ALJ/DKF/sid **Date of Issuance 9/5/2008**

Decision 08-09-012 September 4, 2008

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Integrate Procurement Policies and Consider Long-Term Procurement Plans.	Rulemaking 06-02-013 (Filed February 16, 2006)

(See Appendix A for a list of appearances.)

DECISION ON NON-BYPASSABLE CHARGES FOR NEW WORLD GENERATION AND RELATED ISSUES

TABLE OF CONTENTS

DECISION ON NON-BYPASSABLE CHARGES FOR NEW WORLD GENERATION AND RELATED ISSUES

1. Summary

By this decision, we implement new generation[1] non-bypassable charges (NBCs) previously established by Decision (D.) 04-12-048 and D.06-07-029. The applicability and form of these charges are determined for customers of the investor-owned utilities (IOUs)[2] that choose direct access (DA)[3] service or the services of a community choice aggregator (CCA),[4] as well as municipal departing load (MDL)[5] and customer generation departing load (CGDL)[6] customers. Among other things, this decision:

---

1 New generation includes generation from both fossil fueled and renewable resources contracted for or constructed by the investor-owned utilities subsequent to January 1, 2003.

2 Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E) and Southern California Edison Company (SCE).

3 DA load customers purchase electricity from an independent electric service provider (ESP) and receive transmission and distribution service from the IOU.

4 CCAs are governmental entities formed by cities and counties to serve the energy requirements of their local residents and businesses. The IOU continues to provide transmission and distribution service.

5 Departing load (DL) generally refers to retail customers who were formerly IOU customers but now receive energy, transmission and distribution services from publicly owned utilities, self-generation or other means. MDL refers to DL served by a "publicly owned utility" (POU) as that term is defined in Public Utilities Code Section 9604(d), including municipalities or irrigation districts. There are two categories of MDL: transferred MDL and new MDL. Transferred MDL is load that was served by an IOU on or after December 20, 1995, and subsequently departed to be served by a POU. (Resolution E-4064, p. 1, fn. 1.) MDL also includes new MDL, which is load that has never been served by an IOU but is located in an area that had previously been in the IOU's service territory (as that territory existed on February 1, 2001) and was annexed or otherwise expanded into by a POU." (Resolution E-4064, p. 1, fn.1.)

1. Determines that once departed from bundled service, MDL (with the exception of large municipalizations) and CGDL will not have to pay the new generation related NBCs because, by procuring resources based on LTPP forecasts that exclude CGDL and MDL classes, the IOU will not have incurred costs on behalf of these customers.

2. Determines that for large municipalizations whose loads are included in the adopted load forecasts, the Commission will address the cost responsibility for payment of the new generation related NBCs through an application process.

3. Determines that the new generation NBC authorized by D.04-12-048 should be implemented as a component of the cost responsibility surcharge (CRS).[7] The revised CRS shall be calculated on the following bases:

(*footnote continued from previous page*)

[6] The term "Customer Generation" refers to cogeneration, renewable technologies, or any other type of generation that (a) is dedicated wholly or in part to serve a specific customer's load; and (b) relies on non-utility or dedicated utility distribution wires rather than the utility grid, to serve the customer, the customer's affiliates and/or tenant's, and/or not more than two other persons or corporations.

[7] The other components include the ongoing competition transition charge (ongoing CTC), and Department of Water Resources (DWR) power and bond charges. For PG&E, DA and non-exempt MDL are responsible for the Energy Charge Recovery Amount (ECRA), formerly the regulatory asset charge, which recovers PG&E's bankruptcy-related costs pursuant to D.03-12-035. This charge was included as an element to be collected from CRS in D.04-02-062. Pursuant to D.04-11-015, the ECRA superseded and replaced the regulatory asset charge on March 1, 2005. For SCE, DA and DL were responsible for the historical procurement charge (HPC), which recovers costs from a settlement of the filed rate case in federal court. SCE has fully recovered this charge, and the HPC is no longer being collected.

- With a few exceptions, use of a total portfolio approach that accounts for the ongoing CTC, DWR power charges and D.04-12-048 charges.[8] This includes netting the individually calculated annual charges and carrying over any negative total charge to offset positive charges in subsequent years. Further, we determine that pre-restructuring resources[9] should continue to be included in the portfolio of resources used in determining any ongoing CTC and D.04-12-048 charges, once cost recovery of the DWR contracts ends. Finally, we will address the effects of the 10-year limitation on cost recovery of new non-renewable portfolio standard (RPS) generation resources on bundled customer indifference, on a case-by-case basis, if and when the IOUs request cost recovery extensions, pursuant to the provisions of D.04-12-048.
- Use of the market benchmark adopted in D.06-07-030, as modified by D.07-01-030, to determine above-market costs.
- Use of a vintaging methodology based on the calendar year in which customers depart and on whether they depart in the first or second half of the calendar year.

2. Background

Track 3 of Phase II of this proceeding was established in March 2007 to separately address NBCs and related issues. Specifically, Track 3 and this

---

[8] Public Utilities Code Section 367(a) sets forth the method for the calculation of the ongoing CTC. Also, in some situations, there will be departing load customers who do not pay the DWR power charges, and thus, the total portfolio method (indifference calculation) is not applicable in calculating ongoing CTC. (*See* D.07-01-020, p. 5 & D.06-07-030, pp. 35-38; *see* also D.05-01-035, p. 3.) (Order modifying Resolution E-3831 and denying rehearing of Resolution, as modified.)

[9] For purposes of this decision, "pre-restructuring resources" refers to those current IOU resources that existed prior to March 31, 1998 and are not subject to ongoing CTC treatment. These resources consist principally of the IOUs' retained generation (i.e., hydro, coal and nuclear plants). Power from these resources tends to be cheaper when compared to the costs related to ongoing CTC, the DWR contracts and new generation.

decision pertain to the applicability and implementation of new generation related NBCs that were established in D.04-12-048 and D.06-07-029. New generation resources are subject to either the D.04-12-048 NBC or the D.06-07-029 NBC.

By D.04-12-048, the IOUs are allowed to recover the uneconomic or stranded costs related to new generation resources from departing customers. By D.06-07-029, the IOUs are allowed to recover new generation power purchase agreement (PPA) net costs of capacity (total cost less revenues achieved through an energy auction process) from all benefitting customers in the IOUs' service territories. Customers subject to the D.06-07-029 NBC would be allocated resource adequacy (RA) credits for use in satisfying certain Commission RA requirements. The utility will identify new generation PPAs for which it elects to use the D.06-07-029 cost allocation methodology at the time it files an application for approval of the PPAs.

Subsequent to the establishment of Track 3, the majority of implementation issues related to the NBC established by D.06-07-029 have been resolved by D.07-09-044. That decision adopted an uncontested settlement that specified the principles for the D.06-07-029 energy auction and the implementation details for the corresponding allocation of benefits and costs.

A prehearing conference for Track 3 was held on July 12, 2007. Evidentiary hearings were held September 17 through September 21, 2007. Opening Briefs were filed on October 31, 2007. Reply briefs were filed on November 15, 2007, at which time this track of the proceeding was submitted for decision.

Testimony on NBC and related issues was prepared by each of the following parties:

PG&E
SCE
SDG&E
Alliance for Retail Energy Markets (AReM)
California Clean DG Coalition (CCDC)
California Municipal Utilities Association (CMUA)
Cogeneration Association of California (CAC) and Energy Producers and Users Coalition (EPUC), jointly
Hercules Municipal Utility (Hercules)
Merced Irrigation District (Merced ID)
Modesto Irrigation District (Modesto ID)
The Utility Reform Network (TURN)
Western Power Trading Forum (WPTF)

Each of the parties, with the exception of WPTF and CAC, filed opening briefs.[10] In addition, the Division of Ratepayer Advocates (DRA), the City and County of San Francisco (CCSF) and the South San Joaquin Irrigation District (SSJID) each filed opening briefs. Reply briefs were filed by PG&E, SCE, SDG&E, AReM, CCDC, CMUA, EPUC, Merced ID/Modesto ID, TURN and DRA.

A list of acronyms and abbreviations used in this decision is included in Appendix B. A list of certain terms used in this decision is included in Appendix C.

---

[10] Merced ID and Modesto ID filed joint opening and reply briefs.

2.1. D.04-12-048

In Rulemaking (R.) 04-04-003, the Commission issued D.04-12-048, which adopted the 2004 long-term procurement plans (LTPPs) of the IOUs. As part of that decision, to ensure a long term, reliable energy supply for California customers and to address the utilities' concern they could end up over procuring resources and incurring the stranded costs associated with these resources given the potential for a significant portion of their load to take service from a different provider, the Commission authorized the IOUs to recover stranded costs associated with new PPAs and utility-owned generation from all customers. Among other things, the Commission found and concluded the following:

> In general, we agree that the utilities should be allowed to recover their net stranded costs from all customers, which may require the application of additional cost responsibility surcharges or other non-bypassable surcharges. (Finding of Fact 33.)
>
> Ensuring that utilities be allowed to recover their net stranded costs from all customers meets the Commission'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. (Conclusion of Law 13.)
>
> Requiring departing customers to assume a fair share of their costs, and thus avoiding cost shifting, is also consistent with the Commission's policy of holding captive ratepayers harmless as required by state law. (*See* Conclusion of Law 14.)

While D.04-12-048 authorized the IOUs to recover the stranded costs of their electric resource commitments, the decision did not specify the implementation mechanism for the NBC. Consequently, implementation details were deferred to R.06-02-013,[11] and subsequently to Track 3.

Additionally, the issue of applicability of non-bypassable charges as it relates to forecasted departing load (e.g., historic municipal and distributed generation (DG) load shedding) was also included in Track 3.[12]

2.2. D.06-07-029

As part of R.06-02-013, the Commission issued D.06-07-029 which adopted a cost allocation mechanism (CAM) that allows the advantages and costs of new generation to be shared by all benefiting customers in an IOU's service territory. The decision designated that the IOUs should procure the new generation through long-term PPAs. By the CAM, the capacity and energy from the PPAs are unbundled and the rights to the capacity are to be allocated among all load serving entities (LSEs) in the IOU's service territory. Such allocated rights to the capacity can be applied toward each LSE's resource adequacy requirements. The LSEs' customers receiving the benefit of this additional capacity would pay only for the net cost of this capacity, determined as a net of the total cost of the contract minus the energy revenues associated with dispatch of the contract. Among other things, the Commission also found and concluded the following:

---

[11] For instance, see p. 15 and Conclusion of Law 16 of Resolution E-4046.

[12] In a September 10, 2007 electronic-mail response to a September 7, 2007 electronic-mail inquiry issued by the parties during their preparation of the master briefing outline, the assigned Administrative Law Judge (ALJ) for Track 3 indicated that while it might have been appropriate to address this issue as part of forecasting in Track 2, it did not appear that it was clearly stated as an issue in that track, and therefore, it would be addressed in Track 3.

> This mechanism disaggregates the energy and capacity components of the newly acquired generation, so that the only non-bypassable charge levied is for the net capacity costs, and the non-IOU LSEs retain the ability to manage their energy purchases. (Finding of Fact 21.)
>
> It is reasonable, and consistent with law, for the Commission to adopt this limited and transitional cost allocation mechanism to support the development of new generation by having the costs and benefits shared by all customers. (Conclusion of Law 5.)
>
> The IOUs shall make an election at the time they seek contract approval from this Commission whether or not they intend that the cost allocation mechanism adopted by this decision should apply to the contract. The Commission's decision on the IOUs' applications will determine the cost allocation mechanism that will apply. Contracts ineligible for this cost allocation mechanism, or contracts to which the IOUs elect not to apply this cost allocation mechanism at the time seeking Commission approval of the contract, are still subject to the rules of D.04-12-048. (Conclusion of Law 6.)
>
> It is reasonable to defer many of the implementation details of this cost-allocation mechanism to Phase II of this proceeding along with associated ratemaking issues. (Conclusion of Law 10.)

In D.07-09-044, the Commission adopted an unopposed settlement agreement that included the procedures for energy auctions, the products offered by the IOUs in the energy auctions and the allocation of the benefits and net costs of the new generation contracts designated for the energy auction process. The Commission elaborated that additional implementation details would be addressed in Track 2 of the proceeding. Today's decision addresses any remaining CAM implementation issues identified by parties. The issue of applicability consistent with that described above for D.04-12-048 is also addressed in the context of the CAM.

3. Guiding Principles

In addressing issues related to NBCs, the Commission has generally applied the bundled customer indifference principle, whereby bundled customers should be no worse off, nor should they be any better off as a result of customers choosing alternative energy suppliers (ESP, CCA, POU or customer generation).[13] The Commission has also supported the principle that stranded costs should be recovered from those customers who benefited from the stranded asset,[14] as well as those customers on whose behalf the IOU incurred these costs. It is reasonable that we continue to use these guiding principles in reconciling issues related to the implementation of the D.04-12-048 and D.06-07-029 NBCs.

The notion that each customer pay its fair share of the costs the IOU incurred on behalf of this customer or the load associated with this customer is part of these guiding principles.[15] Therefore, the rule is that when costs are

---

[13] For example, in D.04-12-048, Finding of Fact 28, the Commission stated, "The threshold policy issue underlying cost responsibility surcharges is to ensure that remaining bundled ratepayers remain indifferent to stranded costs left by the departing customers."

[14] For example, in D.04-12-048, Finding of Fact 15, the Commission stated, "Allowing the utilities to recover stranded costs from all customers who benefited is consistent with recent Commission policy with regards to new resource additions." Also in D.03-04-030, Finding of Fact 20, the Commission stated, "Granting exceptions to certain portions of the CRS for customer generation up to 3,000 MW [megawatt] will not result in any cost-shifting among customers, since costs for those MW were not incurred by DWR."

[15] Pub. Util. Code § 366.2(d); D.02-11-022, p. 158, Conclusion of Law 21; D.03-04-030, p. 39; D.03-07-028, p. 13; D.04-12-046, p. 24; D.04-12-048, p. 57; D.05-09-022, pp. 15-16.

incurred on its behalf, that customer must pay its fair share of the costs. A corollary rule is that if no costs are incurred on its behalf, then the customer's fair share can be determined to be zero.[16]

With respect to the CRS established by this decision to implement the D.04-12-048 NBC, we are guided by previously established principles used to implement the existing CRSs for DA, CCA, MDL and CGDL.[17]

4. Applicability of Stranded Cost Recovery and Net Cost Allocation NBCs

4.1. Forecasted Departing Load

Whether or not departing load should be forecasted and reflected in the IOUs' load forecasts is not an issue in this track of the proceeding. The structure of the load forecasts used in developing the LTPPs has already been addressed in Track 2, and any related issues have been reconciled in D.07-12-052.[18] Now in Track 3, we are considering the implications of any forecasted departing loads, as determined in D.07-12-052, on the applicability of NBCs to certain customer groups. This has been raised as an issue in the context of both MDL and CGDL and recognized as an issue within the scope of this track of the proceeding.

The IOUs have taken the position that the Commission has already determined that departing load forecasts should not be a basis for releasing

---

[16] The Legislature has given the Commission the authority to determine the fair share and the fair share can be determined to be zero. (*See* Pub. Util. Code, § 366.2(d); D.03-07-028, p. 61; D.04-12-046, pp. 38-39; D.04-12-059, pp. 13-14.)

[17] Appendix D provides a summary of consumer responsibility for various IOU/DWR cost elements related to CRSs.

[18] The LTPP Phase II, Track 2 decision in this proceeding.

departing customers from having to pay the NBCs. In D.04-12-048, the Commission stated, "In general we agree that the utilities should be allowed to recover their net stranded costs from all customers, which may require the application of additional cost responsibility surcharges or other non-bypassable surcharges." (Finding of Fact 33.) Furthermore, in D.06-07-029, we stated, "It is reasonable, and consistent with law, for the Commission to adopt this limited and transitional cost allocation mechanism to support the development of new generation by having the costs and benefits shared by all customers." (Conclusion of Law 5.) We continue to support these general determinations.

As a part of determining the cost allocation, we need to examine and determine the fair share of certain customers, in particular MDL and CGDL, because of the implications of the LTPP load forecasts that anticipate departing load based on historical trends. This consideration of the fair share is necessary to ensure bundled customer indifference and the proper alignment of benefits and cost responsibility.[19] Based on such examination, as discussed below, we have considered the extent to which MDL and CGDL customers will be subject to both the D.04-12-048 and D.06-07-029 NBCs.

---

19 Addressing this issue now is consistent with D.07-11-051 wherein the Commission, in modifying D.06-07-029, stated, "Our definition of benefiting customers subject to the cost allocation mechanism does not include current POU customers, and departing customers who take POU service will not be able to avoid cost responsibility pursuant to D.04-12-048, as modified by D.05-12-022. As noted in D.04-12-048, Ordering Paragraph 9, IOUs are required to forecast and plan for departing load as they file their biennial long-term procurement plans which establish each IOU's long-term resource needs. <u>Further, we will consider issues of need in a subsequent phase of this proceeding and POUs may address whether specific facts suggest refining our approach to the allocation of costs to municipal departing load.</u>" (Ordering Paragraph 1(h), emphasis added.)

4.1.1. Positions of the Parties

In general, the issue revolves around the position of certain parties[20] that the IOUs' load forecasts should reflect reasonable amounts of MDL and CGDL, the IOUs should not be procuring for that forecasted DL, there should therefore be no associated costs, and consequently the proposed new generation NBCs should not be imposed on those departing customers.

The principal objections to this proposal have been raised by the IOUs and TURN. PG&E argues this proposal should be rejected because:

1. the Commission has already declined to exclude departing load that is forecast;

2. for policy and planning reasons, forecasting is not an appropriate basis for exceptions;

3. the intervenors have not demonstrated that PG&E has forecast specific departing loads;

4. parties that are not willing to bear the burden of incorrect forecasts should not be excluded; and

5. allowing exceptions based on forecasts will lead to endless litigation and disputes.

SCE adds that departing load introduces additional uncertainty and error into the utility's load forecast and results in additional costs. To avoid unfairly shifting these risks and costs to remaining bundled service customers, according to SCE, all customers taking bundled service at the time resource commitments

[20] This position is advocated by CMUA, Merced ID, Modesto ID, and CCDC, each on behalf of its specific interests.

are made should be responsible for the above-market (stranded) costs of those resources, if any, either through paying the bundled service rate or a CRS designed to recover these costs. SDG&E makes a similar argument.

TURN argues that when the average cost of a utility's supply portfolio is higher than the current market price of power, any departing load – forecasted or not – will increase the average cost to the remaining bundled service customers, resulting in stranded costs.

4.1.2. Discussion

As noted by the IOUs, the Commission has previously stated that the D.04-12-048 net stranded costs should be recovered from all customers, and the CAM was adopted in D.06-07-029 to support the development of new generation by having the costs and benefits shared by all customers. However, in considering the effects of forecasted departing load on the applicability of the NBCs, we must ensure the outcome of our determination is, to the extent possible, consistent with the preservation of bundled customer indifference and cost recovery from customers on whose behalf resources were procured. In that regard, we must determine the fair share of the departing load for the costs the IOU incurred on behalf of that load. In D.04-12-048, the Commission stated:

> A major issue in this proceeding is the extent to which the utilities will be compensated for investments or purchases that they must make in order to meet their obligations to provide reliable service to their customers. The implementation of CCA, departing municipal load, and the potential for lifting, in some form or another, the current ban on allowing new DA all create a great degree of uncertainty as to the amount of load the existing utilities will be responsible for serving in the future. Given the potential for a significant portion of the utilities' load to take service from a different provider, the utilities are concerned that they could end up

> over-procuring resources and incurring the stranded costs associated with these resources.
>
> One solution to this problem, discussed above, is the adoption of load forecasts that seek to address, to the extent possible, the uncertainties over the future load that the utilities will be responsible for. Another solution is for the utilities to be entitled to recover any stranded costs occurring as a result of their efforts to meet their load obligations.

Given these two possible solutions to offset the effects of departing load, it is necessary to first determine what types of departing load are reflected or not reflected in the adopted LTPP load forecasts.

Issues related to load forecasts were litigated in Phase II, Track 2 of this proceeding and are addressed in detail in D.07-12-052. In determining the appropriate load forecasts, D.07-12-052 relied heavily on the CEC's Integrated Energy Policy Report (IEPR) process and states the following:

> The last LTPP decision, D.04-12-048, directed the IOUs to prepare a Medium-Load Plan Scenario in future LTPPs using the CEC's IEPR base case load-forecast scenario or an Alternative Base Case load-forecast scenario, if the utility chose to file one. In R.04-04-003, the predecessor LTPP rulemaking that resulted in D.04-12-048, the assigned Commissioner issued a ruling on March 14, 2005 (hereinafter referred to as the "IEPR Ruling") directing all parties interested in the IOUs' load forecasts for 2006 to participate in the CEC's 2005 IEPR process since the Commission did not intend to re-examine specified issues resolved during the IEPR process. (D.07-12-052, p. 22, footnote omitted.)
>
> We clarify in this decision, and will reiterate in the OIR for the next LTPP proceeding, that the IOUs are to use the CEC's forecast in their LTPPs. The CEC's IEPR process is the proper forum to litigate and contest issues related to each IOU's demand forecast. If an IOU believes that the CEC's forecast is too "conservative" or that the CEC should use different forecasting models, data or other inputs,

that IOU must bring those issues up and have them resolved in the IEPR proceeding. (D.07-12-052, pp. 27-28.)

We find it prudent to review load forecast sensitivities, but for purposes of granting procurement authority, need determination should be based on the CEC's base forecast under baseline (1-in-2) temperature conditions pursuant to D.04-12-048. (D.07-12-052, p. 28.)

We concur with many of the concerns raised by the CEC and other parties. To address these concerns and conform to our own policy directives, we base the IOU need determination tables on the CEC's base case, 1 in 2 summer temperature demand forecast (the three need tables, PGE-1, SCE-1, and SDGE-1, all use the forecasts from CEC's 2007 IEPR issued on November 21, 2007). (D.07-12-052, p. 29.)

While we recognize that the 2007 IEPR forecast estimates were not vetted in this proceeding, many aspects of the IEPR forecasting process were. The IEPR process is a public one, involving many of the same participants that are parties to this proceeding, and the IEPR document is a public document. We find it prudent to update the forecast estimates used as inputs in this decision based on the most current public information available to us, particularly given the long time lag that has occurred since the LTPPs were developed. The California Energy Demand Forecast, 2008-2018, the underlying load forecast which the 2007 IEPR assumes, had not been officially adopted by the CEC, as of the mailing of this Proposed Decision. We note that the incorporation of the draft 2007 IEPR demand forecast into our overall needs analysis may give certain parties concern, however, we believe that the draft forecast provides a better 'snapshot' of the current needs of the system. (D.07-12-052, footnote 38, pp. 29-30.)

As indicated above, the LTPP load forecasts adopted by D.07-12-052 were based on the November 2007 California Energy Demand 2008-2018 Staff Revised Forecast[21] (2007 IEPR Demand Forecast) and are shown in Tables PGE-1, SCE-1, and SDGE-1 of that decision. Each table indicates the forecasts were based on the CEC's 2007 IEPR 1-in-2 peak demand. For PG&E and SCE the tables indicate that the service area calculation includes bundled and DA customers and excludes POUs. This is verified by examination of the 2007 IEPR Demand Forecast, on which the D.07-12-052 load forecasts are based. For example for the year 2007, D.07-12-052 represents the 1-in-2 Service Area Summer Temperature demand to be 19,845 MW for PG&E. This is the load used in D.07-12-052 to determine PG&E's Service Area Surplus (Deficit) for that year. That demand amount can be traced back to the 2007 IEPR Demand Forecast by adding PG&E's bundled load of 18,827 MW and PG&E direct access load of 1,017 MW, as shown on Form 1.5b.

In the IEPR process, IOUs are required to quantify and document their assumptions about migrating load. This information is needed to support compliance with AB 1723 (PRC 25302.5), which require all LSEs to provide the CEC with their "forecasted load that may be lost or added" by a POU or CCA or served by an ESP. The CEC is to perform an assessment of migrating load in each IOU service territory and submit the results to the CPUC.

---

21 http://www.energy.ca.gov/2007publications/CEC-200-2007-015/CEC-200-2007-015-SF2.PDF

That bundled load does not include POU load (and the associated MDL)[22] is demonstrated on Form 1.4b in the 2007 IEPR Demand Forecast which shows bundled and direct access loads separately from POU loads. In general, forecasts of demand, including that for MDL, reflect historical consumption, economic and demographic projections, weather adjustments and specific inputs from LSEs.[23]

That CGDL is also reflected in the D.07-12-052 adopted load forecasts can be verified by examination of the 2007 IEPR Demand Forecast in the discussion related to Self Generation. It states, "As discussed in Chapter 1, the peak demand forecast is reduced by the projected effects of the SGIP, CSI and other similar programs. The effects of these programs are forecast based on recent trends in installations." (2007 IEPR Demand Forecast, p. 74.)[24] Historic and forecasted CGDL peak demand is shown as "Total Private Supply" on Form 1.4 of the 2007 IEPR Demand Forecast.

The above discussion of how departing load is reflected in the adopted load forecasts is also consistent with our understanding of how departing load is

---

[22] The 2007 IEPR Demand Forecast, p. 35 indicates that the individual LSE forecasts were also adjusted to account for load migration (customers migrating from one service provider to another).

[23] 2007 IEPR Forecast, p. 35.

[24] The referenced Chapter 1 states in part, "To forecast future self-generation load, staff used the IOU reports on completed new interconnections and pending applications to develop projections of capacity additions of new interconnections. (Footnote omitted.) The interconnection reports provide a detailed picture of capacity addition trends."

considered in the load forecasts prepared by the IOUs.[25] In D.07-12-052, we stated:

> Regarding parties' concerns over PG&E's assessment of departing load, we concur with PG&E's response that its analysis of system need is not impacted by possible future load shifting due to DA and CCA, and that future DG and MDL is captured by historical trends used to develop the forecast.[26]

Similar statements are made with regard to SCE and SDG&E departing loads.[27]

Based on the load forecasts adopted in D.07-12-052, it would be appropriate to employ both of the solutions expressed in D.04-12-048 related to IOU procurement for departing load. For IOU customers that are eligible to, and do, choose DA service from an ESP and for customers that decide to use a CCA, D.07-12-052 indicates that their loads are included in the adopted load forecasts on which the LTPPs are based. Therefore, the IOUs would be procuring resources on their behalf, and NBCs should be imposed on these customers when they cease taking procurement services from the IOUs, in order to maintain bundled customer indifference. Imposition of the NBCs is appropriate,

---

[25] Regarding the load forecasts prepared by the IOUs, the effects of CGDL were reflected, as indicated in each IOU's LTPP which included a section on forecasting DG (PG&E's 2006 LTPP, Volume 1, pp. IV-20 – IV-25, SCE's 2006 LTPP, Volume 1B, pp. 16-24, and SDG&E's 2006 LTPP, pp. 194-197). It was also established that the CEC demand forecast reflects embedded amounts of DG (CCDC, Wong, 8 Tr. 1046-1047). MDL is implicitly reflected in SCE's load forecast as a decline in SCE's bundled load growth through the extrapolation of historical data. (*See* Exhibit 37, p. 37 and SCE, Canning 2 RT, pp. 216-218.) PG&E similarly takes projected POU departing load into account in its load forecast. (*See* PG&E, Aslin, 5 RT, pp. 647-660.)

[26] D.07-12-052, pp. 34-35.

[27] *Id. at* pp. 39 and 42.

because CCA, and to an extent customers currently eligible to return to DA, create uncertainty regarding what loads the IOUs will be required to serve. At this time, there is insufficient history of such transactions and limited knowledge of customers' intent to pursue such transactions in the future, for the IOUs to use in determining how much, or how long, power should be procured on such customers' behalf. Planning for these customers' needs and imposing the NBCs if and when these customers choose alternative procurement services is a reasonable way to address the problem.[28]

On the other hand, D.07-12-052 indicates that future CGDL and MDL are captured by historical trends used to develop the load forecasts. Therefore, the forecasted loads associated with MDL and CGDL customers are not included in the D.07-12-052 adopted load forecasts. This is consistent with the solution expressed in D.04-12-048 whereby the Commission would adopt load forecasts that seek to address, to the extent possible, the uncertainties over the future load that the utilities will be responsible for.

