro Capacity	4,734	Aggregated data tables (4)
i)	**Total Utility-Controlled Physical Resources**	**7,098**	**Sum of f) through h)**
	Contractual Resources		
j)	DWR Contracts	263	IOU public capacity tables (4)
k)	QF Contracts	2,517	IOU public capacity tables (4)
l)	Renewable Contracts (2)	103	Aggregated data tables (4)
m)	Other Bilateral Contracts (2)	1,268	Aggregated data tables (4)
n)	**Total Contractual Resources**	**4,151**	**Sum of j) through m)**
o)	**TOTAL EXISTING & PLANNED CAPACITY**	**11,248**	***Sum of i) and n)***
p)	**Existing Interruptible/ Emergency Programs and Dispatchable Demand Response**	**374**	IOU public capacity tables (4)
q)	**TOTAL PROCUREMENT NEED**	***10,080***	***Difference of e) and total of o) and p)***
	ADDITIONAL PREFERRED RESOURCES		
r)	Uncommitted Energy Efficiency	1,095	Uncommitted energy efficiency reported by IOU (7)
s)	Uncommitted Dispatchable Demand Response (8)	1,165	CPUC target of 5% of service territory load shown in a)
t)	Renewables	1,017	Generic renewables reported by IOU for accelerated renewables case, reported in aggregated data tables (6)
u)	Distributed Generation/ CHP	*Target to be developed by Energy Commission and CPUC in 2006*	
v)	**TOTAL ADDITONAL PREFERRED RESOURCES (3)**	**3,277**	***Sum of r) through u)***

Table B-20: Capacity Range of Need Calculation Example (continued)

w)	**ADDITIONAL UNDESIGNATED NEED (3)**	**6,804**	***Difference of q) and v)***
x)	**Aging Plant Replacement**	**4,900**	capacity of the aging plants located in the service territory of that IOU (5)

Notes:

(1) - Peak distribution service area demand is used for calculation of the uncommitted dispatchable demand response targets.

(2) - Distribution service area data are presented here because the IOU bundled customer data are confidential.

(3) - Total additional preferred resource will increase and the additional undesignated need will decrease when DG/CHP targets are established in 2006, since some undesignated need will be designated to DG/CHP.

(4) - Data from aggregated data tables or IOU public capacity tables are based on IOU filings for the reference case, except as noted. (Source: *Resource Plan Aggregated Data Results (Aggregated Tables Report)*, California Energy Commission Revised Staff Report, CEC-150-2005-001-REV, November, 2005.)

(5) - The aging plant replacement ramps up to the full share in 2012. For 2009, the value is 25 percent of the full share, for 2010 it is 50 percent, and for 2011 it is 75 percent.

(6) - These values may include contractual resources held by the publicly owned utilities in the PG&E planning area or by ESPs.

(7) - These values are calculated from Tables 2-4, 2-10, and 2-15 in the *RPSA Report* and utility comments on the report. Because the demand forecast includes programs through 2008, the MW savings for 2008 are subtracted from the cumulative totals from line 1. These calculated values have then been increased by 15 percent to compensate for the true impact of demand-side programs on required reserves when they are implemented and reduce customer demand. The energy efficiency goals adopted by the CPUC that these values are based on are for all customers in the IOU's distribution service territory.

(8) - The value reflects the full goal of 5% of distribution service area demand to be achieved by 2007 and beyond. These calculated values have been increased by 15 percent to compensate for the true impact of demand-side programs on required reserves when they are implemented and reduce customer peak demand. The estimated impacts of the programs authorized under R.02-06-001, Critical Peal Pricing tariffs authorized by the CPUC pursuant to the applications filed in summer 2005, the portion of the DWR Demand Reserves Partnership allocated to each IOU, and other mechanisms that are eligible to satisfy the goals are included here. The difference between the goal and the sum of authorized program impacts is the amount remaining to be achieved from new or expanded programs and tariffs.