---

[28] In its Opening Comments on the Proposed Decision, p. 5, AReM indicates that SDG&E's approved load forecasts reflect reasonably foreseeable DA load migration and that it follows that based on the rationale for excluding MDL and CGDL customers from new generation NBC cost responsibility, DA-eligible customers located in SDG&E's service territory should also be exempt from the new NBCs. The record indicates otherwise. Form 1.4b of the 2007 IEPR Demand Forecast shows a constant forecast of DA demand over time for SDG&E. Also, in its Reply Comments on the Proposed Decision, SDG&E clarified that while DA load shown in its compliance capacity tables increase slightly over the planning period, this increase is driven by the assumption that usage per customer increases slightly over time not and not a forecast of DA customer increases. Therefore, it is evident that DA load migration has not been forecasted for SDG&E, and DA eleigible customers in SDG&E's service territory should not be excluded from the new generation NBCs..

We note that the use of historic information and trends to reflect future departing load reduces some risk to the IOUs of possibly adopting overly optimistic estimates and tends to limit the dispute and litigation related to what the appropriate levels of departing load should be. For instance, PG&E states that MDL bypass is no longer expected to be materially different than recent trends captured in the historic data.[29] While there may be differences between the amounts of departing load implicit in the load forecasts and the amounts recorded on a year-by-year basis, over time any such variations should level out and bundled customer indifference will be maintained. Also, as long as historic information and trends are the basis for reflecting the departing load in the load forecast, unexpected annual variations between actual and assumed departing loads will result in the assumed forecast departing load levels being adjusted up or down in the future based on the historic amounts, again resulting in bundled customer indifference being maintained over time.

---

[29] Exhibit 211, Response to Question II.2.

Forecasting the effects of CGDL and MDL has been done in the past[30] and, as discussed previously, is done as part of the CEC's IEPR process which, at least for the foreseeable future, will be the basis for Commission's LTPP load forecasts. We reiterate the guidance provided in D.07-12-052, that the CEC's IEPR process is the proper forum to litigate and contest issues related to each IOU's demand forecast, including any concerns related to the accuracy of the predicted MDL and CGDL in the CEC forecast.

What we must consider now is (1) what it means for this departing load to be reflected in the load forecast, and (2) given that meaning, whether these departing load customers should be fully responsible, partially responsible, or not responsible at all, for the new generation NBCs established by D.04-12-048 and D.06-07-029.[31] This is integral to our determination of the departing load's fair share.

---

[30] CGDL has been excluded from procurement related charges based on load forecasts in previous Commission decisions. (*See* D.03-04-030, p. 54, D.04-12-048, Ordering Paragraph 11, and D.04-10-035, p. 20.) Regarding MDL, the Commission excepted transferred MDL indentified in the Bypass Report in D.04-11-014 (see pp. 4 and 40), Findings of Fact 3 and 18, Conclusion of Law 5, and Ordering Paragraph 4); the Commission excepted new MDL associated with the transferred MDL identified in the Bypass Report in D.04-11-014 (*see* pp. 4-5, 21, Findings of Fact 10 and 11, and Ordering Paragraph 2) and the Commission granted an exception to new MDL of "existing" POUs in D.03-07-028 (see p. 61, Findings of Fact 12, 13, and 16, Conclusions of Law 9 and, 10, and Ordering Paragraph 6) and extended it to other new MDL on the basis that new MDL was implicitly accounted for in the utility forecasts (*see* D.04-11-014, pp. 10-13, Findings of Fact 2 and 4, and Conclusions of Law 1 and 3, and Ordering Paragraphs 1 and 2).

[31] The fact that system needs are not impacted by possible load shifting due to DA and CCA means that the load forecasts are not reduced to reflect DA and CCA. It is therefore unnecessary to examine the implications of forecasted load reductions in this context, and no party has recommended that we do so.

Exclusion of MDL and CGDL from the load forecast can only logically be interpreted to mean that the LTPP, which uses that load forecast to determine resource needs in the forecast year, does not include any resources to serve that departing load in that forecast year and beyond. Accordingly, in such circumstances, it would be reasonable to determine that the fair share of departing load for paying the new generation NBCs would be zero. Stranded costs are avoided for these forecasted departures via the combination of (1) the layering of generation procurement by the IOUs (both in terms of procurement of longer term, shorter term and "spot" market resources and in terms of the sequenced procurement of resources which in turn results in resources regularly dropping out of the portfolio as contracts expire) and (2) forecast increases in load from new and existing customers.

As discussed below, in applying this departing load fair share concept, we have considered new generation resources that become operational (1) during the year that these customers depart and beyond and (2) before these customers depart.

For those new generation resources that become operational during the year that MDL and CGDL customers depart and beyond, those departing load customers should not be responsible for any new generation NBCs. That is because when the commitments for those resources are made the load forecasts on which procurement needs are based do not include loads related to MDL and CGDL. Such departing loads have been forecasted and are not included in the load forecasts used in determining the need for those resources. Those resources are therefore not procured on behalf of these departing load customers for any time period and their fair share of the costs should be zero.

We must also consider cost responsibility related to those new generation resources that become operational and begin to provide energy prior to the date that these customers depart the IOUs' systems. For transferred MDL and CGDL customers, they would have taken bundled service from the utility, for some period of time, prior to the year in which they depart. For the time that they are bundled service customers, they would pay for any operative new generation resources as part of their bundled service rates. However when they depart, their cost responsibility for such resources should end. That is because, at the time the resource commitments are made, (1) the LTPP load forecasts exclude forecasted amounts of MDL and CGDL; (2) these customers will eventually become the departing customers for which those amounts of MDL and CGDL are forecasted; and (3) therefore, in effect, these customers' loads are only reflected in the LTPP load forecast for the years in which they are bundled service customers. Therefore, (1) the IOUs' procurement needs related to these customers are only identified and planned for in the years in which they are bundled service customers; (2) the IOUs' procurement commitments are made on behalf of these customers only for the time that they are on bundled service; and (3) these customers' fair share of the costs related to these resources should be zero after they depart.

Consistent with our overall guiding principles for resolving NBC implementation issues, these departing customers should not pay any NBC related to new generation resources that were not procured on their behalf, as these customers' fair share would be zero. We will not impose either the D.04-12-048 or D.06-07-029 NBCs on MDL and CGDL, since these classes of departing load are reflected in the load forecasts on which the LTPPs are based. Also, since there are no resources or associated costs in the forecast year related to the load departing in that year, there is no cost shifting to bundled customers when these departing customers leave.

In supporting the IOUs, TURN argues that the question of whether or not some amount of future departing load may have been reflected in a prior forecast sponsored by a utility or adopted by this Commission or the CEC should be irrelevant to the applicability of the NBCs at issue in this proceeding. It is TURN's position that when the average cost of a utility's supply portfolio is higher than the current market price of power, any departing load – forecasted or not – will increase the average cost to the remaining bundled service customers, resulting in stranded costs. We do not agree with TURN's conclusion that therefore under all such circumstances departing load customers should be assessed an NBC.

The more important consideration is the appropriate measure of ratepayer indifference. All other things being equal, exclusion of forecasted departing load from the LTPP load forecasts and exclusion of MDL (with the exception of large municipalizations) and CGDL customers from cost responsibility for new generation resources after the customers depart leaves existing bundled customers with the same cost responsibility as was anticipated when the LTPP load forecasts were made. That is simply because the forecasted departing customers were not anticipated to be served after they depart because their loads are excluded from the forecasts on which the procurement decisions are based. The fact that the forecasted departing customers actually depart does not affect the costs to the bundled customers when compared to costs associated with the assumptions in the sales forecasts and procurement plans associated with the new generation resources. In that regard, bundled customers are appropriately indifferent to the departure of the forecasted departing customers.

To summarize, as opposed to DA and CCA, MDL and CGDL do not create a large degree of uncertainty regarding what loads the IOUs will be required to serve. The adopted load forecasts directly address the effect of MDL and CGDL, and the consequent LTPPs are not developed to serve those departing loads. These forecasts justify our determination that the fair share of these departing load customers will be zero. Accordingly, imposition of the D.04-12-048 and D.06-07-029 NBCs is not necessary for MDL or CGDL customers. However, with a large municipalization, we take a different approach as discussed in Section 4.1.4 below.

4.1.3. TURN's Recommendation for a Binding Notice of Intent Process

TURN argues that a binding notice of intent (BNI) process provides a much more robust way of dealing with the uncertainty regarding future departing loads than endless debating over who included or should have included which potential departing loads in a past forecast. TURN notes Commission has adopted this approach for CCA load.

In general, we agree with TURN's position that if a potential departing customer is not willing to commit to a firm departure date via a BNI, then that customer should remain liable for the potential stranded costs associated with any commitments the utility enters into prior to the date of the actual departure. However, that customer should only be responsible for commitments that were made on its behalf. This principle is embodied in the determination of the fair share. In the case of CCA, the IOU's are procuring and making procurement commitments on behalf of potential CCA customers until the specific dates indicated by the BNIs. That is because loads associated with these customers are included in the IOUs' load forecasts on which their procurement decisions are based. That is not the case for MDL and CGDL customers with respect to the new generation NBCs. As indicated by D.07-12-052, the IOUs exclude these departing loads in their forecasts. As stated previously, for this reason, the IOUs are essentially not procuring on behalf of MDL and CGDL customers in the year they depart and beyond. Accordingly, it is reasonable to determine that the fair share for the new generation costs would be zero. Although the BNI process may be a viable approach for determining when IOU procurement on behalf of certain customers ends, it is not relevant in addressing the NBC applicability issue of whether these customers should be assessed any NBC at all under a fair share analysis.

4.1.4. Effect of Large Municipalizations

As discussed above, our analysis of the fair share cost responsibility for MDL is based in large part on our determination that such load is reasonably reflected in the historical trends used in developing the adopted LTPP load forecasts. However, at some point the historical trends of MDL may no longer reasonably represent the amounts of MDL that will occur. This point would be reached if there is a "large municipalization" in the forecast year. While there is no precise measure of what constitutes a "large municipalization," in the context of this decision, we are defining "large municipalization" as any portion of an IOU's service territory that has been taken control of or annexed by a POU where the amount of load departing the IOUs' service territories due to the municipalization is of such a large magnitude that it cannot reasonably be assumed to have been reflected as part of the historical MDL trends used in developing the adopted LTPP load forecasts. SCE states that its long-range retail load forecasts use historical data starting from 1991 and that all sizeable annexations occurred prior to 1991.[32] PG&E indicates that it would likely remove any large municipalizations from the historical data but adds that it is difficult to quantify what "large" would be.[33] SDG&E indicates that it has no existing or planned municipalization at this time.[34]

Therefore, if a large municipalization occurs in a particular year, the associated departing load would logically have been part of that year's LTPP load forecast, and the IOUs would have been making new generation resource commitments on behalf of those departing customers up until the time they depart or provide appropriate notice of departure. Unlike that for MDL and CGDL, which are reflected in the LTPP load forecasts, it cannot be argued that large municipalization load, which is not forecasted for LTPP purposes, should be excluded from new generation cost responsibility. That is because when the commitments for resources that were procured prior to these customers' departure are made, there is no forecasted information that would indicate that customers would be departing due to large municipalizations at any time over the lives of the resources. Procurement would have been planned accordingly. Therefore, under the principle of allocating fair share, large municipalization departing customers should be fully responsible for the new generation NBCs.

Imposition of new generation NBCs on customers departing due to large municipalizations shall be accomplished through a separate application filed by

[32] Exhibit 212, Response to Question 2.

[33] Exhibit 211, Response to Question II.2.

[34] Exhibit 213, Response to Question 8.

the affected IOU. Customers' NBC cost responsibility shall be determined through a fair share analysis based on the record of that proceeding. The IOU has the burden to show the departures are within the definition of a large municipalization, especially as it relates to how the large municipalization is or is not reflected in the adopted LTPP load forecasts.

For purposes of determining when the IOUs should stop procuring new generation resources for these departing customers, a BNI process similar to that established for CCAs is reasonable.[35] As determined in D.04-12-048 and D.05-12-041, customers choosing CCA service will be responsible for new generation NBCs associated with the resources procured prior to departure if no BNI is submitted. If a BNI is submitted, the customer will pay only the NBC associated with new generation resources procured prior to the date the BNI is submitted to the IOU. In the event that the CCA cannot meet the BNI date, the CCA will be liable for any net incremental procurement costs incurred by the utility. The IOUs should make this process available for large municipalizations.

If the large municipalization entity does not wish to provide a BNI, the actual departure date is a reasonable date to determine large municipalization NBC cost responsibility, similar to that for CCAs. While we prefer this BNI process, we will not strictly impose its conditions, recognizing that there may be a reason, possibly having to do with the timing of the processes in finalizing a large municipalization, for the entity not to choose either the use of the BNI or the actual departure date, but to recommend some alternative date instead.

---

[35] CCAs and large municipalizations are similar in that there is potential for significant load migration and neither is reflected in the LTPP load forecasts.

However, we will impose the burden on the large municipalization entity to demonstrate the reasonableness of using its proposed date as opposed to a BNI date or the actual departure date for determining when the IOU should no longer procure new generation resources for the departing customers.[36] If that burden is not met, the actual departure date will be used for that purpose.

4.1.5. New Western Area Power Administration (WAPA) Departing Load and Split Wheeling Departing Load

PG&E requests that it be made clear that the new generation NBCs also apply to new WAPA departing load[37] and split wheeling departing load,[38] consistent with D.03-09-052 and D.06-05-018.[39] In those decisions, the Commission determined that:

> A CRS shall be imposed on split wheeling preference power customers to the extent they received a portion of their power through PG&E bundled service to the extent such power exceeds the customer's CRD in the manner contemplated under the existing provisions of Contract 2948A. (D.03-09-052, Ordering Paragraph 4)

---

[36] If the large municipalization entity is of the belief that, at some point in time, the IOU should have known the load would be departing by a certain date, the municipal entity should explain why a BNI commitment could not have been made by the municipal entity to reflect that.

[37] New WAPA departing load is additional customer load of certain so-called 'new allottee" customers who, for example, were served by PG&E under its retail tariffs prior to expiration of Contract 2948-A with WAPA but are now served by WAPA.

[38] Split wheeling departing load is that portion of the load of certain so-called "split-wheeling" customers which, for example, was served by PG&E under its retail tariffs prior to the expiration of PG&E's Contract 2948-A with WAPA but is now served by WAPA.

[39] PG&E Initial Comments on the Proposed Decision, p. 12. There were no replies to this comment.

> The following new Ordering Paragraph (OP) 8 is added (reordering current OPs 8 and 9): "PG&E is directed to promptly file an advice letter with the appropriate amendments to its tariff to bill and collect CRS and other applicable nonbypassable charges from preference power customers consisting of 'Additional Customer Load' relating to the specific list of delivery points listed in Appendix C of the WDT Agreement, that have taken bundled service from PG&E on or after February 1, 2001, and subsequently reduced or terminated such service to take electric service from WAPA or another similarly situated entity." (D.06-05-018, Ordering Paragraph 5)

In its testimony, PG&E included such loads as being subject to the D.04-12-048 NBC.[40] No party provided responsive testimony or other evidence that shows such loads should be excluded from that charge.

Regarding the D.06-07-029 NBC, the Commission stated:

> In summary, Section 380 allows an IOU to recover the costs it incurs to sustain "system reliability and local area reliability" from all customers "on whose behalf the costs are incurred." We construe benefiting customers as defined in Section IV.B.1 as those customers on whose behalf the costs are incurred. (D.06-07-029, p. 41.)

No party provided testimony or other evidence that would indicate that PG&E would not incur the D.06-07-029 NBC related costs on behalf of new WAPA departing load and split wheeling departing load customers while they are customers of PG&E. Therefore, we conclude that the new generation NBCs should apply to new WAPA departing load and split wheeling departing load consistent with our rationale for assigning generation related cost responsibility in D. 03-09-052 and D.06-05-018.

---

[40] *See* Exhibit 7, p. II-5.

4.2. AReM's Request for Confirmation Regarding Customers Currently Eligible to Return to DA

AReM asks the Commission to confirm that bundled service customers who are eligible to return to DA should also be exempted from the NBC associated with D.04-12-048. PG&E, SCE, SDG&E, and TURN oppose AReM's request.

4.2.1. Parties' Positions

In D.04-12-048, the Commission authorized the IOUs to recover the stranded costs of new utility procurement resulting from departing load from "all customers, including departing [load/customers]."[41] AReM argues that, when read in context, this wording specifically excludes customers that are currently eligible for direct access. That is, "departing load" and "departing customers," as used in D.04-12-048, do not include customers that are currently on direct access or customers that are currently on bundled service but are eligible for direct access.

The opposition's principal response to AReM's assertion is that the Commission in D.04-12-048 determined that the IOUs should be allowed to recover stranded costs from all bundled customers, including departing load customers. There are no stated exceptions.

AReM supports its conclusion by citing D.03-12-059 and D.04-06-011 where the Commission stated various customers that are currently ineligible for direct access should be obligated to pay for stranded costs for 10 years.

---

[41] D.04-12-048, pp. 60 and 63.

In reply, PG&E states that in D.04-12-048, the Commission referenced these two decisions to support its decision to limit NBCs to 10 years. It did not cite these decisions as a basis for excluding DA eligible customers. PG&E adds that notably, just before the language quoting these two decisions, the Commission states that stranded costs should be recovered from all customers, which would include DA eligible customers.

AReM also references D.05-09-022 which addressed various petitions for modification of D.04-12-048, including the petitions filed by AReM and ESPs in which it was argued that the Commission does not have the authority to impose NBCs on direct access customers for purposes of allowing the IOUs to recover stranded costs associated with new procurement commitments. The Commission held, "[W]e may lawfully hold future direct access customers responsible for the recovery of new generation costs."[42] AReM emphasizes the word "future." AReM argues that the Commission made no reference to customers that are currently eligible for direct access, indicating that would have been a glaring omission if the Commission had actually intended for the stranded cost NBCs authorized in D.04-12-048 to apply to such customers.

In reply, TURN states that today's bundled service customers who happen to be eligible for DA and subsequently depart to take service from an AReM member are precisely "future" direct access customers as specified in D.05-09-022. TURN also states that the mere fact that the Commission did not single out "currently bundled customers who are eligible to return to direct access" from other types of departing load does not prove AReM's point. If

[42] D.05-09-022, p. 15.

anything it proves the opposite – that all types of departing load are subject to the NBC.

AReM also states that arguments for imposing the charge on DA eligible customers ignore the existence of the elaborate rules developed by the Commission to govern the movement of DA-eligible customers to and from direct access so as to prevent gaming and costs being shifted to bundled customers. Under those rules, if a customer that is on direct access wants to return to bundled service, it must provide the utility with six months advance notice and will only become eligible to receive bundled service from the utility at the same rate as other customers at the end of the notice period. In addition, the customer is required to remain on bundled service for a minimum of three years, and if the customer wants to go back to direct access after the end of its minimum three-year commitment period, it must provide the utility with six months advance notice.

AReM argues that the Commission left open the possibility that it would later extend the minimum commitment period beyond three years if there was evidence that a longer period was "necessary to avoid stranding long-term portfolio supply obligations undertaken to serve DA customers returning to bundled status…."[43] According to AReM, the Commission has not seen a need to do so, because the Commission's rules to prevent cost shifting by DA customers also ensure that DA customers impose no costs on bundled customers. AReM states that any costs incurred by the utility in its long-term procurement are incurred solely for the benefit of bundled customers, and since customers

---

[43] See D.03-05-034, Finding of Fact 13.

that are currently eligible for direct access do not create stranded costs when they move to direct access, imposing the stranded cost NBCs on such customers would be inconsistent with the principle that costs should be allocated on the basis of causation.

In response TURN argues the potential for stranded costs resulting from load departing from the bundled portfolio is exactly what the relevant portions of D.04-12-048 were all about. Rather than "not seeing a need" to address the circumstances described in D.03-05-034, the Commission saw a need and addressed it by adopting the stranded cost NBC. TURN adds that AReM's further statement that: "any costs incurred by the utility in its long-term procurement are incurred solely for the benefit of bundled customers" proves TURN's point. Currently bundled customers who happen to be eligible for direct access are just that – bundled customers, the very people for whom the utility is incurring costs.

4.2.2. Discussion

We do not adopt AReM's request to confirm that bundled service customers who are eligible to return to DA should be exempted from the NBC associated with D.04-12-048. We generally agree with the responses by the IOUs and TURN as detailed above. None of the decisions cited by AReM specifically exclude these customers from the charge.[44] In D.04-12-048, we found that the

---

[44] AReM is correct that D.03-12-059 finds: "Although Edison established a need for Mountainview, in order to not over-burden ratepayers in the early years of the contract, we adopt TURN's proposal that all customers of Edison that are currently ineligible for direct access be obligated to pay for stranded costs for the first 10 years of Mountainview's life." (Finding of Fact 22.) However, at the time of the decision, dated December 18, 2003 the relevant former DA customers who had returned to bundled

Footnote continued on next page

stranded costs should be recovered from all customers and did not indicate any exceptions. By our decision today, we have addressed the implementation of the D.04-12-048 NBC by employing the previously used principles of bundled customer indifference and customer responsibility for costs incurred on their behalf. We consider this to be logical and fair, and consistent with the principle of these customers paying their fair share for costs incurred on their behalf, and of preventing cost-shifting. We do not see such logic or fairness in AReM's request.

As described by AReM, there is a detailed process by which certain customers can return to DA service. However, until these customers return to DA, they are no different from the other bundled customers on whose behalf the IOUs are making procurement related decisions. Until the proper notice is given, the IOUs have no way of knowing if and when such customers will depart. The IOUs therefore properly include the related loads of the potential DA customers in their load forecasts. By doing so, the IOUs are procuring and making procurement commitments on behalf of these customers. As is the case with all other customers, these customers should be subject to the D.04-12-048 NBC for procurement commitments made on their behalf up until the date they provide notice to the IOUs of their intent to return to DA.

(*footnote continued from previous page*)

service would have been "currently" (as of the decision date) ineligible for DA, because of the three-year commitment obligation established by D.03-05-034.

4.3. Above-Market Standard Offers for New QF Contracts

In D.07-09-040, dated September 20, 2007, the Commission ordered that the utilities make standard offer contracts available to existing qualifying facilities (QFs) with expiring PPAs or to new QFs. PG&E argues that this requirement, similar to RPS and RA requirements, impacts utility procurement and creates uncertainty in resource planning, and to the extent the prices in the new QF standard offer contracts are above-market prices, bundled customers may incur additional stranded costs. In its opening brief, PG&E requested that the Commission, in this decision, affirm that stranded costs associated with these contracts can be recovered under D.04-12-048 or D.06-07-029.[45] In reply briefs, SCE agreed with PG&E's request. No other party replied on this topic.

We agree that the IOUs should be able to impose NBCs for the above market costs of these new QF contracts. This can be accomplished through the D.04-12-048 NBC, and we will authorize that NBC for this purpose. However, there has been no demonstration of need for cost recovery of these new QF contracts through the CAM that was authorized by D.06-07-029, and we will not do so. The CAM was designed to get new system reliability resources built and the resigning of QF contracts does not accomplish that. Even for contracts with new QFs, cost recovery under the CAM may not make sense due to the requirements and costs associated with the energy auction process.

---

[45] Evidentiary hearings in Track 3 concluded on September 21, 2007. The opening brief was the first real opportunity for PG&E to raise this issue in this proceeding.

4.4. Other Applicability Related Issues that Will Not Be Addressed in this Proceeding

D.04-12-048 and D.06-07-029 established the NBCs at issue here in Track 3 of this proceeding. In general, Track 3 was intended to address implementation issues related to NBCs. That scope was modified slightly to include the issue of determining the fair share of DL liability of the new generation NBCs. Our obligation is to reconcile issues properly within the established scope. TURN's BNI proposal directly relates to this issue and we felt it necessary to address AReM's request for clarification. We also felt a need to address PG&E's request regarding the inclusion of new QF contracts, since it is relevant to the applicability of the NBCs at issue and came about because of our recent decision on the matter. However, there were also other issues that related somewhat to the applicability of NBCs which were identified and addressed by certain parties in the Track 3 briefing process. They include such things as:

- There is a lack of statutory basis for NBCs;
- Utilities should not be able to recover NBCs for procurement costs arising in the normal course of business;
- NBCs will "chill" combined heat and power and CGDL development;
- The benefits of CGDL justify an exclusion to the NBCs; and
- Imposition of the stranded cost NBCs on customers currently eligible for direct access would hamper retail competition.

While many of these issues may have been rendered moot by our resolution of the applicability of the NBCs as they relate to DL, they are also outside the scope of this track of the proceeding and will not be addressed in this decision. Such issues should be, or should have been, pursued in the proceedings that established the charges, not in this proceeding which was principally designed to implement the charges. To fully address such issues now would not be fair to the parties that did not fully address the related arguments in briefs. Those parties, with good reason, assumed the issues were beyond the scope of the proceeding and treated them accordingly, and so shall we.

5. Framework for the D.04-12-048 NBC

The IOUs propose that D.04-12-048 NBC recovery should be implemented in the form of a surcharge based on the extent that certain generation resources are uneconomic and the costs may be stranded. To make that determination, the costs of the appropriate generation resources would be compared to a market benchmark. If the resource costs are greater than the market costs, the resources are considered uneconomic and a surcharge based on that difference would be imposed. Having a customer, who chooses an alternative energy supply, pay a surcharge that covers the uneconomic portion of the resource costs associated with that customer's departure will leave the bundled customer indifferent to the departure. This general framework is reasonable, and we will adopt it for the purpose of implementing the D.04-12-048 NBC, subject to our previous determinations regarding the applicability of the charges.

6. Implementation Issues for Cost Allocation Under D.04-12-048

Two principal implementation issues that have been identified in this proceeding relate to (1) whether the D.04-12-048 NBC should be determined in isolation (separate charge approach) or in conjunction with other resources and other related CRS obligations (total portfolio approach); and (2) the method by which new resource obligations are determined for specific customers considering when those customers depart or choose alternative energy providers (vintaging). We also address issues related to the cost-effectiveness and the actual calculation of the NBC in this portion of the decision.

6.1. Total Portfolio and Separate Charge Approaches

Under the total portfolio approach, the uneconomic costs associated with new generation resources[46] are determined in conjunction with the economic and uneconomic costs associated with older generation resources. Under the separate charge approach, the uneconomic costs associated with new generation resources are determined separate from that for older generation resources. In either case, new generation NBCs (based on either the total portfolio or separate charge approach) would be imposed in those years in which generation costs are shown to be uneconomic, that is higher than the market benchmark costs, and the NBCs would recover no more than those uneconomic costs for those years. New generation NBCs would not be imposed in those years where the generation costs are lower than the market benchmark costs.

6.1.1. Positions of the Parties

6.1.1.1. Total Portfolio

In a series of decisions in R.02-01-011 (the DA/DL CRS proceeding) and R.03-10-003 (the CCA proceeding), the Commission adopted CRSs applicable to DA, MDL, CGDL and CCA. As explained earlier, the components of the CRS include the ongoing CTC and the DWR power and bond charges. Also, for PG&E, DA and MDL are responsible for the ECRA, which recovers PG&E's bankruptcy-related costs.[47]

---

[46] The total portfolio does not include contracts subject to the CAM adopted by the Commission in D.06-07-029.

[47] For SCE, the HPC was also included as part of the CRS; however, the HPC was paid off and is no longer a part of the CRS.

The total portfolio approach is used in determining the power charge indifference amount (PCIA), which is the DWR power charge element of the CRS. The revenue requirement of the total portfolio of resources, which includes the DWR contracts, resources subject to ongoing CTC and pre-restructuring resources not subject to ongoing CTC (primarily utility retained generation (URG)), are compared to market costs. If the total portfolio costs exceed the market costs, that difference represents the uneconomic or stranded costs. Dividing that difference by total bundled customer and departing customer usage results in an "indifference amount," which in this case is positive and represents what departing customers should pay in order that remaining bundled customers remain indifferent to their departure. The PCIA is then calculated by subtracting the ongoing CTC charge from the positive indifference amount. If the PCIA is positive, the amount collected through the PCIA is remitted to the DWR to reduce the bundled service customers' DWR power charge obligation, while the ongoing CTC amount would be credited to the Energy Resource Recovery Account (ERRA) balancing account. If the PCIA is negative, there would be no remittance to the DWR and the entire indifference amount would be credited to the ERRA.