Figure B-1: PG&E Annual Energy Range of Procurement Need

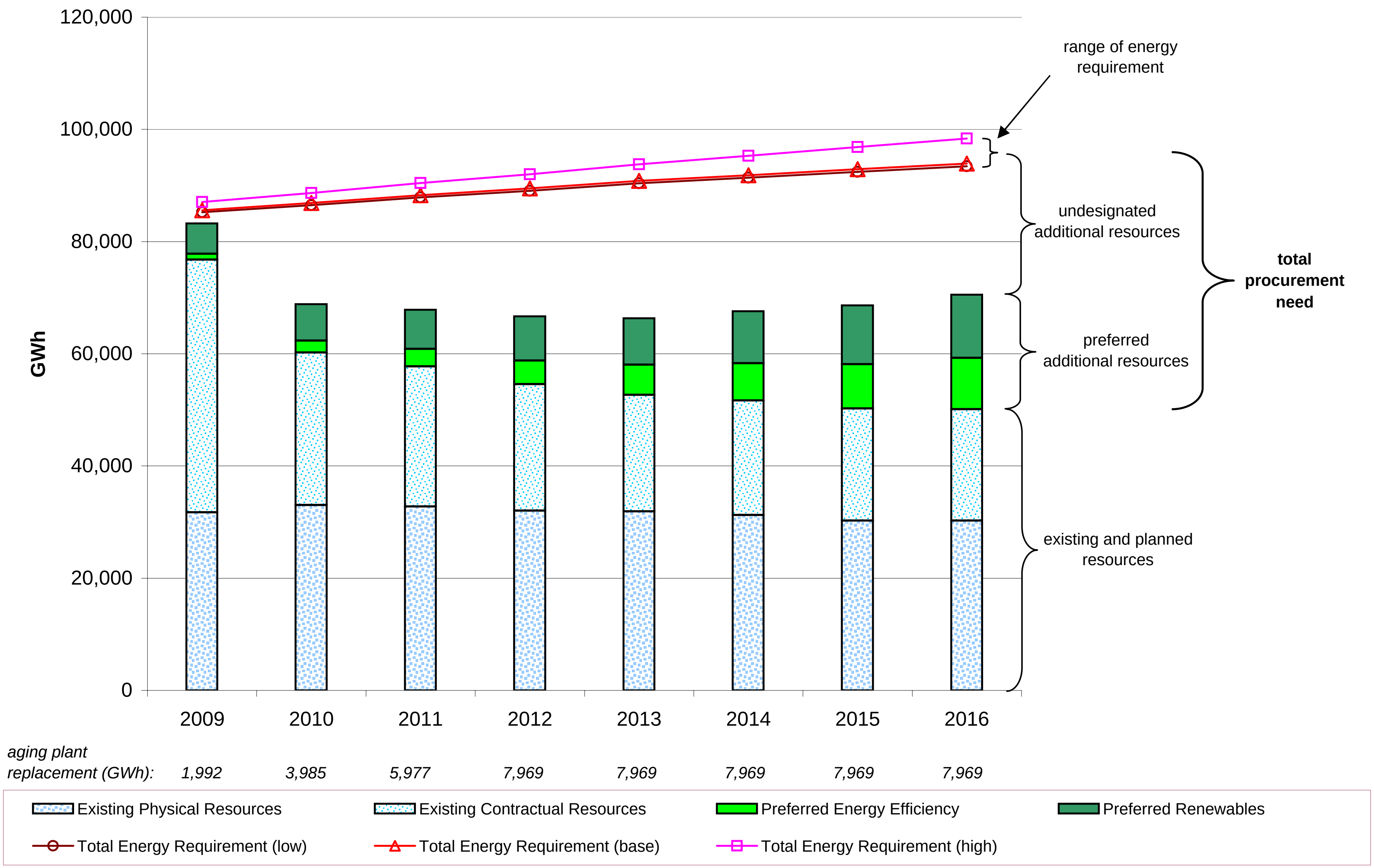


Figure B-2: PG&E Annual Capacity Range of Procurement Need

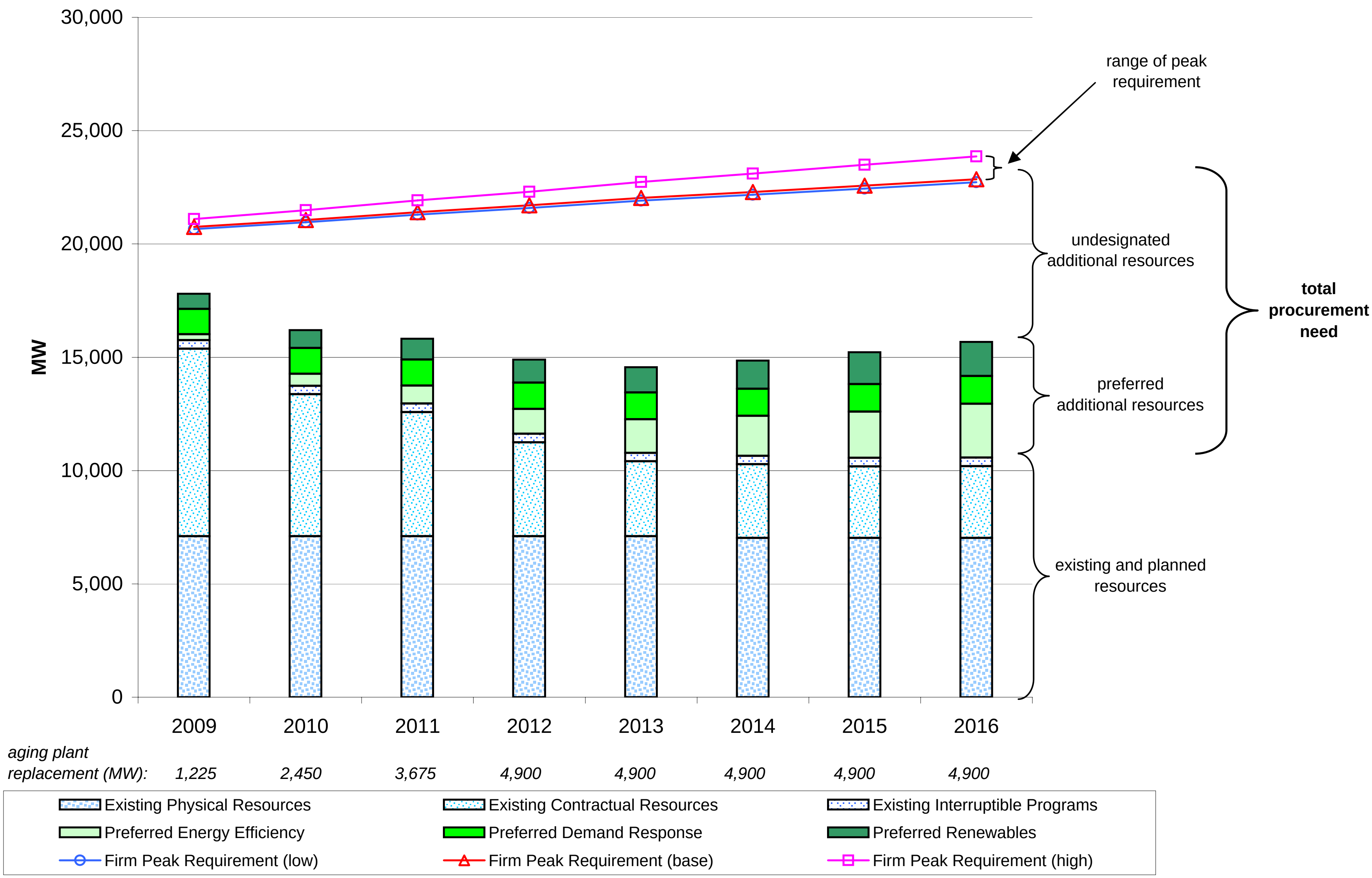


Figure B-3: SCE Annual Energy Range of Procurement Need

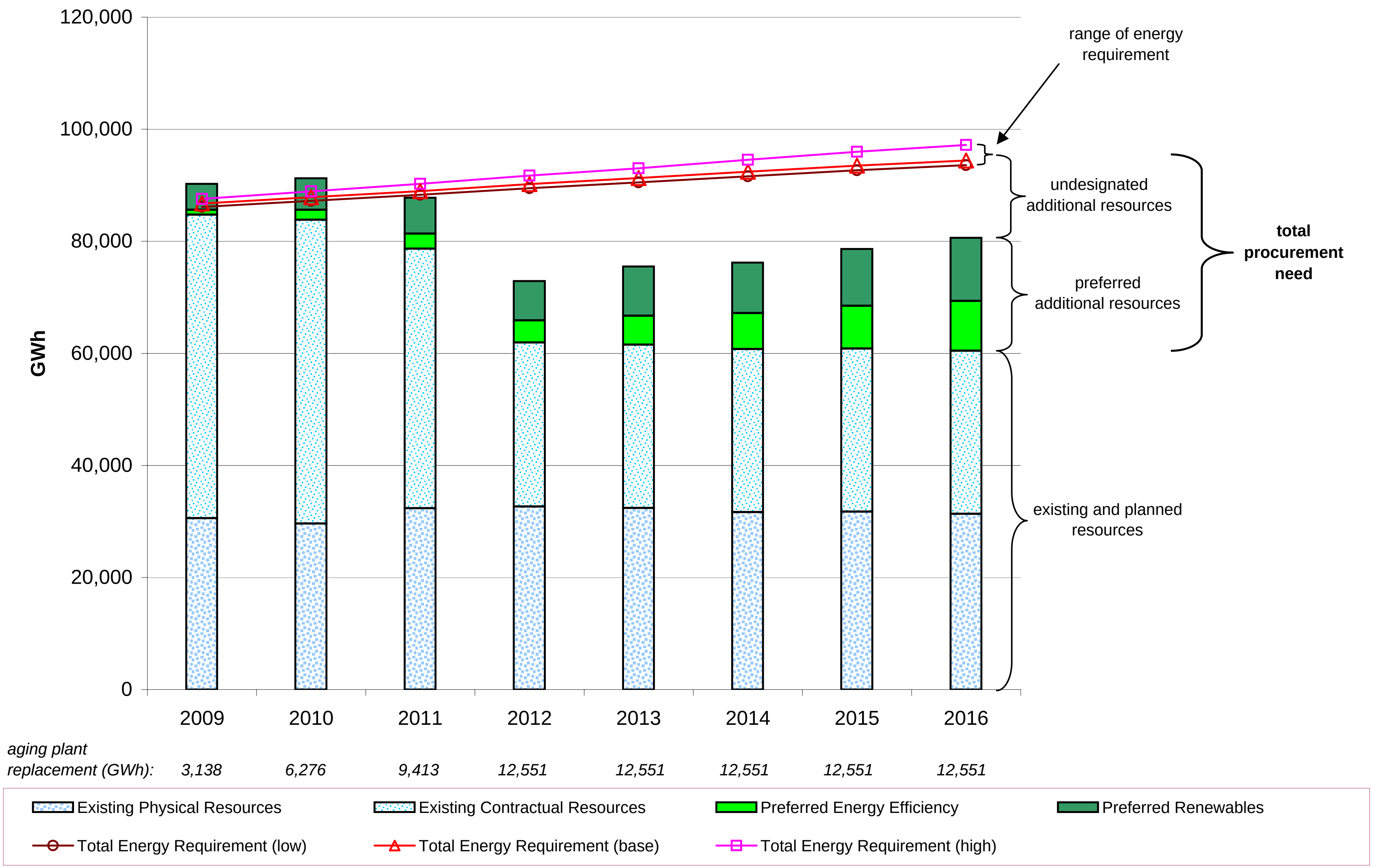


Figure B-4: SCE Annual Capacity Range of Procurement Need

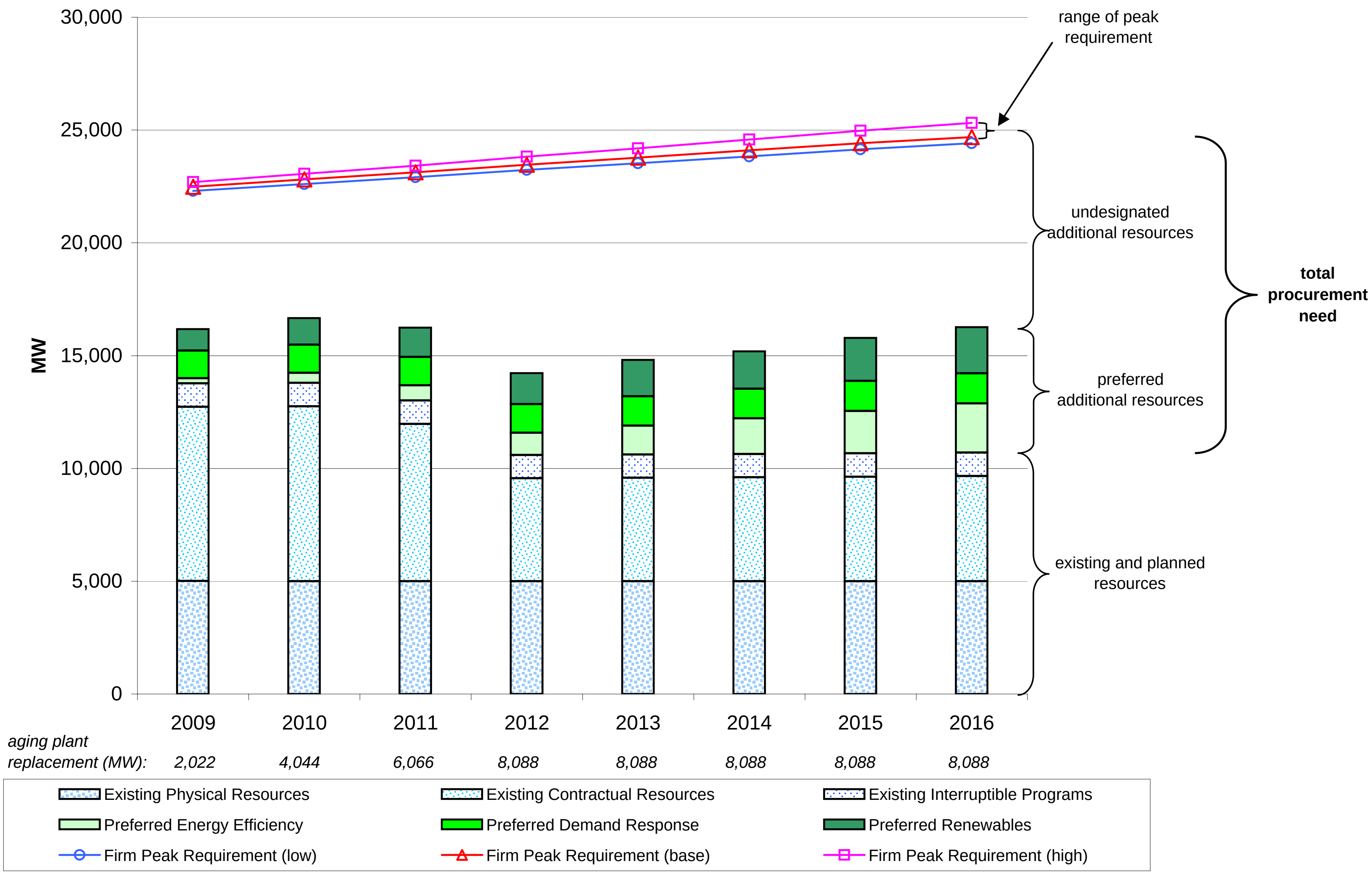


Figure B-5: SDG&E Annual Energy Range of Procurement Need

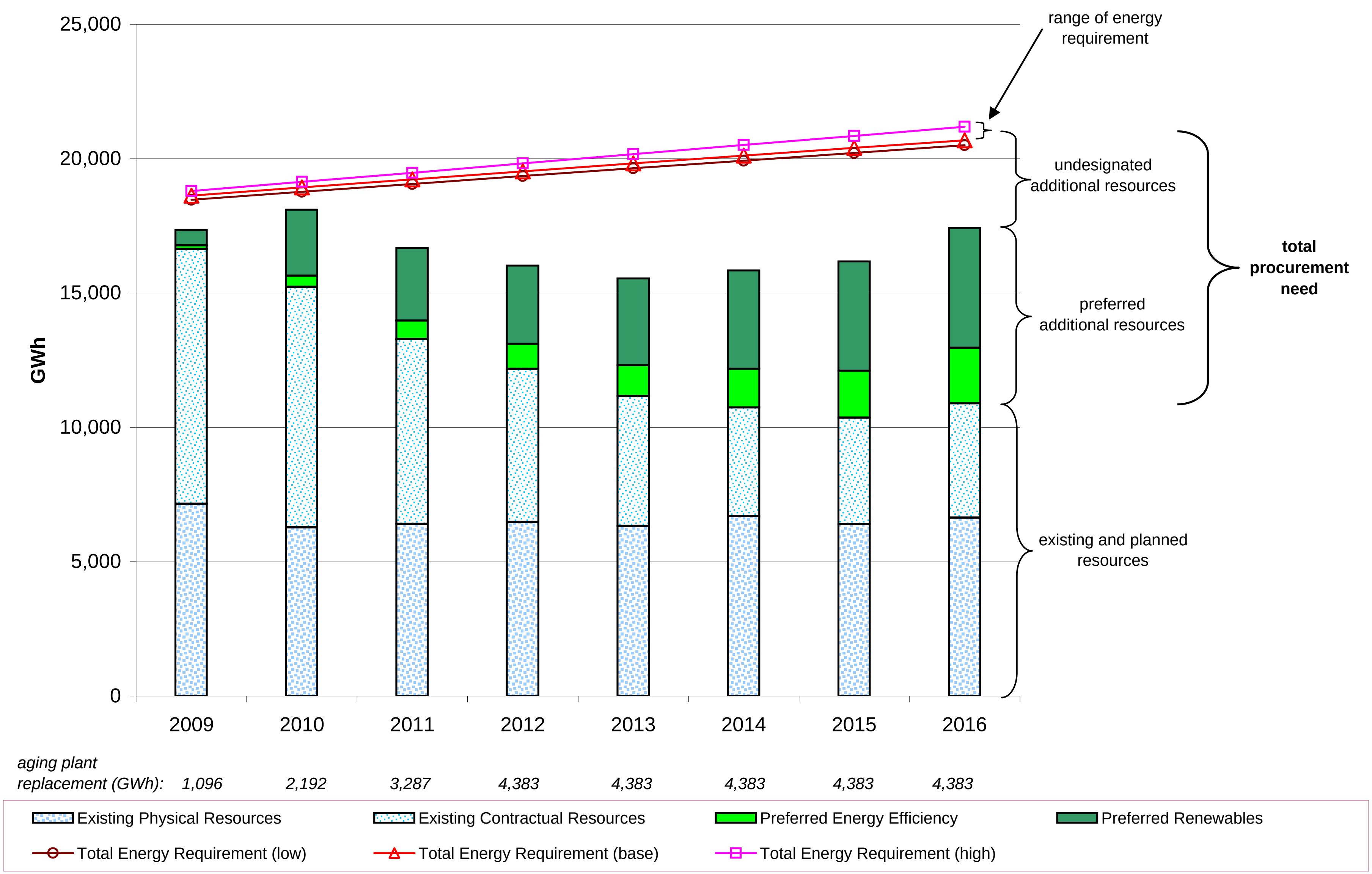


Figure B-6: SDG&E Annual Capacity Range of Procurement Need

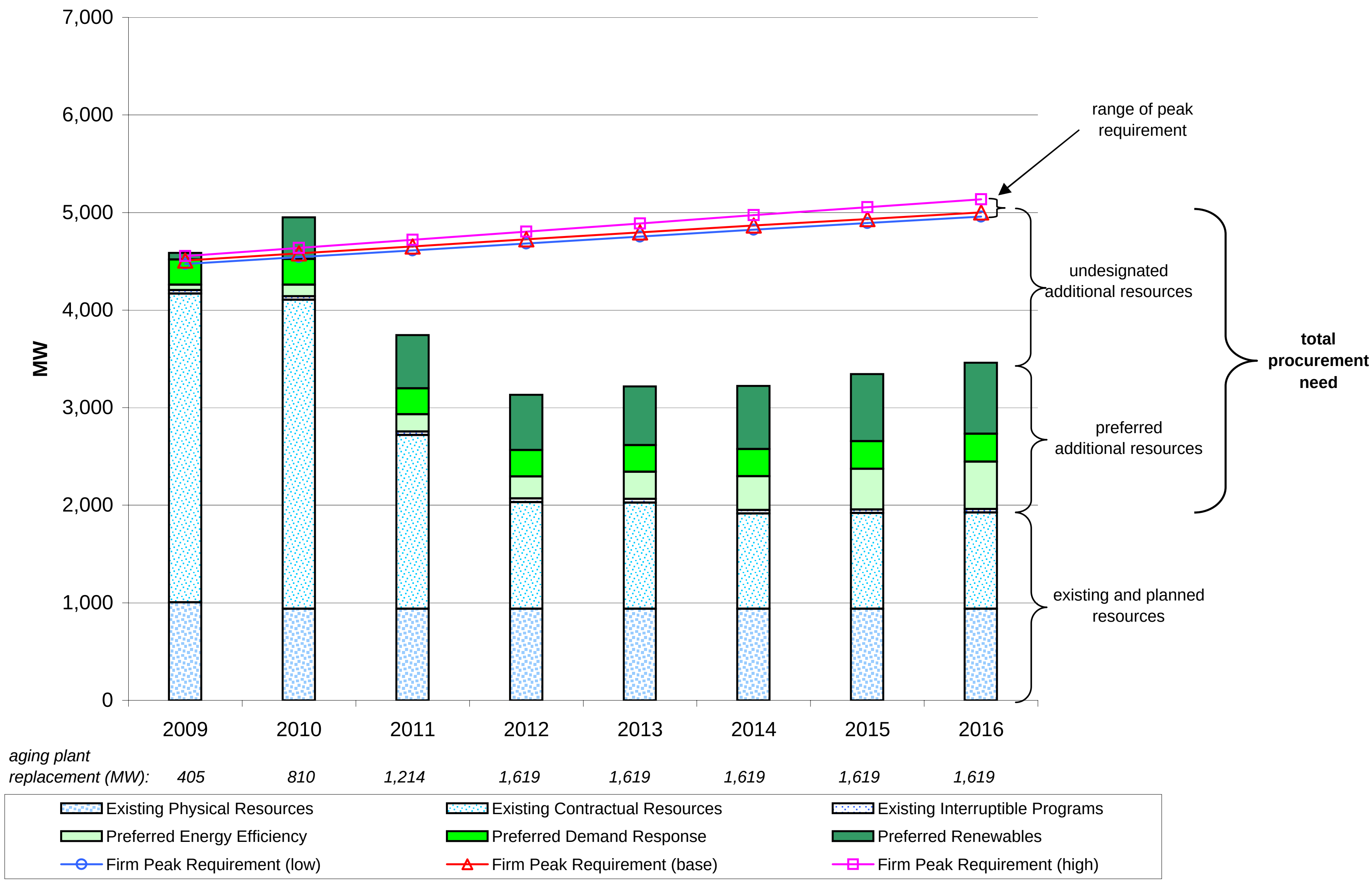


Figure B-7: Combined IOU Annual Energy Range of Procurement Need

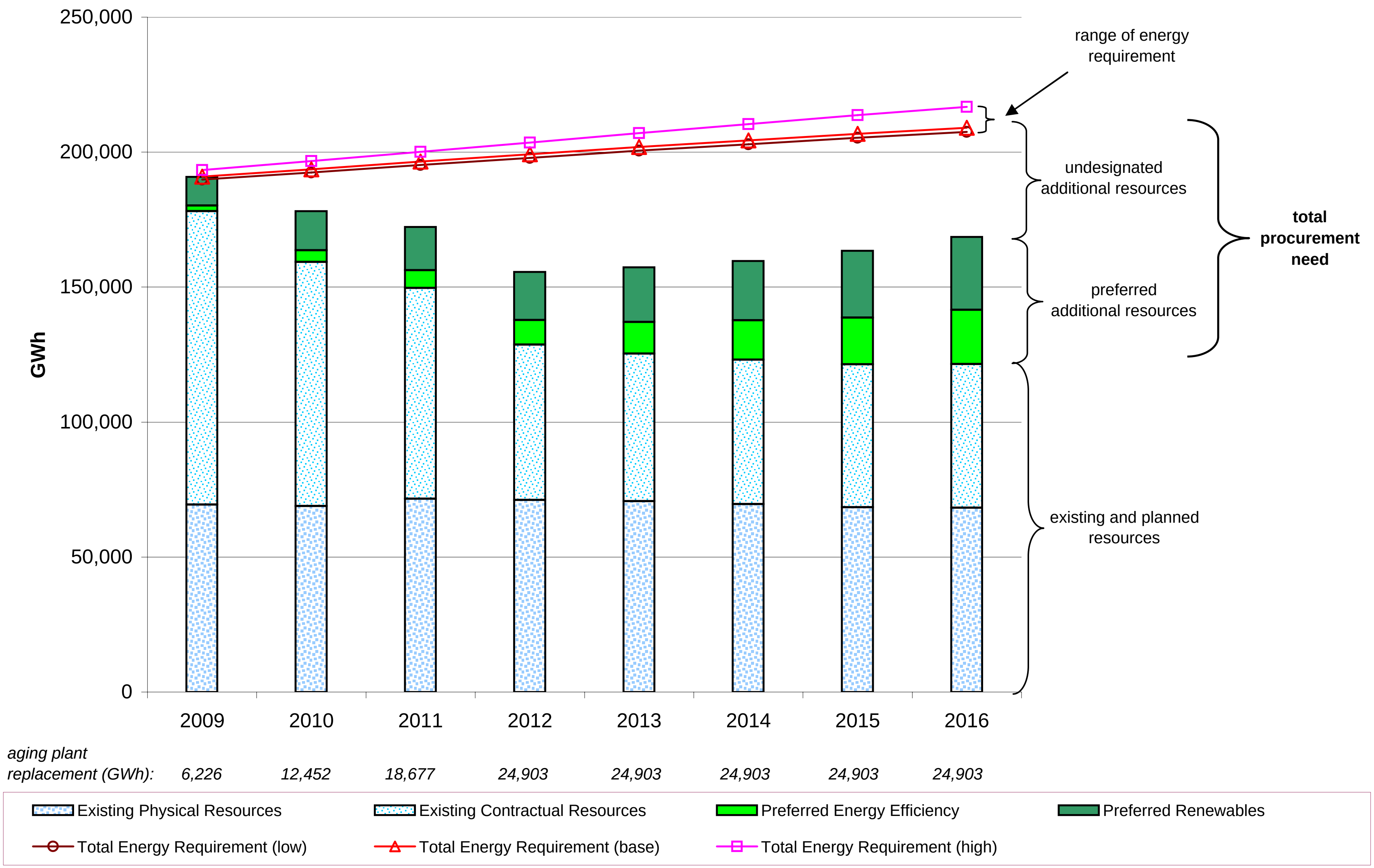
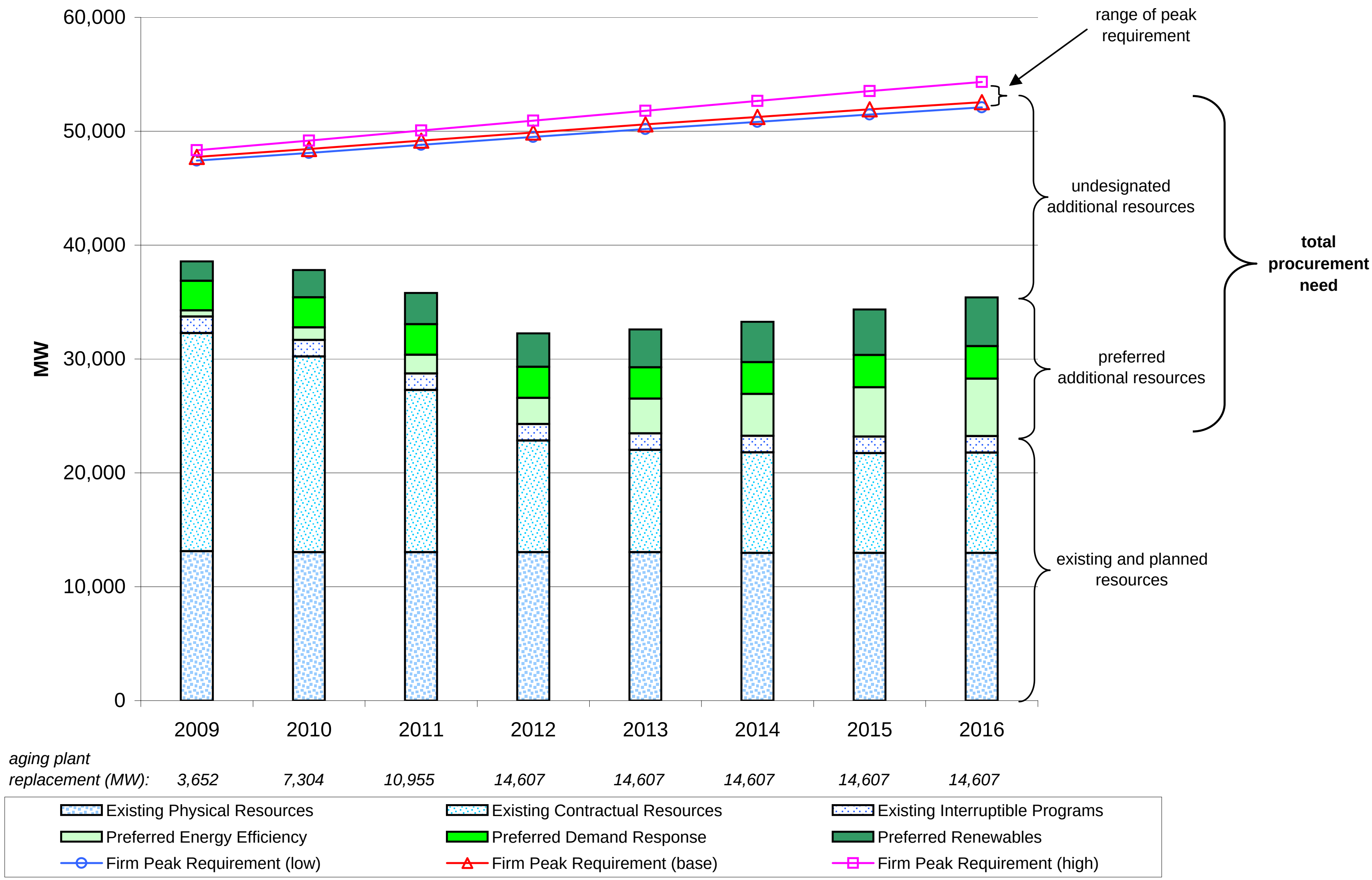


Figure B-8: Combined IOU Annual Capacity Range of Procurement Need



Appendix C

Comments on the *Draft Transmittal Report*

Appendix C: Comments on the *Draft Transmittal Report*

This appendix includes the comment letters received on the *Draft Transmittal Report*. Responses to these comments are included in Appendix D. The comments in each letter have been coded to allow the reader to trace the responses back to the comments themselves. This coding was done using the Adobe Acrobat markup tool; to print a copy with the coding intact requires selecting "Document and Markups" from the pull-down list under "Comments and Forms" in the Adobe Acrobat or Adobe Reader print screen.

Pacific Gas and Electric Company

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November 8, 2005

ELECTRONIC DELIVERY

California Energy Commission
Docket Office
Attn: Docket No. 04-IEP-1K
1516 Ninth Street, MS-4
Sacramento, CA 95814-5512

Re: Comments of Pacific Gas and Electric Company

Pacific Gas and Electric Company (PG&E) respectfully submits the following comments on the Committee Draft Transmittal of the 2005 Energy Report Range of Need and Policy Recommendations to the California Public Utilities Commission.

Thank you for considering our comments. Please feel free to call me at (415) 973-6463 if you have any questions about this matter.

Sincerely,

Les Guliasi

LGG

Enclosure

Pacific Gas and Electric Company Comments on
The California Energy Commission's
<u>Committee Draft Transmittal of 2005 Energy Report Range of Need and Policy Recommendations to the California Public Utilities Commission</u>
<u>Draft Transmittal Report</u>

Introduction

PG&E takes this opportunity to comment on the <u>Committee Draft Transmittal of *2005 Energy Report* Range of Need and Policy Recommendations to the California Public Utilities Commission, Draft Transmittal Report</u> (CEC-100-2005-008-CTD) ("Draft"). PG&E appreciates the hard work and extensive discussion among the Energy Report Committee, CEC staff, and stakeholders that has preceded this Draft. Unfortunately, the Draft includes recommendations on resource requirements and policies that are not factually supported in this proceeding. As discussed below, PG&E respectfully requests that the Draft's conclusions on resource be revised in order to ensure the resource requirements are consistent with the CEC's technical analysis and promote the development of necessary, cost-effective, and environmentally beneficial generation. Additionally, PG&E believes that many of the policy recommendations included in the Draft are more appropriately discussed in the CEC IEPR report. Finally, PG&E recommends the Draft be revised to provide a more detailed evaluation of the cost impacts of the included recommendations and the subsequent costs to consumers.