If the total portfolio costs are lower than market costs resulting in a negative indifference amount, the customers' departure is economic. However, departing customers do not receive a credit on their bills for negative indifference amounts. Instead, negative indifference amounts can be carried over to offset future positive indifference amounts but are not eligible to be applied against any other components of the CRS.

To implement the D.04-12-048 NBC, SCE recommends using the existing CRS total portfolio approach for calculating an indifference amount except the total portfolio would now also include new generation resources subject to the D.04-12-048 NBC. Also, customers' cost responsibility for new generation resources would vary depending on when the customers depart and which new generation resources were committed to on their behalf prior to their departure. The revenue requirement would have to be calculated for each vintage of the utility's total portfolio of generation resources and contractual commitments. In its annual ERRA proceeding, SCE will set forth its total generation revenue requirement for each vintage of departing load and will also identify the portion of it that relates to costs covered by Public Utilities Code Section 367(a) to enable the calculation of the ongoing CTC. The total generation revenue requirement for each vintage will then be added to SCE's allocated DWR power charge revenue requirement to determine the revenue requirement on which an indifference amount will be calculated. Those revenue requirements would be compared to the market costs benchmarks and indifference amounts and PCIAs can be calculated and charged for each vintage of total portfolios, similar to the existing CRS calculations, as described above.

SCE supports the total portfolio approach because it is simple and provides departing customers with the benefit of any below-market assets they leave behind by netting them against any above-market costs in the total portfolio (including commitments made after D.04-12-048 was issued).

The total portfolio approach is preferred by SCE, SDG&E, AREM, Hercules, Merced ID, and Modesto ID. However, both SCE and SDG&E indicate D.04-12-048 is ambiguous as to whether a separate charge should be used and request the Commission clarify its intentions in this proceeding. If a separate charge is used, SCE indicates it does not oppose PG&E's proposal. Also, SCE and SDG&E note that in D.07-05-005, the Commission resolved the issue of whether negative non-bypassable charges reflecting below market costs of a utility's procurement portfolio should be carried over from one year to the next. However, while the Commission held that a negative indifference amount in a given year should be carried-forward to cancel out future positive indifference amounts,[48] SCE and SDG&E state the decision is ambiguous as to whether that netting of negative versus positive indifference amounts applies only as long as the PCIA, or the DWR indifference concept, is in place. SCE and SDG&E therefore request that the Commission clarify how long it intends the carry-forward of negative indifference amounts to apply.

TURN is concerned with the 10-year limitation on cost recovery for non-renewable resources and recommends that, in order to maintain bundled customer indifference, the total portfolio should include the lower cost pre-restructuring resources that are not subject to ongoing CTC treatment for 10 years, ending in 2010, to offset the effect of the 10-year limitation on NBC cost recovery for non-RPS resources. If that adjustment were adopted, TURN would support carrying over negative indifference amounts to offset positive indifference amounts in future years. SDG&E supports TURN's proposal to limit the time that pre-restructuring resources are included in the total portfolio. PG&E indicated that if the Commission does not adopt PG&E's separate charge proposal, it should, at a minimum, adopt the limitation on pre-restructuring resources proposed by TURN. DRA indicated that, while it agrees with PG&E's approach, it could also support TURN's proposal.

---

48 See D.07-05-005, pp. 18-21.

6.1.1.2. Separate Charge

Rather than employing the total portfolio approach, PG&E has proposed a separate charge approach, where the new generation resources subject to the D.04-12-048 NBC, and only those resources, are used when comparing resource revenue requirements to market costs. Any resultant positive indifference amounts would represent the uneconomic costs that departing customers should pay in order that remaining bundled customers remain indifferent to their departure. The resultant charges are separate from the ongoing CTC and DWR power charges which would continue to be calculated separately as part of the existing CRS.

If the separate charge results in below-market costs, i.e., a negative indifference amount, the departure of customers would be economic. Under PG&E's proposal, there would be no credit on the departing customers' bills to reflect the negative indifference amount. Also the negative indifference amount could not be carried over to offset future positive indifference amounts.

PG&E argues that the D.04-12-048 NBC is different than the ongoing CTC and DWR power charges in a number of important ways and there are a number of differences between the approaches which justifies its proposal. They are:

- First, the D.04-12-048 charges apply to prospective generation costs, unlike ongoing CTCs, which recover QF and utility-owned generation costs, and the DWR-related costs.

- Second, the D.04-12-048 NBCs have certain limitations that do not apply to ongoing CTCs and DWR power charges, such as the 10-year limit on recovery for nonrenewable resources, including both PPAs and utility-owned generation. The CTC and DWR-related charges are for the life of the contracts at issue.

- Third, the D.04-12-048 charges apply to "all customers," unlike ongoing CTCs and the DWR power charges for which the Commission has granted some limited exceptions. Because the D.04-12-048 non-bypassable charges differ from ongoing CTC and DWR power charges, the Commission determined that an "additional" non-bypassable charge was necessary.

DRA supports PG&E's proposed approach.

6.1.2. Discussion

The principle of bundled customer indifference is paramount in considering the total portfolio/separate charge issue. Again, bundled customer indifference means that bundled customers should be no worse off nor should they be any better off due to departing loads. To start, we must determine what the real differences are between the separate charge approach and the total portfolio approach. Based on what those differences are and how they are viewed when considering bundled customer indifference, we can determine our preference. We can then consider whether the D.04-12-048 NBC 10-year limitation on cost recovery for nonrenewable resources necessitates some kind of adjustment to maintain bundled customer indifference; and if so, what that adjustment should be.

6.1.2.1. The Handling of Negative Charges

In total, the resources and costs for determining the charges for the remaining ongoing CTC costs, DWR related costs and the costs for new generation resources authorized by D.04-12-048 are the same under the total portfolio approach and the approach that calculates the D.04-12-048 charge separate from the ongoing CTC/DWR power charge. As clarified during evidentiary hearing by SCE witness Jazayeri, at this point, the only difference between the separate charge and the total portfolio approaches is how negative charges are handled in the calculations.[49]

If all the calculated charges were positive, the departing customer would pay the same amount under both approaches. The only difference would be that the total portfolio approach, which considers all of the resources and costs together, would result in one combined charge; while the separate charge approach would result in two charges - the combined ongoing CTC/DWR power charge and the separate D.04-12-048 charge, which when added together would equal the total portfolio charge.[50]

However, if one of the charges is negative, the separate charge and total portfolio approaches would result in different charges, at least initially. For example, if the combined ongoing CTC/DWR power charge for any particular year is negative and the D.04-12-048 charge is positive, the two approaches would yield different total charges for that particular year.

Under the total portfolio approach, the three charges are essentially netted against each other and the result may be positive or negative. If the combined amount is positive, the customer would pay the combined charge. If the combined charge is negative, the customer would not pay anything and the combined negative charge would be carried over for use in subsequent years.

Under the separate charge approach, the customer would not pay anything for the ongoing CTC/DWR power charge and the entire negative

---

49 SCE, Jazayeri, 11 RT 1442-1445.

50 The total portfolio methodology does not apply if a customer does not pay the DWR power charges. (*See* D.05-01-035, p. 3; D.06-07-030, pp. 34-38; D.07-01-020, p. 5.)

amount would carry over for use in subsequent years. The customer would also separately pay the full amount of the D.04-12-048 charge. Therefore, in that particular year, under these circumstances, the customer would pay a higher amount under the separate charge approach. However, when looked at over a number of years, in situations where the ongoing CTC/DWR power charge is negative, the customer may essentially pay the same amount under either approach, since even under the separate charge approach, the negative ongoing CTC/DWR power charge, while not offsetting the D.04-12-048 charge in that particular year, can be used to offset positive ongoing CTC/DWR power charges in subsequent years.

The principal difference between the separate charge approach and the total portfolio approach occurs when the D.04-12-048 NBC charge for any particular year is negative. Under the separate charge approach, the customer would not pay a D.04-12-048 charge, similar to what would happen if the combined ongoing CTC/DWR power charges were negative. However, in contrast to the negative ongoing CTC/DWR power charges being carried over for use in subsequent years, the separate negative D.04-12-048 charge would not be carried over for use in subsequent years. That negative amount then could never be reflected in calculating the customer's charge. Under these circumstances, over time, the total of the two separate annual charges would diverge from the total of the annual total portfolio charges, simply because the negative D.04-12-048 charge is never accounted for in calculating charges -- not in the particular year in which it occurs, nor in any subsequent year.

The handling of negative charges was previously addressed in D.07-05-005. In that decision, we stated:[51]

> …By allowing for negative indifference amounts to be netted against future positive amounts, the goal of bundled customer indifference is preserved…
>
> …By recognizing only positive indifference amounts, but not tracking offsetting effects attributable to negative indifference, PG&E's proposed method could result in a permanent net positive indifference amount charged to DA/DL customers. The indifference charge is intended to capture the applicable above-market procurement costs. Indifference is achieved when there is neither an under-or-over recovery of such indifference charges from DA/DL customers..."
>
> …Therefore, in order to maintain indifference, both positive and negative indifference effects must still be tracked, with the negative amounts offsetting positive amounts…

While the Commission's reasoning in that decision applied to the existing DA/DL CRS calculations, the basic principles directly relate to handling of negative charges in this proceeding as described above. It is similarly necessary that negative indifference amounts be carried over for use in subsequent years to maintain bundled customer indifference. The total portfolio approach is consistent with this principle. PG&E's separate approach is not. While we could adopt PG&E's separate approach after first modifying it to conform to our previous determinations regarding the carryover of negative indifference amounts, we prefer instead to adopt the use of the total portfolio approach for

---

[51] *See* D.07-05-005, pp. 18-19.

use in implementing the D.04-12-048 NBC. This preference is primarily based on our understanding of the implications of each approach with regard to the handling of pre-restructuring resources not subject to ongoing CTC, as discussed below. The use of the total portfolio approach is necessary to implement provisions of this decision regarding the use of these pre-restructuring resources in determining cost responsibility once recovery of the DWR power charge ends.

6.1.2.2. Pre-restructuring Resources not Subject to Ongoing CTC Treatment

One of PG&E's objections to the total portfolio approach is related to whether or how long the pre-restructuring resources[52] should be included in the portfolios for calculating ongoing CTC, DWR power charges and D.04-12-048 charges. PG&E argues that requiring new generation costs to be offset by generation that is 25 to 30 years into its depreciation cycle does not truly capture the stranded costs associated with the new generation, and departing customers should not receive the benefits of existing generation after they leave bundled service. By PG&E's separate charge approach, the pre-restructuring resources are not included in the calculation of the separate D.04-12-048 charge. Also, while PG&E acknowledges that currently these resources are reflected in the calculation of the PCIA, PG&E also states that the indifference standard and current total portfolio approach expire once the DWR power charge ends. When that happens, as a consequence of PG&E's separate charge approach for the

[52] For purposes of this decision, "pre-restructuring resources" refers to those current IOU resources that existed prior to March 31, 1998 and are not subject to ongoing CTC treatment. These resources consist principally of the IOUs' retained generation (i.e., hydro, coal and nuclear plants). Power from these resources tends to be cheaper when compared to the costs related to ongoing CTC, the DWR contracts and new generation.

D.04-12-048 charge, only the ongoing CTC would remain in the existing CRS calculation, effectively eliminating the use of pre-restructuring resources.[53]

SCE, in recommending the total portfolio approach, does not indicate that pre-restructuring resources should ever be excluded from the portfolio. SCE's statement that its proposal "provides the departing customers with the benefit of any below-market assets they leave behind by netting them against any above-market cost in the total portfolio (including commitments made after D.04-12-048 was issued)," suggests, to the extent contracts have not expired or generation assets are not yet retired, the pre-restructuring resources would remain in the portfolio as long as D.04-12-048 charges were being calculated and assessed. Similar to the current DWR power/ongoing CTC methodology, the total indifference amount would be calculated, the ongoing CTC portion would be calculated pursuant to Pub. Util. Code § 367(a), and that amount would be subtracted out of the total resulting in the D.04-12-048 charge.

In D.02-11-022, the Commission determined that a total portfolio approach was appropriate for use in calculating the DA CRS, stating:

> The intent underlying the indifference calculation, however, is to determine the cost shifting that resulted from the migration of certain bundled customers to DA. An accurate measure of cost shifting cannot be determined if we selectively focus only on certain

[53] Consistent with D.06-07-030, pre-restructuring resources cannot be used to mitigate the costs of ongoing CTC alone. In that decision, we stated "We thus conclude that applying a bundled customer indifference standard is not appropriate in deriving the cost responsibility for MDL customers if no DWR power charge is paid. We shall apply a total portfolio indifference standard to MDL CRS obligations only where a DWR power charge is applicable. The indifference adjustment does not change the ongoing CTC that applies uniformly to all bundled, DA and DL customers." (D.06-07-030, p. 37.)

> components of cost shifting while ignoring others. The directive in D.02-03-055 was to consider all cost shifting, not just those effects attributed to the DWR portion of the total portfolio. The netting of [utility retained generation] URG savings does not imply that those URG resources are somehow dedicated to serving DA customers. The attribution of savings to DA customers merely reflect the change in costs experienced by bundled customers associated with their use of those dedicated resources. (D.02-11-022, p. 25.)

That reasoning is directly applicable to our consideration of the D.04-12-048 charge. By including only the D.04-12-048 resources in the portfolio, the separate charge approach only considers cost shifting associated with those resources. Bundled customer indifference will only be maintained if all resources are included in the portfolio used to calculate the related charges, whether it is the ongoing CTC, DWR power charges and D.04-12-048 charges or just the ongoing CTC and D.04-12-048 charges. Therefore, the use of the total portfolio and the inclusion of the pre-restructuring resources in that portfolio is the appropriate approach to use for the duration of the D.04-12-048 NBC cost recovery[54] even after cost recovery of the DWR power charge ends.

Similarly, the current provisions related to negative indifference charge carryover for use in subsequent years should be continued once DWR power charge recovery ends. Again, this is necessary to maintain bundled customer indifference. D.07-05-005 did state that at the expiration of the DWR contract term, the applicability of the indifference requirement would also expire. That made sense in the context of that decision, since it was the recovery of the DWR

---

[54] The pre-restructuring resources would be included in the portfolio as long as they have not been retired.

contracts themselves that necessitated the total portfolio approach and bundled customer indifference as it relates to such recovery. With the expiration of the DWR contract term, none of this would have been necessary, and the applicability of the indifference requirement as it relates to DWR power charge cost recovery should also have ended. However, with the inclusion of D.04-12-048 cost recovery as part of the total portfolio, the reasons cited in D.07-05-005, as discussed above as to why negative indifference charge carryover is appropriate, apply even after expiration of the DWR contract term. That reasoning is as valid for cost recovery related to the ongoing CTC and D.04-12-048 charges as it was for cost recovery related to the ongoing CTC and DWR power charges.

6.1.2.3. The 10-Year Limitation on Cost Recovery Under D.04-12-048

As discussed below, we have considered the effects of the D.04-12-048 provision whereby cost recovery for non-renewable resources is limited to 10 years, and we do not feel it is necessary to make any related changes to the total portfolio approach at this time.

In D.04-12-048, the Commission concluded:

> The utilities should be allowed to recover stranded costs for their non-RPS resource commitments from departing load over either the life of the contract or 10 years, whichever is less. The ten-year recovery period should also apply to any utility-owned generation acquired as a result of the procurement process, commencing once the resource begins commercial operation. Stranded costs arising from RPS procurement activities should be collected from all customers, including departing load, over the life of the contract. The utilities should be allowed the opportunity to justify in their applications, on a case-by-case basis, the desirability of adopting a cost recovery period of longer than ten years for their non-RPS resource commitments. Cost recovery for that portion of a resource

> acquired by the utilities to meet local reliability needs should be recovered from all customers. (Conclusion of Law 16.)

Two proposals have been made to address the perceived effects of this 10-year cost recovery limitation. There is PG&E's separate charge approach which effectively abandons use of the supposedly cheaper pre-restructuring resources as soon as DWR power charge cost recovery ends. There is also TURN's proposal for use of a total portfolio approach which would include the pre-restructuring resources in the total portfolio only through 2010. In both cases, the resultant D.04-12-048 charge would likely be higher than it would be if there were no limitations on including pre-restructuring resources in the total portfolios. Both PG&E and TURN argue that their proposals are necessary to maintain bundled customer indifference with respect to the D.04-12-048 10-year limitation for cost recovery of non-RPS resources.

As support for its position TURN argues, "As long as new non-RPS resources can only be included for 10 years, consistency would dictate that pre-restructuring non-QF resources should only be included in the total portfolio for ten years as well. Otherwise, there is a bias in the calculation that interferes with the achievement of bundled ratepayer indifference on a total portfolio basis."[55]

However, the D.04-12-048 10-year cost recovery limitation is for each specific non-RPS resource. TURN's pre-restructuring resource limitation is not specific for each resource but is instead applicable to the total portfolio with a set end date of 2010. Since the DWR power costs are continuing and will likely not

---

[55] TURN Opening Brief, p. 7. *See* also Exhibit 117, p. 13.

end until after 2010, the pre-restructuring resources would have been included in the total portfolio anyway to maintain bundled customer indifference in the calculation of the fully recoverable DWR power charge for that entire 10-year period. If a non-RPS resource begins providing energy in 2011, cost recovery of the related D.04-12-048 charge would extend 10 years through 2020. Yet under TURN's proposal, in the calculation of the related D.04-12-048 charges, the pre-restructuring resources would not be included in the total portfolio for any of those years. TURN's argument that a limitation on the use of pre-restructuring resources fairly offsets its perceived effects of the D.04-12-048 10-year limitation on cost recovery for non-RPS resources is not persuasive.

Similarly, while PG&E's separate charge approach has not been adopted by this decision, when its separate charge approach and existing CRS are looked at in total, pre-restructuring resources would also cease to be considered in determining these charges at a specific point in time. That would be when the DWR power charge ends. We see the same problems with that as we do with TURN's proposal to end the use of pre-restructuring resources in the total portfolio in 2010.

As indicated, we do not see the logic or fairness in ending the use of pre-restructuring resources in the total portfolio as of 2010 or as of the date that cost recovery for the DWR power charge ends as a way to address the D.04-12-048 limitation on cost recovery for non-RPS resources and will not do so.

With respect to non-RPS resources that will be available for more than 10 years but which are limited to 10-year NBC recovery, the utilities can, over time, adjust their load forecasts and resource portfolios to mitigate the effects of DA, CCA, and any large municipalizations on bundled service customer indifference. By the end of a 10-year period, we assume the IOUs would be able to make substantial progress in eliminating such effects for customers who cease taking bundled service during that period. Furthermore, as provided by D.04-12-048, uneconomic costs associated with new non-RPS resource contracts of 10 years or less are fully recoverable, and the uneconomic costs of new RPS contracts are fully recoverable over the length of the contract with no limitation.

We must also consider the possibility that for non-RPS contracts or utility resource assets with lives significantly longer than 10 years, there may be a point in time when such resources may become more economic, when compared to the market benchmark, than many of the other newer resources existing during that time period, and thus may in effect lower future total portfolio costs similar to the manner in which the pre-restructuring resources currently have in lowering current total portfolio costs. The fact that such lower costs would also not be reflected in the total portfolio after the initial 10 year period may have an impact on the need to extend the length of time that certain resources should remain in the total portfolio.

However, if the IOUs believe a cost recovery period extension is appropriate and necessary for specific non-RPS resources, they can make such requests under the provisions of D.04-12-048. The Commission can then tailor its findings, conclusions and remedies to the specific facts of each case and can fully extend, partially extend or not extend the cost recovery period. We believe this process is fair and more reasonable than implementing some overall limitation on the resource portfolio mix.

6.1.2.4. RPS Resources

In a number of advice letter filings requesting approval of RPS power purchase agreements, PG&E included a request to recover the above market costs of the contracts through a NBC, consistent with its interpretation of D.04-

12-048. The Commission consistently declined to do so, indicating that it would not address such above market cost recovery in the resolutions and indicated that R.06-02-013 was the appropriate procedural forum for addressing those issues.[56] In Resolution E-4138, dated December 20, 2007, the Commission clarified its intent as follows:

> …by this resolution we make no determination of whether stranded costs will in fact be incurred during the life of this contract. However, to the extent that such costs should occur, such costs will be eligible for stranded cost recovery subject to any determination in R.06-02-013 or any other proceeding regarding the implementation of cost recovery provisions of D.04-12-048….

To further clarify, with respect to the implementation of the stranded cost provisions of D.04-12-048 that are addressed in today's decision, the NBCs, which include any above market costs related to RPS contracts, will not apply to departing load that is excluded from the load forecasts used to develop the IOUs' LTPPs. The excluded departing load includes MDL, with the exception of large municipalizations, and CGDL. DA and CCA load are fully subject to the D.04-12-048 NBC. Furthermore, RPS contracts are fully recoverable over the life of the contracts. When calculating the CRS, the RPS contracts will be blended in with other generation resources under the total portfolio analysis. The costs of all of the resources would be compared to the applicable benchmark price to determine whether there are any above market costs. The applicable benchmark price will be calculated as set forth in D.06-07-030 and modified by D.07-01-030.

---

[56] For example, see Resolutions E-4046, E-4047, E-4055 and E-4084, E-4110, E-4084, and E-4138.

Also, since the D.04-12-048 NBC is based on a total portfolio analysis of an above-market price and is not intended to allocate specific resources to specific customers, none of the benefits or attributes of the RPS contracts will be transferred to those customers who pay the D.04-12-048 NBC at this time. We note, though, that future developments in the State's renewable and/or greenhouse gas policies may both necessitate and facilitate a review of the manner in which renewables attributes are treated with respect to departing load and the new generation NBC to best maintain ratepayer indifference and the State's various policy objectives.

6.1.2.5. Future Modifications

The D.04-12-048 NBC was established for a number of reasons including the uncertainty caused by potential increases in DA,[57] CCA and DL.[58] The need for the NBC is likely to be long lasting. Given the potential long-term nature of the charge, we must allow for the possibility that certain future circumstances

---

[57] The potential increase in DA is dependent on the outcome of our proceedings regarding the lifting of the DA suspension. Our reference to this potential increase is not intended to prejudge the outcome of those proceedings.

[58] In D.04-12-048, the Commission stated, "A major issue in this proceeding is the extent to which the utilities will be compensated for investments or purchases that they must make in order to meet their obligations to provide reliable service to their customers. The implementation of CCA, departing municipal load, and the potential for lifting, in some form or another, the current ban on allowing new DA all create a great degree of uncertainty as to the amount of load the existing utilities will be responsible for serving in the future. Given the potential for a significant portion of the utilities' load to take service from a different provider, the utilities are concerned that they could end up over-procuring resources and incurring the stranded costs associated with these resources." (D.04-12-048, p. 55.)

may result in a need to modify the NBC related processes adopted in this decision.

For instance, SCE believes that the current methodology for determination of a market price benchmark is reasonable as long as the load departure does not increase significantly above that seen in the post-2001 period. If it does increase significantly, SCE indicates it may ask the Commission to revisit the issue.[59] SDG&E also states that it is not clear that the benchmark would be appropriate in the future should DA reopen or significant load migrates via CCA.[60] Significant shifts in load may affect other things such as the need for renewable contracts and how such contracts should be handled in the recovery of stranded costs.

If, due to future changing circumstances, the processes adopted by this decision for determining the NBC become unworkable, unbalanced, or unfair, parties may propose and request, for our consideration, modifications to the form of the NBC or the manner in which the NBC should be determined or calculated.

6.1.2.6. Summary

To summarize, we adopt the use of a CRS calculation using a total portfolio approach that accounts for the ongoing CTC, DWR and D.04-12-048 charges. This includes netting the individually calculated annual charges and carrying over any negative total charge to offset positive charges in subsequent years. Further, we determine that pre-restructuring resources should continue to be included in the portfolio of resources used in determining the D.04-12-048

---

[59] SCE, Exhibit 34, p. 14.

[60] SDG&E, Exhibit 51, p. 1.

charges, once recovery of DWR power costs ends. We will address the effects of the 10-year limitation on cost recovery of new non-RPS generation resources on bundled customer indifference, on a case-by-case basis, if and when the IOUs request cost recovery extensions, pursuant to the provisions of D.04-12-048. Finally, should the processes adopted by this decision become unworkable, unbalanced, or unfair, parties may request, for our consideration, modifications to the form of the D.04-12-048 NBC or the manner in which that NBC should be determined or calculated.

6.2. Vintaging

For this proceeding, we define vintaging as the process of assigning a departure date to departing customers in order to determine those customers' generation resource obligations.[61] To implement the stranded cost recovery principles adopted in D.04-12-048, the IOUs must track the generation costs, including the costs of certain generation commitments, incurred to serve departing customers up to the point when a particular customer departs and the IOU no longer provides procurement services to serve its load. The law permits the recovery of stranded costs from those customers who are responsible for stranded costs related to resource and contractual commitments made by the IOU up until the time of the customer's departure and that departing customers should bear no cost responsibility for such commitments the IOU makes after their departure. The determination of a departure date is extremely difficult, especially one that tracks customers by the day, the week or the month of departure and vintages them accordingly. Each of the IOUs has made an

[61] Departing customers also include new MDL.

alternative recommendation to establish a departing customer's vintage, and certain other parties have indicated their preferences and recommendations on this issue.

6.2.1. Positions of the Parties

PG&E proposes annual vintaging. For example, if a customer leaves in 2009, it would be responsible for any stranded costs associated with new generation resource commitments made in 2009 and previous years, but would not be responsible for commitments made in 2010. PG&E states that its proposal is consistent with its ERRA, which is forecasted on an annual basis. PG&E adds that its proposal reflects the reality that negotiating a new PPA or obtaining Commission approval may take some time, and that although the PPA may be executed or approved later in a calendar year after a customer departs, negotiations were started or the contract was submitted to the Commission for approval before the customer departed, on behalf of that customer and other bundled customers.

PG&E states that some parties have advocated shorter vintage periods, such as a six-month vintage. However, shorter periods will only add to the complexity of administering the D.04-12-048 NBCs. Under these proposals, within any given year there would be two or more classes of customers with certain vintages, requiring the tracking of when specific resource commitments were made and when customers left. Moreover, this proposal ignores the fact that a PPA may be executed or approved by the Commission later in the year, but was originally negotiated or submitted on behalf of the customer before it departed. PG&E notes the vintage period included in Modesto's Board approved NBC tariff is an annual vintage, which is what PG&E proposes here.

PG&E concludes that the Commission should adopt PG&E's annual vintaging proposal because it is equitable and can be easily administered.

SCE proposes to vintage the departing customers by the calendar year in which they depart and on whether they depart in the first or second half of the calendar year. Customers leaving or providing SCE a binding notice of intent to leave in the first half of 2009 would be assigned a vintage that would include all the resources that SCE contracted for up through December 2008. For example, a customer that departs in April 2009 (first half of 2009) will be responsible for the stranded costs associated with utility commitments made through December 2008. However, a customer that departs in September 2009 (second half of 2009) will be responsible for the stranded costs associated with utility commitments made through December 2009. SCE adds that it should be understood that "the time a commitment is made" refers to when SCE executes a contract or begins the construction of a new generation resource, not when deliveries begin under the contract or the generation resource becomes operational.

SDG&E proposes the same vintaging methodology as proposed by SCE, indicating that while no single vintaging methodology is perfect for all situations, this is the fairest and most cost-effective methodology overall.

Hercules states that bundled customer indifference cannot be achieved if departing customers are held responsible for generation commitments made after their departure. As a result, Hercules prefers SCE's proposal (assigning vintage years to departing customers) to PG&E's proposal because, under SCE's proposal, at most a customer will be held responsible for generation commitments made up to six months after departure, compared to up to 12 months after departure under PG&E's proposal.

TURN indicates that while its bundled customer constituency would benefit from slightly greater stranded cost recovery under PG&E's method, SCE's approach strikes a better balance than does the PG&E proposal. TURN adds that if its other recommendations that are designed to insure bundled ratepayer indifference were adopted, it would support the SCE proposal on this issue.

DRA states that it supports SCE's and SDG&E's proposals adding that the Commission must craft a workable solution that balances the rights of departing load customers with the practicality of utility administration.

AReM notes that the Commission will be considering a broad range of issues related to a new retail market structure in its rulemaking concerning DA (R.07-05-025) and urges the Commission defer the development of a vintaging system for DA customers to that proceeding. However, if such a vintaging system is to be adopted in this proceeding, AReM recommends that DA customers should be assigned a vintage that corresponds with the month in which they provide notice to their utility of their intent to depart bundled service. AReM states that while, in theory, each customer should be assigned an individual "vintage" corresponding to the precise time that the customer gives notice of its intent to depart, it recognizes that this could impose a significant administrative burden, as it would require the NBCs for each customer to be calculated separately. Instead, AReM indicates that it would support a method that assigns a customer a vintage based on the month that a customer gives notice of its intent to depart bundled service, and in which customers who notify the utility of its intent to depart in a given calendar year are responsible for commitments made through June of that year.

Under AReM's proposal, customers who provide notification in January would pay for the stranded costs of up to six months of resource additions that were not made on their behalf, and customers who provide notification in December are exempt from the stranded costs of up to six months of resource additions that were made on their behalf. AReM argues that bundled customers would be left indifferent, since the overpayments and underpayments should, on average, cancel each other out, and there is no room for gaming, since a customer is never any better off for delaying his departure.

CCDC asserts that the vintage of DG customers is 2002 and, therefore, customers who install DG after 2002 should not be subject to stranded cost recovery under D.04-12-048 or net cost allocation under D.06-07-029. CCDC argues that, for purposes of vintaging, load should be considered departing as of the date an IOU knew, or should have known, of the departure and notes the record in R.02-01-011 demonstrates that the IOUs had knowledge of DG departing load at least as early as 2001. It is CCDC's position that the IOUs should have continued forecasting DG departing load, the IOUs should be incorporating those forecasts into its procurement plans, the IOUs should not be procuring power for load they forecast will depart, and therefore the date of departure, or the vintage, for DG departing load, should be 2002. If the Commission does not set 2002 as the vintage for all CHP DG, then CCDC supports SCE's vintaging proposal.

Merced ID and Modesto ID similarly state that the Commission should confirm that the vintage of the transferred and new municipal departing load of Modesto ID and Merced ID is 2002 and, therefore, that the transferred and new municipal departing load of Modesto ID and Merced ID is not subject to stranded cost recovery under D.04-12-048 or net cost allocation under D.06-07-

029. Merced ID and Modesto ID recommend that vintaging for non-exempt departing load should be based on SCE's proposal.

EPUC states that if no exemption is adopted for CGDL, the IOUs should use six month periods for vintaging purposes.

CCSF recommends there be at least two vintaging periods per year.

6.2.2. Discussion

The CCDC and the Merced ID/Modesto ID proposals that the vintage year for their customers should be 2002 are essentially based on the premise that forecasted load should be excluded from having to pay the new generation NBCs. This issue was addressed earlier in this decision. As discussed in Section 4.1, MDL, with the exception of large municipalizations, and CGDL customers' fair share will be zero, and thus, they are excluded from having to pay the D.04-12-048 NBCs. The reason for the exemption is that these loads were excluded from the load forecasts used to develop the LTPPs. (See discussion above.) It is therefore unnecessary to address the 2002 vintage year issue.

We will not grant AReM's request to defer the development of a vintaging system for DA customers to R.07-05-025. Earlier in this decision, we determined that customers who are eligible to return to DA should not be excluded from having to pay the NBC associated with D.04-12-048. A vintaging methodology needs to be adopted now in order to determine the related cost responsibility, if and when such customers return to DA. If there are any vintaging related determinations made in R.07-05-025 that affect what is adopted in our decision today, we will consider modifications to today's decision, as necessary, at that time.

For DA customers, CCA customers,[62] and customers departing due to a large municipalization that is not reflected in the departing load forecasts, there are two general vintaging proposals as described above in the parties' positions. PG&E proposes that December 31st should be the assigned departure date for vintaging purposes for those customers departing in any particular year. Most customers would therefore have an assigned departure date that is later than the actual departure date. On the other hand, SCE proposes that customers departing in the first half of the year would have a departure date for vintaging purposes of December 31st of the prior year, while customers departing in the second half of the year would have a departure date for vintaging purposes of December 31st of the year in which they depart. By this method, some customers will have assigned departure dates that are earlier than the actual dates, while others will have assigned departure dates that are later than the actual dates. As indicated above, this proposal is supported by a number of parties and is perceived to be fairer than PG&E's proposal.

First of all we agree that it is necessary to have some simplifying methodology so that the IOU does not have to figure out and administer the actual vintage for every customer.[63] However, in simplifying the process, most

---

62 An optional BNI process exists for customers choosing CCA. The departure date would be the CCA stated date on which the BNI is based. For those CCA customers who do not choose the BNI process, their departure date is when they cease taking procurement services from the IOU.

63 We agree with SCE's statement that "Ideally, departing customers should bear no cost responsibility for the resource and contractual commitments SCE makes after their departure. In practice, however, it is extremely difficult to track customers by the day, the week or the month of departure and assign them a CRS vintage. Vintaging based on calendar quarters could be done; however, it gets more and more difficult because

Footnote continued on next page

customers will have assigned departure dates that will not be the same as the actual date. The consequence of having a later than actual departure date is that the customer may end up being responsible for resource commitments made after that customer's actual departure (likely to benefit the remaining bundled customers), while the consequence of having an earlier than actual departure date is that the customer may end up not being responsible for certain resource commitments before that customer's actual departure (tending to be potentially adverse to the remaining bundled customers). Under PG&E's proposal, most customers will have assigned departure dates that are later than actual. This proposal would almost certainly benefit the remaining bundled customers in the long term. Under SCE's proposal there will be customers with assigned departure dates that are both earlier and later than actual. Over the long term, potential benefits and adverse effects to bundled customers would tend to balance out under this proposal. Consistent with our commitment to adhere to the bundled customer indifference principle where possible, we will adopt SCE's proposal to use two departure dates for vintaging purposes. We will also adopt SCE's related proposal that "the time a commitment is made" is when the IOU executes a contract or when the IOU begins the construction of a new generation resource, not when deliveries begin under the contract or the generation resource becomes operational. With regard to PG&E's concerns regarding complexity, the

---

(*footnote continued from previous page*)

you will have now four categories of customers to deal with instead of one or two. It can go even monthly, but it just becomes an administrative nightmare." (SCE Opening Brief, pp. 7-8; see also Exhibit 34, p. 11 and SCE, Jazayeri, 11 RT 1441.)

SCE proposal would still use annual electric revenue adjustment mechanism (ERAM) forecasts, and we do not see the process of assigning the vintage based on either the year in which the customer departs or the year before the customer departs (SCE proposal) as being any more complicated than assigning the vintage based on the year in which the customer departs (PG&E proposal). An assignment to a particular year needs to be done in either circumstance. Also, we are not persuaded to adopt PG&E's proposal for the stated reason that negotiating a new PPA or obtaining Commission approval on behalf of a departing customer and other bundled customers before the customer departs may take additional time that is not directly reflected in the vintaging process. As indicated previously, we have adopted SCE's vintaging proposal which includes the identification of resource commitments that are made on behalf of departing customers based on when the IOU executes a contract or begins the construction of a new generation resource. That sufficiently covers the timeframe for departing customers' cost responsibility.

AReM's alternative proposal to use commitments as of June 30 for DA customers leaving bundled service in that year is similar to SCE's proposal in that, over time, the effect of customers having assigned departure dates earlier than the actual dates would be balanced by the effect of customers having assigned departure dates later than the earlier the actual dates. The only difference is that under AReM's proposal, DA customers departing in the first half of the year would have an assigned departure date that is later than their actual departing dates, while DA customers departing in the second half of the year would have an assigned departure date that is earlier than their actual departing dates. This is the opposite of SCE's proposal whereby customers departing in the first half of the year would have an assigned departure date that is earlier than their actual departing dates, while customers leaving in the second half of the year would have an assigned departure date that is later than their actual departing dates. Fairness and bundled customer indifference can be achieved under either approach. For consistency, we prefer to use one approach for all customers. Also, it is not clear what additional work would be involved in developing the June 30th, or mid-year, portfolios and the associated costs. The generation revenue requirement set forth in the ERRA proceedings and the allocated DWR power charge revenue requirements are generally determined on a full-year basis. For that reason, as well as the fact that it was preferred by a majority of the parties, we choose to adopt the SCE vintaging proposal over that of AReM.

The six-month proposal by EPUC appears to be similar to PG&E's proposal except the lengths of the vintaging periods are halved. There is still the problem of having most assigned departure dates being later than the actual departure dates. The six-month proposal would also add administrative burdens, since resource vintages and revenue requirements would also have to be determined on a six month rather than annual basis.

6.3. Calculation of the D.04-12-048 NBC

The D.04-12-048 NBC will be reflected as an element of the CRS as explained above. The new generation costs will be calculated annually by each IOU as part of the generation revenue requirement determined in its ERRA proceeding. The adopted DWR power charge revenue requirement is determined from the DWR revenue requirement allocation proceeding. With this information, the indifference amounts can be calculated. Since the calculation of the indifference amount requires both the adopted generation revenue requirement and adopted DWR power charge revenue requirement, each utility will submit the calculation of the indifference amount for each vintage of departing load in its advice letter implementing the later of the annual ERRA decision or the annual DWR revenue requirement allocation decision, as is currently done.[64] Those advice letters will be reviewed by the Commission's Energy Division, but parties have the opportunity to protest the advice letter filings if they see a need to do so. Also, issues regarding consistency of the implementation and calculation of the CRSs with respect to this decision can be raised and litigated in the forecast phase of the IOUs' ERRA proceedings.

Examples of CRS calculations that include new generation charges are shown in Appendix E to this decision.[65]

6.3.1. Areas of Agreement

While all parties did not address all aspects of the calculation of the D.04-12-048 NBC and related CRS, there appeared to be a few areas where there did not appear to be any disagreements. They include (1) the use of the market benchmark adopted in D.06-07-030, as modified by D.07-01-030, to determine above-market costs and (2) the use of a forecast of costs, done through the ERRA, without an after-the-fact true-up. Both are reasonable and should be used in determining the D.04-12-048 NBC and related CRS.

Regarding the market benchmark, SCE believes that the current methodology for determination of a market price benchmark is reasonable as

---

[64] *See* D.06-07-030, pp. 22-29 and Exhibit 34, p. 15.

[65] These calculations are illustrative and not all-inclusive. For instance, it does not include a total portfolio calculation for MDL that may be subject to the DWR power charge but not the D.04-12-048 NBC. In practice, the IOUs will calculate the CRS in their Advice Letter filings, and parties can review them and protest as they see fit.

long as the load departure does not increase significantly above that seen in the post-2001 period.[66] If it does increase significantly, SCE states that it may ask the Commission to revisit the issue, indicating that, in that case, it may be appropriate, for example, to calculate a mark-to-market for the utility portfolio for each calendar year (or smaller intervals such as each quarter) and assign the resulting stranded costs to all customers departing during that calendar year for all future years. SCE also cites Finding of Fact 38 of D.04-12-048, which recognizes that future development of liquid and competitive capacity markets and the implementation of the California Independent System Operator's Market Redesign and Technology Upgrade may warrant a modification to the adopted market price benchmark. SCE's concerns are legitimate. We will leave it to the parties to propose such changes, if and when they become necessary, in the proceedings where the market benchmark is calculated and used (e.g., the ERRA).

6.3.2. Levelized Fixed Costs

Based on the cross-examination of PG&E witness Winn on the cost recovery concept that, for a specific amount of utility plant, the accumulated depreciation is lower in the earlier years, and the associated net plant and fixed costs are therefore higher in the earlier years, when compared to the later years,[67] Merced ID/Modesto ID argue that the Commission should require that the IOUs should use a levelized calculation of the fixed costs of utility owned generation assets. Merced ID/Modesto ID suggests the Commission could have a

---

66 Merced ID/Modesto ID indicated agreement with this belief.

67 PG&E, Winn, 10 RT 1215-1218.

workshop to address implementation of a levelized cost calculation. CCDC and EPUC make similar recommendations.

While the concept of levelized fixed cost recovery may be valid under certain circumstances, we will not deviate from normal capital cost recovery in this instance. As suggested by Merced ID/Modesto ID, CCDC and EPUC the fixed cost revenue requirement in the latter years of a project's life may be less than in the early years. This is principally due to the reduced rate base amount caused by the accumulated depreciation up until that time. However, in this proceeding we are dealing with stranded cost recovery that may last for 10 years while the project itself may have up to a 30-year life or more. Regarding the proposed levelized fixed cost recovery proposal, we do not feel it is equitable for customers who will only be paying for 10 years of the project's depreciation to be entitled to the entire reduced revenue requirement effect that results from the accumulated depreciation that will have been paid by other customers for 30 years or more. Therefore we will not adopt the levelized fixed cost recovery proposal for use in this track of the proceeding.

6.3.3. Determination of Capacity Adders and Line Loss Adjustments

EPUC also states a need for workshops related to the determination of capacity adders and line loss adjustments. However, EPUC did not explain what is wrong with either the values of these items or the way that these items are included in NBC calculation, or make any proposals to address any perceived shortcomings. No other party stated a need or recommended workshops for these purposes, and no party expressed agreement with EPUC in this regard. Such workshops have not been justified and will not be required by this decision.

6.4. Cost-Effectiveness

CCDC, Merced ID and Modesto ID have recommended that the Commission should evaluate the cost-effectiveness of the IOU's proposal for determining stranded costs, vintaging customers and calculating and imposing NBCs.

Also, Hercules states that no NBC should be billed to a departing load customer if the cost of determining, billing and collecting the charge exceeds the revenues to be collected. Hercules argues that without this limitation the IOU's bundled customers would be forced to pay more for billing and collecting departing load charges than the revenues would otherwise justify, thus violating basic principles of cost benefit.

6.4.1. ALJ Questions

While certain parties questioned the cost-effectiveness of the NBCs, no party provided any analysis or other evidence that would indicate whether or not the NBCs proposed by the IOUs in this proceeding were, or were not, cost-effective when comparing the costs of implementing and imposing the charges with the revenues that might be generated by such charges.

In order to address this issue, the ALJ requested the IOUs to provide the following:[68]

1. NBC related activities necessary to do the following:

---

[68] Draft questions were provided to the parties on September 19, 2007 and were discussed at the end of evidentiary hearing on September 21, 2007. Based on that discussion, certain changes were made, and the final questions were attached to the September 21, 2007 Reporter's Transcript (Volume 14).

a. Calculate the system average new generation NBC by vintage year or calculate the cost responsibility surcharge by vintage year.
b. Determine cost allocations.
c. Identify the customer.
d. Determine the customers NBC.
e. Bill the customer.
f. Collect and process a customer's payments.
g. Develop and maintain necessary tools and data base to perform items a. through f.

2. Estimates of the costs for each of the activities identified in response to Item 1 by cost center if possible. For Items 1.c. through 1.f. provide estimates of costs on a per customer basis.
3. For each cost identified in response to Item 2, an indication of whether the cost is a recurring or non-recurring cost. Include the frequency of recurring costs.
4. For each cost identified in response to Item 2, an indication of whether the cost is incremental to costs currently incurred by the utility or whether the cost is embedded in costs currently incurred by the utility.
5. Range of potential revenues that might be realized by imposition of an NBC, including that related to low, medium, and large usage customers, based on NBCs calculated using new generation costs or to total portfolio costs being 5% and 10% above the market price benchmark.
6. Conclusions and explanations of conclusions on the cost-effectiveness of imposing the NBC.
7. All assumptions and calculations related to 1 through 6.
8. Provide the information requested in Questions 1 through 7 for existing procurement related non-bypassable charges.

The intent of the ALJ's questions was to determine whether a reasonable forecast of revenues associated with NBCs could reasonably be expected to exceed the incremental costs of implementing and imposing the NBCs, which is generally the issue that was raised by the parties. There was no intention to determine the cost-effectiveness of previously authorized and implemented charges such as the ongoing CTC or DWR power charge.

PG&E, SCE and SDG&E's response to the questions in Exhibits 211, 212 and 213 were filed on October 12, 2007. To allow parties the opportunity to comment on, or express concerns related to, the materials contained in the exhibits, a date of October 19, 2007 was set for the filing of responses to the exhibits. Responses were filed by CMUA, EPUC, Merced ID/Modesto ID, and CCSF.

6.4.2. Responses to the IOU Exhibits

According to CMUA, the information contained in the IOU documents should be afforded no more weight than that attributed to any response to a data request not subjected to cross-examination. CMUA states that neither PG&E nor Edison provides any supporting documentation or verification for their conclusions that the New Generation NBCs are cost effective. Rather, the IOUs' conclusions are based on an analysis that lumps together all classes of departing load – existing and potential – into one large group. CMUA argues that until such time as the IOUs respond completely to all the elements of the request, providing the Commission more comprehensive and detailed cost information, and until such information is subjected to additional examination and scrutiny, the Commission cannot conclude that the New Generation NBCs are cost-effective. CMUA urges the Commission to regard the IOUs' filings as merely the first step in addressing this issue, and as the initial basis upon which to develop a more detailed record.

EPUC states (1) SDG&E erred in describing past applicability of NBCs to customer generation departing load (CGDL); (2) SCE's filing does not show cost-effectiveness of application of the proposed NBC to CGDL; and (3) PG&E does not provide a method for distinguishing between incremental load growth met with a direct transaction and normal course of business load changes or show how much it would cost the utility to distinguish between them. Additionally, according to EPUC, it remains unclear how a CGDL customer's standby service would be accounted for in determining this utility procurement departing load charge and whether the customer may essentially be charged twice for the same energy.

EPUC concludes that the IOUs' filings are inconclusive regarding the cost-effectiveness of applying a new procurement NBC on CGDL and further highlight the need for an exemption for these customers.

The primary concern Merced ID and Modesto ID have with the IOUs' cost-effectiveness exhibits is that they combine MDL with DA and CCA departing load. By applying the above-market assumptions to such a large potential departing load customer base, the IOUs overstate potential New Generation NBC revenues and understate the NBC collection costs potentially attributable to MDL. Additionally, Merced ID and Modesto ID state the IOUs' exhibits are superficial, contain errors and fail to fully respond to several of the questions.

Merced ID and Modesto ID request that the Commission (1) should require the IOUs to calculate potential New Generation NBC revenues for MDL only; (2) accord the IOUs' cost-effectiveness exhibits the weight of untested argument and use them only for the purpose of developing the scope of any further investigation it undertakes regarding the cost-effectiveness of any New Generation NBC; (3) consider findings in D.07-09-041 regarding PG&E's billing practices and findings in the Presiding Officer's Decision in Investigation 06-06-014 regarding manipulation of customer satisfaction data in SCE's Performance Based Ratemaking in deciding what weight to ascribe the cost-effectiveness exhibits of each; and (4) recognize PG&E's admissions that (i) it is aware of POU annexation proposals, and (ii) it has the ability to adjust its load forecasts to reflect successful proposals.[69]

CCSF states there are significant issues of concern arising from the IOUs' responses, including the following:

- PG&E appears to overstate the nature of Commission approval of current NBCs;

- The IOUs appear to over-estimate the size of the potential departing load;

- PG&E asserts that the "overwhelming majority" of new municipal load will use PG&E gas service (implicitly assuming that all such developments will include gas as a service). Neither assumption is substantiated;

- PG&E's proposed use of such gas records, even where it may be possible, seems potentially improper;

- PG&E and SCE appear to give no response to ALJ Question 8; and

[69] In their Opening Brief, Merced ID/Modesto ID urge the Commission to undertake a further investigation into the cost-effectiveness of NBCs, including those implemented in connection with electric industry restructuring and the energy crisis, perhaps using Exhibits 211, 212 and 213 as tools in developing the scope of any such further investigation. They note that the Commission uses established tests from the California Standard Practices Manual: Economic Analysis of Demand-Side Management Programs (October 2001) to determine the cost-effectiveness of IOU programs from various perspectives, including ratepayers, society and program participants (here, departing load) and request that the Commission ultimately evaluate the cost-effectiveness of the proposed NBCs from all three perspectives.

- The responses generally seem to marginalize the incremental costs of these NBCs in a way that seems at odds with part of the IOUs' positions in litigation.

According to CCSF, the information cannot be deemed either accurate or reliable absent any test of its veracity, and the opportunity alone to offer comment is a poor substitute for time to review, opportunity to serve discovery and/or opportunity to cross-examine the proponents of the assertions at issue.

CCSF recommends the responses not be admitted as additional testimony, the exhibit numbers should be vacated and the submissions be identified as "Responses" with the express ruling that they are to be given the weight of untested argument only.

6.4.3. Discussion

In an October 23, 2007 ruling, the ALJ ruled that, in order to issue a timely decision for this track of the proceeding, the cost-effectiveness issue would not be pursued as far as having the utilities augment or correct their exhibits, providing parties the opportunity to conduct further discovery and prepare responsive analyses, or providing parties the opportunity to cross-examination the IOUs on information contained in the exhibits. The ALJ also acknowledged the concerns expressed in the parties' responses as described above. While the exhibits were received into evidence, it was indicated that they would be weighed accordingly and that the value of the information in determining the cost-effectiveness of NBCs either generally or for a specific type of departing load is therefore limited. It is with this understanding that we now address this issue.

If new generation costs or total portfolio costs were 5% to 10% above the market price benchmark, the information provided by the IOUs demonstrates that imposition of the new generation NBCs would be cost-effective when analyzed on an incremental basis. For example, PG&E indicates that its costs to implement the D.04-12-048 NBC include a one-time billing system upgrade cost of between $5.8 and $7.5 million and recurring annual costs of approximately $23,331 per year. The revenues, which would be fully credited back to bundled customers to off-set above market generation costs, could be between $7.1 million a year (5% incremental departing load and 5% above market benchmark) and $28.5 million a year (10% incremental departing load and 10% above market benchmark) a year. PG&E states that over a 10-year period, this could result in revenues between $71 million and $285 million, depending on market conditions and departing load. SCE indicates most costs are embedded and quantifies incremental costs of between $200,000 to $1,200,000 to develop and maintain systems and data bases.

SCE estimates potential annual revenues of approximately $25 million (5% above market benchmark) and $50 million (10% above market benchmark). SDG&E estimates a potential range of yearly revenues of between $854,835 to $6,786,076 (assuming a total portfolio cost that is 5% and 10% above the 2007 market benchmark, allocated to a range of incremental departing load forecasts of 4% and 8%).

SDG&E indicates that implementation of tools and data bases would be a one-time cost of approximately $85,000 and determining the customers NBC would be a one time cost per account of approximately $2. According to SDG&E, there are no incremental costs associated with most of the other activities.

As explained earlier, the information provided by the IOUs was not subject to cross-examination. Whether certain costs are reasonable or are correctly classified as recurring, non-recurring, embedded or incremental is an issue that will not be resolved in this proceeding. Also, the IOUs' analyses could not and did not consider our resolution of the issue related to the applicability of the charges discussed earlier in of this decision. However, the description of the activities and, when provided, the quantification of costs appear to be in a reasonable range. What we conclude from this information is that potentially there is a substantial amount of revenue at stake in the new generation NBCs and at least under certain circumstances (e.g., CCA, large municipalizations and the potential for reopening direct access) the overall incremental revenues generated by the D.04-12-048 NBC would likely more than offset the overall incremental costs of implementing the NBC. In order to capture any revenues associated with the NBCs, the necessary costs to implement the charges must be incurred. In light of potentially significant amounts of new generation NBC revenues, it is reasonable to incur such charges. We make this finding with the understanding that undertaking any detailed cost-effectiveness analyses[70] for these particular NBC charges at this time would be a speculative and not a particularly revealing exercise. That is because the costs for future new generation resources, the future market benchmark prices and the future amounts of load shifting caused by DA, CCA, MDL and CGDL would be the principal elements in any such analyses, and are generally unknown at this time.[71] It is also for these reasons that we will not pursue the cost-effectiveness issue any further in this proceeding.

---

[70] For instance, some parties insist the analyses should be done separately by type of customer (DA, CCA, MDL and CGDL).

[71] We note that at this point it is not cost effective to set up and implement an NBC for MDL and CGDL customers, because at this point they are excluded from having to pay

Footnote continued on next page

For the same reasons, once the charges are in place, it is reasonable for the IOUs to collect the NBCs without continually having to demonstrate cost-effectiveness for particular charges for particular customers.[72]

6.5. Additional Issues

6.5.1. Limit on NBCs

Merced ID/Modesto ID state that it is possible that the level of stranded cost recovery and/or net cost allocation mechanism NBCs will be unreasonably high and recommend that the Commission evaluate these NBCs on an annual basis and determine whether it is appropriate to establish and implement a cap.

The Merced ID/Modesto ID assertion regarding the possible high level of stranded cost recovery is very general and not supported by any specific basis or reasoning. Prior to the costs of any of these new generation resources being included in the revenue requirement and being eligible for stranded cost recovery, the Commission will have already examined both the need and costs of

---

(*footnote continued from previous page*)

the charges, once these customers depart. There would be no revenues to offset any incremental costs. However, in the event that a large municipalization occurs, having procedures authorized and in place will facilitate the imposition and collection of potentially significant amounts of NBCs. The same can be said for significant amounts of CCA should they occur. Also, while there may be some DA activity at this time related to customers returning to DA service, significant amounts of activity and significant amounts of NBCs may result in the event that DA is reopened.

[72] We also note that even if the D.04-12-048 NBC were somehow demonstrated to not be cost-effective for certain customers, imposing their departing load costs on bundled customers would be contrary to the general principle against cost shifting. The maintenance of bundled customer indifference to that departing load would have to be addressed in some other manner.

the projects. We do not anticipate that our processes will result in unreasonably high levels of stranded cost recovery. It is not necessary to establish an annual procedure to determine whether it is appropriate to establish and implement a stranded cost recovery cap.

6.5.2. Cost Recovery Period for non-RPS PPAs

With respect to PPAs for non-RPS commitments, Merced ID/Modesto ID and CCDC interpret the D.04-12-048 provision that the IOUs should be allowed to recover any stranded costs that may arise over either the life of the contract or 10 years, whichever is less, to mean stranded cost recovery should begin when the PPA is signed, not when the project commences operation. We do not agree with that interpretation. From the time that the PPA is signed to the time the project commences operation, there are generally no payments being made. Essentially all costs to the IOU and the associated cost recovery from customers will begin with the commencement of operation of the project, and that is when the 10-year cost recovery period should begin.

For example, departing DA load in 2010 will be required to pay for nine years for a non-RPS resource that begins commercial operation in 2009, but for a non-RPS resource that is contracted for by the IOU in 2008 and will begin commercial operation in 2013, this customer will owe NBCs related to this resource from 2013-2022.

7. Framework for the D.06-07-029 NBC

For each new generation resource subject to the CAM adopted by D.06-07-029, there is also an associated annual revenue requirement or cost that must be recovered from ratepayers to make the IOUs whole for their investments. In this case, that cost is the total annual resource cost less the revenues that would be obtained through an energy auction. The remaining net cost is an approximation of the capacity value of the resource and equals the cost of the associated RA credits. The RA credits have value in that they can be used to satisfy certain Commission RA requirements.[73] [74] Bundled customers will be indifferent to the choice of a customer to use alternative energy supplier, if the IOU charges the customer an NBC associated with that customer's share of the annual net resource cost and assigns the associated RA credit to the customer. This is accomplished in D.06-07-029 as follows in the adopted proposal:

> 15. The IOU should charge the benefiting customers the net cost of capacity, determined as a net of the total cost of the contract minus the energy revenues associated with dispatch of the total contract. All RA counting benefits and net costs are spread to the LSEs whose customers are allocated costs based on share of 12-month coincident peak, adjusted on a monthly basis to facilitate load migration. The contract costs paid and RA benefits received by DA (or CCA and muni load) and bundled customers should be based on a share basis equal to the credit share received. (D.06-07-029, p. 31.)

As described above, customers who choose DA or CCA will be assessed a NBC for the net cost of capacity, and the LSE to which they migrate will receive the related RA credits.