In addition to these comments on the Draft, PG&E provides additional comments to the proposed revised Tables included in Appendix B, provided by CEC staff on November 7, 2005. PG&E appreciates the opportunity afforded by the Committee, acting upon PG&E's recommendation at the November 4, 2005, Committee hearing, to enable the IOUs and interested parties to confer with CEC staff to clarify the information presented in the Tables accompanying the Draft Transmittal Report. This extra step in the process was necessary to ensure that the Draft is credible and useful for resource planning in the CPUC's 2006 Long Term Plan proceeding. Our comments to the revised table are included in Appendix A of this document.

General Comments

This genesis of this report was CPUC President Peevey's assigned commissioner's rulings (ACRs) of September 2004 and March 2005 that the CEC would determine the appropriate level and range of resource needs for the 2006 long-term plan (LTP) for each investor-owned utility (IOU) within the IEPR process. PG&E and many other parties expected this process to follow the successful but informal cooperation between the CPUC and the CEC in assessing each utility's 2004 LTP, which made good use of the CEC staff's extensive resource planning knowledge. In short, PG&E expected that the Draft would provide an update on the forecasts in each utility's approved 2004 LTP, based on known and foreseeable changes since 2004, which have been expected to be PG&E-1

modest. Instead the Draft presents forecasts that sometime refer to physical capacity and at other times to contractual capacity; that contradict other CEC assessments of resource need, and that mix new public policy discussion with what was supposed to be an objective, quantitative-based exercise.

PG&E commented recently on the new public policy positions reflected in the Draft, especially in the areas of Distributed Generation and Combined Heat and Power. (See PG&E's comments of October 14, 2005 on the Draft IEPR.) Many of these new public policy recommendations have been inserted into the Draft, and, thus, we reiterate these comments in brief here. We believe the public policy positions should be removed from the Draft as they are outside the scope of this part of the IEPR proceeding.

PG&E-2

The Draft's recommendations for PG&E requirements contradict all other analyses of Northern California resource needs

The Draft's determinations of resource need and requirements contradict all other analyses of Northern California requirements, including the CEC's own July, 2005 analysis in this proceeding (California and Western Electricity Supply Outlook, Staff Report[1]). In particular, Table B-5 of the Draft presents PG&E-area "Base Demand Case" capacity requirements for the period 2009-2016, including a need for over 4,000 MW of new resources in 2009, 7,300 in 2010 and increasing dramatically beyond this timeframe.

PG&E-3

This assessment is significantly different from the CEC's July, 2005 analysis, which projects that Northern California is adequately resourced through 2010. Further, the July analysis comports with the CEC's adopted 2004 Update to the Energy Report of a year ago, which reported that the PG&E area would have well in excess of 15% planning reserves through 2008 (based on an expected case)[2]. Additionally, the July 2005 WECC Power Supply Assessment projects Northern California will have a reserve margin of over 17% through 2009.[3] PG&E notes that it provided the same information on load and resources that was used in all of the 2005 analyses.

Resource Accounting Tables present regional contractual resource requirements, not IOU physical requirements

In order to ensure that the Draft is credible and useful for resource planning, PG&E recommends that it be edited to clarify that the resource need presented represents the ***contractual requirements for load serving entities*** (LSEs) in the IOU planning area and not the physical requirements for new generating capacity or the contractual requirements of individual IOUs. As discussed above, previous CEC and WECC analyses demonstrate that Northern California has sufficient physical resources to meet its total energy requirements for the next several years, and the need determinations provided in this

PG&E-4

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[1] California and Western Electricity Supply Outlook, Staff Report[1], CEC-700-2005-019, July, 2005
[2] Integrated Energy Policy Report 2004 Update, CEC-100-04-006CTF, October, 2004, Table A-3
[3] WECC 2005 Power Supply Assessment, presentation by Stan Holland, WECC, at July 26, 2005 CEC IEPR Hearing

Draft presenting a range of contractual resource requirements. This clarification was discussed in detail by the Energy Report Committee at the November 4, 2005 hearing on the Report.

The Report should also be revised to emphasize the need requirements are planning-area requirements, not individual IOU requirements. The annual Resource Accounting Tables included in Appendix B of the Draft present loads and resources owned and controlled by both utility and non-utility LSEs. According to PG&E's calculation the "Additional Non-Designated Need" presented on the tables reflect not only PG&E's resource position, but also the net requirements for all other LSEs in the PG&E-Planning Area. PG&E-4, cont.

The Draft overstates electric resource requirements

The Draft tables included in Appendix B presents "Additional Non-Designated Need" for the PG&E planning area that significantly overstates current electric resource requirements by ignoring planned resource additions. In 2005 PG&E applied to the CPUC to assume ownership and complete construction of the 530 MW Contra Costa 8 generating plant, and has executed several long-term contracts with renewable resources. Further, PG&E is currently in the process of evaluating bids to procure up to 2200 MW, as defined and approved in PG&E's last CPUC-approved long-term procurement plan. While this is briefly discussed in the Draft Report these resources are not represented on the tables, and procurement to the CEC recommended amounts would result in significant over-procurement. PG&E-5

The tables do not accurately represent regional supply and demand. The tables present total "Service Area Demand" for the IOU planning area, but for supply resources only includes the "claimed" capacity of generation rather than the total capacity available in the market. The table presents "existing capacities" for only those resources claimed by LSEs in their submitted supply forms, but many existing generation resources currently have no firm capacity sales contracts and, as such, this capacity would not have been claimed and is not included in this resource balance. The result is that requirements are overstated since available capacity not under contract, or new and un-contracted capacity that becomes available during the forecast period, is not considered to be regional resources. For example, PG&E's portfolio includes over 4000 MW of expiring DWR-contracted resources. It is highly unlikely that this generating capacity will disappear, and will be available for contract after the DWR contracts for this capacity expire. PG&E-6

Replacing aging power plants will neither meet customer requirements nor reduce costs

The Draft includes a policy recommendation that IOUs should replace capacity from what the CEC had deemed to be aging power plants. It assumes that these resources will be retired by 2012 and proposes that the investor owned utilities should replace this capacity, specifically proposing "To facilitate the retirement of these aging power plants, PG&E-7

the Energy Commission has apportioned these 50 plants to the three IOUs based on their physical location, along with their existing capacity…."(p.46) This apportionment of new capacity requirements without consideration of utility need or cost raises several troubling concerns.

The Draft has failed to provide any basis for the retirement assumption. Most of the proposed retiring resources located in Northern California are not utility owned, and PG&E is unaware of specific retirement plans for these resources. If utilities were to prospectively replace these resources and they are not retired, the resulting stranded costs would be substantial. PG&E notes that it is planning to retire the Hunters Point Generating Station in 2006 and the Humboldt Bay Generating Station prior to 2010. PG&E-8

Further, requiring the utilities to replace this non-utility generation will result in subsidization of non-utility energy service providers and direct access customers by utility customers. The CEC reports that IOU loads represent approximately 60% of statewide electricity demand, yet expects them to replace all of the aging plant capacity, much of which is currently sold to non-utility LSEs. The likely result of this will be that utilities would incur the cost of replacing this generation, and the existing, less-expensive generation will be contracted by non-utility participants.

Load forecast will require updating for CPUC Long-Term Procurement Plan

The Draft recognizes that some of the information used in constructing the range of need shown in the tables in this report will be out of date by the conclusion of the CPUC's 2006 long-term procurement proceeding (LTPP). The Draft offers the following guidelines for when and how adjustments to the numbers would be appropriate.

> In terms of the demand forecasts, the Energy Commission believes that the revised staff forecast provides the appropriate basis for the 2006 LTPP. A biennial proceeding focused upon the long-term cannot be a good source of short term demand forecasts that are updated frequently for recent historic data and near-term expectations. Such near-term demand forecasts are appropriate for many operating activities. The Energy Commission does not anticipate any conditions in which an update of the staff revised forecast for the years 2008 and beyond would be appropriate….(page 55) PG&E-9

PG&E disagrees with the above statement, and believes that adjustments are appropriate. The range of annual average growth rates for PG&E energy and peak demand over the period 2004-2006, as shown in Table 11, page 75, appear reasonable. However, as the long term planning process moves into the CPUC phase, these growth rates must be "calibrated" to recent levels of observed demand in order to produce more realistic estimates of MWh and MW demand during the forecast horizon. Staff's revised projections, as shown in the Draft, are currently calibrated to 2004 observed demand.

Allowing for another update, which could still rely on the staff's solid growth rates, will avoid the very real possibility that staff's 2008-2016 projections in MWh or MW will be inconsistent with more recent observed data on energy use and peak demand that is not now available but may be available prior to the filing of the IOU's 2006 long-term procurement plans.

Energy Efficiency should be treated in a consistent fashion throughout the forecast horizon

The current analysis underlying the Integrated Energy Policy Report does not include PG&E's full forecast of energy efficiency savings in a manner consistent with the way PG&E treats this demand side resource. The Draft report treats forecasted energy efficiency savings beyond 2008 as a supply-side resource. There are two problems with such treatment: (a) it makes comparisons difficult; and (b) it incorrectly reduces the cost-effectiveness of future energy efficiency programs, since they no longer receive the credit they deserve for reducing the need for reserves.

PG&E-10

The inconsistent treatment of targeted energy efficiency savings in the Draft creates confusion. For example, Table 6 suggests that the LSE's aggregate forecasts for the PG&E planning area are lower than the staff's projection. However, as PG&E pointed out in its June 30th workshop presentation, the forecasts are not comparable. If placed on a comparable basis, the aggregate LSE projections for PG&E's planning area are very likely to be above, not below, the levels projected by CEC Staff.

PG&E requests that the CEC avoid confusion by modeling energy efficiency savings as a reduction to projected demand throughout the forecast period.

The Draft must distinguish between customer-scale distributed generation (DG) and large combined heat and power (CHP) generating facilities

As PG&E has noted in comments on the Draft IEPR, the IEPR Committee has used the terms "Distributed Generation ("DG") and Combined Heat and Power ("CHP") interchangeably. The lack of clarity about when the CEC refers to DG and when the CEC refers to CHP is confusing and can even be misleading.

PG&E-11

The terms "DG" and "CHP" encompass a very broad range of facilities with varying levels of efficiency, air emissions and other environmental impacts, and system impacts, from small residential photovoltaic systems to very large cogeneration plants. As such, policies should be developed with a careful consideration of the very different forms of DG and CHP.

PG&E recommends that the final Report include a clear definition of distributed generation, and continues to recommend the following:

> Distributed generation is electricity produced on a customer site from generators under 10 MW in size that are interconnected to the utility distribution system and

that are designed predominantly to serve load at the customer site or over the fence to one or two adjacent customers.

PG&E appreciates the CEC's effort to hold utilities revenue neutral through reinstitution of an Electricity Revenue Adjustment Mechanism. However, PG&E is disheartened by the implication that PG&E is somehow opposed to CHP and other DG because the policies proposed by the CEC run counter to PG&E's shareholder interests. This is not the case. As we explained to the CEC in a letter to Commissioner Pfannenstiel on September 8, 2005, PG&E's shareholders are indifferent to the amount of DG installed by our customers because various revenue adjustment mechanisms ensure that PG&E recovers any costs created by departing load..

PG&E supports DG as one of the choices our customers can make to meet their energy needs. Consistently throughout the IEPR process, PG&E has been supporting inclusion of cost benefit analysis in the decision making process. We have also consistently called for thoughtful policy decisions that are informed by cost benefit analysis rather than policy recommendations that support DG or CHP without including cost considerations. We do this because any uneconomic policy recommendations will have a negative impact on our customers (NOT our shareholders). If there is to be such an impact, it should be in carefully considered situations only, where the total resource costs justify it or where overwhelming policy considerations justify limited impacts on other customers. PG&E-12

Existing and new CHP are not necessarily fuel-efficient, cost-effective or environmentally superior to other thermal generation

The Draft makes several policy recommendations for CHP that are essentially the public policy advocacy positions of current cogeneration companies: that the IOUs should buy all electricity from CHP plants in their territories under standard offer contracts of at least ten years duration; that the CEC and CPUC should develop a yearly procurement target for CHP; and that the IOUs should be required to schedule CHP power at cost.

PG&E objects to the Draft adopting as recommended public policy these recommendations, without having considered the views of other stakeholders and interested parties. During the October 6, 2005, Committee hearing on the 2005 IEPR Committee Draft Report PG&E offered oral and subsequent written comments regarding its position on the benefits as well as the difficulties encountered with its cogeneration experience. None of PG&E's observations are reflected in the Draft. PG&E-13

The CPUC has jurisdiction under PURPA to establish wholesale rates for the purchase of power from qualifying facilities only. Not all CHP qualifies as QF power; thus the Draft's recommendation that the CPUC establish avoided cost rates and contract terms for the sale of all power from CHP may run afoul of federal law. For non-QFs selling to the utilities at wholesale, FERC has exclusive jurisdiction to set just and PG&E-14

reasonable rates. As we discuss below, FERC has jurisdiction to determine which cogenerators will be certified as QFs.

There are several good public policy reasons to reject or restrict the carte blanche long-term extension of existing QF cogeneration contracts and to oppose an open ended standard offer for new cogeneration facilities instead of market-based pricing and terms. PG&E has detailed its concerns in this area in our response to the Draft IEPR and extensively in our Avoided Cost testimony before the CPUC.[4] We reiterate these arguments briefly here.

PG&E-15

First, a cost-effectiveness test (as the Draft IEPR concluded) is essential. Such a test would reveal that efficient cogeneration projects are in fact cost effective, can be and are economically competitive with other generation sources. Efficient cogeneration projects do not need the help of governmental programs and public subsidies. On the other hand, no public benefit is realized from economically propping up old, inefficient, cogeneration projects with outdated and inferior environmental controls, many of which are owned by large industrial and oil producing companies.

Second, the issue of expiring QF Power Purchase Agreements (PPAs) is presently being considered by the CPUC in its QF Avoided Cost Proceeding. PG&E submitted testimony in that proceeding, examining the validity of cogeneration industry claims regarding the benefits realized from cogenerated power in California. In its testimony PG&E rebuts these representations and shows that the most cost effective manner of providing for the state's future energy supply needs is not through the extension of the PPAs of old, inefficient cogeneration plants, but through the construction of state-of-the-art modern generation facilities.

Third, the capacity of older cogeneration units nearing the end of their contracts in PG&E's territory is not large. We think many of these plants may be able to continue generating electricity even if paid only market prices in the future, but even if we are wrong and the cogenerators fail to continue after their contracts expire, we would only be losing about 500 MW through the year 2010. This potential lost capacity is a small fraction of the capacity of new, already licensed but yet-to-be-constructed generation projects in PG&E's service area.

Fourth, the whole question of what types of CHP will be certified by FERC as qualifying facilities under PURPA is under review as part of FERC's implementation of the 2005 Energy Policy Act. The outcome of that review is uncertain, but will probably decrease the range of cogeneration facilities deemed to be QFs and eligible for avoided-cost pricing. The CEC and the CPUC should not act hastily to order the utilities to enter into contracts with facilities which may be determined to have too small a thermal load to be qualified as QFs.

[4] See PG&E's prepared and rebuttal testimony in the CPUC's R. 04-04-003 and 04-04-025 of August 31, 2005 and October 28, 2005 regarding Qualifying Facilities Policy and Pricing Issues.

Finally, giving CHP a set aside while making renewables compete through RFOs would give CHP an advantage over renewables and would be inconsistent with the concept of renewables as the rebuttable presumption. PG&E-16

Conclusion

PG&E believes that the Draft should be revised to present a range of utility contractual resource needs as envisioned by CPUC President Peevey's ACR. PG&E believes that such revisions must and should be included before the Draft is finalized and transmitted to the CPUC.

Appendix A

Pacific Gas and Electric Company
Comments on CEC IEPR
Proposed Revised Annual Aggregated Energy Resource Accounting Tables and Annual Aggregated Capacity Resource Accounting Tables

Pacific Gas and Electric Company (PG&E) appreciates the opportunity to comment on the CEC Staff's proposed revised annual Aggregated Energy Resource Accounting Tables of November 7, 2005. These tables, included as Appendix B to the Committee Draft Transmittal of 2005 Energy Report Range of Need and Policy Recommendations to the California Public Utilities Commission, Draft Transmittal Report, present the capacity and energy balances for the period 2009-2016 for the states load serving entities (LSEs). PG&E appreciates the effort that staff has expended developing these tables and understands the difficulty in presenting information is a comprehensive manner. PG&E provides the following recommendations for revising the tables in order to increase the clarity of the information so that it may be better understood by all reviewers and users.

First, PG&E recommends that the final Appendix B include a discussion of the methodology used in developing the tables. While discussion of the methodology is included in Chapter 5 of the Report, it would be very helpful to the reader of the tables to include the relevant methodology along side the tables. PG&E-17

Second, PG&E recommends re-arranging the tables in order to present the "Aging Plant Replacement" information at the bottom of the sheet and not on the table itself. PG&E appreciates that the Committee wants to present the capacity and energy from Aging Plant Replacement with the contractual resource need information, but the current table design is confusing. Aging Plant Replacement capacity and energy values are not used in any calculations on the table, and it is unclear why this information resides on the table. PG&E believes the CEC goal of presenting this information with the resource need information is achieved by simply including it beneath the table. PG&E-18

Finally, PG&E recommends the tables be renamed "(IOU***)-Planning Area*** (Scenario) Demand Case" rather than the current "(IOU) (Scenario) Demand Case" in order to reflect the nature of the information presented on the tables. The current table titles are something of a misnomer, as the tables include a composite of utility information and non-utility information. While PG&E cannot speak to the comprehensiveness of the non-IOU information, the tables do not present PG&E-specific demand case data. Changing the tables name would clarify for the reader that they are not examining utility–specific information. PG&E-19

SOUTHERN CALIFORNIA
EDISON

An *EDISON INTERNATIONAL* Company

(U 338-E)

Southern California Edison Company's Comments On The Committee Draft Transmittal Of 2005 Integrated Energy Policy Report Range Of Need And Policy Recommendations To The California Public Utilities Commission

Before the
California Energy Commission

Rosemead, California
November 8, 2005

LAW#1257868

Southern California Edison Company's Comments On The Draft Transmittal

Table Of Contents

Section	Page

Table Of Contents (Continued)

Section	Page

I.