MDL, with the exception of large municipalizations, and CGDL have been excluded from having to pay the D.06-07-029 NBC, as discussed in Section 4.1 of

---

[73] As PG&E states, "CAC/EPUC is correct that distributed generation is not a load-serving entity and is not required to meet the Commission's RA requirements. However, the RA credits allocated to departing distributed generation customers are valuable. Because Load-Serving Entities (LSEs) need to satisfy annual and monthly RA requirements, these departing customers may be able to sell or transfer these credits to LSEs that have an RA deficiency." (Exhibit 18, pp. 14-15.)

this decision. However, in the future, if any costs and RA credits are allocated to large municipalization customers, the adopted proposal in D.06-07-029 and the adopted implementation details in D.07-09-044 are not clear as to what these departing customers are supposed to do with their allocated RA credits. Per the guidance provided in D.07-12-052, the IOUs are not to be procuring system reliability resources on behalf of POUs, and CGDL customers are not LSEs. There is no direct use of RA credits for these departing customers. It appears they would be directly billed for the costs through a NBC and given the associated RA credits, possibly to resell to an LSE who has use for such credits. We will modify this outcome slightly as described below, to lessen the individual departing customer's burden of reselling the credits.

Bundled customer indifference can be achieved by placing a value on the RA credit and having the IOU net that amount out of the NBC and letting the IOU maintain that RA credit for its use. The departing customer would be responsible for any uneconomic costs which in this case are represented by the total annual PPA cost, less energy auction revenues, less the value of the RA credit. We will apply this procedure to any large municipalization customers to which the D.06-07-029 net cost NBC may apply.[75] By this decision, these DL

(*footnote continued from previous page*)

[74] A value of the RA credit could be determined by analyzing the ongoing market transactions for such products.

[75] To the extent that new WAPA departing load and split wheeling departing load customers are subject to the D.06-07-029 NBC and have no use for RA credits, this procedure should also apply.

customers will not receive the RA credit associated with their departing load and will not be responsible for the market value of the RA credit. However, they will still be responsible for any uneconomic costs, and bundled customers will remain indifferent to their departure.

8. Implementation Issues for Cost Allocation Under D.06-07-029

PG&E, SCE, SDG&E and TURN refer to D.07-09-044 wherein the Commission adopted an uncontested settlement that specified the principles for the D.06-07-029 energy auction and the implementation details for the corresponding allocation of benefits and costs,[76] and indicate nothing further needs to be done on this subject in this proceeding.

While most other parties are silent on this matter, AReM proposes certain modifications as discussed below. Also, EPUC raises a number of issues pertaining particularly to CGDL customers and states that they must be addressed, if the Commission does not exclude all CGDL from having to pay the D.06-07-029 charge. They include the following:

- Determination of a "capacity factor" exemption for qualifying CGDL;
- Determination of allocation method for RA credits to individual CGDL customers;
- Establishment of mechanisms to guard against "double-billing" CGDL customers that also take standby service by the IOUs;

[76] Unlike the D.04-12-048 NBCs, D.06-07-029 costs are not costs that are factored into and recovered through the total portfolio methodology.

- Establishment of mechanisms to guard against mistaken billing of load that is exempt from the definition of departing load (e.g., normal course of business load changes, back-up generation); and

- Regarding PG&E's proposal that CGDL customers "re-sell" the allocated but not needed RA credits, determination of identification methods for "purchasers" of RA credits.

Since we have essentially excluded all CGDL from having to pay both the D.04-12-048 and D.06-07-029 NBCs, as determined earlier in this decision, we need not address these issues at this time. However, we do note that consideration of the "capacity factor" exemption is beyond the scope of this track of the proceeding; there has been no demonstration that an allocation method for RA credits to individual CGDL customers does not already exist; the need to establish mechanisms to guard against "double-billing" CGDL customers that also take standby service by the IOUs and to guard against mistaken billing of load that is exempt from the definition of departing load has not been demonstrated; and the determination of identification methods for "purchasers" of RA credits is not necessary due to the manner in which this decision handles such credits.

8.1. Use of the DA CRS

In order to minimize the administrative burden associated with implementing the D.06-07-029 NBC, AReM recommends that, for DA customers, the charge be collected through the existing DA CRS. AReM does not provide any details on its proposal, and its intentions are not clear. If AReM is proposing that the D.06-07-029 costs be included with other utility procurement costs similar to the total portfolio approach adopted for the D.04-12-048 cost allocation, PG&E would oppose this proposal. PG&E argues that (1) the D.06-07-029 CAM is unique in that it allocates both benefits (i.e., RA credits) and costs and (2) any proposal to blend the D.06-07-029 costs with other stranded costs is contrary to the express terms of the settlement, which AREM signed on to as a settling party.[77]

8.1.1. Discussion

The D.06-07-029 NBC is distinct from the elements of the DA CRS in that the charge itself is based on a cost that is net of the energy value, and there are associated RA credits. If and how those elements would be included in a charge that is based on a comparison of the costs of the energy and capacity of the IOUs resources to a market price benchmark is not explained by AReM.

Also, as explained in the principles for the energy auction process and products:

> 4. Net costs shall be calculated and determined separately for each Energy Auction PPA, and net costs shall not be netted against or in any way impacted by the costs of other resources in the utility's resource portfolio.[78]

The DA CRS and the D.06-07-029 NBC should therefore be calculated and billed as separate items.

8.2. Inclusion of the Charge under the DA CRS Cap

AReM recommends that, in order to prevent the NBCs from imposing an undue economic burden on DA customers and acting as a further drag on the DA market, the Commission should include the NBCs under the 2.7 cent per

[77] PG&E Reply Brief, pp. 37-38.

[78] D.07-09-044, Appendix A, p. 22.

kilowatt hour (kWh) cap for the DA CRS established in D.02-11-022 and affirmed in D.03-07-030. SCE and PG&E oppose the recommendation.

SCE states that AReM's proposal is procedurally improper. According to SCE, presenting this proposal for the first time in Opening Brief deprives other parties of their due process rights. SCE further notes that, for PG&E and SDG&E, the 2.7 cent per kWh DA CRS cap is no longer in effect because they have already recovered their DA CRS undercollection, and for SCE the cap is expected to be eliminated by the end of 2008. Also, DA customers' LSEs will receive RA capacity credits in exchange for paying this NBC. This will allow them to reduce the cost of procuring capacity for DA customers and their corresponding charge to DA customer for such capacity.

PG&E states that there is nothing in the settlement that the Commission recently approved that would support capping the D.06-07-029 costs, and AReM should have proposed a cap in the settlement if it believed this was an important issue. PG&E also states that capping the net costs that could be allocated to DA customers would result in bundled customer bearing a greater share of the burden of the new generation costs, unfairly shifting costs to bundled customers. Also, since AReM suggests capping the costs, but not the allocation of the RA benefits, PG&E argues that DA customers should not be allowed to receive the full RA benefits of the D.06-07-029 cost allocation mechanism while only bearing a limited amount of the costs.

8.2.1. Discussion

We agree with SCE's statement that AReM's proposal is procedurally improper. AReM could have, and should have, made this proposal in its prepared testimony, not in Opening Briefs. However, we will address it at this time. Having to consider other parties' due process rights is obviated by the fact that AReM's proposal is rejected.

First of all, the 2.7 cent/kWh DA CRS caps will have expired for all three IOUs by the end of 2008. Without a more definitive showing of need, we are reluctant to reinstate such caps, at any level, along with the necessary procedures for recovery of undercollections. Furthermore, the ESPs will be receiving RA credits. They should pay for such credits as they are received and used, not on some deferred basis. The need and equity of AReM's proposal has not been demonstrated, and it will not be adopted.

8.3. Five-Year Limitation

The adopted CAM in D.06-07-029 specified in part:[79]

2. New generation approved by this Commission and eligible for the cost allocation mechanism will receive cost recovery for a period of up to 10 years. We limit the maximum term of any cost paid by all customers to the term of the contract, or 10 years, which ever is less, from the time that the new unit comes online.

3. We intend this cost allocation mechanism to be in place for the term of the contract or up to 10 years, whichever is less, from the time the new unit comes on line. However, the mechanics of this cost allocation mechanism may change depending on the new market-based system which may evolve.

Rather than using the adopted cost recovery period of up to 10 years, AReM recommends that the Commission limit application of the CAM (or any similar ratemaking mechanism it may adopt for such purposes) to five years. AReM cites cross-examination testimony in a previous track of this proceeding, which indicates the utilities' long-term procurement plans are sufficiently flexible to allow them to adjust their portfolios to accommodate significant changes in load within a few years, and asserts the shorter five-year period would be adequate to avoid any cost shifting. PG&E, SCE and SDG&E oppose the five-year limitation.

PG&E states that the fact that the utility can adjust the amount it procures does not eliminate the above-market costs it must pay for contracts it has already entered into on behalf of the benefiting customers, and argues that AReM's proposal to limit the D.06-07-029 cost allocation mechanism to five years would result in remaining bundled customers bearing a disproportionate share of the costs for new generation associated with long-term contracts, which will typically be 10 years or longer.

SCE states that AReM offers no legitimate reason for disrupting the careful balance the Commission achieved in D.06-07-029 (and on which SCE relied in entering into power purchase agreements for new generation resources) and that AReM's attempt to reduce the cost recovery period should be rejected.

SDG&E state that AReM's proposal contradicts the Commission's ruling in D.06-07-029 that the recovery period be up to 10 years, and that, with respect to AReM's argument that the IOUs' procurement activities are flexible enough to allow for a five-year recovery period, the Commission considered that argument in D.04-12-048 and concluded that a 10-year period was justified.

(*footnote continued from previous page*)

[79] D.06-07-029, p. 27.

8.3.1. Discussion

AReM argues the IOUs' long-term procurement plans are sufficiently flexible to allow them to adjust their portfolios to accommodate significant changes in load within a few years. AReM bases its argument on cross examination of utility witnesses in another track of this proceeding, where such flexibility was acknowledged. However, that examination related to increased DA load only. In the context of the CAM, DA load planned for by the IOUs includes existing DA load as well as increased DA load. Also, the IOUs must continually take into account ongoing MDL and CGDL in their procurement activities and may have to make further adjustments for potential CCAs or large municipalizations. AReM does not address the manner in which the IOUs would adjust their procurement when faced with all of these possibilities or whether any of the adjustments might result in additional costs that would be borne by bundled customers only. Also, it is one thing for the IOU to be able to adjust it's portfolio to accommodate significant changes in a short period of time in terms of physical energy purchases, however, it is quite another to do so in a manner that would result in bundled customer indifference. There is insufficient justification for modifying the length of the CAM as adopted in D.06-07-029, and we will not adopt AReM's request to do so.

9. Comments on Proposed Decision

The proposed decision (PD) of the ALJ in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed on August 11, 2008 by PG&E, SCE/TURN, AReM, CCDC, California Large Energy Consumers Association (CLECA)/California Manufacturers and Technology Association (CMTA), CMUA, EPUC, Merced ID/Modest ID, and Northern California Power Agency (NCPA).[80] Reply comments were filed on August 18, 2008 by PG&E, SCE/TURN, SDG&E, AReM, CCDC, CMUA, CCSF, DRA, EPUC, Merced ID/Modest ID, and NCPA.

To the extent that the comments merely reargued the parties' positions taken in their briefs, those comments have not been given any weight. The comments which focused on factual, legal or technical errors have been considered, and, if appropriate, changes have been made. Our consideration of comments related to the more controversial issues is summarized below.

9.1. Applicability of the NBCs

PG&E states that there is no evidence that the adopted load forecasts in this proceeding reflect MDL and CGDL. The PD discussion related to the applicability of the NBCs, has been revised to reflect the fact that the load forecasts adopted in D.07-12-052 are based on the CEC's 2007 IEPR Demand Forecast and to explain the evidence that supports the finding that loads associated with MDL (with the exception of large municipalizations) and CGDL are forecasted to depart and therefore are not included in the CEC load forecasts that were adopted in D.07-12-052 as the forecasts on which new generation needs are to be based in the LTPPs.

SCE and TURN state that the PD never explains why MDL and CGDL that are forecasted years after new generation resources have been acquired should benefit from the stranded cost reduction that increased load or flexibility in

---

[80] On August 18, 2008, NCPA filed a motion for party status. There were no responses, and the motion is granted.

procuring resources of various terms can bring about. The PD has been expanded to explain that even for these resources, at the time the resource commitments are made, (1) the LTPP load forecasts exclude forecasted amounts of MDL and CGDL; (2) these customers will eventually become the departing customers for which those amounts of MDL and CGDL are forecasted; and (3) therefore, in effect, these customers' loads are only reflected in the LTPP load forecast for the years in which they are bundled service customers. Therefore, (1) the IOUs' procurement needs related to these customers are only identified and planned for in the years in which they are bundled service customers; (2) the IOUs' procurement commitments are made on behalf of these customers only for the time that they are on bundled service; and (3) these customers' fair share of the costs related to these resources should be zero after they depart.

SCE and TURN express concern with the PD statement that the fair share of customers in a "large municipalization" may be zero because the large municipalization was foreseeable. We have reconsidered and removed this statement explaining that such customers have NBC cost responsibility for those resources procured on their behalf prior to the date of their departure or prior to an appropriate alternative date for ending cost responsibility for new generation resources such as that related to a BNI. Such customers' fair share can be zero only for those resources procured after such dates. We also agree with the assessment of SCE and TURN that a BNI process is a reasonable and preferable means for establishing when the IOU should have known about departures related to a large municipalization and should have excluded them from its load forecasts. However, we do provide an opportunity for the large municipalization entity to propose and justify an alternative date for determining the end of cost responsibility for new generation resources that is neither a BNI date nor the actual departure date. The burden would be on the municipal entity to justify why the alternative date is more appropriate than what would be established in a BNI process.

PG&E argues that large municipalizations should be treated no different than DA and CCA and that calculating the fair share owed by each large municipalization on a case-by-case basis (by application) is inappropriate. We disagree. It is necessary that the affected IOU demonstrate on a case-by-case basis that the related annexation cannot reasonably be assumed to have been reflected as part of the historical MDL trends used in developing the adopted LTPP forecasts. Also, there may be a reason why a large municipalization should have a date for determining the end of cost responsibility for new generation resources that is neither a BNI date nor the actual departure date. An application process is a fair way to resolve these potential issues and we will not change the PD in that regard.

PG&E states that it should be made clear that NBCs also apply to New WAPA Departing Load and Split Wheeling Departing Load, consistent with D.06-05-018 and D.03-09-052. There were no replies to this comment. In its testimony, PG&E included such loads as being subject to the D.04-12-048 NBC (Exhibit 7, p. II-5). No party proposed such loads should be excluded from that charge. Similarly, no party proposed such loads should be excluded from that subject to the D.06-07-029 NBC. Consistent with D.06-05-018 and D.03-09-052 which assigned generation related NBC cost responsibility for new WAPA departing load and split wheeling departing load, we agree with PG&E's claim that such departing load should be subject to the D.04-12-048 and D.06-07-029 NBCs. The PD has been modified accordingly.

9.2. The D.04-12-048 NBC

PG&E and SCE/TURN continue to object to the 10-year cost recovery limitation for non-RPS resources. In general they believe that bundled customer indifference is violated by this limitation, especially since the PD would leave lower cost pre-restructuring resources in the total portfolio for the entire life of such resources. SCE and TURN urge the Commission to remove the 10-year limitation. PG&E argues all resources should be allowed in the total portfolio over the entire term of the PPA or life of a utility owned generation asset, or the inclusion of the pre-restructuring resources should be limited, in a manner previously recommended by TURN.

We are not convinced that the PD should be modified in this regard. First, PG&E, SCE and TURN apparently assume the resources in question will be uneconomic not only over the initial 10-year period, but over a substantial amount or perhaps the entire amount of the remaining PPA term or utility asset life. That may or may not be the case, depending on the economics of the specific resource. Second, by D.04-12-048, the IOU has the opportunity to request extension of the cost recovery period on a case-by-case basis. While this does not provide the certainty that the SCE/TURN or PG&E proposals do, we are convinced that it is a fair way for the Commission to review what the IOUs have done over time to mitigate potential stranded costs, what effect unlimited cost recovery for RPS contracts and 10 year or less non-RPS contracts has on overall stranded costs, and what the long term economics of the resources in questions are over time compared to that of other resources in the total portfolio. With that review, the Commission can make a better determination of the need to extend cost recovery periods in order to maintain bundled customer indifference over time.[81]

10. Assignment of Proceeding

Michael R. Peevey is the assigned Commissioner and David K. Fukutome is the assigned Administrative Law Judge in this phase of the proceeding.

Findings of Fact

1. It is reasonable to use the bundled customer indifference principle as well as the principle that stranded costs should be recovered from those customers who benefited from the stranded asset, in reconciling issues related to the implementation of the D.04-12-048 and D.06-07-029 NBCs.

2. The notion that each customer pay its fair share of the costs the IOU incurred on behalf of this customer or the load associated with this customer is an integral part of the principles of bundled customer indifference and prevention of cost-shifting.

3. In this proceeding, it is reasonable to apply the rule: when costs are incurred on its behalf, that customer must pay its fair share of the costs, and the corollary rule: if no costs are incurred on its behalf, then the customer's fair share can be determined to be zero.

4. Whether or not departing load should be forecasted and reflected in the IOUs' load forecasts is not an issue in this track of the proceeding.

---

[81] We do not expect to see such requests for every resource with an expected term or life exceeding 10 years. While it is up to the IOU to decide whether and why an extension for a particular resource is necessary, it bears the burden to justify the request in terms of the factors discussed in this decision.

5. The structure of the load forecasts used in developing the LTPPs has already been addressed in Track 2, and any related issues have been reconciled in D.07-12-052.

6. It is reasonable and necessary to examine the implications of forecasted departing load on the applicability of NBCs, to ensure bundled customer indifference and the proper alignment of benefits and cost responsibility, which will be based on a determination of the fair share of the departing load for these NBCs.

7. For the three IOUs, system need is not impacted by possible future load shifting due to DA and CCA, and future CGDL and MDL are captured by historical trends used to develop the load forecasts.

8. The use of historic information and trends to reflect future departing load reduces some risk to the IOUs of possibly adopting overly optimistic estimates and tends to limit the dispute and litigation related to what the appropriate levels of departing load should be.

9. For IOU customers that are eligible to, and do, choose DA service from an ESP and for customers that decide to use a CCA, their loads are included in the D.07-12-052 adopted load forecasts on which the LTPPs are based.

10. Planning for the needs of IOU customers that are eligible to, and do, choose DA service from an ESP and customers that decide to use a CCA and imposing NBCs, if and when these customers choose alternative procurement services, is reasonable.

11. The loads associated with MDL (with the exception of large municipalizations) and CGDL customers are not included in the CEC load forecasts that were adopted in D.07-12-052 as the forecasts on which new generation needs are to be based in the LTPPs.

12. The LTPP, which uses load forecasts to determine resource needs in the forecast year, does not include any resources to serve forecasted MDL and CGDL in the forecast year and beyond, which result in a fair share of zero, once these customers depart.

13. All other things being equal, exclusion of forecasted departing load from the LTPP load forecasts and exclusion of MDL (with the exception of large municipalizations) and CGDL customers from cost responsibility for new generation resources after the customers depart leaves existing bundled customers with the same cost responsibility as was anticipated when the LTPP load forecasts were made.

14. While the BNI process may be a viable approach for determining when IOU procurement on behalf of certain customers ends, it is not relevant in addressing the NBC applicability issue of whether these departing customers should be assessed any NBC at all under a fair share analysis.

15. Due to the manner in which we have resolved the applicability issue, a BNI process for determining when IOU procurement on behalf of ongoing MDL and CGDL customers ends is unnecessary.

16. It is reasonable for the IOUs to impose D.04-12-048 and D.06-07-029 NBCs on departing load associated with large municipalizations that are not represented in the historical trends used to develop the load forecasts.

17. There is no testimony or other evidence to refute PG&E's claim that D.04-12-048 and D.06-07-029 NBCs should apply to new WAPA departing load and split wheeling departing load.

18. It is reasonable for the IOUs to impose D.04-12-048 and D.06-07-029 NBCs on new WAPA departing load and split wheeling departing load.

19. Bundled customers who are eligible to return to DA service have not specifically been excluded from having to pay the D.04-12-048 NBC.

20. Up until the time that bundled customers who are eligible to return to DA service give proper notice that they will return to DA service, they are no different from the other bundled customers on whose behalf the IOUs are making procurement related decisions.

21. The D.07-09-040 requirement that the utilities make standard offer contracts available to existing QFs with expiring PPAs or to new QFs impacts utility procurement and creates uncertainty in resource planning, and, to the extent the prices in the new QF standard offer contracts are above-market prices, bundled customers may incur additional stranded costs.

22. The general framework of having a customer who chooses an alternative energy supply pay a surcharge that is calculated to cover the uneconomic portion of the resource costs associated with that customer's departure will leave the bundled customer indifferent to the departure and is reasonable for implementing the D.04-12-048 NBC.

23. At this point, the only difference between the separate charge and the total portfolio approaches is how negative charges are handled in the calculations.

24. The total portfolio approach is consistent with prior Commission decision regarding the carryover of negative charges. The separate charge approach is not.

25. The use of the total portfolio approach is necessary to implement provisions of this decision regarding the use of pre-restructuring resources in determining cost responsibility once recovery of the DWR power charge ends.

26. Bundled customer indifference will only be maintained if all resources are included in the portfolio used to calculate the related charges, whether it is the CTC, DWR and D.04-12-048 charges or just the CTC and D.04-12-048 charges.

27. The use of the total portfolio and the inclusion of the pre-restructuring resources in that portfolio is the appropriate approach to use for the duration of D.04-12-048 cost recovery.

28. With the inclusion of D.04-12-048 cost recovery as part of the total portfolio, the reasons cited in D.07-05-005 as to why negative indifference charge carryover is appropriate apply even after expiration of the DWR contract term.

29. The argument that a limitation on the use of pre-restructuring resources fairly offsets any perceived effects of the D.04-12-048 10-year limitation on cost recovery for non-RPS resources is not persuasive.

30. If the IOUs believe a cost recovery period extension is appropriate and necessary for specific resources, they can make such requests under the provisions of D.04-12-048.

31. The Commission has consistently declined PG&E's advice letter requests to recover the above market costs of RPS contracts through a NBC, consistent with its interpretation of D.04-12-048, indicating that it would not address such above market cost recovery in the resolutions but that R.06-12-013 was the appropriate procedural forum for addressing those issues.

32. With respect to the implementation of the stranded cost provisions of D.04-12-048, the NBCs, which include any above market costs related to RPS contracts, will not apply to departing load that is excluded from the load forecasts used to develop the IOUs' LTPPs. The excluded departing load includes MDL, with the exception of large municipalizations, and CGDL. DA and CCA load are fully subject to the D.04-12-048 NBC.

33. When calculating the CRS, the RPS contracts are blended in with other generation resources under the total portfolio analysis.

34. Future developments in the State's renewable and/or greenhouse gas policies may both necessitate and facilitate a review of the manner in which renewables attributes are treated with respect to departing load and the new generation NBC to best maintain ratepayer indifference and the State's various policy objectives.

35. It is necessary to have some simplifying methodology so that the IOU does not have to figure out and administer the actual vintage (date of departure) for every customer.

36. Since customers who are eligible to return to DA have not been excluded from having to pay the NBC associated with D.04-12-048, it is necessary to determine a vintaging methodology for customers choosing DA, as part of this decision.

37. Under PG&E's vintaging (date of departure) proposal, where customers leaving in a particular year would be responsible for stranded costs associated with new generation resource commitments made through the end of that year, most customers will have assigned departure dates that are later than actual.

38. Under SCE's vintaging (date of departure) proposal, where customers leaving in the first half of any particular year would be responsible for stranded costs associated with new generation resource commitments made through the end of the previous year and where customers leaving in the second half of any particular year would be responsible for stranded costs associated with new generation resource commitments made through the end of that particular year, there will be customers with assigned departure dates that are both earlier and later than actual.

39. Over the long term, potential benefits and adverse effects to bundled customers would tend to balance out under SCE's vintaging proposal, but would not under PG&E's proposal.

40. The SCE vintaging proposal, when compared to the PG&E proposal, is fairer for customers that are leaving and more appropriately reflects bundled customer indifference.

41. AReM's alternative proposal to use commitments as of June 30 of any particular year for vintaging DA customers leaving bundled service in that year is similar to SCE's proposal in that, over time, the effect of customers having assigned departure dates earlier than the actual dates would be balanced by the effect of customers having assigned departure dates later than the earlier the actual dates.

42. AReM's alternative vintaging proposal would require mid-year revenue requirement determinations for costs normally determined on a full calendar year basis.

43. For consistency, SCE's vintaging proposal is preferable to that of AReM.

44. The six-month vintaging proposal by EPUC is problematical because most assigned departure dates will be later than the actual departure dates, and the proposal is administratively burdensome.

45. In determining the CRS which includes the D.04-12-048 NBC, (a) the use of the market benchmark adopted in D.06-07-030, as modified by D.07-01-030, to determine above-market costs and (b) the use of a forecast of costs, done through the ERRA, without an after-the-fact true-up, are reasonable.

46. It is not equitable for customers who will only be paying for 10 years of a project's depreciation to be entitled to the entire reduced revenue requirement

effect that results from the accumulated depreciation that will have been paid by other customers for 30 years or more.

47. The need for workshops related to the determination of capacity adders and line loss adjustments has not been demonstrated.

48. The costs for future new generation resources, the future market benchmark prices and the future amounts of load shifting caused by DA, CCA, MDL and CGDL would be principal elements in a detailed cost-effectiveness analysis of NBCs, and are generally unknown at this time.

49. In light of potentially significant amounts of new generation NBC revenues, it is reasonable to incur costs to implement the NBCs.

50. The incremental costs of billing and collecting the new generation NBCs are likely to be negligible.

51. Once the charges are in place, it is reasonable for the IOUs to collect the NBCs without continually having to demonstrate cost-effectiveness for particular charges for particular customers.

52. The Merced ID/Modesto ID assertion regarding the possible high level of stranded cost recovery is very general and not supported by any specific basis or reasoning.

53. Prior to the costs of any of the new generation resources being included in the revenue requirement and being eligible for stranded cost recovery, the Commission will have already examined both the need and costs of the projects.

54. It is not necessary to establish an annual procedure to determine whether it is appropriate to establish and implement a stranded cost recovery cap.

55. PPA costs to the IOU and the associated cost recovery from customers will begin with the commencement of operation of the project.

56. Regarding the D.06-07-029 NBC, customers who choose DA or CCA will be assessed a NBC for the net cost of capacity, and the LSE to which they migrate will receive the related RA credits.

57. Since the IOUs are not procuring system reliability resources on behalf of the POUs, and CGDL customers are not LSEs, there is no direct use of RA credits for these departing customers, to the extent such customers are subject to the CAM.

58. Where RA credits are not directly assigned to an LSE, bundled customer indifference can be achieved by placing a value on the RA credit and having the IOU net that amount out of the NBC and letting the IOU maintain that RA credit for its use.

59. EPUC has raised specific CAM concerns that relate only to CGDL customers but has indicated that these concerns need not be addressed, if CGDL customers are excluded from the CAM.

60. The D.06-07-029 NBC, which is based on a cost that is net of the energy value and which has associated RA credits, is distinct from the elements of the DA CRS, which have both energy and capacity costs and no RA credits.

61. The principles for the energy auction process and products as adopted by D.07-09-044 state that net costs shall be calculated and determined separately for each Energy Auction PPA, and net costs shall not be netted against or in any way impacted by the costs of other resources in the utility's resource portfolio.

62. The 2.7 cent/kWh DA CRS caps will have expired for all three IOUs by the end of 2008.

63. The ESPs will be receiving RA credits and they should pay for such credits as they are received and used, not on a deferred basis, which might result with the reinstatement of the DA CRS cap.

64. AReM only addresses IOU procurement flexibility in the context of increased DA load.

65. AReM does not address the manner in which the IOUs would adjust their procurement when faced with all DA, CCA, and departing load possibilities or whether any of the adjustments might result in additional costs that would be borne by bundled customers only.

Conclusions of Law

1. MDL and CGDL customers should not pay any NBCs related to new generation resources that were not procured on their behalf.

2. Forecasting the effects of CGDL and MDL has been done in the past, is reasonable and should continue in developing the load forecasts for LTPP purposes.

3. Imposition of the D.04-12-048 and D.06-07-029 NBCs is not necessary or appropriate for MDL or CGDL customers, since MDL and CGDL is factored into (i.e., the associated loads are excluded from) the CEC load forecasts for the IOUs adopted in D.07-12-052 for the 2006 and future LTPPs, and therefore the fair share of these customers should be zero upon departure.