INTRODUCTION

Southern California Edison Company (SCE) submits the following comments on The Committee Draft Transmittal of 2005 Energy Report Range of Need and Policy Recommendations to the California Public Utilities Commission issued November 2005 (Draft Transmittal).

As the California Public Utilities Commission (CPUC) specifically asked the California Energy Commission (CEC) to use its Integrated Energy Policy Report (IEPR) process as "the appropriate venue for considering issues of load forecasting, resource assessment and scenario analysis, to determine the appropriate level and range of resource needs for load serving entities (LSEs) in California."[1] SCE initially comments on several areas where the Draft Transmittal has grossly misinterpreted the scope of the assessment the CPUC desired and made policy determinations which unfairly disadvantage investor-owned utilities (IOUs) and their bundled-service customers relative to all other participants in the market.

SCE-1

Among these issues are the Draft Transmittal's: a) recommendation that IOUs make commitments that are not required of any other LSEs; b) recommendation that the CPUC restrict renewable procurement through the requirement of standard contract terms; c) recommendation that the CPUC require IOUs to buy, through standard offer contracts all electricity from combined heat and power (CHP) plants in the IOUs' service territories at the IOUs' avoided costs; and d) publishing of residual net short estimates. As SCE has already addressed each of these issues in its October 14, 2005 Comments on the Draft 2005 Integrated Energy Policy Report it will not restate those concerns here, however, SCE

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[1] *See* CPUC Assigned Commissioner's Ruling on Interaction Between the CPUC Long-Term Planning Process and the CEC IEPR Process, issued September 16, 2004, at 1.

incorporates those previous comments by reference. Accordingly, SCE limits its comments here to issues related to load forecasting (including mistakes and inconsistencies in the resource accounting tables) and renewable resources.

II.
COMMENTS ON LOAD FORECASTING ISSUES

SCE has a number of concerns related to the CEC's current load forecasting process. These issues have the potential to create serious problems between utility and CEC Staff forecasts in the future. SCE's other comments in this section apply directly to the Draft Transmittal.

A. Issues With The CEC's Forecasting Process and Models

As SCE has indicated throughout the IEPR process, the CEC Staff's underlying load forecasting process and models lead to serious and irreconcilable differences between utility load forecasts and CEC Staff load forecasts. These processes and models must be revised in order to provide the most accurate load forecast information.

SCE-2

Prior to deregulation, the CEC conducted bi-annual Common Forecast Methodology (CFM) workshops and hearings pursuant to regulations authorized by the Warren-Alquist Bill. At those hearings, which took place between the early 1980s and 1996, SCE forecasters developed opinions about the CEC's forecasting process. For example, SCE found that the CEC's methodology was not in the best interests of Californians or SCE's ratepayers because the CEC's in-house developed, end-use forecasting model was overly complex in construction and overly simplistic in results.[2]

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[2] Such end-use models more accurately predict load for smaller customers than they do for larger customers.

SCE has been informed that the CEC Staff is, to a large extent, still using versions of the problematic models and processes to develop information for the Draft Transmittal. Thus, the Draft Transmittal contains many of the same shortcomings which pervaded the CEC load forecast determinations ten years ago. Some of the issues raised by the CEC's model are:

- What is the price elasticity in each of the residential, commercial, and industrial end-use models? If the price of electricity is raised by 10%, what is the first year, and continuing, impact on consumption and peak demand?
- What is the elasticity of the three models with respect to the primary economic driver—the income elasticity of the residential model, the employment or income elasticity of the commercial model, and the value added, or employment elasticity, of the industrial model? For a 10% change in the economic input, what is the first year, and the continuing, impact over the forecast period on consumption and peak demand?
- What is the "back-cast" accuracy of the models from 1985 through 2005? In prior CFM hearings, SCE frequently observed that when the model was run over a historical period, with recorded economic drivers, the trend predicting consumption was severely biased, as opposed to the results when a recorded consumption trend was utilized. In general, end-use models do not reflect growth rates of consumption that actually occur. Specifically, the CEC Staff model over-predicts the early part of the historical consumption period, and under-predicts the latter part of this period. This means that for the last year of recorded data, the model would predict significantly lower consumption than actually occurred. Extending a forecast from this point would

SCE-2, cont.

obviously lead to a low forecast. SCE has, for years, advised the CEC Staff of this problem with its model. The CEC's model is inherently flawed and should not be used as the basis for State forecasts. Despite SCE's warnings to the CEC Staff, this issue continues to be one leading to disagreements between utility forecasting staffs and the CEC's forecasting staff.

SCE-2, cont.

For all of the foregoing reasons, the model and processes used by the CEC Staff to develop the Draft Transmittal are fundamentally flawed and will continue to be so until the concerns raised by SCE here are addressed. SCE urges the CEC and the CPUC to promptly move to address these issues.

B. Specific Issues With Regard to the Draft Transmittal

1. The CEC's Draft Transmittal Should Include a Summary Table of Demand Forecasts, Which Accounts For Committed and Uncommitted Energy Efficiency and Demand-Side Management Programs

As a general concept, SCE believes that the CEC's reports should always publish one summary table reflecting the forecasts of demand that the CEC expects to show up at the meter. This means, that even if "uncommitted" energy efficiency (EE) and Demand Side Management (DSM) are handled as supply resources, and not deductions to the demand forecast (and if handled as a resource they should have a 15% reliability adder so they are equivalent to a reduction in demand, since that is how they will "show up" in the end), there should be tables wherein committed and uncommitted EE and DSM are both deducted from the demand forecast. Accordingly, when the Draft Transmittal details the level at which energy demand will grow over the next decade, that figure should have uncommitted EE and DSM deducted from the demand forecast. Uncommitted EE is still EE, it is not a generator, and, if funded, it will only have the effect of reducing demand. To

SCE-3

publish a demand forecast that only deducts committed EE and then provide a report that discusses California's needs, based on those demand results, exaggerates expected demand growth.

Uncommitted EE may not be funded, but it is still presumed "likely to occur," and should be deducted from the demand forecast in the CEC's summary table of the demand outlook for California. SCE has not identified such a summary table in this Draft Transmittal, and it should be added. If, however, the CEC Staff wants to compare "consumption forecast with just committed EE" against "consumption forecasts with committed and uncommitted EE deducted," it should at least emphasize that the ultimate intention is to forecast "demand" as what the meters will show, given the input assumptions, and not to leave a confusing trail of pieces of the demand forecast. SCE-3 (cont.)

2. <u>The Draft Transmittal Should Clarify That Labels of "Committed" and "Uncommitted" EE Programs Do Not Reflect SCE's Commitment to Such Programs</u>

SCE's internal forecasting methodology assumes that Public Goods Charge (PGC)-funded programs continue in the long-term. The methodology also looks to SCE's management for guidance as to the Company's commitment to future accelerated EE. Based on this direction, SCE includes estimates of EE for the 20 or 25 year forecast horizon. SCE does this so that its forecasts will show the impact on sales and demand of its policies with regard to EE. SCE-4

If the Draft Transmittal shows an early termination of PGC or advanced EE programs, this result is only because the CEC's instructions for filling out the IEPR forms specifically indicated that the normal assumptions SCE makes should be changed. For this reason, the labels of "committed " and "uncommitted" used in the Draft Transmittal should not be viewed as indicative of SCE's commitment to such programs, rather they are solely the product of the CEC's instructions for the IEPR process. As currently drafted, the Draft Transmittal does not make clear that the labels "committed" and "uncommitted" are not indicative of SCE's commitment to such EE programs. The Draft Transmittal should be revised to reflect this clarification. SCE-4, cont.

3. <u>The Draft Transmittal's Resource Accounting Tables Should Include Uncommitted EE</u>

The Draft Transmittal's reserve planning tables should include uncommitted EE with a 15% adder, such that uncommitted EE has the impact of reducing demand forecasts. Tables B7 through B12 in the Draft Transmittal do not appear to have done this. The failure to account for uncommitted EE has thus essentially overstated SCE future resource needs. SCE-5

4. <u>The Draft Transmittal's Resource Accounting Tables Should Use Either Planning Area or Bundled Area, But Not Both In The Same Table</u>

Tables B7 through B12 mix "planning area" and "bundled" load and supply data. It is also unclear which information in the tables is provided by the IOUs and which is the product of a CEC forecast. The CEC Staff should correct these errors and clarify the sources for their information. The CEC should also explicitly state its assumptions regarding the future of direct access and community choice aggregation. SCE-6

5. <u>Treatment of Aging Power Plant Replacement In The Draft Transmittal's Resource Accounting Tables Is Confusing</u>

Tables B7 through B12 confusingly address aging power plants. The CEC's intention with regard to these power plants should be clarified. SCE-7

III.

COMMENTS ON THE DRAFT TRANSMITTAL'S POLICY RECOMMENDATIONS

SCE is surprised that the vast majority of Draft Transmittal addresses policy issues. Instead of focusing on issues related to future procurement needs, the CEC uses the Draft Transmittal to promote its own policy positions. In this respect, the Draft Transmittal merely parrots many of the statements made in the Draft 2005 IEPR. For this reason, SCE incorporates fully by reference its written comments on the Draft 2005 IEPR. Additionally, SCE reemphasizes its position on the following issues in the Draft Transmittal.

A. The Draft Transmittal Contains Unsupported Recommendations Regarding the Need for Long-Term Renewables Contracts

Section 3.1.1 of the Draft Transmittal states, "[t]he lack of long-term contracts also hinders the development of renewable resources."[3] In, fact, SCE has recently executed long term contracts with eligible renewable resource project developers for up to1,350 MW of capacity. San Diego Gas & Electric and Pacific Gas and Electric Company have also executed long term contracts representing more than 1,100 MW and 225 MW respectively. All three IOUs have begun their 2005 solicitations, and SCE has received numerous bids. Thus, the CEC's assessment and recommendations on this issue are not supported by analysis and are contrary to fact.

SCE-8

Further, the CPUC has jurisdiction over the development of contract terms, approval of contracts, and monitoring and enforcement of progress towards renewable portfolio standard (RPS) goals. Accordingly, the Draft Transmittal's

[3] Draft Transmittal at 9.

inclusion of recommendations regarding this issue are unnecessary and should be deleted.

B. The Draft Transmittal's Recommendation's Regarding Standardized Contracts Should Be Deleted

In Section 3.1.2, the CEC states, "In addition to the previous discussion of long-term contracts, there was a significant volume of testimony in this proceeding regarding the need for standardized contracts."[4] This "testimony" consists of the unsworn comments of counsel and a limited number of Qualifying Facility representatives rehashing issues that have been fully resolved by the CPUC in D.04-06-014, which addressed and rejected arguments concerning the need for standardized contracts to implement the RPS legislation. Likewise, the issue of whether standardized contracts for cogeneration is an issue over which the CPUC has jurisdiction and which it is actively investigating in R.04-04-025. SCE-9

Because these issues are squarely, and solely, within the CPUC's jurisdiction, it is inappropriate for the CEC to use the Draft Transmittal to make policy recommendations to the CPUC. This is even more egregious since the CPUC has based its recommendation solely on the unsworn and unsubstantiated statements of clearly biased participants in an ongoing CPUC proceeding. For this reason, the Draft Transmittal's statements on this issue should be deleted.

C. The Draft Transmittal's Unsubstantiated Statements Concerning Cogeneration Should Be Deleted

In Section 3.1.2, the Draft Transmittal concludes its discussion of cogeneration with the following recommendations:

> ♦ By the end of 2006, the CPUC should require IOUs to buy, through standard offer contracts, all electricity from

[4] Draft Transmittal at 11.

> CHP plants in their service territories as delivered at the utility's avoided cost, as determined by the CPUC in R.04-04-025....
>
> ♦ Relative to system planning, the Assessment of California CHP Market and Policy Options for Increased Penetration determined a realistic goal of 5,400 MW of CHP by 2020, which is attainable if policies recommended here are implemented.

These policy recommendations prejudge the outcome of an ongoing CPUC proceeding in which the CEC is not a participant. Accordingly, this matter (sometimes described as a cogeneration portfolio standard) is the subject of hundreds of pages of sworn testimony recently submitted in R.04-04-025. Whether it is appropriate to adopt policies consistent with the CEC's recommendations is a matter squarely within the CPUC's jurisdiction pursuant to PURPA, and the CPUC has undertaken evidentiary hearings to consider the merits of this type of proposal. The notion of a mandatory set aside for cogeneration implicates a number of pricing, equity and environmental issues which are only scantly addressed in the Draft Transmittal or in the CEC's prior analysis of cogeneration, and by such omission, ignores the detrimental cost and environmental consequences of this policy on bundled-service customers. One has to reflect on the billions of dollars Californians have already paid to subsidize cogeneration under its previous must-take, standard contract model. For this reason, the CPUC should only adopt policies that are consistent with State and Federal law, which result in value for ratepayers and which guarantee the claimed benefits of cogeneration for the State of California, particularly with respect to claims of fuel efficiency and reduction of natural gas consumption.

SCE-9, cont.

Because the Draft Transmittal's recommendations on this matter are contrary to measured analysis, not based in fact, and appear to be premised on flawed assumptions, they should be deleted. SCE-9, cont.

D. The Draft Transmittal's Attack on the CPUC's Decision Approving the IOUs' Least-Cost/Best Fit Methodology Should Be Deleted

In Section 3.2 of the Draft Transmittal, the CEC states, "A recent review by the Energy Commission of evaluation criteria indicated significant shortcomings in the market value and portfolio fit criteria that are currently being used by utilities."[5] The RPS legislation, as implemented by the CPUC is sufficient to sort bids on the basis required by statute. For this reason, the Draft Transmittal should delete any reference to this issue.

E. Transmission Project Recommendations

SCE agrees with the Draft Transmittal's assessment of transmission in Section 9.3. It is imperative that the CPUC do whatever it can to move transmission projects forward. SCE-10

SCE notes, however, that the approval, construction and availability of transmission is integrally related to the resource potential for renewable development, and the Draft Transmittal fails to make recommendations that would even remotely support assertions concerning the State's ability to tap into the potential often claimed by the CEC.

For example, the CEC's Renewable Resources Development Report asserts, with little if any substantiation, that there is 63,000 MW of potential concentrating solar power available in Imperial, Kern, Los Angeles, Riverside and San Bernardino counties. Yet the Draft Transmittal does not discuss the facilities and facility SCE-10, cont.

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[5] Draft Transmittal at 16.

upgrades that would be required to develop any of this potential. This disconnect between the CEC's recommendations on accelerated renewable development and the need and recommendations for transmission facilities to accomplish renewable penetration at levels greater than 20% is at best a troubling lapse, and certainly requires further consideration.

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November 8, 2005

California Energy Commission
Dockets Office
1516 Ninth Street, MS-4
Sacramento, CA 95814-5512

RE: Docket No. 04 IEP 1K – Sempra Energy Utilities Comments on the 2005 Committee Draft Transmittal Report

Dear Commissioners:

On behalf of the Sempra Energy Utilities, San Diego Gas and Electric and Southern California Gas Company, attached are comments in response to the 2005 Committee Draft Transmittal Report, Range of Need of Policy Recommendations to the CPUC. We appreciate the opportunity to provide comments and participate in this important process to ensure that California achieves its energy resource needs.

Sincerely,

Bernie Orozco

Sempra Energy Utilitites Comments on the
Committee Draft Transmittal Report, Docket No. 04 IEP 1K

During 2005, the California Energy Commission (CEC) has undertaken extensive proceedings to address a wide range of energy issues important to California as part of the CEC's Integrated Energy Policy Report (IEPR) proceeding. The CEC has prepared a Draft Report, released on October 25, 2005, that will be transmitted to the California Public Utilities Commission (CPUC) and used in the CPUC's 2006 resource planning process. The Draft Transmittal Report communicates to the CPUC the CEC's assessment of range of need and policy recommendations for this joint resource planning effort.

San Diego Gas & Electric Company (SDG&E) appreciates the hard work of the CEC throughout this undertaking, and particularly recognizes the dedication of the IEPR Committee and CEC staff in this process. SDG&E and SoCalGas, in addition to other utilities and stakeholders, contributed substantial analysis and data as part of this effort and have also participated in many of the IEPR hearings, including the one held on November 4, 2005 addressing the Draft Transmittal Report. SDG&E would also note that many of its comments offered regarding the Draft Committee Report,[1] dated September 2005, are equally applicable to this Draft Transmittal Report.

To summarize, SDG&E urges the CEC to recognize that a balanced approach to solving the state's most vexing and critical resource and transmission planning issues will be essential to achieving adequate, reliable, and affordable energy supplies for all Californians. Most would agree that today's pressing problems require additional supplies and the transmission needed to get those supplies to loads. Even in this simple statement is a requirement for balance and trade-offs, however. New generation, built far from load centers, will require new transmission. Existing supplies, denied access to market by transmission congestion, cannot address load needs. SDG&E is concerned that the current Draft CEC IEPR Reports have not sufficiently achieved this balance and send conflicting messages.

SDG&E also observes that at times the utilities receive more policy guidance and targets from regulators than can realistically be accommodated into their resource plans. Trying to simultaneously meet every goal, no matter how individually worthy, can result in greater than necessary resource additions at higher than necessary costs to consumers. Thus, policy guidance from this IEPR should come with the flexibility needed to allow those carrying out the policy to achieve the goals in a manner that balances meeting the goals with reasonable costs for consumers. In sum, achieving a goal one year later than planned at a lower long-term total cost to consumers should not be viewed as failure, but should be an acceptable plan.

Sempra-1

The Draft Transmittal Report reflects a lot of hard work by the CEC Staff, and many positive aspects of the Draft Report are not addressed here by SDG&E. Rather, we focus on several areas that SDG&E strongly urges the CEC to revise before adopting a final report for transmittal to the CPUC. If the CEC is unable to make the changes advocated here, SDG&E will continue to

[1] See SDG&E Comments filed on October 14, 2005.

challenge these aspects of the CEC's analysis to the extent these issues are advanced in the CPUC's resource planning proceeding.