4. For departing loads of large municipalizations that are not reflected in the historical trends used in developing the adopted LTPP load forecasts, the IOUs should file an application requesting a Commission determination of the fair share of these customers for paying the D.04-12-048 and D.06-07-029 NBCs.

5. The D.04-12-048 and D.06-07-029 NBCs should be imposed on new WAPA departing load and split wheeling departing load, consistent with D.06-05-018 and D.03-09-052.

6. Since the IOUs are procuring and making procurement commitments on behalf of bundled service customers who are eligible to return to DA service up

until the dates associated with these customers' notices to return to DA service, these customers should, as is the case with all other customers, be responsible for those procurement commitments made on their behalf and should be subjected to the D.04-12-048 NBC.

7. The IOUs should be able to recover above-market costs of new QF standard offer contracts through the D.04-12-048 NBC.

8. The total portfolio approach should be used for calculating the D.04-12-048 NBC.

9. To the extent that they continue to exist, pre-restructuring resources should continue to be included in the total portfolio for the duration of the D.04-12-048 NBC cost recovery.

10. The current provisions related to negative indifference charge carryover for use in subsequent years should be continued once DWR power charge recovery ends.

11. The effects of the 10-year limitation on cost recovery of new non-RPS generation resources on bundled customer indifference should be considered, on a case-by-case basis, if and when the IOUs request cost recovery extensions, pursuant to the provisions of D.04-12-048.

12. Given the potential long-term nature of the charge, allowances should be made for the possibility that certain future circumstances may result in a need to modify the D.04-12-048 NBC related processes adopted in this decision.

13. AReM's request to defer the development of a vintaging system for DA customers to R.07-05-025 should be denied.

14. SCE's vintaging (date of departure) proposal should be adopted.

15. Regarding vintaging, "the time a commitment is made" is when the IOU executes a contract or begins the construction of a new generation resource, not

when deliveries begin under the contract or the generation resource becomes operational.

16. Levelized fixed cost recovery should not be used for determining the D.04-12-048 NBC.

17. Workshops related to the determination of capacity adders and line loss adjustments should not be required.

18. The cost-effectiveness of NBCs should not be pursued any further in this proceeding.

19. The D.04-12-048 NBC 10-year cost recovery period for PPAs should begin with the commencement of operation of the project.

20. To the extent that large municipalization customers are subject to the CAM, the departing customers should be responsible for any uneconomic PPA costs which are represented by the total annual PPA cost, less energy auction revenues, less the value of the RA credit, with the IOU retaining the RA credit for its own use.

21. Since, by this decision, CGDL customers have been excluded from the CAM, it is not necessary to address EPUC's CAM concerns that relate only to CGDL customers.

22. The DA CRS and the D.06-07-029 NBC should be calculated and billed as separate items.

23. The need and equity of AReM's proposal to include the D.06-07-029 NBC under a 2.7 cent/kWh DA CRS cap has not been demonstrated, and the proposal should not be adopted.

24. There is insufficient justification for modifying the length of the CAM as adopted in D.06-07-029, and AReM's recommendation to do so should not be adopted.

25. This decision should be made effective immediately.

O R D E R

IT IS ORDERED that:

1. Decision (D.) 04-12-048 and D.06-07-029 non-bypassable charges (NBCs) shall be imposed on direct access (DA) and community choice aggregation customers, as well as new Western Area Power Administration (WAPA) departing load and split wheeling departing load customers.

2. Because customer generation departing load (CGDL) and municipal departing load (MDL) are excluded, as classes, from the adopted load forecasts on which the investor-owned utilities (IOUs) long term procurement plans (LTPPs) are based, CGDL and MDL customers are excluded from having to pay the D.04-12-048 and D.06-07-029 NBCs, including any above market costs related to RPS contracts, with the exception of those customers described in Ordering Paragraph 3.

3. Consistent with the provisions in this decision, an IOU may file an application requesting implementation of the D.04-12-048 and D.06-07-029 NBCs on departing load associated with a large municipalization. In the application, the IOU should demonstrate how the loads of these customers were included in an adopted load forecast, establishing that the IOU reasonably incurred costs on behalf of such customers. The Commission will determine the fair share of these customers for paying the D.04-12-048 and D.06-07-029 costs based on a departure date established through a binding notice of intent or alternative process.

4. Bundled service customers who are eligible to return to direct access shall not be excluded from having to pay the NBC associated with D.04-12-048.

5. The IOUs are allowed to recover the above-market costs of new qualifying facilities standard offer contracts through the D.04-12-048 NBC.

6. As described in the body of this decision, the D.04-12-048 NBC shall be implemented as a component of the cost responsibility surcharge (CRS), calculated on a total portfolio basis with the netting of individually calculate annual charges and the carrying over of negative total charges for use in offsetting positive charges in subsequent years.

7. Pre-restructuring resources shall continue to be included in the portfolio of resources used in determining D.04-12-048 charges, once recovery of DWR power costs ends.

8. If, due to future changing circumstances, the processes adopted by this decision for determining the D.04-12-48 NBC become unworkable, unbalanced, or unfair, parties may propose and request modifications to the form of the NBC or how the NBC should be determined or calculated.

9. The Alliance for Retail Energy Market's request to defer the development of a vintaging system for DA customers to Rulemaking (R.) 07-05-025 is denied.

10. A vintaging (date of departure) methodology, where customers leaving in the first half of any particular year would be responsible for stranded costs associated with new generation resource commitments made through the end of the previous year, and where customers leaving in the second half of any particular year would be responsible for stranded costs associated with new generation resource commitments made through the end of that particular year, is adopted.

11. Levelized fixed cost recovery shall not be used in determining the D.04-12-048 NBC.

12. The D.04-12-048 NBC 10-year cost recovery period for power purchase agreements (PPAs) shall begin with the commencement of operation of the project.

13. To the extent that large municipalization, new WAPA departing load or split wheeling departing load customers are subject to the cost allocation mechanism (CAM), the departing customers should be responsible for any uneconomic PPA costs which are represented by the total annual PPA cost, less energy auction revenues, less the value of the resource adequacy (RA) credit, with the IOU retaining the RA credit for its own use.

14. The DA CRS and the D.06-07-029 NBC shall be calculated and billed as separate items.

15. The D.06-07-029 NBC shall not be included under a 2.7 cent per kilowatt hour DA CRS cap.

16. The maximum term length of the CAM shall remain at 10 years, as adopted in D.06-07-029.

17. The Northern California Power Association's Motion for Party Status, filed August 14, 2008, is granted.

18. R.06-02-013 is closed.

This order is effective today.

Dated September 4, 2008, at San Francisco, California.

MICHAEL R. PEEVEY
President
DIAN M. GRUENEICH
JOHN A. BOHN
RACHELLE B. CHONG
TIMOTHY ALAN SIMON
Commissioners

APPENDIX A

************ SERVICE LIST ***********

Last Updated on 21-JUL-2008 by: SM2

R0602013 LIST

************* **PARTIES** *************

Marc D. Joseph
Attorney At Law
ADAMS, BROADWELL, JOSEPH & CARDOZO
601 GATEWAY BLVD., STE. 1000
SOUTH SAN FRANCISCO CA 94080
(650) 589-1660
mdjoseph@adamsbroadwell.com
For: Coalition of California Utility Employees and California Unions for Reliable Energy

James Weil
Director
AGLET CONSUMER ALLIANCE
PO BOX 37
COOL CA 95614
(530) 885-5252
jweil@aglet.org
For: AGLET CONSUMER ALLIANCE

Evelyn Kahl
Attorney At Law
ALCANTAR & KAHL, LLP
120 MONTGOMERY STREET, SUITE 2200
SAN FRANCISCO CA 94104
(415) 421-4143
ek@a-klaw.com
For: Energy Producers & Users Coalition

Michael Alcantar
Attorney At Law
ALCANTAR & KAHL, LLP
1300 SW FIFTH AVENUE, SUITE 1750
PORTLAND OR 97201
(503) 402-9900
mpa@a-klaw.com
For: Cogeneration Association of California

Rod Aoki
Attorney At Law
ALCANTAR & KAHL, LLP
120 MONTGOMERY STREET, SUITE 2200
SAN FRANCISCO CA 94104
(415) 421-4143
rsa@a-klaw.com
For: Cogeneration Association of California

John R. Redding
ARCTURUS ENERGY CONSULTING, INC.
44810 ROSEWOOD TERRACE
MENDOCINO CA 95460-9525
(707) 937-0878
johnrredding@earthlink.net
For: Silicon Valley Leadership Group

Scott Blaising
Attorney At Law
BRAUN BLAISING MCLAUGHLIN P.C.
915 L STREET, STE. 1270
SACRAMENTO CA 95814
(916) 682-9702
blaising@braunlegal.com
For: CALIFORNIA MUNICIPAL UTILITIES ASSN.

Kris G. Chisholm
Staff Counsel
CALIFORNIA ELECTRICITY OVERSIGHT BOARD
770 L STREET, SUITE 1250
SACRAMENTO CA 95831
(916) 322-8633
kris.chisholm@eob.ca.gov

Michael Doughton
Senior Staff Counsel
CALIFORNIA ENERGY COMMISSION
1516 9TH STREET MS-14
SACRAMENTO CA 95814
(916) 654-5207
mdoughto@energy.state.ca.us

Baldassaro Di Capo, Esq.
CALIFORNIA ISO
LEGAL AND REGULATORY DEPARTMENT
151 BLUE RAVINE ROAD
FOLSOM CA 95630
(916) 608-7157
bdicapo@caiso.com

Grant A. Rosenblum
GEETA THOLAN
Staff Counsel
CALIFORNIA ISO
151 BLUE RAVINE ROAD
FOLSOM CA 95630
(916) 608-7138
grosenblum@caiso.com
For: California Independent System Operator Corp.

Nancy Rader
CALIFORNIA WIND ENERGY ASSOCIATION
2560 NINTH STREET, SUITE 213A
BERKELEY CA 94710
(510) 845-5077
nrader@calwea.org
For: California Wind Energy Association

APPENDIX A

************** SERVICE LIST *************

Last Updated on 21-JUL-2008 by: SM2

R0602013 LIST

Lynne M. Brown
CALIFORNIANS FOR RENEWABLE ENERGY INC.
24 HARBOR ROAD
SAN FRANCISCO CA 94124
(415) 285-4628
l_brown246@hotmail.com

Michael E. Boyd
CALIFORNIANS FOR RENEWABLE ENERGY, INC.
5439 SOQUEL DRIVE
SOQUEL CA 95073
(408) 891-9677
michaelboyd@sbcglobal.net

Stephen A. S. Morrison
DENNIS J. HERRERA, THERESA L. MUELLER
CITY & COUNTY OF SAN FRANCISCO
CITY HALL, RM 234
1 DR CARLTON B. GOODLET PLACE
SAN FRANCISCO CA 94102-4682
(415) 554-4637
stephen.morrison@sfgov.org
For: CITY & COUNTY OF SAN FRANCISCO

Fritz Ortlieb
Attorney At Law
CITY OF SAN DIEGO
1200 THIRD AVENUE, SUITE 1200
SAN DIEGO CA 92101
(619) 236-6318
fortlieb@sandiego.gov
For: City of San Diego

L. Jan Reid
COAST ECONOMIC CONSULTING
3185 GROSS ROAD
SANTA CRUZ CA 95062
(831) 476-5700
janreid@coastecon.com

Mary Lynch
Vp - Regulatory And Legislative Affairs
CONSTELLATION ENERGY COMMODITIES GRP
2377 GOLD MEDAL WAY, SUITE 100
GOLD RIVER CA 95670
(916) 526-2860
mary.lynch@constellation.com
For: CECG

Sara O'Neill
Vp - Regulatory And Government Affairs
CONSTELLATION NEW ENERGY, INC.
SPEAR TOWER, 36TH FLOOR
ONE MARKET STREET
SAN FRANCISCO CA 94105
(415) 293-8003
sara.oneill@constellation.com
For: Constellation New Energy, Inc.

William H. Chen
Dir. Energy Policy West Region
CONSTELLATION NEW ENERGY, INC.
2175 N. CALIFORNIA BLVD., STE. 300
WALNUT CREEK CA 94596
(925) 287-4703
For: Constellation New Energy, Inc.

Clyde Murley
CONSULTANT TO NRDC
1031 ORDWAY STREET
ALBANY CA 94706
(510) 528-8953
clyde.murley@comcast.net
For: Union of Concerned Scientists

Michael D. Evans
CORAL POWER L.L.C.
4445 EASTGATE MALL, SUITE 100
SAN DIEGO CA 92120
(858) 526-2103
michael.evans@shell.com
For: Coral Power L.L.C.

R. Thomas Beach
CROSSBORDER ENERGY
2560 NINTH STREET, SUITE 213A
BERKELEY CA 94710-2557
(510) 549-6922
tomb@crossborderenergy.com
For: California Cogeneration Council (CCC)

Carl K. Oshiro
Attorney At Law
CSBRT/CSBA
100 PINE STREET, SUITE 3110
SAN FRANCISCO CA 94111
(415) 927-0158
ckomail@pacbell.net

APPENDIX A
************ SERVICE LIST ***********
Last Updated on 21-JUL-2008 by: SM2
R0602013 LIST

Cynthia A. Fonner
Senior Counsel
CONSTELLATION ENERGY GROUP INC
500 WEST WASHINGTON ST, STE 300
CHICAGO IL 60661
(312) 704-8518
Cynthia.A.Fonner@constellation.com
For: Constellation Energy Commodities Group Inc, Constellation NewEnergy Inc, and Constellation Generate LLC

Richard D. Ely
DAVIS HYDRO
27264 MEADOWBROOK DRIVE
DAVIS CA 95618
(530) 753-8864
Dick@DavisHydro.com
For: Northern California Small Hydro Assn.

Salle E. Yoo
Attorney At Law
DAVIS WRIGHT TREMAINE
505 MONTGOMERY STREET, SUITE 800
SAN FRANCISCO CA 94111-6533
(415) 276-6564
salleyoo@dwt.com
For: South San Joaquin Irrigation District

Edward W. O'Neill
Attorney At Law
DAVIS WRIGHT TREMAINE LLP
505 MONTGOMERY STREET, SUITE 800
SAN FRANCISCO CA 94111-6533
(415) 276-6587
edwardoneill@dwt.com
For: California Large Energy Consumers Association

Jeffrey P. Gray, Attorney At Law
DAVIS WRIGHT TREMAINE, LLP
505 MONTGOMERY STREET, SUITE 800
SAN FRANCISCO CA 94111-6533
(415) 276-6500
jeffgray@dwt.com
For: Calpine Corporation

Ann L. Trowbridge
RALPH R. NEVIS
DAY CARTER MURPHY LLC
3620 AMERICAN RIVER DRIVE, SUITE 205
SACRAMENTO CA 95864
(916) 570-2500 X103
atrowbridge@daycartermurphy.com
For: Merced Irrigation District/Sacramento Municipal Utility

Gregory Klatt
Attorney At Law
DOUGLASS & LIDDELL
21700 OXNARD STREET, SUITE 1030
WOODLAND HILLS CA 91367-8102
(818) 961-3002
klatt@energyattorney.com
For: Alliance for Retail Energy Markets/The Filing Parties

Jane E. Luckhardt
Attorney At Law
DOWNEY BRAND LLP
555 CAPITOL MALL, 10TH FLOOR
SACRAMENTO CA 95814
(916) 444-1000
jluckhardt@downeybrand.com

Dan L. Carroll
Attorney At Law
DOWNEY BRAND, LLP
555 CAPITOL MALL, 10TH FLOOR
SACRAMENTO CA 95814
(916) 444-1000
dcarroll@downeybrand.com
For: Merced Irrigation District and Modesto Irrigation District

Audra Hartmann
DYNEGY, INC.
980 NINTH STREET, SUITE 2130
SACRAMENTO CA 95814
(916) 441-6242
Audra.Hartmann@Dynegy.com
For: LS Power Generation, LLC

Joseph Paul
Senior Corporate Counsel
DYNEGY, INC.
4140 DUBLIN BLVD., STE. 100
DUBLIN CA 94568
(925) 829-1804 X-105
joe.paul@dynegy.com
For: Dynegy

APPENDIX A

************** SERVICE LIST **************

Last Updated on 21-JUL-2008 by: SM2

R0602013 LIST

District/California Clean DG Coalition
Daniel W. Douglass
Attorney At Law
DOUGLASS & LIDDELL
21700 OXNARD STREET, SUITE 1030
WOODLAND HILLS CA 91367
(818) 961-3001
douglass@energyattorney.com
For: Western Power Trading Forum

Andrew Brown
Attorney At Law
ELLISON & SCHNEIDER, LLP
2015 H STREET
SACRAMENTO CA 95814
(916) 447-2166
abb@eslawfirm.com
For: Constellation Energy Commodities Group, Inc./ Sierra Pacific Power Company

Jeffery D. Harris
Attorney At Law
ELLISON, SCHNEIDER & HARRIS
2015 H STREET
SACRAMENTO CA 95811-3109
(916) 447-2166
jdh@eslawfirm.com

Greggory L. Wheatland
Attorney At Law
ELLISON, SCHNEIDER & HARRIS, LLP
2015 H STREET
SACRAMENTO CA 95811-3109
(916) 447-2166
glw@eslawfirm.com
For: Hercules Municipal Utility

Carolyn Kehrein
ENERGY MANAGEMENT SERVICES
2602 CELEBRATION WAY
WOODLAND CA 95776
(530) 668-5600
cmkehrein@ems-ca.com

Norman J. Furuta
Attorney At Law
FEDERAL EXECUTIVE AGENCIES
1455 MARKET ST., SUITE 1744
SAN FRANCISCO CA 94103-1399
(415) 503-6994
norman.furuta@navy.mil
For: Federal Executive Agencies

Crystal Needham
Senior Director, Counsel
EDISON MISSION ENERGY
18101 VON KARMAN AVE, STE 1700
IRVINE CA 92612-1046
(949) 798-7977
cneedham@edisonmission.com

Joseph F. Wiedman
Attorney At Law
GOODIN MACBRIDE SQUERI DAY & LAMPREY LLP
505 SANSOME STREET, SUITE 900
SAN FRANCISCO CA 94111
(415) 392-7900
jwiedman@goodinmacbride.com

Brian T. Cragg
VIDHYA PRABHAKARAN
GOODIN, MACBRIDE, SQUERI, DAY & LAMPREY
505 SANSOME STREET, SUITE 900
SAN FRANCISCO CA 94111
(415) 392-7900
bcragg@goodinmacbride.com
For: Independent Energy Producers Association

James D. Squeri
Attorney At Law
GOODIN, MACBRIDE, SQUERI, RITCHIE & DAY
505 SANSOME STREET, SUITE 900
SAN FRANCISCO CA 94111
(415) 392-7900
jsqueri@gmssr.com
For: Powerex Corp.

Jeanne Armstrong
MICHAEL DAY
Attorney At Law
GOODIN, MACBRIDE, SQUERI, RITCHIE & DAY
505 SANSOME STREET, SUITE 900
SAN FRANCISCO CA 94111
(415) 392-7900
jarmstrong@gmssr.com
For: South San Joaquin Irrigation District/Reliant Energy

Vidhya Prabhakaran
MICHAEL B. DAY
GOODIN,MACBRIDE,SQUERI,DAY,LAMPREY
505 SANSOME STREET, SUITE 900
SAN FRANCISCO CA 94111
(415) 392-7900
vprabhakaran@goodinmacbride.com

APPENDIX A

************** SERVICE LIST *************

Last Updated on 21-JUL-2008 by: SM2

R0602013 LIST

Steve Isser
VP, General Counsel
GOOD COMPANY ASSOCIATES
816 CONGRESS AVE., SUITE 1400
AUSTIN TX 78701
(512) 279-0766
sisser@goodcompanyassociates.com
For: Good Company Associates

Curtis Kebler
J. ARON & COMPANY(GOLDMAN SACHS)
2121 AVENUE OF THE STARS
LOS ANGELES CA 90067
(310) 407-5619
curtis.kebler@gs.com

LOCAL POWER
4281 PIEDMONT AVENUE
OAKLAND CA 94611
(510) 451-1727

Robert Freehling
Local Power Research Director
LOCAL POWER
PO BOX 606
FAIR OAKS CA 94574
(916) 966-3410
rfreeh123@sbcglobal.net
For: Women's Energy Matters/Local Power

Ann G. Grimaldi
MCKENNA LONG & ALDRIDGE LLP
101 CALIFORNIA STREET, 41ST FLOOR
SAN FRANCISCO CA 94111
(415) 267-4000
agrimaldi@mckennalong.com
For: Center for Energy and Economic Development

Sara Steck Myers
Attorney At Law
122 28TH AVENUE
SAN FRANCISCO CA 94121
(415) 387-1904
ssmyers@att.net
For: Center for Energy Efficiency and Renewable Technologies

Audrey Chang, Staff Scientist
NATURAL RESOURCES DEFENSE COUNCIL
111 SUTTER STREET, 20TH FLOOR
SAN FRANCISCO CA 94104
(415) 875-6100
achang@nrdc.org

For: Reliant Energy, Inc.

Gregg Morris
Director
GREEN POWER INSTITUTE
2039 SHATTUCK AVENUE, STE 402
BERKELEY CA 94704
(510) 644-2700
gmorris@emf.net
For: Green Power Institute

Christopher C. O'Hara
Assistant General Counsel-Regulatory
NRG ENERGY
211 CARNEGIE CENTER DRIVE
PRINCETON NJ 08540
(609) 524-4926
chris.ohara@nrgenergy.com

Kerry Hattevik
Director Of Reg. And Market Affairs
NRG ENERGY
829 ARLINGTON BLVD.
EL CERRITO CA 94530
(510) 227-9188
kerry.hattevik@nrgenergy.com
For: Mirant Corporation

G. Alan Comnes
DAVID LLOYD
NRG ENERGY, INC.
1817 ASTON AVENUE, SUITE 104
CARLSBAD CA 92008
(503) 239-6913
alan.comnes@nrgenergy.com
For: NRG Energy, Inc.

Kathryn Wig
Paralegal
NRG ENERGY, INC.
211 CARNEGIE CENTER
PRINCETON NY 08540
(609) 524-4926
Kathryn.Wig@nrgenergy.com

Noel Obiora
Legal Division
RM. 4107
505 VAN NESS AVE
San Francisco CA 94102 3298
(415) 703-5987
nao@cpuc.ca.gov
For: Division of Ratepayer Advocates

APPENDIX A

************ SERVICE LIST ***********

Last Updated on 21-JUL-2008 by: SM2

R0602013 LIST

For: NATURAL RESOURCES DEFENSE COUNCIL

Alan Comnes
NRG ENERGY
3934 SE ASH STREET
PORTLAND OR 97214
(503) 239-6913
alan.comnes@nrgenergy.com
For: West Coast Power

Edward V. Kurz
Attorney At Law
PACIFIC GAS AND ELECTRIC COMPANY
77 BEALE ST., B30A
SAN FRANCISCO CA 94105
(415) 973-6669
evk1@pge.com
For: Pacific Gas and Electric Company

Stephen L. Garber
JONATHAN D. PENDLETON
Attorney At Law
PACIFIC GAS AND ELECTRIC COMPANY
77 BEALE STREET; MCB30A
SAN FRANCISCO CA 94105
(415) 973-8003
slg0@pge.com
For: Pacific Gas and Electric Company

Ryan Flynn
PACIFICORP
825 NE MULTNOMAH STREET, 18TH FLOOR
PORTLAND OR 97232
(503) 813-5854
ryan.flynn@pacificorp.com

Marion Peleo
Legal Division
RM. 4107
505 VAN NESS AVE
San Francisco CA 94102 3298
(415) 703-2130
map@cpuc.ca.gov
For: DRA

Rory Cox
RATEPAYERS FOR AFFORDABLE CLEAN ENERGY
311 CALIFORNIA STREET, SUITE 650
SAN FRANCISCO CA 94104
(415) 399-8850 X 302
rcox@pacificenvironment.org

Charles Middlekauff
WILLIAM V. MANNHEIM, EDWARD KURTZ
Attorney At Law
PACIFIC GAS AND ELECTRIC COMPANY
PO BOX 7442
SAN FRANCISCO CA 94120
(415) 973-6971
crmd@pge.com
For: Pacific Gas and Electric Company

Central Files
SAN DIEGO GAS & ELECTRIC
8330 CENTURY PARK COURT, CP31E
SAN DIEGO CA 92123
(858) 654-1766
centralfiles@semprautilities.com

John Pacheco
Attorney At Law
SAN DIEGO GAS & ELECTRIC
101 ASH STREET
SAN DIEGO CA 92101
(619) 699-5130
jpacheco@sempra.com
For: San Diego Gas & Electric

Wendy Keilani
SAN DIEGO GAS & ELECTRIC
8330 CENTURY PARK COURT, CP32D
SAN DIEGO CA 92123
(858) 654-1185
wkeilani@semprautilities.com

Lisa Urick
CARLOS F. PENA
Attorney At Law
SAN DIEGO GAS & ELECTRIC COMPANY
101 ASH STREET
SAN DIEGO CA 92101
(619) 699-5070
lurick@sempra.com
For: San Diego Gas & Electric

Jim Hendry
SAN FRANCISCO PUBLIC UTILITIES COMM.
1155 MARKET STREET, 4TH FLOOR
SAN FRANCISCO CA 94103
jhendry@sfwater.org

APPENDIX A

************ SERVICE LIST ***********

Last Updated on 21-JUL-2008 by: SM2

R0602013 LIST

For: Local Power

Eric Larsen
Environmental Scientist
RCM INTERNATIONAL, L.L.C.
PO BOX 4716
BERKELEY CA 94704
(510) 834-4568
elarsen@rcmdigesters.com

Deana M. White
MICHAEL MONTOYA, BERJ PERSEGHIAN
Attorney At Law
SOUTHERN CALIFORNIA EDISON COMPANY
2244 WALNUT GROVE AVENUE
ROSEMEAD CA 91770
(626) 302-1936
deana.white@sce.com
For: SOUTHERN CALIFORNIA EDISON Company

Janet S. Combs
JENNIFER T. SHIGEKAWA
SOUTHERN CALIFORNIA EDISON COMPANY
PO BOX 800
2244 WALNUT GROVE AVENUE
ROSEMEAD CA 91770
(626) 302-1524
janet.combs@sce.com
For: Southern California Edison company

Robert Keeler, Sr. Attorney
SOUTHERN CALIFORNIA EDISON COMPANY
2244 WALNUT GROVE AVENUE
ROSEMEAD CA 91770
(626) 302-4563
robert.keeler@sce.com
For: Southern California Edison

Jennifer Chamberlin
Mgr. Of Reg. And Gov. Affairs
STRATEGIC ENERGY, LLC
2633 WELLINGTON CT.
CLYDE CA 94520
(925) 969-1031
jchamberlin@strategicenergy.com

Theodore Roberts
Senior Counsel
SEMPRA GLOBAL
101 ASH STREET, HQ 12B
SAN DIEGO CA 92101-3017
(619) 699-5111
troberts@sempra.com
For: Sempra Global

Jeffrey Shields
SOUTH SAN JOAQUIN IRRIGATION DISTRICT
PO BOX 747
RIPON CA 95366
(209) 249-4645
jshields@ssjid.com

Joseph Greco
TERRA-GEN POWER LLC
9590 PROTOTYPE COURT, SUITE 200
RENO NV 89521
(775) 850-2245
jgreco@terra-genpower.com

Michel Peter Florio
MATTHEW FREEDMAN/ROBERT FINKELSTEIN
Attorney At Law
THE UTILITY REFORM NETWORK
711 VAN NESS AVENUE, SUITE 350
SAN FRANCISCO CA 94102
(415) 929-8876 X302
mflorio@turn.org
For: THE UTILITY REFORM NETWORK (TURN)

Attn: Michael Shames
UTILITY CONSUMERS' ACTION NETWORK (UCAN)
3100 FIFTH AVE., STE. B
SAN DIEGO CA 92103
(619) 696-6966
mshames@ucan.org
For: UCAN

Karen E. Bowen
WINSTON & STRAWN LLP
101 CALIFORNIA STREET, 39TH FLOOR
SAN FRANCISCO CA 94111
(415) 591-1100
jkarp@winston.com
For: Mirant Callifornia, LLC,Mirant Delta,LLC and Mirant Potrero, LLC

APPENDIX A

************** SERVICE LIST *************

Last Updated on 21-JUL-2008 by: SM2

R0602013 LIST

For: Strategic Energy, LLC

Eric C. Woychik
STRATEGY INTEGRATION LLC
9901 CALODEN LANE
OAKLAND CA 94605
(510) 387-5220
eric@strategyi.com
For: Comverge, Inc.

Keith R. Mccrea
Attorney At Law
SUTHERLAND, ASBILL & BRENNAN, LLP
1275 PENNSYLVANIA AVE., N.W.
WASHINGTON DC 20004-2415
(202) 383-0705
keith.mccrea@sablaw.com
For: California Manufacturers & Technology Association

Lisa A. Cottle
Attorney At Law
WINSTON & STRAWN LLP
101 CALIFORNIA STREET, 39TH FLOOR
SAN FRANCISCO CA 94111
(415) 544-1105
lcottle@winston.com
For: Mirant California,LLC, Mirant Delta,LLC,and Mirant Potrero,LLC

Barbara George
WOMEN'S ENERGY MATTERS
PO BOX 548
FAIRFAX CA 94978
(510) 915-6215
wem@igc.org
For: WOMEN'S ENERGY MATTERS

********** **STATE EMPLOYEE** ***********

Kathryn Auriemma
Energy Division
AREA 4-A
505 VAN NESS AVE
San Francisco CA 94102 3298
(415) 703-2072
kdw@cpuc.ca.gov

Amanda C. Baker
Energy Division
AREA 4-A
505 VAN NESS AVE
San Francisco CA 94102 3298
(415) 703-1691
ab1@cpuc.ca.gov

Simon Baker
Energy Division
AREA 4-A
505 VAN NESS AVE
San Francisco CA 94102 3298
(415) 703-5649
seb@cpuc.ca.gov

Valerie Beck
Consumer Protection & Safety Division
AREA 2-D
505 VAN NESS AVE
San Francisco CA 94102 3298
(415) 703-5264
vjb@cpuc.ca.gov

Kenneth Bruno
Consumer Protection & Safety Division
AREA 2-E
505 VAN NESS AVE
San Francisco CA 94102 3298
(415) 703-5265
kab@cpuc.ca.gov

Chi Doan
CALIF. DEPT OF WATER RESOURCES
3310 EL CAMINO AVE., ROOM LL94
SACRAMENTO CA 95821
(916) 574-0612

Jeff Diamond
CALIFORNIA ELECTRICITY OVERSIGHT BOARD
770 L STREET, SUITE 1250
SACRAMENTO CA 95814
(916) 322-8629
jdiamond@eob.ca.gov

Clare Laufenberg
CALIFORNIA ENERGY COMMISSION
1516 NINTH STREET, MS 46
SACRAMENTO CA 95814
(916) 654-4859
Claufenb@energy.state.ca.us

APPENDIX A

************** SERVICE LIST *************

Last Updated on 21-JUL-2008 by: SM2

R0602013 LIST

Donald J. Brooks
Energy Division
AREA 4-A
505 VAN NESS AVE
San Francisco CA 94102 3298
(415) 703-2626
dbr@cpuc.ca.gov
For: Energy Division

Carol A. Brown
Administrative Law Judge Division
RM. 5103
505 VAN NESS AVE
San Francisco CA 94102 3298
(415) 703-2971
cab@cpuc.ca.gov

David Vidaver
CALIFORNIA ENERGY COMMISSION
1516 NINTH STREET, MS-20
SACRAMENTO CA 95814
(916) 654-4656
dvidaver@energy.state.ca.us
For: California Energy Commission

Jim Woodward
CALIFORNIA ENERGY COMMISSION
1516 NINTH STREET, MS 20
SACRAMENTO CA 95814-5504
(916) 654-5180
jwoodwar@energy.state.ca.us

Karen Griffin
Executive Office
CALIFORNIA ENERGY COMMISSION
1516 9TH STREET, MS 39
SACRAMENTO CA 95814
(916) 654-4833
kgriffin@energy.state.ca.us
For: California Energy Commission

Kevin Kennedy
Supervisor, Special Projects
CALIFORNIA ENERGY COMMISSION
1516 9TH STREET, MS-48
SACRAMENTO CA 95814
(916) 651-8836

Lana Wong
CALIFORNIA ENERGY COMMISSION
1516 NINTH ST., MS-20
SACRAMENTO CA 95814
(916) 654-4638
lwong@energy.state.ca.us

Marc Pryor
CALIFORNIA ENERGY COMMISSION
1516 9TH ST, MS 20
SACRAMENTO CA 95814
(916) 653-0159
mpryor@energy.state.ca.us

Mike Ringer
CALIFORNIA ENERGY COMMISSION
1516 NINTH STREET, MS-20
SACRAMENTO CA 95814
(916) 654-4168
mringer@energy.state.ca.us
For: California Energy Commission

Bishu Chatterjee
Energy Division
AREA 4-A
505 VAN NESS AVE
San Francisco CA 94102 3298
(415) 703-1247
bbc@cpuc.ca.gov

Joe Como
Legal Division
RM. 5033
505 VAN NESS AVE
San Francisco CA 94102 3298
(415) 703-2381
joc@cpuc.ca.gov

Iryna Kwasny
DEPT. OF WATER RESOURCES-CERS DIVISION
3310 EL CAMINO AVE., STE.120
SACRAMENTO CA 95821
(916) 574-2226
ikwasny@water.ca.gov

Matthew Deal
Executive Division
RM. 5215, 505 VAN NESS AVE
San Francisco CA 94102 3298
(415) 703-2576

APPENDIX A

************ SERVICE LIST ***********

Last Updated on 21-JUL-2008 by: SM2

R0602013 LIST

mjd@cpuc.ca.gov

Nancy Tronaas
CALIFORNIA ENERGY COMMISSION
1516 9TH ST. MS-20
SACRAMENTO CA 95814-5512
(916) 654-3864
ntronaas@energy.state.ca.us

Ross Miller
CALIFORNIA ENERGY COMMISSION
1516 9TH STREET
SACRAMENTO CA 95814
(916) 654-4892
rmiller@energy.state.ca.us
For: California Energy Commission

Andrew Campbell
Executive Division
RM. 5203
505 VAN NESS AVE
San Francisco CA 94102 3298
(415) 703-2501
agc@cpuc.ca.gov

David K. Fukutome
Administrative Law Judge Division
RM. 5042
505 VAN NESS AVE
San Francisco CA 94102 3298
(415) 703-2403
dkf@cpuc.ca.gov

Anne Gillette
Energy Division
AREA 4-A
505 VAN NESS AVE
San Francisco CA 94102 3298
(415) 703-5219
aeg@cpuc.ca.gov

Donna J. Hines
Division of Ratepayer Advocates
RM. 4102
505 VAN NESS AVE
San Francisco CA 94102 3298
(415) 703-2520
djh@cpuc.ca.gov

Paul Douglas
Energy Division
AREA 4-A
505 VAN NESS AVE
San Francisco CA 94102 3298
(415) 355-5579
psd@cpuc.ca.gov

Kevin R. Dudney
Energy Division
AREA 4-A
505 VAN NESS AVE
San Francisco CA 94102 3298
(415) 703-2557
kd1@cpuc.ca.gov

Fred Mobasheri
ELECTRIC POWER GROUP
201 S. LAKE AVE., SUITE 400
PASADENA CA 91101
(626) 658-2015
fmobasheri@aol.com

Laura A. Martin
Energy Division
AREA 4-A
505 VAN NESS AVE
San Francisco CA 94102 3298
(415) 703-2149
lra@cpuc.ca.gov

Jerry Oh
Division of Ratepayer Advocates
RM. 3200
505 VAN NESS AVE
San Francisco CA 94102 3298
(415) 703-2806
joh@cpuc.ca.gov

Sophia Park
Legal Division
RM. 5130
505 VAN NESS AVE
San Francisco CA 94102 3298
(415) 703-2116
sjp@cpuc.ca.gov

APPENDIX A

************** SERVICE LIST *************

Last Updated on 21-JUL-2008 by: SM2

R0602013 LIST

Sara M. Kamins
Energy Division
AREA 4-A
505 VAN NESS AVE
San Francisco CA 94102 3298
(415) 703-1388
smk@cpuc.ca.gov

Sepideh Khosrowjah
Division of Ratepayer Advocates
RM. 4208
505 VAN NESS AVE
San Francisco CA 94102 3298
(415) 703-1190
skh@cpuc.ca.gov

James Loewen
Energy Division
320 WEST 4TH STREET SUITE 500
Los Angeles CA 90013
(213) 620-6341
loe@cpuc.ca.gov

Jaclyn Marks
Energy Division
AREA 4-A
505 VAN NESS AVE
San Francisco CA 94102 3298
(415) 703-2257
jm3@cpuc.ca.gov

Jason R. Salmi Klotz
Energy Division
AREA 4-A
505 VAN NESS AVE
San Francisco CA 94102 3298
(415) 703-3421
jk1@cpuc.ca.gov

Melissa Semcer
Energy Division
AREA 4-A
505 VAN NESS AVE
San Francisco CA 94102 3298
(415) 703-1925
unc@cpuc.ca.gov

Sean A. Simon
Energy Division
AREA 4-A
505 VAN NESS AVE
San Francisco CA 94102 3298
(415) 703-3791
svn@cpuc.ca.gov

Peter Skala
Energy Division
AREA 4-A
505 VAN NESS AVE
San Francisco CA 94102 3298
(415) 703-5370
ska@cpuc.ca.gov

Donald R. Smith
Division of Ratepayer Advocates
RM. 4209
505 VAN NESS AVE
San Francisco CA 94102 3298
(415) 703-1562
dsh@cpuc.ca.gov
For: Division of Ratepayer Advocates

Robert L. Strauss
Energy Division
AREA 4-A
505 VAN NESS AVE
San Francisco CA 94102 3298
(415) 703-5289
rls@cpuc.ca.gov
For: Energy Division

Gustavo Luna
AES CORPORATION
690 N. STUDEBAKER RD.
LONG BEACH CA 90803
(562) 493-7307
gustavo.luna@aes.com

Karen Terranova
ALCANTAR & KAHL, LLP
120 MONTGOMERY STREET, STE 2200
SAN FRANCISCO CA 94104
(415) 421-4143
filings@a-klaw.com

APPENDIX A

**************** SERVICE LIST ***************

Last Updated on 21-JUL-2008 by: SM2

R0602013 LIST

Jeorge S. Tagnipes
Energy Division
AREA 4-A
505 VAN NESS AVE
San Francisco CA 94102 3298
(415) 703-2451
jst@cpuc.ca.gov

Amy C. Yip-Kikugawa
Administrative Law Judge Division
RM. 2106
505 VAN NESS AVE
San Francisco CA 94102 3298
(415) 703-5256
ayk@cpuc.ca.gov

********* **INFORMATION ONLY** **********

Michael Mazur
3 PHASES RENEWABLES, LLC
2100 SEPULVEDA BLVD., STE 37
MANHATTAN BEACH CA 90266
(310) 798-5275
mmazur@3phasesRenewables.com

Kenneth E. Abreu
853 OVERLOOK COURT
SAN MATEO CA 94403
(925) 989-7912
k.abreu@sbcglobal.net

Vitaly Lee
AES ALAMITOS, LLC
690 N. STUDEBAKER ROAD
LONG BEACH CA 90803
(562) 493-7307
vitaly.lee@aes.com

Philippe Auclair
11 RUSSELL COURT
WALNUT CREEK CA 94598
(925) 588-9109
philha@astound.net

Steven S. Schleimer
Director,Compliance & Regulatory Affairs
BARCLAYS BANK, PLC
200 PARK AVENUE, FIFTH FLOOR
NEW YORK NY 10166
steven.schleimer@barclayscapital.com

Nora Sheriff
Attorney At Law
ALCANTAR & KAHL, LLP
120 MONTGOMERY STREET, SUITE 2200
SAN FRANCISCO CA 94104
(415) 421-4143
nes@a-klaw.com
For: Energy Producers & Users Coalition

Seema Srinivasan
Attorney At Law
ALCANTAR & KAHL, LLP
120 MONTGOMERY STREET, SUITE 2200
SAN FRANCISCO CA 94104
(415) 421-4143
sls@a-klaw.com

Frank Annunziato
President
AMERICAN UTILITY NETWORK INC.
10705 DEER CANYON DR.
ALTA LOMA CA 91737-2483
(909) 989-4000
allwazeready@aol.com

Edward G. Poole
Attorney At Law
ANDERSON & POOLE
601 CALIFORNIA STREET, SUITE 1300
SAN FRANCISCO CA 94108-2818
(415) 956-6413
epoole@adplaw.com

Stacy Aguayo
APS ENERGY SERVICES
400 E. VAN BUREN STREET, SUITE 750
PHOENIX AZ 85004
(602) 744-5364
stacy.aguayo@apses.com

Bruce Mclaughlin
Attorney At Law
BRAUN & BLAISING, P.C.
915 L STREET SUITE 1420
SACRAMENTO CA 95814
(916) 326-5812
mclaughlin@braunlegal.com

APPENDIX A

**************** SERVICE LIST ***************

Last Updated on 21-JUL-2008 by: SM2

R0602013 LIST

Barbara R. Barkovich
BARKOVICH & YAP, INC.
44810 ROSEWOOD TERRACE
MENDOCINO CA 95460
(707) 937-6203
brbarkovich@earthlink.net

Reed V. Schmidt
BARTLE WELLS ASSOCIATES
1889 ALCATRAZ AVENUE
BERKELEY CA 94703-2714
(510) 653-3399 X111
rschmidt@bartlewells.com

Peter T. Pearson
Energy Supply Specialist
BEAR VALLEY ELECTRIC SERVICE
42020 GARSTIN ROAD
BIG BEAR LAKE CA 92315
(909) 866-4678 X186
peter.pearson@bves.com

Ryan Wiser
BERKELEY LAB
1 CYCLOTRON ROAD, MS-90-4000
BERKELEY CA 94720
(510) 486-5474
rhwiser@lbl.gov

David Branchcomb
BRANCHCOMB ASSOCIATES, LLC
9360 OAKTREE LANE
ORANGEVILLE CA 95662
(916) 988-5676
david@branchcomb.com

Ryan Bernardo
BRAUN BLAISING MCLAUGHLIN, P.C.
915 L STREET, SUITE 1270
SACRAMENTO CA 95814
(916) 912-4432
bernardo@braunlegal.com

Jennifer Porter
Policy Analyst
CALIFORNIA CENTER FOR SUSTAINABLE ENERGY
8690 BALBOA AVENUE, SUITE 100
SAN DIEGO CA 92123
(858) 244-1177
jennifer.porter@energycenter.org

Sephra A. Ninow
Policy Analyst
CALIFORNIA CENTER FOR SUSTAINABLE ENERGY
8690 BALBOA AVENUE, SUITE 100
SAN DIEGO CA 92123
(858) 244-1186
sephra.ninow@energycenter.org

Beth Vaughan
CALIFORNIA COGENERATION COUNCIL
4391 N. MARSH ELDER COURT
CONCORD CA 94521
(925) 408-5142
beth@beth411.com

Pierre H. Duvair, Ph.D
CALIFORNIA ENERGY COMISSION
1516 NINTH STREET
SACRAMENTO CA 95814
(916) 653-8685
pduvair@energy.state.ca.us

Contance Leni
CALIFORNIA ENERGY COMMISSION
1516 NINTH ST., MS-20
SACRAMENTO CA 95814
(916) 654-4762
cleni@energy.state.ca.us

CALIFORNIA ENERGY MARKETS
517-B POTRERO AVENUE
SAN FRANCISCO CA 94110
(415) 552-1764
CEM@newsdata.com

APPENDIX A

************** SERVICE LIST *************

Last Updated on 21-JUL-2008 by: SM2

R0602013 LIST

Karen Mills
CALIFORNIA FARM BUREAU FEDERATION
2300 RIVER PLAZA DRIVE
SACRAMENTO CA 95833
(916) 561-5655
kmills@cfbf.com

CALIFORNIA ISO
151 BLUE RAVINE ROAD
FOLSOM CA 95630
e-recipient@caiso.com

Judith Sanders
CALIFORNIA ISO
151 BLUE RAVINE ROAD
FOLSOM CA 95630
jsanders@caiso.com
For: California ISO

Karen Lindh
CALIFORNIA ONSITE GENERATION
7909 WALERGA ROAD, NO. 112, PMB 119
ANTELOPE CA 95843
(916) 729-1562
karen@klindh.com

Kevin Duggan, Attorney At Law
CALPINE COPRORATION
3845 HOPYARD ROAD, SUITE 345
PLEASANTON CA 94588
(925) 479-6648
duggank@calpine.com

Avis Kowalewski
CALPINE CORPORATION
3875 HOPYARD ROAD, SUITE 345
PLEASANTON CA 94588
(925) 479-6640
kowalewskia@calpine.com

Kevin Boudreaux
CALPINE CORPORATION
717 TEXAS AVENUE SUITE 1000
HOUSTON TX 77002
(713) 830-8935
boudreauxk@calpine.com

Rachel Mcmahon
Dir. Of Reg. Affairs
CEERT
1100 11TH STREET, SUITE 311
SACRAMENTO CA 95814
(916) 442-7785

Claire E. Torchia
CHADBOURNE & PARKE LLP
350 SOUTH GRAND AVE., STE 3300
LOS ANGELES CA 90071
(213) 892-2105
ctorchia@chadbourne.com

Bob Tang
Assistant Director
CITY OF AZUSA
729 NORTH AZUSA AVENUE
AZUSA CA 91702-9500
(626) 812-5214
btang@ci.azusa.ca.us

Thomas Blair
CITY OF SAN DIEGO
9601 RIDGEHAVEN COURT, STE. 120/MS11
SAN DIEGO CA 92123
(858) 492-6001
tblair@sandiego.gov

Ted Pope
Director
COHEN VENTURES, INC./ENERGY SOLUTIONS
1610 HARRISON ST.
OAKLAND CA 94612
(510) 482-4420 X236
ted@energy-solution.com

Courtney Weddington
Compliance Analyst
COMMERCE ENERGY INC
222 W. LAS COLINAS BLVD., STE. 950-E
IRVING TX 75039
(214) 296-5414
cweddington@commerceenergy.com
For: COMMERCE ENERGY INC

Ann Hendrickson
COMMERCE ENERGY, INC.
222 WEST LAS COLINAS BLVD., SUITE 950E
IRVING TX 75039
(714) 259-2500
ahendrickson@commerceenergy.com
For: COMMERCE ENERGY, INC.

Lynelle Lund
COMMERCE ENERGY, INC.
600 ANTON BLVD., SUITE 2000
COSTA MESA CA 92626
(714) 259-2536
llund@commerceenergy.com

APPENDIX A

************ SERVICE LIST ***********

Last Updated on 21-JUL-2008 by: SM2

R0602013 LIST

rachel@ceert.org

Tam Hunt
Energy Program Director/Attorney
COMMUNITY ENVIRONMENTAL COUNCIL
26 W. ANAPAMU, 2ND FLOOR
SANTA BARBARA CA 93101
(805) 963-0583 X 122
thunt@cecmail.org

David X. Kolk, Ph.D.
COMPLETE ENERGY SERVICE, INC.
41422 MAGNOLIA STREET
MURRIETA CA 92562
(512) 283-1097
Dkolk@compenergy.com

James Mcmahon
CRA INTERNATIONAL
50 CHURCH ST.
CAMBRIDGE MA 02138
(603) 591-5898
jmcmahon@crai.com

Kathleen Esposito
CRESTED BUTTE CATALYSTS LLC
PO BOX 668
CRESTED BUTTE CO 81224
(970) 349-2082
kesposito@cbcatalysts.com

Laurence Chaset
Legal Division
RM. 5131
505 VAN NESS AVE
San Francisco CA 94102 3298
(415) 355-5595
lau@cpuc.ca.gov

Judy Pau
DAVIS WRIGHT TREMAINE LLP
505 MONTGOMERY STREET, SUITE 800
SAN FRANCISCO CA 94111-6533
(415) 276-6587
judypau@dwt.com

Robert B. Gex
Attorney At Law,
DAVIS WRIGHT TREMAINE LLP
505 MONTGOMERY STREET, SUITE 800
SAN FRANCISCO CA 94111-6533
(415) 276-6500
bobgex@dwt.com

Ralph R. Nevis
DAY CARTER & MURPHY LLP
3620 AMERICAN RIVER DR., SUITE 205
SACRAMENTO CA 95864
(916) 570-2500 X109
rnevis@daycartermurphy.com

Dale E. Fredericks
DG POWER LLC
PO BOX 4400
WALNUT CREEK CA 94596-0400
(925) 938-9098
dale@dgpower.com

William F. Dietrich
Attorney At Law
DIETRICH LAW
2977 YGNACIO VALLEY ROAD, NO. 613
WALNUT CREEK CA 94598-3535
(415) 297-2356
dietrichlaw2@earthlink.net

Donald C. Liddell
Attorney At Law
DOUGLASS & LIDDELL
2928 2ND AVENUE
SAN DIEGO CA 92103
(619) 993-9096
liddell@energyattorney.com

Melanie Gillette
DUKE ENERGY NORTH AMERICA
980 NINTH STREET, SUITE 1420
SACRAMENTO CA 95814
(916) 441-6233

Lawrence Kostrzewa
Regional Vp, Development
EDISON MISSION ENERGY
18101 VON KARMAN AVE., STE 1700
IRVINE CA 92612-1046
(949) 798-7922
lkostrzewa@edisonmission.com

Philip Herrington
Regional Vp, Business Management
EDISON MISSION ENERGY
18101 VON KARMAN AVENUE, STE 1700
IRVINE CA 92612-1046
(949) 798-7922
pherrington@edisonmission.com

APPENDIX A

************ SERVICE LIST ***********

Last Updated on 21-JUL-2008 by: SM2

R0602013 LIST

Steve Koerner
Senior Consel
EL PASO CORPORATION
2 NORTH NEVADA AVENUE
COLORADO SPRINGS CO 80903
(719) 520-4443
steve.koerner@elpaso.com

Lynn Haug
ELLISON, SCHNEIDER & HARRIS, LLP
2015 H STREET
SACRAMENTO CA 95814-3109
(916) 447-2166
lmh@eslawfirm.com

Kevin J. Simonsen
ENERGY MANAGEMENT SERVICES
646 EAST THIRD AVENUE
DURANGO CO 81301
(970) 259-1748
kjsimonsen@ems-ca.com

Gregory T. Blue
ENXCO DEVELOPMENT CORP.
5000 EXECUTIVE PARKWAY, STE. 140
SAN RAMON CA 94583
(925) 242-0168 X20
gblue@enxco.com

Saeed Farrokhpay
FEDERAL ENERGY REGULATORY COMMISSION
110 BLUE RAVINE RD., SUITE 107
FOLSOM CA 95630
(916) 294-0322
saeed.farrokhpay@ferc.gov

Ed Chang
FLYNN RESOURCE CONSULTANTS, INC.
2165 MOONSTONE CIRCLE
EL DORADO HILLS CA 95762
(888) 634-0222
edchang@flynnrci.com

Janine L. Scancarelli
Attorney At Law
FOLGER, LEVIN & KAHN, LLP
275 BATTERY STREET, 23RD FLOOR
SAN FRANCISCO CA 94111
(415) 986-2800
jscancarelli@flk.com

Diane I. Fellman
Attorney At Law
FPL ENERGY, LLC
234 VAN NESS AVENUE
SAN FRANCISCO CA 94102
(415) 703-6000
diane_fellman@fpl.com

J. Richard Lauckhart
GLOBAL ENERGY
2379 GATEWAY OAKS DRIVE, STE 200
SACRAMENTO CA 95833
(916) 609-7769
rlauckhart@globalenergy.com

Ronald Moore
GOLDEN STATE WATER/BEAR VALLEY ELECTRIC
630 EAST FOOTHILL BOULEVARD
SAN DIMAS CA 91773
(909) 394-3600 X 682
rkmoore@gswater.com

Isser Steve
Vice President/General Counsel
GOOD COMPANY ASSOCIATES
816 CONGRESS AVENUE, STE 1400
AUSTIN TX 78701
(512) 279-0766
sisser@goodcompanyassociates.com

Norman A. Pedersen
HANNA AND MORTON LLP
444 SOUTH FLOWER STREET, SUITE 1500
LOS ANGELES CA 90071-2916
(213) 430-2510
npedersen@hanmor.com

Raj N. Pankhania
HERCULES MUNICIPAL UTILITY
111 CIVIC DRIVE
HERCULES CA 94547
(510) 799-8208
raj.pankhania@ci.hercules.ca.us

Kimberly Kiener
IMPERIAL IRRIGATION DISTRICT
504 CATALINA BLVD.
SAN DIEGO CA 92106
(619) 990-6627
kmkiener@cox.net

APPENDIX A

**************** SERVICE LIST ***************

Last Updated on 21-JUL-2008 by: SM2

R0602013 LIST

David Olsen
IMPERIAL VALLEY STUDY GROUP
3804 PACIFIC COAST HIGHWAY
VENTURA CA 93001
(805) 653-6881
olsen@avenuecable.com

Steven Kelly
Policy Director
INDEPENDENT ENERGY PRODUCERS
1215 K STREET, SUITE 900
SACRAMENTO CA 95814
(916) 448-9499
steven@iepa.com
For: INDEPENDENT ENERGY PRODUCERS ASSN

Robert E. Burt
INSULATION CONTRACTORS ASSN.
4153 NORTHGATE BLVD., NO.6
SACRAMENTO CA 95834
(916) 568-1826
bburt@macnexus.org
For: Insulation Contractors Association

Jody S. London
JODY LONDON CONSULTING
PO BOX 3629
OAKLAND CA 94609
(510) 459-0667
jody_london_consulting@earthlink.net

Keith G. Johnson
Senior Market And Product Developer
151 BLUE RAVINE ROAD
FOLSOM CA 95682
(916) 608-7100
kjohnson@caiso.com

Dennis M.P. Ehling
Attorney At Law
KIRKPATRICK & LOCKHART NICHOLSON GRAHAM
10100 SANTA MONICA BLVD., 7TH FLOOR
LOS ANGELES CA 90067
(310) 552-5000
dehling@klng.com

Richard W. Raushenbush
Attorney At Law
LATHAM & WATKINS LLP
505 MONTGOMERY STREET, SUITE 2000
SAN FRANCISCO CA 94111
(415) 395-8237

Martin Homec
Attorney At Law
LAW OFFICE OF MARTIN HOMEC
PO BOX 4471
DAVIS CA 95617
(530) 867-1850
martinhomec@gmail.com

William H. Booth
Attorney At Law
LAW OFFICES OF WILLIAM H. BOOTH
67 CARR DRIVE
MORAGA CA 94596
(925) 296-2460
wbooth@booth-law.com
For: CA Large Energy Consumers Association

Patrick Stoner
Program Director
LOCAL GOVERNMENT COMMISSION
1303 J STREET, SUITE 250
SACRAMENTO CA 95814
(916) 448-1198 X 309
pstoner@lgc.org

Paul Fenn
LOCAL POWER
4281 PIEDMONT AVE.
OAKLAND CA 94611
(510) 451-1727
paulfenn@local.org

Lynne Mackey
LS POWER DEVELOPMENT
400 CHESTERFIELD CTR., SUITE 110
ST. LOUIS MO 63017
lmackey@lspower.com

John W. Leslie
Attorney At Law
LUCE, FORWARD, HAMILTON & SCRIPPS, LLP
11988 EL CAMINO REAL, SUITE 200
SAN DIEGO CA 92130
(858) 720-6352
jleslie@luce.com

Richard Mccann Ph.D
M.CUBED
2655 PORTAGE BAY, SUITE 3
DAVIS CA 95616
(530) 757-6363
rmccann@umich.edu

APPENDIX A

************** SERVICE LIST *************

Last Updated on 21-JUL-2008 by: SM2

R0602013 LIST

richard.raushenbush@lw.com

David Marcus
PO BOX 1287
BERKELEY CA 94701
(510) 528-0728
dmarcus2@sbcglobal.net

C. Susie Berlin
MCCARTHY & BERLIN LLP
100 W. SAN FERNANDO ST., SUITE 501
SAN JOSE CA 95113
(408) 288-2080
sberlin@mccarthylaw.com

Barry F. Mccarthy
Attorney At Law
MCCARTHY & BERLIN, LLP
100 W. SAN FERNANDO ST., SUITE 501
SAN JOSE CA 95113
(408) 288-2080
bmcc@mccarthylaw.com

Grace C. Wung
MCDERMOTT WILL & EMERY LLP
28 STATE STREET
BOSTON MA 02109
(617) 535-4069
gwung@mwe.com
For: Morgan Stanley Capital Group, Inc.