Load Forecast and Uncommitted Energy Efficiency

SDG&E has serious concerns regarding the combination of the load forecast and uncommitted energy efficiency (EE) amounts used in the report for years 2009 – 2016. SDG&E cannot support the report as currently drafted because subtracting future EE goals from Staff's load forecast results in a net need that substantially underestimates capacity and energy needs from 2009 through 2016. As Staff stated in the Transmittal Report, "Savings that SDG&E attributes to future DSM programs may to some extent be already accounted for in the Energy Commission's model as part of the effects of building decay, equipment replacement, price effects, and building and appliance standards" (Draft Report, p. 80). SDG&E agrees with this statement and believes future EE efforts are already embedded in the Staff load forecast. However, the report also shows the full amount of future EE goals as a resource. Subtracting the full amount of uncommitted EE double counts the impact of future EE resulting in an incorrect assessment of future resource needs. Sempra-2

If the load forecast and uncommitted EE are adopted as presented in Staff's resource plan, the resulting capacity need for SDG&E's service area would only increase by a total of 75 MW from 2009 to 2016, or roughly 10 MW per year. To put this in perspective, Staff's load forecast including all energy efficiency savings for the years 2005-2008 projects an average load growth of 82 MW per year. In recent history, SDG&E has experienced peak load growth in excess of 100 MW per year. Thus, the use of Staff's load forecast combined with the total amount of uncommitted EE produces an unrealistic resource plan that will underestimate future resource needs by about 500 MW.

This problem of double-counting future EE savings does not apply only to SDG&E. Using the area peak demand forecasts and the uncommitted EE savings for all three of the IOUs as presented in Tables B-5, B-11, and B-17, one can calculate that the combined capacity need of all three IOUs totals 405 MW for the 2009-2016 period. Therefore, adoption of this resource plan will seriously underestimate the statewide need for resources.

Lastly, SDG&E notes that although the Transmittal Report claims to provide a range of need, the range is so narrow that for all practical purposes there is no range. Staff's low scenario is only 37 MW below the base case in 2016 and their high scenario is 118 MW above the base case in 2016. A range of only 3% over twelve years into the future is much too narrow. Sempra-3

Resource Accounting

In reviewing the tables for SDG&E (B13-B18), a number of changes need to be made to properly account for the total resource need and how reserves are calculated. These changes are needed because the current tables would result in SDG&E acquiring substantially more resources than are needed and result in a 40-60% reserve margin depending on the year. This excess reserve is the result of three major items that all need to be corrected before the final tables are submitted.

First, adding procurement to account for the potential replacement of aging power plants is unnecessary. SDG&E's submitted resource plans meet the forecasted loads and the required reserves for SDG&E's bundled load. Thus, SDG&E has already addressed this issue. SDG&E's plan added resources that replace the aging plants (or contracted with them) as a supply source. As such, there is no need to add an increment of procurement in either the energy or capacity table.

Sempra-4

It should also be noted that the possible impact of retiring plants will impact supplies available to all customers, not just bundled customers of the IOUs. SDG&E is already undertaking long-term planning and an orderly procurement process to deal with these older units. SDG&E is adding over 1,100 MW of new plants to its service area and is currently studying the addition of a major new transmission line, both of which will allow for the retirement of some of the existing aging plants. SDG&E also plans to undertake its future procurement well in advance of its needs to allow new plants to compete with the older plants.

Sempra-5

Second, the tables calculate an amount of capacity needed to meet a 15% reserve margin based on total system load, not the IOUs' bundled load shown in the table. This would in essence be requiring the IOUs to procure reserves for all load serving entities (LSEs). The CPUC has adopted a resource adequacy program that requires each LSE to procure its own reserves. The IOUs are not responsible for procuring reserves for the total load in the service area. Thus, any reserve requirement in the table should be reserves for the IOUs' bundled load only.

Sempra-6

Third, the table as presented would result in SDG&E having to procure reserves for uncommitted energy efficiency and uncommitted demand response programs. This is contrary to the cost benefit analysis of these programs which assumes that these programs eliminate the need for reserves. These uncommitted resources will reduce the load in the future and thus reduce the need for reserves. The tables should either move these resource options up in the table and subtract them from load prior to calculating reserves, or "gross up" the amount of capacity available from these resources by 15%.

Sempra-7

<u>Committed Interruptible and Dispatchable Demand Response</u>

The line for Existing Interruptible/Emergency Programs for SDG&E is currently not correct. At the time the original forms were submitted to the CEC, SDG&E had 6 MW of committed interruptible programs and 30 MW of committed dispatchable demand response programs. At a very minimum, this total should be shown on this line and the line relabeled to state that it includes dispatchable demand programs as well as interruptible programs. However, it should be noted that since the forms were submitted, the CPUC has approved additional programs and SDG&E currently has programs that total 86 MW of committed interruptible and dispatchable demand response programs.

Sempra-8

<u>Need to Update All Data Items</u>

The report states that a number of line items in the tables will need to be updated and a number of them will not need to be updated as part of the CPUC's long-term procurement planning process. The reality is that all items should be updated. The data used by the CEC in these tables represent data provided to the CEC on March 1 and April 1, 2005. To meet these deadlines, the data had to be gathered months in advance. The CPUC's long-term procurement

Sempra-9

planning process should use the best data available at that time, and not data that in many cases will be over a year old. Because the IOUs will make financial commitments on behalf of their customers based on the outcome of the CPUC process, the CPUC decision should rely on the best available data. The IOUs will need to be able to update all line items. These will include but not be limited to updates to the load forecast to reflect 2005 actual, new commitments, changes in capacity ratings of units, changes necessary to comply with the CPUC's resource adequacy proceeding decision, and changes in resources that have been approved by the CPUC since the CEC data was submitted. Staying with year old data will not serve the interests of ratepayers. Sempra-9, cont.

Other Items

In Section 7.3.1.4, the report implies that all Combined Heat and Power (CHP) is distributed generation, which is incorrect. In fact, the majority of the CHP that sells back to the IOUs are large generation stations that do not fit the definition of distributed generation. The report should treat DG and CHP as two different and distinct items. Sempra-10

SDG&E also objects to the report's reference to a claim that the lack of long-term contracts hinders the development of renewables (Section 3.1.1, page 10). All of the contracts SDG&E has executed with renewables have been long-term contracts to enhance the development of new renewable sources. Sempra-11

Conclusion

SDG&E appreciates the extensive efforts that the CEC has invested in this IEPR process. To ensure that the process moves ahead with the best interests of ratepayers represented, SDG&E strongly urges that the changes advocated here should be adopted by the CEC in its final Transmittal Report to the CPUC.

05.11.08

Comments of the Natural Resources Defense Council (NRDC) on the *Committee Draft Transmittal of* 2005 Energy Report *Range of Need and Policy Recommendations to the California Public Utilities Commission*

Docket Number 04-IEP-1K
November 8, 2005

Submitted by:
Audrey Chang, NRDC

The Natural Resources Defense Council (NRDC) appreciates the opportunity to offer these comments on the California Energy Commission's (CEC) *Committee Draft Transmittal of* 2005 Energy Report *Range of Need and Policy Recommendations to the California Public Utilities Commission* (Draft Transmittal Report). NRDC is a non-profit membership organization with a long-standing interest in minimizing the societal costs of the reliable energy services that Californians demand. We focus on representing our more than 130,000 California members' interest in receiving affordable energy services and reducing the environmental impact of California's electricity consumption.

We commend the CEC staff for distilling the *2005 Integrated Energy Policy Report* (IEPR) into a Transmittal Report to inform the California Public Utilities Commission (CPUC) 2006 procurement proceeding. Many of our comments presented here reflect those that we have presented regarding the IEPR as a whole, but some are specific to the Transmittal Report.

The Transmittal Report should include policy recommendations to the CPUC.

Some parties expressed surprise at the November 4, 2005 hearing that policy recommendations were included in the Transmittal Report. It is appropriate for the CEC to use this document to convey to the CPUC its recommendations that are relevant to and that will improve the CPUC's 2006 procurement proceeding process. NRDC supports the inclusion of these policy recommendations in the Transmittal Report.

NRDC supports the CEC and CPUC working together to adopt the greenhouse gas performance standard, without the use of offsets.

NRDC strongly supports the Greenhouse Gas Performance Standard proposed in the draft IEPR and further described in Chairman Desmond's memorandum dated September 22, 2005. This policy is needed both to achieve the Governor's GHG reduction targets and to protect Californians from the significant financial risks associated with additional investments in highly carbon-intensive generating technologies. We oppose the use of offsets to meet the standard because allowing for offsets would greatly diminish the risk mitigation benefits of the policy and discourage the investments in advanced technologies that are needed to achieve the Governor's long-term reduction targets. We support the CEC and CPUC working together to ensure that all of California will be protected from the financial risks of global warming pollution. NRDC-1

NRDC recommends that the Transmittal Report encourage the CPUC to direct the IOUs to perform portfolio analyses examining future resource fuel types.

The draft Transmittal Report correctly notes that the use of portfolio fit criteria has "value when looking at a single asset, [but] are less valid when examining a larger portfolio" (page 16). This points to an aspect of analysis that is currently missing from the IOUs' procurement process: true *portfolio* resource planning through examination of future resource fuel types.

Although an analysis of the future resource fuel types that the load-serving entities could expect to be part of their portfolios was not conducted for this 2005 IEPR, we strongly recommend that the CEC encourage the CPUC to require the IOUs to perform this sort of *portfolio* resource analysis as a part of their resource planning. To better inform California's energy policy, the IOUs should examine the likely future composition of their electricity mix, and the associated costs, risks and environmental impacts that customers can expect. We outline the need for this sort of true resource planning on pages 12-13 of our October 14, 2005 comments on the draft IEPR. NRDC-2

In addition, pages 44 and 47 of the draft Transmittal Report note that the CEC and CPUC share a commitment to implementing the loading order and thus preferred resources (energy efficiency, renewables, and distributed generation) are identified. However, there is currently no way to ensure that the last component of the loading order, clean fossil generation, is followed. Resource fuel type analysis by the IOUs using the "greenhouse gas adder" will help close this gap.

The CEC should recommend that the PUC's long-term planning process include a comprehensive risk analysis.

Assessing, managing, and mitigating risks is one of the utilities' most important and most challenging responsibilities in creating comprehensive and integrated resource plans. Similarly, overseeing the utilities' management and mitigation of risks is one of the CPUC's most important responsibilities in ensuring that customers receive reliable, affordable, and environmentally sensitive energy services. If ever a reminder was needed of this fact, the crisis of 2000 and 2001 showed forcefully that careful management of both financial and reliability risks is absolutely essential to the state's wellbeing.

While the CPUC has implemented a process for managing short-term price risks through the use of a Customer Risk Tolerance, it is the long-term planning process that enables the IOUs and the CPUC to compare resource alternatives in a manner that captures interactive *portfolio* effects. Without long-term integrated planning, a utility that analyzes procurement options one by one is likely to "miss the forest for the trees." Each individual investment decision may seem like the best decision, but the *additive* effect of the decisions and the impact on the overall portfolio would not be considered without true long-term plans.

This process should include testing a number of potential resource portfolios to determine their total long-term costs, to conduct a risk analysis of those portfolios under various scenarios, and to select an optimal portfolio that best meets the portfolio manager's objectives. Given the numerous risks in the electric industry, it is essential to conduct a risk analysis to test how robust each portfolio is in the face of various uncertainties. There are generally at least three different types of risks: (i) risks that can be quantified and for which historical experience can inform assessments of the future risk (e.g., load forecasts, natural gas price risk);[1] (ii) risks that can be quantified but for which no historical experience can inform the assessment (e.g., future regulation of carbon dioxide emissions); and (iii) risks that cannot be easily quantified, but can be qualitatively assessed (e.g., a change in FERC's market design, public acceptance of new resource siting, etc.). The preferred resource plan is generally the portfolio that has the lowest lifecycle cost (i.e., lowest anticipated long-term revenue requirement) and is most robust in the face of various risks, among other factors. The Commission can look to other utilities' risk analyses, including PacifiCorp, Idaho Power, Puget Sound Energy, for examples of what a portfolio-level risk assessment should include. Of course, a risk analysis will only be meaningful if the resource fuel types are identified and analyzed, as we discussed above.

The "range of need" should explicitly state what portion consists of contractual vs. physical needs.

The graphs showing the annual energy and capacity ranges of need that were presented by Staff at the November 4, 2005 hearing were extremely helpful in helping the reader visualize how the range of need was constructed. We recommend that these graphs be included in the final Transmittal Report.

NRDC-3

The "range of need" currently encompasses both contractual and physical needs, but the distinction between the two is not always clear in the tables and graphs in the draft Transmittal Report. The CEC should avoid sending the unintentional signal that the entire amount of need is for new physical capacity that needs to be built, when some of this need can be fulfilled through contracts for existing physical resources. In addition, the additional need from retiring power plants should be separately identified.

The description of the CEC's demand forecast should be explicit about the treatment of energy efficiency and should include at minimum the energy efficiency that will be funded by the public goods charge (PGC).

As in the draft IEPR, it is unclear from the draft Transmittal Report text (section 5.1 and 5.3) whether no efficiency savings at all are included past 2008, or whether only PGC-funded savings are included similar to the 2003 IEPR. Since the PGC is legislatively mandated through 2011 and will not change during this time, it effectively serves as a minimum floor for efficiency investments during this timeframe and should be included in the "committed" energy efficiency in the demand forecast. Savings from PGC-funded energy efficiency programs can be estimated based on historical performance of energy efficiency programs. Further comments regarding the treatment of energy efficiency in the CEC demand forecast can be found on page 14 of NRDC's October 14, 2005 comments on the draft IEPR.

NRDC-4

[1] Of course, while historical experience is extremely useful in assessing risks, this information must always be combined with informed judgment about the future.

In addition, it should be clarified whether the energy efficiency numbers apply to the IOU bundled load or entire service territory. It seems that the "uncommitted energy efficiency" shown in the Appendix B tables for each IOU does not match the energy savings goals set by the CPUC for the IOUs. Although these goals may be modified in future years, their current levels reflect the existing policy set for the IOUs, and the IOUs' plans should reflect this. NRDC-5

The utilities' decoupling mechanisms are effective in removing financial disincentives for any demand-side reductions, not just energy efficiency.

Page 14 includes the recommendation that "[a]pproaches such as the Earned Rate Adjustment Mechanism [ERAM], which were successful in keeping IOUs revenue-neutral for energy efficiency programs, could be implemented for CHP and DG." Indeed, ERAM, the *Electric* Rate Adjustment Mechanism was successful, and a new generation of decoupling mechanisms adopted by the CPUC for all the major IOUs has been key to California's successes in energy efficiency.[2] These decoupling mechanisms are strategy-neutral and will also help eliminate financial disincentives for any activities that would otherwise impact the IOUs' revenues by reducing their sales volume. NRDC-6

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[2] For a discussion of the new generation of decoupling mechanisms, see Bachrach, D., S. Carter and S. Jaffe, "Do Portfolio Managers Have An *Inherent* Conflict of Interest with Energy Efficiency?" *The Electricity Journal,* Volume 17, Issue 8, October 2004, pp. 52-62.

BEFORE THE CALIFORNIA ENERGY RESOURCES CONSERVATION AND DEVELOPMENT COMMISSION

In the Matter of: Preparation of the *2005 Integrated Energy Policy Report*	Docket No. 04-IEP-1K

COMMENTS OF DUKE ENERGY NORTH AMERICA ON THE 2005 COMMITTEE DRAFT TRANSMITTAL OF 2005 ENERGY REPORT RANGE OF NEED AND POLICY RECOMMENDATIONS TO THE CALIFORNIA PUBLIC UTILITIES COMMISSION

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BEFORE THE CALIFORNIA ENERGY RESOURCES CONSERVATION AND DEVELOPMENT COMMISSION

In the Matter of: Preparation of the *2005 Integrated Energy Policy Report*	Docket No. 04-IEP-1K

COMMENTS OF DUKE ENERGY NORTH AMERICA ON THE 2005 COMMITTEE DRAFT TRANSMITTAL OF 2005 ENERGY REPORT RANGE OF NEED AND POLICY RECOMMENDATIONS TO THE CALIFORNIA PUBLIC UTILITIES COMMISSION

Pursuant to the Notice of Committee Hearing and Availability of the 2005 Committee Draft Transmittal Report, Duke Energy North America ("DENA") provides these comments for the Committee's consideration. For the reasons explained below, DENA urges the CEC to recommend to the California Public Utilities Commission ("CPUC") that 3-5 year "interim contracts" be pursued to shore up the availability of existing resources while additional work is completed with respect to development of full resource adequacy implementation and a formalized capacity market.

The Transmittal Report includes policy recommendations that are aimed at phasing out older power plants. The Transmittal identifies approximately 50 power plants throughout the state that have been relied on in recent years to meet peak demand.[1] The CEC advocates the replacement of these plants on a pre-ordained basis, presumably via long-term contracts with the utilities. To forward this policy recommendation, the CEC advocates imputing an additional capacity requirement to the IOUs, irrespective of whether those assets are in fact included in the utility's portfolio developed to meet customer needs and satisfy regulatory requirements such as

[1] This number excludes publicly owned utility generation assets that are similarly situated in terms of vintage to investor owned utility generation assets.

the Resource Adequacy Requirement ("RAR").[2] The rate of capacity phase-out is 25% of the utility's aged unit capacity per year beginning in 2009 such that the all the identified resources are retired by 2012.

DENA believes that the CEC's ultimate goals are laudable (namely more efficient and environmentally acceptable resources), but that the means of pursuing the goals through a strict phase-out approach may not be necessary as improved market structures are anticipated to be operating in that timeframe. However, as DENA has stressed for some time, a 3-5 year interim contracting approach for existing resources should be undertaken to maintain the availability of existing resources for reliability purposes pending full implementation of RAR and a formal capacity market.[3]

Duke-1

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[2] See Transmittal Report, page 46:

> To facilitate the retirement of these aging power plants, the Energy Commission ***has apportioned these 50 plants to the three IOUs based on their physical location, along with their existing capacity and the average energy produced in 2002 through 2004***. In order to ensure that sufficient investment takes place in the next round of procurement to provide for the orderly replacement of the retiring plants with new resources, ***the Energy Commission is including the full amount of the existing capacity and average energy generation of these plants for 2002 through 2004 in the identified need for each of the IOUs for 2012 and beyond***.

[3] See, e.g., DENA's involvement before the CPUC in its *Comments of Duke Energy North America on the Proposed Decision of ALJ Wetzell Regarding Resource Adequacy Issues*, September 20, 2004 in R.04-04-003 arguing that the utilities should be given interim or transitional procurement authority to secure capacity in anticipation of RAR; *Opening Brief of Duke Energy North America on Electric Utility Resource Planning,* October 18, 2004 in R.04-04-003 arguing in favor of a interim contracting arrangement as described in testimony presented in that case; *Reply Brief of Duke Energy North America on Electric Utility Resource Planning,* November 1, 2004 in R.04-04-003, arguing for interim steps to maintain availability of existing capacity while focusing on the eventual development of a formal capacity market structure; *Comments of Duke Energy North America on the Proposed Decision of ALJ Brown Regarding Electric Utility Long Term Resource Plans*, December 6, 2004 in R.04-04-003 arguing for including authority for interim procurement contracts with existing capacity; C*omments of Duke Energy North America In Response to Commissioner's Ruling Regarding Interim Resource Adequacy Obligation*, February 18, 2005 in R.04-04-003; *Supplemental Comments of Duke Energy North America Concerning Latest Round of Workshops on Resource Adequacy Issues*, May 10, 2005 in R.04-04-003; *Comments of Duke Energy North America Regarding Draft Energy Action Plan II*, July 1, 2005 letter to CEC President Peevey and CEC Chairman Desmond; *Reply Comments of Duke Energy North America in CEC Docket 04-IEP-1D, California and Western Electricity Supply Outlook Report*, August 5, 2005.

With the institution of the RAR at the CPUC, older existing resources will retain value for reserves purposes. Stated differently, existing resources that may not have particularly advantageous heat rates retain important market value in terms of satisfying RAR and providing capacity required during peak periods. Whether or not the units are ultimately dispatched would be an issue that reflects either the contracting LSEs' portfolio or the system needs as determined by CAISO. Duke-2

The ability of these facilities to secure economic support over the longer-run will determine their retirement date. If, for example, a formalized capacity market is developed and the capacity from these resources is not supported in that market, it is reasonable to assume that an asset owner will decide from that market's price signals whether to retire or mothball an asset. Moreover, given the utilities' various competitive solicitations that should be expected during this time period, as long as existing resources (including those already under contract) can bid to provide longer-term resource commitments, then the market mechanism will replace these assets.

DENA believes that the "interim contracting" approach it has advocated for some time will help avoid potential capacity shortages between now and the first expected wave of new infrastructure around 2009. DENA's concern, and its proposed "interim contracting" solution, centers upon the failure of today's wholesale market structure to support existing capacity that does not have a bilateral contract with a load serving entity, and the potential risk to system reliability that could arise should these facilities retire before replacement resources are online. If, as is expected, the CPUC's RAR policy includes the local reliability area capacity requirement by 2007 *and* a formalized capacity market is developed quickly, owners of existing older generation will have market opportunities to invest in newer infrastructure that will provide better fuel efficiency and environmental benefits. Duke-3

The CEC shares DENA's concern about a potential capacity gap, and believes that the RAR policies and a formalized capacity market, when fully implemented, will provide a strong market-based mechanism to provide new capacity when and where needed. In the meantime, existing capacity should remain available through 3-5 year "interim" contracts to provide time for the implementation of those market mechanisms. Duke-4

Accordingly, DENA requests that the CEC revise its recommendation to the CPUC and focus on the completion of RAR and implementation of a formalized capacity market, rather than simply long-term contracting by the utilities, but that "interim" contracting of 3-5 years should be taken as a "bridge" to maintain existing capacity during the full implementation of RAR. This suggested revision to the Transmittal Report will better reflect the efforts already underway at the CPUC and elsewhere, and will acknowledge that there are other market-based means of encouraging infrastructure improvement. Duke-5

Respectfully submitted,

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BEFORE THE CALIFORNIA ENERGY COMMISSION
OF THE STATE OF CALIFORNIA

In the Matter of: Preparation of the 2005 Integrated Energy Policy Report	Docket No. 04-IEP-1K

COMMENTS OF THE COGENERATION ASSOCIATION OF CALIFORNIA AND THE ENERGY PRODUCERS AND USERS COALITION ON THE 2005 COMMITTEE DRAFT TRANSMITTAL REPORT

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November 8, 2005

BEFORE THE CALIFORNIA ENERGY COMMISSION
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In the Matter of: Preparation of the 2005 Integrated Energy Policy Report	Docket No. 04-IEP-1K

COMMENTS OF THE COGENERATION ASSOCIATION OF CALIFORNIA AND THE ENERGY PRODUCERS AND USERS COALITION ON THE 2005 COMMITTEE DRAFT TRANSMITTAL REPORT

The Cogeneration Association of California[1] (CAC) and the Energy Producers and Users Coalition[2] (EPUC) submit the following comments to the California Energy Commission (Energy Commission) on the 2005 Draft Transmittal Report (Report). The comments are submitted pursuant to the Energy Commission's October 25, 2005 Notice of Committee Hearing and Availability of the 2005 Committee Draft Transmittal Report.

CAC/EPUC supports the policy recommendations for CHP resources contained in the Report at pages 14-15. As stated in CAC/EPUC's October 14, 2005 comments on the draft IEPR, the recommendations address real obstacles

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1 CAC represents the power generation, power marketing and cogeneration operation interests of the following entities: Coalinga Cogeneration Company, Mid-Set Cogeneration Company, Kern River Cogeneration Company, Sycamore Cogeneration Company, Sargent Canyon Cogeneration Company, Salinas River Cogeneration Company, Midway Sunset Cogeneration Company and Watson Cogeneration Company.

2 EPUC is an ad hoc group representing the electric end use and customer generation interests of the following companies: Aera Energy LLC, BP America Inc. (including Atlantic Richfield Company), Chevron U.S.A. Inc., ConocoPhillips Company, ExxonMobil Power and Gas Services Inc., Shell Oil Products US, THUMS Long Beach Company, Occidental Elk Hills, Inc., and Valero Refining Company - California.

to CHP preservation and development and will facilitate retention of the many benefits which these resources provide to the State. The Report's recommendations are appropriately based upon a comprehensive review of the issues through staff and consultant reports, the receipt of both oral and written comments from all interested parties, and full day workshops on the issues.[3]

The Report's recommendations are also consistent with the energy agencies' efforts to coordinate the IEPR and procurement proceedings. The March 14, 2005 Assigned Commissioner's Ruling (ACR) addressed how the 2005 IEPR and 2006 CPUC procurement proceedings would be coordinated.[4] Specifically, the ACR sets forth what should be included in the Energy Commission's Transmittal Report as follows:

> *As part of the 2005 IEPR process, the CEC will also prepare a "Transmittal Report" for use by the CPUC in the 2006 procurement proceeding; that document will contain the specific information identified in Commissioner Peevey's ACR issued September 16, 2004, in R.04-04-003, and in D.04-12-048.* (ACR at 6)

Attachment A to the September 16, 2004 ACR sets forth the specific information required. Attachment A notes in pertinent part that the "*CEC's 2005 Integrated Energy Policy Report ("IEPR") process will estimate need for resource additions, evaluate policies and recommend appropriate resource strategies for the state to meet forecasted load on a biennial cycle*." This process includes but is not limited to recommending "*broad, statewide resource preference policies.*"

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3 The Assessment of California CHP Market and Policy Options for Increased Penetration, April, 2005, alone is 185 pages long.

4 Assigned Commissioner's Ruling Detailing How The California Energy Commission 2005 Integrated Energy Policy Report Process Will Be Used In The California Public Utilities Commission's 2006 Procurement Proceedings And Addressing Related Procedural Details, R.04-04-003, March 14, 2005

Attachment A goes on to note that the "*CPUC's procurement process will produce IOU-specific procurement plans, require competitive generation solicitations, incorporate needed transmission upgrades and guide preferred resource acquisition to ensure resource adequacy on a biennial cycle beginning in 2006*." As part of this process the "*CEC provides ranges of likely need and resource assessment for individual IOUs* <u>*and statewide policy preferences from IEPR*</u>*.*" (emphasis added) Accordingly, the Report's recommendations for CHP are completely consistent with Commissioner Peevey's ACR.

The recommendations contained in the Report are also consistent with Governor Schwarzenegger's review of the Energy Commission's 2004 IEPR Update. In response to the recommendation in the IEPR that the forecasts, resource assessments, and policy preferences of the Energy Report would be incorporated into an explicit resource adequacy requirement for all retail electricity suppliers to guide resource procurement, the Governor replied:

> *The California Public Utilities Commission (CPUC) has already indicated in its recent rulings and decisions that the products of the Energy Commission's Energy Report will be used to guide long-term resource procurement in CPUC proceedings. Both agencies are to be commended for this effort.*[5]

More specifically, in response to the recommendation that a transparent electricity distribution system planning process that addresses the benefits of distributed generation, including cogeneration, should be created, the Governor responded:

> *I agree. An important benefit of clean distributed generation for electricity systems is that it can occur right at load centers, reducing the need for*

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[5] Review of Major Integrated Energy Policy Report Recommendations (Review) at 1 (August 23, 2005 correspondence to Honorable Don Perata).

further infrastructure additions. The CPUC should develop tariffs that encourage the installation of distributed generation and cogeneration systems.[6]

The Governor concluded his review by stating in pertinent part: "*[t]he Energy Report is, as I have modified its assessments and recommendations pursuant to Public Resources Code 25307(a-b), a sound basis for energy policy analysis and development, going forward. I expect all state agencies to use it as a common foundation for making their energy related decisions*." (Review at 14)

Most significantly, the recommendations contained in the Report are critical in light of the positions taken by the California utilities at the CPUC regarding the preservation of existing, and development of new, CHP resources. In sharp contrast to the positive recommendations contained in the Report, Southern California Edison Company (SCE) and Pacific Gas & Electric Company (PG&E) (collectively, Utilities) proposals in the long-term QF policy proceeding (R.04-04-003) would actually serve to discourage these valuable resources. Cogen-1

The Utilities offer both existing and new CHP facilities three options as an alternative to the targeted recommendations contained in the Report. The first is for CHP resources to bid into utility requests for offers (RFOs).[7] The Utilities submit this proposal despite the fact that for the most part, they seek resources which are freely dispatchable; a status which the Report recognizes CHP does not have due to CHP's thermal load requirements. (IEPR at 77) As one example of this, on November 3, 2005, Watson Cogeneration Company submitted Cogen-2

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6 Review at 6.

7 PG&E Prepared Testimony in R.04-04-003, August 31, 2005 at 4-1; SCE Prepared Opening Testimony in R.04-04-003, August 31, 2005 at 109.

comments to the Energy Commission on the IEPR describing in part their experience with a recent RFO issued by SCE. A copy of Watson's comments is attached for the Energy Commission's convenient reference. Moreover, the offer for CHP to bid into RFOs (even assuming that non-dispatchable CHP would be eligible to bid in the RFO) seems particularly hollow when the utilities continue to acquire significant resources, resources which displace the need for CHP capacity, completely outside of the RFO process.

The second option is for CHP resources to attempt to negotiate long-term contracts with the Utilities.[8] The IEPR Committee is well aware of and has appropriately noted in the IEPR that the IOUs recent history of negotiating long term contracts with CHP operators has not been a positive one. (IEPR at 76)

Cogen-3

The third option is a one year contract at market prices.[9] One year contracts simply do not incent generators to invest in upgrades or significant maintenance to existing facilities or to build new facilities. As noted in the IEPR, long-term contracts with a minimum ten year term are required in order for CHP owners to make well-informed investment decisions and provide assurances to both the Energy Commission and the Utilities of the long-term availability of these resources. (IEPR at 77-78)

Cogen-4

The primary concern of industrial processes that require steam is insuring that steam supply. This can be accomplished through either existing or new

Cogen-5

8 PG&E Prepared Testimony in R.04-04-003, August 31, 2005 at 4-1; SCE Prepared Opening Testimony in R.04-04-003, August 31, 2005 at 112.

9 PG&E Prepared Testimony in R.04-04-003, August 31, 2005 at 4-1; SCE Prepared Opening Testimony in R.04-04-003, August 31, 2005 at 113.

CHP facilities or through boilers. The CHP option requires a repository for the electric energy produced by the CHP process, often on a 24/7 basis. Options which threaten the reliable delivery of steam to the industrial process simply will not encourage either existing or new CHP operations. The Utilities proposals do not provide any assurances that industrial facilities can rely upon CHP to provide their steam requirements because none of the Utilities proposals insures a reliable repository for the CHP process electric energy. In short, the Utilities proposals serve to discourage CHP and will not achieve the Energy Commission's IEPR goals of retaining existing CHP capacity and encouraging the development of new capacity. The Utilities' hostility to CHP operators is further exemplified by testimony filed by PG&E in R.04-04-003 which attempts to incorrectly characterize state policy preferences toward CHP (presumably including the Energy Commission's IEPR) as only applying to facilities smaller than 20 MW;[10] an interpretation clearly at odds with the express intent of the IEPR to preserve and promote CHP of all sizes.

CONCLUSION

The Utilities' proposals for CHP at the CPUC emphasize how critical the Report's recommendations are for the preservation of existing CHP resources and the encouragement of new resources. CAC/EPUC fully supports the Report's recommendations and look forward to working with the Energy Commission on implementation of the recommendations in the CPUC's 2006 procurement process.

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[10] PG&E Rebuttal Testimony in R.04-04-003 at 2-11.

Dated: November 8, 2005

Respectfully submitted,

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ATTACHMENT

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November 3, 2005

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Mr. Michael Peevey
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RE: Implementing the 2005 IEPR - Creating a Cogeneration Portfolio Standard

Dear Chairman Desmond and President Peevey:

We support the California Energy Commission's efforts to establish sound energy policy for California and appreciate your recognition of the important role and benefits that cogeneration provides to our state. Implementation of your cogeneration policy recommendations, in the form of a Cogeneration Portfolio Standard, constitutes a key element of the necessary framework to maintain continued investment in cogeneration resources that are so important to California energy supply and security. Regulatory certainty in the form of long-term commitments for the delivery of power under just and reasonable conditions is vital to a cogeneration facility and its thermal host.

Cogeneration is among the most effective and efficient forms of power generation available because it generates very real and quantifiable environmental and energy savings compared to separate production of heat and electricity. The Energy Action Plan II and 2005 Integrated Energy Policy Report (IEPR or the Report) have correctly identified cogeneration as a key element of California's loading order strategy that will help meet the state's energy efficiency and renewable energy goals. Therefore, continued promotion of cogeneration in California in the form of a Cogeneration Portfolio Standard is part of a sound strategy for the efficient use of energy that is both complementary and supplementary to the strategy of increased use of renewables.

Businesses in California with legitimate thermal needs utilize heat associated with the production of electricity to make cogeneration a cost effective, low-emission generation option that provides for efficient use of limited natural gas resources and helps meet California's growing energy needs. Cogeneration is a viable end-use efficiency strategy for California businesses and an essential element of customer choice that helps keep industrial users commercially competitive while also providing the benefits of diversification that are critical to the continued reliability and security of California's power grid, transportation fuels and industrial infrastructures.

Cogeneration enhances reliability by decreasing the grid's peak load requirements and benefits the IOU's and ratepayers by relieving congestion on the transmission system, providing ancillary services and reducing electric line losses and transmission costs. From a security standpoint, cogeneration facilities were also largely responsible for keeping the lights on in California during the darkest days of the 2000-2001 energy crisis, many running months without certainty of payment in order to maintain the viability of critical state industrial infrastructure. Most recently, Hurricanes Rita and Katrina in the Gulf Coast area of the United States have provided additional lessons in the importance of cogeneration in sustaining infrastructure so critical to our economy and national security. On-site cogeneration at industrial facilities such as refineries and chemical plants were key to getting those operations up and running again while other facilities dependent upon the power grid waited weeks for restoration of transmission facilities.

Watson Cogeneration Company is an important contributor to California's energy infrastructure. The facility produces enough power to supply over 400,000 homes and, as the sole provider of process steam and power to BP's Carson refinery, is literally the engine behind the production of 20% of California's in-state production of gasoline, 30% of its diesel, and a significant portion of the jet fuel that supplies LAX. However, given the current state of the California energy market, Watson's ability to continue to fulfill this role depends on the certainty that only a long-term power sales agreement can provide; it is the certainty of a buyer for the project's power that ensures Watson will be able to cogenerate both steam and electricity dependably, efficiently, and without interruption.

Simply put, unless Watson has the certainty of a home for its base-loaded power after its current SCE contract expires in April 2008, it cannot commit to continue to provide process steam to the BP refinery. In turn, BP's need for a reliable supply of steam is too critical to allow it to wait until the last minute in the hopes that a buyer for Watson's power will suddenly emerge. Absent firm commitments on steam and power sales, at some point the refinery will have no choice but to secure an alternative source of reliable steam (including industrial boilers); this will both eliminate the inherent environmental and fuel efficiencies provided by Watson as a cogeneration facility, and jeopardize Watson's ability to continue to generate power for the LA basin.

Testimony provided to the CEC and its staff during the IEPR proceedings has clearly identified and accurately described the obstacles faced by other existing and proposed cogeneration projects. The utilities in their filings and comments to the Report have intimated that there are no major barriers to the development of cogeneration in California. However, clear and compelling evidence presented during hearings for the IEPR and elsewhere demonstrates that this is simply not the case.

SCE issued a 5-Year Request for Offers on or about July 1, 2005 in which it invited non-dispatchable qualifying facilities to submit offers. Watson's view is that SCE's expressed encouragement for **non-dispatchable** base-loaded QFs to participate in this RFO appeared to be in direct conflict with their stated preference for this RFO. The RFO Transmittal letter clearly stated that, "SCE is primarily interested in receiving offers for **dispatchable** *(emphasis added)*, low capacity cost, higher heat rate tolled units located within the Los Angeles area …" and "QF resources that are **dispatchable** *(emphasis added)* during on-peak periods or curtailable during mid-peak and/or off-peak periods...". QFs, by their basic design and purpose, are inherently **non-dispatchable**, which brings into question the genuineness of the invitation for QFs to participate in this RFO. Nevertheless, Watson submitted a timely and competitive offer in response to this RFO. Now, a full 4 months after the solicitation, Watson still faces cessation of its contract, despite its long history of dependable service to SCE. Perhaps this is why standard offer contracts for non-dispatchable cogeneration resources were necessary in the first place, to ensure that sound energy policy could be fairly implemented for the benefit of Californians.

The CEC has proposed realistic and sound solutions to the obstacles facing cogeneration as identified in the IEPR and correctly states, "current state policy must change for California to tap into this potential generation source and, equally important, retain the existing pool of CHP (cogeneration) so critical to the reliable operation of the grid." Regulatory certainty is vital to a cogeneration facility and its thermal host; therefore the state policy objectives identified in the IEPR should be implemented by the creation of a Cogeneration Portfolio Standard.

By instituting a ***Cogeneration Portfolio Standard***, the CEC and CPUC can establish the necessary framework to maintain continued investment in cogeneration resources that are so important to California energy supply and security. Elements of an effective plan should include

(1) A minimum goal for procurement from cogeneration resources in the IOUs integrated resource investment plans,

(2) A requirement that, absent the availability of a viable long-term standard offer contract, each of the state IOUs enter into negotiations for bilateral extensions of existing cogeneration QF contracts within a reasonable timeframe,

(3) Meaningful recognition (i.e. through dispatch restrictions and CAISO tariffs) that cogeneration resources run in order to meet the needs of thermal hosts. For operational reasons, most cogeneration facilities must run continuously on an around-the-clock basis.

(4) Incentives for cogeneration projects that reduce congestion by providing transmission and distribution benefits in load centers (e.g. through a local reliability capacity payment)

Watson Cogeneration Company urges the CEC, CPUC, and CAISO to work together and take the necessary actions to implement a sound cogeneration policy that ensures efficient cogeneration resources can continue to meet California's growing energy needs by removing the regulatory barriers and uncertainty that are discouraging cogeneration retention and new development.

Respectfully,
Watson Cogeneration Company

Thomas A. Lu
Executive Director

cc: Mike Chrisman, Secretary for Resources, State of California
Dan Skopec, Deputy Cabinet Secretary, Office of the Governor
Dennis Albiani, Deputy Legislative Secretary, Office of the Governor
Geoffrey Brown, Commissioner, California Public Utility Commission
Susan Kennedy, Commissioner, California Public Utility Commission
Dian Grueneich, Commissioner, California Public Utility Commission

John Bohn, Commissioner, California Public Utility Commission
Jackalyne Pfannenstiel, Vice-Chair, California Energy Commission
Arthur Rosenfeld, Commissioner, California Energy Commission
James Boyd, Commissioner, California Energy Commission
John Geesman, Commissioner, California Energy Commission

BEFORE THE
CALIFORNIA ENERGY RESOURCES CONSERVATION AND
DEVELOPMENT COMMISSION

In the Matter of: Preparation of the *2005 Integrated Energy Policy Report*	Docket No. 04-IEP-1K

COMMENTS OF
CONSTELLATION ENERGY COMMODITIES GROUP, INC. AND
CONSTELLATION NEWNERGY, INC. ON
CALIFORNIA ENERGY COMMISSION DRAFT TRANSMITTAL REPORT

November 8, 2005

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BEFORE THE
CALIFORNIA ENERGY RESOURCES CONSERVATION AND DEVELOPMENT COMMISSION

In the Matter of: Preparation of the *2005 Integrated Energy Policy Report*	Docket No. 04-IEP-1K

COMMENTS OF CONSTELLATION ENERGY COMMODITIES GROUP, INC. AND CONSTELLATION NEWNERGY, INC.ON CALIFORNIA ENERGY COMMISSION DRAFT TRANSMITTAL REPORT

I. Introduction and Summary

On October 25, 2005, the California Energy Commission ("CEC") issued the *Committee Draft Transmittal of 2005 Energy Report Range of Need and Policy Recommendations* ("Transmittal Report") to the California Public Utilities Commission ("CPUC"). Pursuant to *Notice of Committee Hearing and Availability of the 2005 Committee Draft Transmittal Report*, the CEC invited comments on the Transmittal Report and Constellation Energy Commodities Group, Inc. and Constellation NewEnergy, Inc. (collectively "Constellation") appreciates this opportunity to do so.

In general, Constellation finds the Transmittal Report to provide a wealth of information and documentation that will serve the CPUC's upcoming 2006 Long Term Procurement Process ("2006 LTPP") well. In addition to providing the specific information on the range of need that each of the IOUs must address in the 2006 LTPP, the CEC's expressed commitment to ensuring that the 2006 LTPP is an open and transparent process is a very welcome and necessary element of California's continued progress to workable competitive markets. However, there is one area of concern with the Transmittal Report that Constellation will address in these comments. The concern has to do with the CEC's specific advocacy for the IOUs to enter into new long term contracts despite the fact that other approaches and mechanisms to support infrastructure development are currently under consideration at the CPUC and CAISO.[1] While it is important to ensure that the deployment of new generation resources follows the loading order and encourages new, environmentally beneficial conventional generation, Constellation believes the particular advocacy in the Transmittal Report is premature. Constellation's specific concerns and recommendations in regard to these issues are as follows:

A. Execution by the IOUs of long term power purchase contracts that substitute for rate based generation (or IOU self-build, should that be considered) will perpetuate and prolong the existing hybrid market structure[2] in California, and undermine the effectiveness of competitive market structures, the development of which are already well underway in several CPUC and CAISO proceedings.[3]

Constellation -1

B. To the extent that such long term IOU contracts are deemed necessary to address urgent reliability requirements that cannot be met within the competitive wholesale market framework being implemented by the CPUC and CAISO, their scope and duration must be carefully circumscribed to ensure that they do not compromise on the development of the nascent competitive wholesale markets.

C. To ensure that there will not be continued reliance on such contracts to ensure reliability – i.e., in order to ensure that competitive market structures will be successful, steps must be taken to reform IOU procurement practices that lead to such contracts. Specifically, IOU procurement practices should be designed to move increasingly toward full requirements competitive procurement practices in

Constellation -2

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[1] See *Transmittal Report* at page 9: "A careful review of the record developed during this proceeding demonstrates that policies encouraging long-term contracts would increase deployment of both new renewable and new conventional generations. Provide a hedge against increasing natural gas prices, and increase environmental and reliability benefits associated with diminished reliance on the state's aging fleet of existing plants." See also page 11: "In sum, the most important action the CPUC can take in the 2006 procurement proceeding is to compel the IOUs to enter into long-term contracts, particularly contracts with renewable facilities. Long-term contracts will encourage development of new conventional and renewable resources, both reducing reliance on aging, less efficient plants and providing important gas-price hedging advantages. The result will be a more reliable market, with environmental and economic benefits accruing to all utility customers."

[2] As used herein, the "hybrid market structure" refers to the continued existence of vertically integrated IOU structures in which a significant percentage of available generating capacity is still owned and operated pursuant to cost-of-service/rate-based regulation. In addition, an additional significant amount of generating capacity is committed to IOU operation via long term Power Purchase Agreement ("PPAs"), the cost recovery of which is assured via rate-based regulation.

[3] *I.e.,* CPUC Docket R.04-04-003 and upcoming LTPP proceeding per D.05-10-031; FERC Docket EL05-146 re MOO reform and RCST capacity backstop contract; and CAISO MRTU effort, with upcoming tariff filing.

which the IOUs procure from the wholesale market the products and services they need to meet their load obligations.

D. Constellation respectfully suggests that the Transmittal Report simply highlight the need to have mechanisms in place to support infrastructure development, without particularly advocating for any single structure or form, particularly since the CPUC and CAISO are in the process of undertaking additional proceedings to complete the Resource Adequacy Requirement mechanism and develop a formalized capacity market structure for California. Constellation -3

E. Constellation respectfully suggests that the Transmittal Report be revised to recognize the impact on retail market competition that will occur due to a failure to anticipate departing loads and the resulting potential over-procurement of resources by utilities. Constellation -4

Constellation raises these concerns only to highlight its views on the impact of IOU procurement practices on the development of competitive wholesale markets (and, in turn, the development of competitive retail markets). The CEC has carefully developed the needs assessment contained in the Transmittal Report, which is a critical element to the upcoming CPUC proceedings. In the upcoming CPUC 2006 LTPP case, Constellation plans to re-introduce the concept of "full requirements competitive procurement" that it first presented in testimony in the last CPUC LTPP procurement docket.[4]

II. Constellation Comments

A. Allowing New Resource Requirements To Be Met Through New Long Term IOU Contracts Of The Traditional PPA Type (Or IOU Self-Build) Will Delay, If Not Preclude, The Development Of Competitive Wholesale Markets.

The stability of wholesale market structures and confidence that regulatory policy changes will not undermine the value of investments is key to ensuring new investments in developing competitive generation assets in California. Such stability will not be achieved, nor will investor confidence develop, if new infrastructure is procured through mechanisms that Constellation -5

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[4] *See*, August 6, 2004 Direct Testimony of Constellation Power Source in CPUC Docket R.04-04-003; *See also*, CPUC D.04-12-048, pages 175-176, wherein the CPUC stated that the slice of load concept was to be considered as one of the "second generation" topics.

perpetuate California's currently existing hybrid market structure. Under the existing hybrid market structure, assets (both physical and contractual) that have rate-based cost recovery protection do not compete on a level playing field with assets that do not have guaranteed rate recovery protection. In short, the current hybrid market structure skews market price signals upon which the merchant assets rely for revenues and upon which they rely to incent buyers to execute long term contracts. It is simply not possible to build investor confidence when resource requirements are only successfully developed outside the competitive market structures. Accordingly, Constellation does not believe that the Transmittal Report should advocate new long-term contracts that substitute for rate based generation as a permanent market feature to promote new asset development.

B. Urgently Needed Near Term Resources, Once Identified, Must Be Procured With Special Attention Given To How Those Investments Can Be Managed So As Not To Undermine The Long Term Development Of Competitive Wholesale Markets.

There is no arguing, however, that investor confidence in wholesale market structures will take some time to develop. In contrast, there is concern that California needs new generating capacity in the immediate term. Moreover, today's conventional wisdom holds that a long term contract between a developer and an IOU is the only way to secure financing for new generation resources. Conflicts between these two goals - securing immediate investment, while not undermining confidence in the developing competitive wholesale markets – can and must be managed.

Constellation-6

In order to manage these somewhat conflicting goals, the parameters of the specific resources that are urgently needed must be clearly and narrowly defined as to the magnitude and locational requirements, and the contracts that the IOUs enter into must be for as short a duration as possible. Consideration should also be given as to whether any increase in the IOU share of asset ownership (both physical or contractual) necessary to secure the new generation asset development in the near term should be offset by IOU divestiture of a similar amount of IOU owned generation through a competitive offering, so that there is no net change in the current market balance between existing IOU controlled assets (physical and contractual assets) and non-utility assets.

Constellation believes that these issues will be best addressed in the upcoming CPUC LTPP proceeding. Accordingly, the Transmittal Report should acknowledge that the CPUC will be reviewing various "second generation" issues with the intent of creating long-term market structures that will support and encourage development of new generation infrastructure through workable wholesale competition.

C. Shifting IOU Procurement Practices Away From Procurement Of Power Supply Infrastructure To Procurement Of Energy Products And Services Would Eliminate Many Of The Issues That Currently Impede Competitive Investment, Would Shield Ratepayers From Market Risk, And Would Facilitate The Development Of Competitive Retail Markets.

The focus of the LTPP has been to analyze infrastructure requirements necessary for the IOUs to serve their load. Constellation believes that the efforts underway at the CPUC and CAISO will ensure that price signals in the wholesale energy, capacity, and ancillary services markets will lead to infrastructure investment when and where it is needed. Entities that serve load at the retail level should seek the products and services they need to meet their load obligations from the wholesale markets. This is already the case for Electricity Service Providers ("ESPs") and Community Choice Aggregators ("CCAs"). But it is not the case for the IOUs in the hybrid market. Current procurement regulations imposed on the IOUs require them to submit plans to secure assets (both physical and contractual) to serve anticipated load. In

Constellation-7

meeting those requirements, the IOUs effectively transfer market risks associated with those procurement decisions and investments onto their ratepayers.

Constellation has suggested before the CPUC that the IOUs should offer to wholesale suppliers the opportunity to provide products and services to meet their load obligations, as those load obligations change due to weather, customer switching, load growth, and other factors that influence hour to hour and year to year demand for electricity - rather than being subject to procurement practice regulations that require them to secure specific power supply resources that do not match their load serving obligations. Such procurement practices would move the risks associated with the IOU's current procurement approach away from the IOUs (and their ratepayers) and back to the wholesale suppliers, entities that are in the best position to manage those risks. Such full requirements competitive procurement practices are widespread throughout the Northeast and Mid-Atlantic, and can serve as useful models here in California.

Not only would the full requirement competitive procurement processes serve to shift market risk away from ratepayers, as noted above, it would also help to resolve several of the issues raised in the Transmittal Report. For instance, full requirements competitive procurement practices by the utilities would shift customer attrition risk away from the utilities and thus eliminate one of the key reasons that the IOUs have been reluctant to support customer choice. Furthermore, where these competitive procurement processes have been implemented, the bid evaluation processes are based on one parameter only – price, eliminating many, if not all, the evaluation transparency issues raised in the Transmittal Report. Finally, implementation of these procurement practices by the IOUs would provide a strong measure of support for the development of wholesale markets, rather than conflicting with their development, by assuring wholesale suppliers that there will be opportunities to serve load at a wholesale level through continuous and transparent solicitations.

D. Departing Load Assumptions and the Resultant Resource Procurements Will Negatively Impact Retail Market Development

Constellation does not believe it is appropriate for the Transmittal Report to advance concepts which would undermine retail customer choice. Thus, Constellation takes issue with the Transmittal Report to the extent that it concludes that resource plans should be based upon load forecasts that do not include any departing load, especially given that the study spans through 2016.[5] Even if the DA market suspension is not lifted until the last DWR contract expires in the 2012-2013 timeframe, *some* level of new DA load during 2012-2013 should be assumed. For the CEC to assume no new departing load in the Transmittal Report will likely lead to the IOUs over procuring long-term resources over that timeframe.

Constellation -8

Moreover, it is overly simplistic to say that the result of over-procurement is merely economic[6] as the costs associated with the over-procurement will continue to be layered upon future departing customers, presumably as nonbypassable charges, and will have a negative impact on the DA market. To that end, care needs to be taken about how policies for encouraging long-term contracting, or term contracting for urgently needed resources, will affect the retail market. Ultimately, retail markets were envisioned to operate independently of utility cost for bundled customer procurement. However, DWR Contracts have, and will continue to have, an affect on customer choices between retail and utility bundled services. Other contracts may do the same. Thus, it is short-sighted to increase the reliance on utility term contracting without also acknowledging and mitigating the very real cost and retail market structure issues that arise as a result of those policies. Failure to explicitly acknowledge cost treatment now

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[5] *See* Transmittal Report, § 5.2 page 43 in published version (page 40 in on-line version).
[6] *See* Transmittal Report, page 42, citing Hal LaFlash (page 39 in the on-line version).

effectively means that the departing customers will likely carry the burden of a cost obligation for those utility decisions well into the future, undermining any benefits they would otherwise receive from those market structures. Failure to take steps to avoid a new generation of stranded costs will essentially re-create the pre-AB 1890 environment.

It is also disingenuous to say that utility planning uncertainty is resolved solely through the structure of the coming and going rules at the Commission.[7] The CPUC has already provided rules for customer re-entry, six months prior notification, with a three-year stay requirement. Those rules allow utilities to adjust their procurement plans accordingly. To direct otherwise would result in a presumption that the only good utility portfolio is a long-term utility portfolio. By all reasoning and from past experience, relying too strongly either on spot markets or long-term contracts creates a risky profile. If we continue to have utility contracting on behalf of customers and do not adopt the "outsourcing" proposal that Constellation advocates, then utilities should maintain a balanced portfolio of resources which will include some short-term, including spot purchases, some medium term and some long-term contracts. Therefore, with such notice, a utility should, at a minimum, be expected to accommodate both customer migrations and customer returns through a balanced portfolio approach and should be held accountable for such decisions. Constellation does not believe that there is any need to modify the coming and going rules to make them more restrictive for direct access customers.

Rather, customer migration and other attrition risks can best be accommodated through the outsourcing functions espoused by Constellation as in that instance, load forecasting functions are the responsibility of the supplier and the retail market is free to develop absent the additional costs associated with unwise procurement practices.

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[7] *See* Transmittal Report, page 43 in published version (page 40 in on-line version).

III. Conclusion

For the reasons described in detail above, Constellation respectfully asks the CEC to revise the Transmittal Report with respect to its advocacy for long-term IOU contracting.

November 8, 2005

Respectfully submitted,

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Appendix D

Responses to the Comments on the *Draft Transmittal Report*

Appendix D: Responses to the Comments on the *Draft Transmittal Report*

Comments on the *Draft Transmittal Report* were filed by PG&E, SCE, Sempra Energy Utilities/ SDG&E, NRDC, Duke Energy North America, CAC/EPUC, and Constellation. The Energy Commission's responses to these comments are provided below. The comment letters themselves are included as Appendix C, and have been coded to correspond to the comment numbers listed in the responses here.

Comment number	Response
Pacific Gas & Electric	
PG&E-1	The *Transmittal Report* is intended to identify the range of need that the IOUs will need to address in the upcoming 2006 procurement proceeding. As such, the emphasis in the tables and graphs presented in the report is on the degree to which each of the IOUs has direct or contractual control of resources needed to meet the load from their bundled service customers, rather than on the physical supply/demand balance for regions within the state. The final report has been edited to make that clear in the text, tables, and graphs.
PG&E-2	President Peevey's September 2004 assigned commissioner ruling, adopted by the CPUC in D.04-12-048, states in Appendix A: "CEC's 2005 Integrated Energy Policy Report ("IEPR") process will estimate need for resource additions, evaluate policies and recommend appropriate resource strategies for the state to meet forecasted load on a biennial basis." Based on this direction, the Energy Commission has included in the *Transmittal Report* those policy recommendations most relevant to the upcoming procurement proceeding and related CPUC proceedings.

Comment number	Response
PG&E-3	The assessment of resource needs presented in the *Transmittal Report* is intended identify the contractual needs of the IOUs, while the allegedly contradictory analyses mentioned in this comment were intended to provide an understanding of the physical supply/demand balance on a regional basis. It is also worth noting that those earlier staff assessments of physical needs were predicated in part on the continued operation of most of the aging power plants that the Energy Commission is recommending being retired by 2012.
PG&E-4	The tables and graphs in the *Transmittal Report* have been revised to make more clear that the resource needs being described are the contractual needs of the IOUs. PG&E is incorrect in characterizing this assessment as representing the contractual needs for the LSEs in the IOU planning area. The data presented in the energy and capacity tables is, to the maximum extent possible, IOU specific. One exception to this is the data on the capacity of renewable contracts and other bilateral contracts, which the IOUs have sued the Energy Commission to keep confidential at the IOU-specific level. The *Draft Transmittal Report* used planning area data from the *Aggregated Tables Report* for these two categories, while the final *Transmittal Report* has subtracted the publicly owned utility share of those categories, leaving distribution service territory level data. The other exception is the uncommitted energy efficiency and uncommitted demand response resources included in the preferred resource category. The Energy Commission has based this data on the adopted CPUC goals in these areas, which are set at the distribution service territory level.
PG&E-5	As noted in the *Draft Transmittal Report*, the Energy Commission recognizes the need to update the tables next year to reflect resource additions. Additional notes have been added to the Appendix B tables to ensure that a reader focusing only on the tables understands the resources shown are based on filings prepared in early 2005.
PG&E-6	As discussed above, the tables are not intended to reflect regional supply and demand, but are IOU-specific to the extent possible and contractually oriented.

Comment number	Response
PG&E-7	The *Energy Report* recommends action to ensure their retirement or replacement by 2012, and the *Transmittal Report* has been drafted with the assumption that this policy recommendation will be implemented.
PG&E-8	The *Energy Report* recommends that utility planning and procurement cease reliance on these plants by 2012, and the *Transmittal Report* has been revised to clarify that this recommendation is not intended to force the IOUs to procure capacity beyond a 15 to 17 percent reserve margin. The Energy Report explains why the continued reliance on these plants is not in the economic interest of utility customers and it would be imprudent for the IOUs to contract with the aging units beyond 2012.
PG&E-9	The Energy Commission does not believe it desirable to complicate the 2006 procurement proceeding for the relatively marginal improvement to the demand forecast for 2009 through 2016 that would be achieved through calibrating to 2005 actual demand, when the entire forecast will be updated in 2007 in the next cycle. As noted in the *Draft Transmittal Report*, the Energy Commission does recognize that the nearer term portion of the demand forecast is likely to require updating, which should be done in a manner consistent with the CPUC resource adequacy proceeding.
PG&E-10	The resource plans provided by the IOUs treated uncommitted energy efficiency programs inconsistently. In the *Transmittal Report*, the Energy Commission is following the general accounting convention that was developed for presenting the summer supply/demand balances to the meetings of the Energy Action Plan agencies. PG&E is correct that the tables in the *Draft Transmittal Report* failed to account for the effect of future demand response and energy efficiency programs on the reserve margin. The final tables have added 15 percent to the capacity of these programs to reflect the reduction in needed reserves when the programs are implemented and reduce future demand.

Comment number	Response
PG&E-11	Section 3.1.2 of the *Transmittal Report* focuses on combined heat and power (CHP) resources, and the recommendations included at the end of this section are those relating to CHP from the executive summary of the *Energy Report*. While the section does begin by noting the preference for renewable and distributed generation resources stated in the *Energy Action Plan*, it does distinguish CHP from other DG resources in a footnote at the beginning of the section.
PG&E-12	The Energy Commission recognizes the importance of cost/benefit methodologies in evaluating CHP resources. For example, the *Energy Report* states, "These mechanisms [to ensure that existing CHP systems retain their baseload positions in IOU portfolios] should rely upon cost/benefit methodologies being developed in CPUC Proceeding R.04-03-107 to make sure that California builds projects that provide the greatest societal benefit." (*Energy Report*, p. 78)
PG&E-13	As noted in the *Draft Transmittal Report*, that report reflected the policies in the *Draft Energy Report* and did not reflect any comments on the *Draft Energy Report.* Those comments were reviewed and considered in preparation of the final *Energy Report.* The final *Transmittal Report* reflects the final *Energy Report* policy recommendations.
PG&E-14	The *Transmittal Report* reflects the *Energy Report's* recommendations to the CPUC on various CHP issues. The Energy Commission believes that these recommendations can be implemented by the CPUC.
PG&E-15	The Energy Commission considered PG&E's comments on the *Draft Energy Report*, including those relating to CHP. The *Transmittal Report* reflects the final *Energy Report* recommendations to the CPUC. The Energy Commission is confident that PG&E will continue to present its views of these issues in the relevant CPUC proceedings.
PG&E-16	The potential CHP resources are not, in general, owned by merchant generators and are not dispatchable resources. As such, the Energy Commission does not believe that it makes sense to force the industrial owners of these facilities to compete in RFOs designed for merchant-owned, dispatchable resources.

Comment number	Response
PG&E-17	Tables 3 and 4, which explain the sources and relationships of the entries in the Appendix B tables, have been repeated in the appendix to assist readers focusing primarily on the tables. The discussion of how the Energy Commission expects the numbers to be used and updated during the 2006 procurement proceeding has also been repeated in Appendix B for the same reason.
PG&E-18	The table has been revised, as have the graphs that were initially prepared for the November 4, 2005, hearing. The tables and graphs now show the aging plant replacement line at the bottom.
PG&E-19	As discussed in response to comment 4, these are not planning area tables. They are IOU-specific to the extent possible.
Southern California Edison	
SCE-1	President Peevey's September 2004 assigned commissioner ruling, adopted by the CPUC in D.04-12-048, states in Appendix A: "CEC's 2005 Integrated Energy Policy Report ("IEPR") process will estimate need for resource additions, evaluate policies and recommend appropriate resource strategies for the state to meet forecasted load on a biennial basis." Based on this direction, the Energy Commission has included in the *Transmittal Report* those policy recommendations most relevant to the upcoming procurement proceeding and related CPUC proceedings.

Comment number	Response
SCE-2	An attack on the fundamental modeling practices of staff should have been aired when the S*taff Draft Forecast*, the *Methods Report*, and the *Comparison Report* were published in June. The Committee offered (for the first of three times) the opportunity for cross-examination on the use of models at the June 30, 2005, hearing on these reports. SCE did not request cross examination of staff in its modeling techniques. SCE did not submit written comments on the S*taff Draft Forecast*, the 200-page *Methods Report*, or the *Comparison Report.* SCE's power point presentation at the June 30 hearing did not question staff's methodology beyond noting that staff and SCE have fundamentally different modeling approaches, and that staff's approach has significantly more assumptions built into it. (6/30/05 TR at pp. 76-77) The SCE presentation noted that the differences between the forecasts were "small at about 3% in peak demand in 2016." (June 30 hearing, SCE presentation, slide 2) As for the specific technical concerns noted in these comments, SCE and other parties were offered the opportunity to cross examine staff on their use of models in the preparation of the demand forecast at the June 30, 2005, hearing noted above; at the October 7, 2005 hearing on the *Revised Staff Forecast* and the *Draft Energy Report;* and at the November 4, 2005, hearing on the *Draft Transmittal Report*. The Energy Commission, based on the extensive record it has developed over the last year, is adopting the revised staff forecast. The Energy Commission notes that in September 2004, and March 2005, President Peevey advised all parties in R.04-04-003 that the CPUC was looking to the 2005 Energy Report proceeding for assessment of load forecasts and resource plans. "The CPUC will not provide an additional opportunity for parties to re-examine IEPR determinations during its 2006 procurement proceedings. Parties will not be permitted to present evidence, testimony, or argument that they presented, or could have presented, in the CEC's IEPR proceeding." (March 2005 ACR, p. 5) In case SCE claims that its concerns about staff's demand forecast methodology falls into the exceptions noted in the ACR for "(i) material new information that could not reasonably have been considered by the CEC during the 2005 IEPR, or (ii) materially changed circumstances," (March 2005 ACR, pp. 5-6) the Energy Commission notes that, according to their comments, SCE has had the basic concerns expressed in this comment since the Common Forecast Methodology process was conducted between the early 1980s and 1996.

Comment number	Response
SCE-3	The resource plans provided by the IOUs treated uncommitted energy efficiency programs inconsistently. In the *Transmittal Report*, the Energy Commission is following the general accounting convention that was developed for presenting the summer supply/demand balances to the meetings of the Energy Action Plan agencies.
SCE-4	Comment noted.
SCE-5	The tables in the *Draft Transmittal Report* failed to account for the effect of future demand response and energy efficiency programs on the reserve margin. The final tables have added 15 percent to the capacity of these programs to reflect the reduction in needed reserves when the programs are implemented and reduce future demand.
SCE-6	The data presented in the energy and capacity tables is, to the maximum extent possible, IOU specific. One exception to this is the data on the capacity of renewable contracts and other bilateral contracts, which the IOUs have sued the Energy Commission to keep confidential at the IOU-specific level. The *Draft Transmittal Report* used planning area data from the *Aggregated Tables Report* for these two categories, while the final *Transmittal Report* has subtracted the publicly owned utility share of those categories, leaving distribution service territory level data. The other exception is the uncommitted energy efficiency and uncommitted demand response resources included in the preferred resource category. The Energy Commission has based this data on the adopted CPUC goals in these areas, which are set at the distribution service territory level.
SCE-7	The text and tables have been revised to clarify the intent of including the aging plant replacement energy and capacity data.
SCE-8	While some recent progress has been made in signing long-term contracts for renewables, the Energy Commission remains concerned at the slow pace overall. The Energy Commission also notes the 'rebuttable presumption' in favor of renewable resources adopted by the CPUC in D.04-12-048, and hopes to see many more long-term renewables contracts resulting from IOU procurement activities as a result.

Comment number	Response
SCE-9	President Peevey's September 2004 assigned commissioner ruling, adopted by the CPUC in D.04-12-048, states in Appendix A: "CEC's 2005 Integrated Energy Policy Report ("IEPR") process will estimate need for resource additions, evaluate policies and recommend appropriate resource strategies for the state to meet forecasted load on a biennial basis." Based on this direction, the Energy Commission has included in the *Transmittal Report* those policy recommendations most relevant to the upcoming procurement proceeding and related CPUC proceedings.
SCE-10	The transmission recommendations included in the report focused on near-term projects. The Energy Commission agrees that longer term transmission needs must be addressed to fully tap the state's renewable resource potential.
Sempra Energy Utilities/ San Diego Gas & Electric	
Sempra-1	The Energy Commission believes that goals established in state law or policy need to be taken seriously. While some flexibility may at times be necessary, the state's established goals should not be treated as options.
Sempra-2	The Energy Commission understands that the goals as established in the CPUC energy efficiency proceeding did not have a clearly documented baseline demand forecast against which to measure, which may lead to problems when applying them to a specific demand forecast. Resolving this issue is beyond the scope of this report, and is more appropriately addressed in the CPUC energy efficiency proceeding. To the extent that the CPUC goals are adjusted in the future, these adjustments can and should be reflected in the tables. The Energy Commission also notes the recent enactment of Senate Bill 1037 (Chapter 366, Statutes of 2005, Kehoe), which adds to the Public Utilities Code section 454.5 (b)(9)(C), which directs each IOU to "first meet its unmet resource needs through all available energy efficiency and demand reduction resources that are cost effective, reliable, and feasible."

Comment number	Response
Sempra-3	The Energy Commission recognizes that the variation across the three cases in the revised staff forecast is relatively narrow, and may not capture the full range of uncertainty in SDG&E demand extending out to 2016. However, no parties raised this issue at any point earlier during the 2005 Energy Report process, including when the revised staff forecast was presented at the October 7, 2005, hearing, and no parties provided written comments on the revised staff forecast at the time. The Energy Commission, based on the record in this proceeding, is adopting the revised staff forecast, and notes that these long-term forecasts will be revisited in each biennial cycle.
Sempra-4	The report has been revised to clarify that the aging plant replacement increment is not being added to the IOU's need. It is featured in the report to reflect the importance of the IOU long term planning process ensuring adequate supplies from other sources to allow an orderly replacement or retirement by 2012.
Sempra-5	The *Energy Report* recommends that utility planning and procurement cease reliance on these plants by 2012, and the *Transmittal Report* has been revised to clarify that this recommendation is not intended to force the IOUs to procure capacity beyond a 15 to 17 percent reserve margin. The Energy Report explains why continued reliance on these plants is not in the economic interest of the utility customers and it would be imprudent for the IOUs to contract with the aging units beyond 2012.
Sempra-6	This mistake has been corrected in the final report.
Sempra-7	SDG&E is correct that the tables in the *Draft Transmittal Report* failed to account for the effect of future demand response and energy efficiency programs on the reserve margin. The final tables have added 15 percent to the capacity of these programs to reflect the reduction in needed reserves when the programs are implemented and reduce future demand.

Comment number	Response
Sempra-8	SDG&E and Energy Commission staff reviewed the information provided by SDG&E in their initial resource plan filings, and agree that 36 MW accurately reflects the status of SDG&E demand response programs at the time the resource plans were filed. The tables in Appendix B have been updated accordingly. As discussed in the report, the Energy Commission expects that this and other information on the tables will be updated as part of the 2006 procurement proceeding to reflect additional programs and resources approved since the resource plans were prepared in early 2005.
Sempra-9	The Energy Commission agrees that many of these items will need to be updated during the 2006 procurement proceeding. The one exception is updating the long-term demand forecast to reflect 2005 actual data. The Energy Commission does not believe it desirable to complicate the 2006 procurement proceeding for relatively marginal improvement to the demand forecast for 2009 through 2016 that would be achieved through calibrating to 2005 actual demand, when the entire forecast will be updated in 2007 in the next cycle. As noted in the *Draft Transmittal Report*, the Energy Commission does recognize that the nearer term portion of the demand forecast is likely to require updating, which should be done in a manner consistent with the CPUC resource adequacy proceeding.
Sempra-10	Section 3.1.2 of the *Transmittal Report* focuses on combined heat and power (CHP) resources, and the recommendations included at the end of this section are those relating to CHP from the executive summary of the *Energy Report*. While the section does begin by noting the preference for renewable and distributed generation resources stated in the *Energy Action Plan*, it does distinguish CHP from other DG resources in a footnote at the beginning of the section.
Sempra-11	While some recent progress has been made in signing long-term contracts for renewables, the Energy Commission remains concerned at the slow pace overall. The Energy Commission also notes the 'rebuttable presumption' in favor of renewable resources adopted by the CPUC in D.04-12-048, and hopes to see many more long-term renewables contracts resulting from IOU procurement activities as a result.

Comment number	Response
Natural Resources Defense Council	
NRDC-1	Comment noted.
NRDC-2	The *Energy Report* calls for "the CPUC, in collaboration with the Energy Commission, should pursue the additional development of portfolio approaches and risk assessment to create a more transparent and standardized method for determining what constitutes least-cost, best-fit. This would allow policy makers to better ensure that IOU resource selections reflect the state's interests in addressing future electricity risk and uncertainty." (*Energy Report*, p. 63)
NRDC-3	Agreed; tables show contractual needs for IOUs.
NRDC-4	The Energy Commission has tried to further clarify, but is leaving uncommitted EE the on resource side even during the period with PGC funds but no funded programs; without specific programs, it is not possible to fold the projected savings into the demand forecast.
NRDC-5	The energy efficiency goals established by the CPUC are based on distribution service area loads. The uncommitted energy efficiency numbers included in the preferred resource categories of the Appendix B tables are based on the data provided by the IOUs in their resource plans on the levels of efficiency energy and capacity savings needed to met those goals. Because the funding for the 2006 through 2008 programs had not yet been approved when the IOUs prepared their resource plans for this proceeding, the programs for those years were reflected in the uncommitted category. Because that program funding has since been approved, the revised staff demand forecast included the effects of those programs. Therefore, the savings through 2008 have been removed from what was reported by the IOUs as 'uncommitted.'
NRDC-6	Comment noted.

Comment number	**Response**
Duke Energy North America	
	The Energy Commission appreciates Duke Energy North America's thoughtful comments. While these comments are to some degree on issues that were beyond the scope of the Transmittal Report itself, they deserve careful consideration by both the Energy Commission and the CPUC in the various proceedings considering the issues raised here.
Duke-1	The Energy Commission agrees that interim contracts are an important bridge from the current situation to a stable long term electricity supply. In the *2004 Energy Report Update*, the Energy Commission recommended that the CPUC "allow the utilities to enter into limited numbers of one- to five-year power purchase contracts as long as these commitments act as a bridge rather than a substitute for long-term procurement of additional new resources." (*2004 Energy Report Update*, p. 16)
Duke-2	The *Energy Report* recommends that the state's utilities undertake long term planning and procurement that will allow for the orderly retirement of the aging power plants by 2012.
Duke-3	The Energy Commission believes that an appropriate focus on long-term procurement in the 2006 procurement proceeding will allow needed new infrastructure to come on line by 2009, and so has focused the *Transmittal Report* on the 2009 through 2016 planning horizon. The Energy Commission agrees that resource adequacy and shorter term procurement activities currently under way at the CPUC will help provide the bridge to 2009.
Duke-4	See response to comment Duke-1.
Duke-5	The Energy Commission strongly supports completing RAR and developing a capacity market, as recommended in the 2004 Energy Report update; these are not issues for 2006 procurement proceeding and so weren't highlighted in *Transmittal Report*.

Comment number	Response
Cogeneration Association of California/ Energy Producers and Users Coalition (CAC/EPUC)	
Cogen-1	Comment noted.
Cogen-2	Comment noted.
Cogen-3	Comment noted.
Cogen-4	Comment noted.
Cogen-5	Comment noted.
Constellation	
	The Energy Commission appreciates Constellation's thoughtful comments. However, the state's energy agencies embraced the current hybrid electricity market in the first Energy Action Plan, adopted by the Energy Commission and CPUC in April and May, 2003, respectively. The Energy Action Plan recognized "that California currently has a hybrid energy market and that state policies can capture the best features of a vigorous, competitive wholesale energy market and renewed, positive regulation." The Energy Commission believes that the challenge facing the state is how to best implement the hybrid market.
Constellation-1	The Energy Commission believes that long-term contracts are urgently needed to stimulate investment in new infrastructure.
Constellation-2	The record of the Energy Report proceeding does not provide a basis for the Energy Commission to make a recommendation on the advisability of this type market structure. The Energy Commission does believe that this issue is one that should be considered as the state moves forward on various electricity market issues.
Constellation-3	The Energy Commission believes that long-term contracts are urgently needed to stimulate investment in new infrastructure in the context of the hybrid market. Avoiding a clear recommendation to that effect risks continued under-investment in new infrastructure.

Comment number	Response
Constellation-4	The Energy Commission believes that appropriate coming-and-going rules will address this concern.
Constellation-5	See response to comment Constellation-1.
Constellation-6	See response to comment Constellation-1.
Constellation-7	The record of the Energy Report proceeding does not provide a basis for the Energy Commission to make a recommendation on the advisability of this type market structure. The Energy Commission does believe that this issue is one that should be considered as the state moves forward on various electricity market issues.
Constellation-8	The Energy Commission is concerned that uncertainty over departing load continues to hinder long-term investment in new infrastructure. Constellation states that procurement based on an assumption of no departing load, as developed in the *Transmittal Report*, will result in over-investment by the IOUs. The Energy Commission believes the much greater risk is that of under-investment resulting from no LSE taking responsibility for procuring resources for future demand because of uncertainty over who will be serving load in the future.