Michael A. Yuffee
MCDERMOTT WILL & EMERY LLP
600 THIRTEENTH STREET, N.W.
WASHINGTON DC 20005-3096
(202) 756-8000
myuffee@mwe.com

Timothy R. Odil
MCKENNA LONG & ALDRIDGE LLP
1875 LAWRENCE STREET, SUITE 200
DENVER CO 80202
(303) 634-4000
todil@mckennalong.com

Douglas Mcfarlan
Vp, Public Affairs
MIDWEST GENERATION EME
440 SOUTH LASALLE ST., SUITE 3500
CHICAGO IL 60605
(312) 583-6024
dmcfarlan@mwgen.com

Joy A. Warren
Regulatory Administrator
MODESTO IRRIGATION DISTRICT
1231 11TH STREET
MODESTO CA 95354
(209) 526-7389
joyw@mid.org

Thomas S. Kimball
MODESTO IRRIGATION DISTRICT
1231 11TH STREET
MODESTO CA 95354
(209) 557-1510
tomk@mid.org

Douglas R. Kiviat
Executive Director
MORGAN STANLEY / COMMODITIES
2000 WESTCHESTER AVENUE
PURCHAWE NY 10577
(914) 225-1571
doug.kiviat@morganstanley.com

Steven Huhman
MORGAN STANLEY CAPITAL GROUP INC.
2000 WESTCHESTER AVENUE
PURCHASE NY 10577
(914) 225-1592
steven.huhman@morganstanley.com

David Morse
1411 W, COVELL BLVD., SUITE 106-292
DAVIS CA 95616-5934
(530) 756-5033
demorse@omsoft.com

John Dutcher
Vice President - Regulatory Affairs
MOUNTAIN UTILITIES
3210 CORTE VALENCIA
FAIRFIELD CA 94534-7875
(707) 426-4003
ralf1241a@cs.com
For: MOUNTAIN UTILITIES

Wayne Amer
President
MOUNTAIN UTILITIES
PO BOX 205
KIRKWOOD CA 95646
(209) 258-7444

APPENDIX A

************** SERVICE LIST *************

Last Updated on 21-JUL-2008 by: SM2

R0602013 LIST

MRW & ASSOCIATES, INC.
1814 FRANKLIN STREET, SUITE 720
OAKLAND CA 94612
(510) 834-1999
mrw@mrwassoc.com

Kenny Swain
NAVIGANT CONSULTING
3100 ZINFANDEL DRIVE, SUITE 600
RANCHO CORDOVA CA 95670
(916) 631-3206
kenneth.swain@navigantconsulting.com

Eric Olson
NAVIGANT CONSULTING INC.
3100 ZINFANDEL DR., STE 600
RANCHO CORDOVA CA 95670-6078
(916) 631-3252
eolson@navigantconsulting.com

Kirby Dusel
NAVIGANT CONSULTING, INC.
3100 ZINFANDEL DRIVE, SUITE 600
RANCHO CORDOVA CA 95670
(916) 834-0684
kdusel@navigantconsulting.com

Paul D. Maxwell
NAVIGANT CONSULTING, INC.
3100 ZINFANDEL DRIVE, SUITE 600
RANCHO CORDOVA CA 95670-6078
(916) 631-2300
pmaxwell@navigantconsulting.com

Julie L. Martin
NORTH AMERICA GAS AND POWER
BP ENERGY COMPANY
501 WESTLAKE PARK BLVD.
HOUSTON TX 77079
(281) 366-8840
julie.martin@bp.com

Scott Tomashefsky
NORTHERN CALIFORNIA POWER AGENCY
180 CIRBY WAY
ROSEVILLE CA 95678-6420
(916) 781-4291
scott.tomashefsky@ncpa.com

wamer@kirkwood.com

Jesus Arredondo
NRG ENERGY INC.
4600 CARLSBAD BLVD.
CARLSBAD CA 99208
(916) 275-7493
jesus.arredondo@nrgenergy.com

Tim Hemig
NRG ENERGY, INC.
1817 ASTON AVENUE, SUITE 104
CARLSBAD CA 92008
(760) 710-2144
tim.hemig@nrgenergy.com

E.J. Wright
OCCIDENTAL POWER SERVICES, INC.
111 WEST OCEAN BOULEVARD
LONG BEACH TX 90802
(562) 624-3309
ej_wright@oxy.com

Jonathan Jacobs
PA CONSULTING GROUP
75 NOVA DRIVE
PIEDMONT CA 94610-1037
(510) 654-9495
jon.jacobs@paconsulting.com

Valerie Winn
Project Manager
PACIFIC GAS & ELECTRIC
77 BEALE STREET, B9A
SAN FRANCISCO CA 94105
(415) 973-3839
vjw3@pge.com

Angela Torr
PACIFIC GAS & ELECTRIC COMPANY
MC N13E
245 MARKET STREET
SAN FRANCISCO CA 94105
(415) 973-6077
ACT6@pge.com

Alice Gong
PACIFIC GAS AND ELECTRIC COMPANY
77 BEALE ST. MC B9A
SAN FRANCISCO CA 94105
AxL3@pge.com
For: PACIFIC GAS AND ELECTRIC COMPANY

APPENDIX A
**************** SERVICE LIST ***************
Last Updated on 21-JUL-2008 by: SM2
R0602013 LIST

Kerry Hattevik
Director Of Reg. And Market Affairs
NRG ENERGY
829 ARLINGTON BLVD.
EL CERRITO CA 94530
(510) 227-9188
kerry.hattevik@nrgenergy.com

Bianca Bowman
Case Coordinator
PACIFIC GAS AND ELECTRIC COMPANY
77 BEALE STREET, MAIL CODE B9A
SAN FRANCISCO CA 94105
(415) 973-4124
brbc@pge.com

Brian K. Cherry
Vp, Regulatory Relations
PACIFIC GAS AND ELECTRIC COMPANY
PO BOX 770000, MAIL CODE: B10C
SAN FRANCISCO CA 94177
(415) 973-4977
bkc7@pge.com

Case Coordination
PACIFIC GAS AND ELECTRIC COMPANY
PO BOX 770000; MC B9A
SAN FRANCISCO CA 94177
(415) 973-4744
regrelcpuccases@pge.com

Ed Lucha
PACIFIC GAS AND ELECTRIC COMPANY
77 BEALE STREET, MAIL CODE B9A
SAN FRANCISCO CA 94105
ell5@pge.com

George Zahariudakis
PACIFIC GAS AND ELECTRIC COMPANY
MAIL CODE B9A
77 BEALE STREET, RM. 904
SAN FRANCISCO CA 94105
(415) 973-2079
gxz5@pge.com

Grace Livingston-Nunley
Assistant Project Manager
PACIFIC GAS AND ELECTRIC COMPANY
PO BOX 770000 MAIL CODE B9A
SAN FRANCISCO CA 94177
(415) 973-4304
GXL2@pge.com

Shaun Halverson
PACIFIC GAS AND ELECTRIC COMPANY
PG&E MAIL CODE B9A
PO BOX 770000
SAN FRANCISCO CA 94177
SEHC@pge.com
For: PACIFIC GAS AND ELECTRIC COMPANY

Soumya Sastry
PACIFIC GAS AND ELECTRIC COMPANY
MAIL CODE B9A
PO BOX 770000
SAN FRANCISCO CA 94177
(415) 973-3295
svs6@pge.com

Stephanie La Shawn
PACIFIC GAS AND ELECTRIC COMPANY
PO BOX 770000, MAIL CODE B9A
SAN FRANCISCO CA 94177
(415) 973-8063
S1L7@pge.com

William V. Manheim
Attorney At Law
PACIFIC GAS AND ELECTRIC COMPANY
PO BOX 7442, LAW DEPT.
SAN FRANCISCO CA 94120
wvm3@pge.com
For: PACIFIC GAS AND ELECTRIC COMPANY

Cathie Allen
Ca State Mgr.
PACIFICORP
825 NE MULTNOMAH STREET, SUITE 2000
PORTLAND OR 97232
(503) 813-7157
californiadockets@pacificorp.com

Sebastien Csapo
PG&E PROJECT MGR.
MAIL CODE B9A
PO BOX 770000
SAN FRANCISCO CA 94177

APPENDIX A

************** SERVICE LIST *************

Last Updated on 21-JUL-2008 by: SM2

R0602013 LIST

Larry Nixon
PACIFIC GAS AND ELECTRIC COMPANY
77 BEALE STREET, MC B10A
SAN FRANCISCO CA 94105
(415) 973-5450
lrn3@pge.com
For: PACIFIC GAS AND ELECTRIC COMPANY

Thomas Darton
PILOT POWER GROUP, INC.
8910 UNIVERSITY CENTER LANE, STE 520
SAN DIEGO CA 92122
(858) 627-9577
tdarton@pilotpowergroup.com

Lisa Weinzimer
Associate Editor
PLATTS MCGRAW-HILL
695 NINTH AVENUE, NO. 2
SAN FRANCISCO CA 94118
(415) 387-1025
lisa_weinzimer@platts.com

David Tateosian
POWER ENGINEERS
PO BOX 2037
MARTINEZ CA 94553
(925) 372-9284
dtateosian@powereng.com

Rick C. Noger
PRAXAIR PLAINFIELD, INC.
2711 CENTERVILLE ROAD, SUITE 400
WILMINGTON DE 19808
(925) 866-6809
rick_noger@praxair.com

Donald Schoenbeck
RCS, INC.
900 WASHINGTON STREET, SUITE 780
VANCOUVER WA 98660
(360) 737-3877
dws@r-c-s-inc.com

James Ross
RCS, INC.
500 CHESTERFIELD CENTER, SUITE 320
CHESTERFIELD MO 63017
(636) 530-9544
jimross@r-c-s-inc.com

sscb@pge.com

Reid A. Winthrop
Corporate Counsel
PILOT POWER GROUP, INC.
8910 UNIVERSITY CENTER LANE, SUITE 520
SAN DIEGO CA 92122
(858) 678-0118
rwinthrop@pilotpowergroup.com

Trent A. Carlson
RELIANT ENERGY
1000 MAIN STREET
HOUSTON TX 77001
(713) 497-4386
tcarlson@reliant.com
For: RELIANT ENERGY INC.

Gary Hinners
RELIANT ENERGY, INC.
PO BOX 148
HOUSTON TX 77001-0148
(713) 497-4321
ghinners@reliant.com

Edward C. Remedios
33 TOLEDO WAY
SAN FRANCISCO CA 94123-2108
(415) 474-7253
ecrem@ix.netcom.com

Wayne Tomlinson
RUBY PIPELINE, LLC
2 NORTH NEVADA AVENUE, 14TH FLR
COLORADO SPRINGS CO 80903
(719) 520-4579
william.tomlinson@elpaso.com

Susan Freedman
Senior Regional Energy Planner
SAN DIEGO ASSOCIATION OF GOVERNMENTS
401 B STREET, SUITE 800
SAN DIEGO CA 92101
(619) 699-7387
sfr@sandag.org

Allen K. Trial
Counsel
SAN DIEGO GAS & ELECTRIC COMPANY
101 ASH STREET, HQ-12
SAN DIEGO CA 92101
(619) 699-5162
atrial@sempra.com

APPENDIX A

************** SERVICE LIST *************

Last Updated on 21-JUL-2008 by: SM2

R0602013 LIST

Robert Ott
RELIANT ENERGY
PO BOX 148
HOUSTON TX 77001-0148
(713) 497-5117
rott@reliant.com

Gina M. Dixon
SAN DIEGO GAS & ELECTRIC COMPANY
8330 CENTURY PARK COURT, MS CP32D
SAN DIEGO CA 92123
(858) 654-1782
gdixon@semprautilities.com

Steve Rahon
Director, Tariff & Regulatory Accounts
SAN DIEGO GAS & ELECTRIC COMPANY
8330 CENTURY PARK COURT, CP32C
SAN DIEGO CA 92123-1548
lschavrien@semprautilities.com

Pedro Villegas
SAN DIEGO GAS & ELECTRIC/ SO. CAL. GAS
601 VAN NESS AVE 2060
SAN FRANCISCO CA 94102
(415) 202-9986
pvillegas@semprautilities.com
For: SAN DIEGO GAS & ELECTRIC/ SO. CAL. GAS

Kurt Kammerer
Director Of Programs
SAN DIEGO REGIONAL ENERGY OFFICE
PO BOX 60738
SAN DIEGO CA 92166-8738
(619) 546-6175
kjk@kjkammerer.com

Sandra Rovetti
Regulatory Affairs Manager
SAN FRANCISCO PUC
1155 MARKET STREET, 4TH FLOOR
SAN FRANCISCO CA 94103
(415) 554-3179
srovetti@sfwater.org

Phillip J. Muller
SCD ENERGY SOLUTIONS
436 NOVA ALBION WAY
SAN RAFAEL CA 94903
(415) 479-1710

Yvonne Gross
SEMPRA GLOBAL
101 ASH STREET, HQ08C
SAN DIEGO CA 92101
(619) 696-2075
ygross@sempraglobal.com

Marcie Milner
Director - Regulatory Affairs
SHELL TRADING GAS & POWER COMPANY
4445 EASTGATE MALL, SUITE 100
SAN DIEGO CA 92121
(858) 526-2106
marcie.milner@shell.com

Osa L. Wolff
Attorney At Law
SHUTE, MIHALY & WEINBERGER, LLC
396 HAYES STREET
SAN FRANCISCO CA 94102
(415) 552-7272
wolff@smwlaw.com

Trevor Dillard
SIERRA PACIFIC POWER COMPANY
PO BOX 10100
6100 NEIL ROAD, MS S4A50
RENO NV 89520-0024
(775) 834-5823
tdillard@sppc.com

Bob Hines
SILICON VALLEY LEADERSHIP GROUP
224 AIRPORT PARKWAY, SUITE 620
SAN JOSE CA 95110
(408) 501-7864

APPENDIX A

************** SERVICE LIST *************

Last Updated on 21-JUL-2008 by: SM2

R0602013 LIST

philm@scdenergy.com

Carlos F. Pena
SEMPRA ENERGY
101 ASH STREET, HQ12
SAN DIEGO CA 92101
(619) 696-4287
cfpena@sempra.com

William Tobin
SEMPRA GLOBAL
101 ASH STREET, HQ08C
SAN DIEGO CA 92101
(619) 696-4868
wtobin@sempraglobal.com

bhines@svlg.net

Robyn Naramore
SOUTHERN CALIFORNIA EDISON
2244 WALNUT GROVE AVE
ROSEMEAD CA 91770
robyn.naramore@sce.com

Beth A. Fox
LAURA I. GENAO
Attorney At Law
SOUTHERN CALIFORNIA EDISON COMPANY
2244 WALNUT GROVE AVENUE, GO1, ROOM 351C
ROSEMEAD CA 91770
(626) 302-6897
beth.fox@sce.com
For: Southern California Edison Company

Case Administration
SOUTHERN CALIFORNIA EDISON COMPANY
LAW DEPARTMENT, ROOM 370
2244 WALNUT GROVE AVENUE
ROSEMEAD CA 91770
(626) 302-6838
Case.Admin@sce.com
For: SOUTHERN CALIFORNIA EDISON COMPANY

Cathy A. Karlstad
SOUTHERN CALIFORNIA EDISON COMPANY
2244 WALNUT GROVE AVE.
ROSEMEAD CA 91770
(626) 302-1096
cathy.karlstad@sce.com

Karen I Lee
SOUTHERN CALIFORNIA EDISON COMPANY
2244 WALNUT GROVE AVENUE
ROSEMEAD CA 91770
(626) 302-6659
karen.lee@sce.com

Hugh Yao
SOUTHERN CALIFORNIA GAS COMPANY
555 W. 5TH ST, GT22G2
LOS ANGELES CA 90013
(213) 244-3619
HYao@SempraUtilities.com

Rasha Prince
SOUTHERN CALIFORNIA GAS COMPANY
555 WEST 5TH STREET, GT14D6
LOS ANGELES CA 90013
(213) 244-5141
rprince@semprautilities.com

Stephen D. Baker
SR. REG. ANALYST, FELLON-MCCORD AND ASS.
CONSTELLATION NEW ENERGY-GAS DIVISION
9960 CORPORATE CAMPUS DRIVE, STE. 2000
LOUISVILLE KY 40223
(502) 214-6313
stephen.baker@constellation.com
For: Fellon-McCord and Associates

Seth D. Hilton
STOEL RIVES
111 SUTTER ST., SUITE 700
SAN FRANCISSCO CA 94104
(415) 617-8943
sdhilton@stoel.com

APPENDIX A

************** SERVICE LIST *************

Last Updated on 21-JUL-2008 by: SM2

R0602013 LIST

Laura Genao
SOUTHERN CALIFORNIA EDISON COMPANY
LAW DEPARTMENT
PO BOX 800 2244 WALNUT GROVE AVE.
ROSEMEAD CA 91770
(626) 302-6842
laura.genao@sce.com
For: Southern California Edison Company

Leon Bass
Senior Attorney
SOUTHERN CALIFORNIA EDISON COMPANY
2244 WALNUT GROVE AVENUE
ROSEMEAD CA 91770
(626) 302-6967
leon.bass@sce.com

Michael A. Backstrom
Attorney At Law
SOUTHERN CALIFORNIA EDISON COMPANY
2244 WALNUT GROVE AVENUE
ROSEMEAD CA 91770
(626) 302-1903
michael.backstrom@sce.com

Michael D. Montoya
Attorney At Law
SOUTHERN CALIFORNIA EDISON COMPANY
2244 WALNUT GROVE AVENUE
ROSEMEAD CA 91770
(626) 302-6057
mike.montoya@sce.com

Janice Lin
Managing Partner
STRATEGEN CONSULTING LLC
146 VICENTE ROAD
BERKELEY CA 94705
(510) 665-7811
janice@strategenconsulting.com

Andrea Weller
STRATEGIC ENERGY, LTD
7220 AVENIDA ENCINAS, SUITE 120
CARLSBAD CA 92209
aweller@sel.com

Patricia R. Thompson
SUMMIT BLUE CONSULTING
2752 DOS RIOS DR.
SAN RAMON CA 94583
(925) 719-0229
Patricia.R.Thompson@gmail.com

Patricia Thompson
SUMMIT BLUE CONSULTING
2920 CAMINO DIABLO, SUITE 210
WALNUT CREEK CA 94597
(925) 935-0270
pthompson@summitblue.com

Elizabeth Stoltzfus
Energy Division
AREA 4-A
505 VAN NESS AVE
San Francisco CA 94102 3298
(415) 703-5586
eks@cpuc.ca.gov

Carla Peterman
UCEI
2547 CHANNING WAY
BERKELEY CA 94720
(917) 538-6667
carla.peterman@gmail.com

Cliff Chen
UNION OF CONCERNED SCIENTISTS
2397 SHATTUCK AVENUE, STE 203
BERKELEY CA 94708
(510) 843-1872
cchen@ucsusa.org

Andrew J. Van Horn
VAN HORN CONSULTING
12 LIND COURT
ORINDA CA 94563
(925) 254-3358

APPENDIX A

************** SERVICE LIST *************

Last Updated on 21-JUL-2008 by: SM2

R0602013 LIST

Adam Briones
THE GREENLINING INSTITUTE
1918 UNIVERSITY AVENUE, 2ND FLOOR
BERKELEY CA 94704
(510) 926-4013
adamb@greenlining.org

Robert Finkelstein, Attorney At Law
THE UTILITY REFORM NETWORK
711 VAN NESS AVE., SUITE 350
SAN FRANCISCO CA 94102
(415) 929-8876 X310
bfinkelstein@turn.org
For: The Utility Reform Network

Khurshid Khoja
Associate
THELEN REID BROWN RAYSMAN & STEINER
101 SECOND STREET, SUITE 1800
SAN FRANCISCO CA 94105
(415) 369-7643
kkhoja@thelenreid.com

Paul C. Lacourciere
THELEN REID BROWN RAYSMAN & STEINER
101 SECOND STREET, SUITE 1800
SAN FRANCISCO CA 94105
(415) 369-7601
placourciere@thelenreid.com

Steve Boyd
TURLOCK IRRIGATION DISTRICT
333 EAST CANAL DRIVE
TURLOCK CA 95381-0949
(209) 883-8364
seboyd@tid.org

Catherine Pollina
WINSTON STRAWN LLP
101 CALIFORNIA STREET, STE 3900
SAN FRANCISCO CA 94111-5894
(415) 591-1000
cpollina@winston.com
For: California Cogeneration Council

Kevin Woodruff
WOODRUFF EXPERT SERVICES, INC.
1100 K STREET, SUITE 204
SACRAMENTO CA 95814
(916) 442-4877
kdw@woodruff-expert-services.com

andy.vanhorn@vhcenergy.com

Robin J. Walther
1380 OAK CREEK DRIVE, NO. 316
PALO ALTO CA 94304-2016
(650) 793-7445
rwalther@pacbell.net

Doug Davie
WELLHEAD ELECTRIC COMPANY
650 BERCUT DRIVE, SUITE C
SACRAMENTO CA 95814
(916) 447-5171
ddavie@wellhead.com

Jerry R. Bloom
Attorney At Law
WINSTON & STRAWN, LLP
333 SOUTH GRAND AVENUE, 38TH FLOOR
LOS ANGELES CA 90071-1543
(213) 615-1756
jbloom@winston.com
For: California Cogeneration Council

Joseph M. Karp
Attorney At Law
WINSTON & STRAWN, LLP
101 CALIFORNIA STREET, 39TH FLOOR
SAN FRANCISCO CA 94111-5894
(415) 591-1000
jkarp@winston.com
For: California Cogeneration Council

APPENDIX A

**************** SERVICE LIST ***************

Last Updated on 21-JUL-2008 by: SM2

R0602013 LIST

(END OF APPENDX A)

APPENDIX B

List of Acronyms and Abbreviations

A. - Application

AB – Assembly Bill

ACR – Assigned Commissioner's Ruling

ALJ – Administrative Law Judge

AReM – Alliance for Retail Energy Markets

BNI – Binding Notice of Intent

CAM – Cost Allocation Mechanism

CAC – Cogeneration Association of California

CCA – Community Choice Aggregation/Aggregator

CCDC – California Clean DG Coalition

CCSF – City and County of San Francisco

CEC – California Energy Commission

CGDL – Customer Generation Departing Load

CMUA – California Municipal Utilities Association

CRS – Cost Responsibility Surcharge

CTC – Competition Transition Charge

D. – Decision

DA – Direct Access

DG – Distributed Generation

DL – Departing Load

DRA – Division of Ratepayer Advocates

DWR – Department of Water Resources

ECRA – Energy Cost Recovery Amount

EPUC – Energy Producers and Users Coalition

ERRA – Energy Resources Recovery Account

ESP – Electric Service Provider

HPC – Historical Procurement Charge

IEPR – Integrated Energy Policy Report

IOU – Investor Owned Utility

LSE – Load Serving Entity

LTPP – Long-Term Procurement Plan

Merced ID – Merced Irrigation District

Modesto ID – Modesto Irrigation District

MDL – Municipal Departing Load

NBC – Non-bypassable Charge

PCIA – Power Charge Indifference Amount

PD – Proposed Decision

PG&E – Pacific Gas and Electric Company

PPA – Power Purchase Agreement

POU – Publicly Owned Utility

QF – Qualifying Facility

R. – Rulemaking

RA – Resource Adequacy

RPS – Renewable Portfolio Standard

SCE – Southern California Edison Company

SDG&E – San Diego Gas & Electric Company

SSJID – South San Joaquin Irrigation District

TURN – The Utility Reform Network

URG – Utility retained Generation

WAPA – Western Area Power Administration

WPTF – Western Power Trading Forum

(END OF APPENDIX B)

APPENDIX C

List of Terms

Following are terms defined in the context of this decision:

Binding Notice of Intent (BNI) -- A commitment to a target date, at which point a CCA is responsible for its own energy procurement and resource adequacy. If the CCA does so, its customers will not be responsible for stranded costs of any utility commitments entered into after the agreed upon date. However, if the CCA does not meet the target date, it will be liable for any incremental costs that the utility incurs in excess of its average portfolio cost to serve the load that the CCA is not able to serve.

Bundled Customer Indifference – A principle, whereby bundled customers should be no worse off, nor should they be any better off as a result of customers departing the system or choosing alternative energy suppliers.

Community Choice Aggregator (CCA) – Governmental entities formed by cities and/or counties to serve the energy requirements of their local residents and businesses. The IOU continues to provide transmission and distribution service.

Cost Adjustment Mechanism (CAM) – Mechanism authorized by D.06-07-029, by which customers are allocated both the net costs of capacity (total PPA costs less energy auction revenues) and the associated capacity rights.

Cost Responsibility Surcharge (CRS) – A surcharge developed to recover certain costs from departing customers. Existing surcharges cover DWR bond and power charges and ongoing competition transition charges. PG&E also collects for the ECRA which recovers bankruptcy-related costs.

Customer Generation Departing Load (CGDL) – Departing load associated with cogeneration, renewable technologies, or any other type of generation that (a) is dedicated wholly or in part to serve a specific customer's load; and (b) relies on non-utility or dedicated utility distribution wires rather than the utility grid, to serve the customer, the customer's affiliates and/or tenant's, and/or not more than two other persons or corporations.

Direct Access (DA) - The ability of a retail customer to purchase commodity electricity directly from the wholesale market rather than through a local distribution utility. DA customers purchase electricity from an independent electric service provider and receive transmission and distribution service from the IOU.

<u>Departing load</u> (DL) – DL generally refers to retail customers who were formerly IOU customers but now receive energy, transmission and distribution services from publicly owned utilities, self-generation or other means.

<u>Fair Share</u> – A customer's cost responsibility for activities performed by the utility on behalf of that customer.

<u>Indifference</u> – Indifference is when the cost of the total portfolio of resources is the same as a market benchmark. In that case, bundled customers are indifferent to departing load. A positive indifference amount indicates the total portfolio costs exceed the market benchmark which indicates that the costs are uneconomic or stranded. A negative indifference amount indicates the total portfolio costs are below the market benchmark.

<u>Large Municipalization</u> - Large municipalization refers to any portion of an IOU's service territory that has been taken control of or annexed by a POU where the amount of load departing the IOUs' service territories due to the municipalization is of such a large magnitude that it cannot reasonably be assumed to have been reflected as part of the historical MDL trends used in developing the adopted LTPP load forecasts.

<u>Municipal Departing Load</u> (MDL) – MDL refers to DL served by a POU as that term is defined in Public Utilities Code Section 9604(d), including municipalities or irrigation districts. For purposes of this decision, MDL also includes <u>new MDL</u>, which is load that has never been served by an IOU but is located in an area that had previously been in the IOU's service territory (as that territory existed on February 1, 2001) and was annexed or otherwise expanded into by a POU.

<u>New Generation</u> – New generation includes generation from both fossil fueled and renewable resources contracted for or constructed by the investor owned utilities subsequent to January 1, 2003.

<u>New WAPA Departing Load</u> – Additional customer load of certain so-called 'new allottee" customers who, for example, were served by PG&E under its retail tariffs prior to expiration of Contract 2948-A with WAPA but are now served by WAPA.

<u>Non-bypassable Charge</u> (NBC) -- A charge that cannot be avoided by departing the system or obtaining alternative services. In this decision, the new generation NBCs are those imposed on all customers, based on their fair share of new generation costs, even if they no longer require utility energy procurement services.

Power Charge Indifference Amount (PCIA) – The DWR power portion of the CRS.

Pre-restructuring Resources - For purposes of this decision, pre-restructuring resources refers to those current IOU resources that existed prior to March 31, 1998 and are not subject to ongoing CTC treatment. These resources consist principally of the IOUs' retained generation (i.e., hydro, coal and nuclear plants). Power from these resources tends to be cheaper when compared to the costs related to ongoing CTC, the DWR contracts and new generation.

Qualifying Facility (QF) – An independent power producer that meets certain regulatory requirements for supplying power to a utility under contract. QFs use cogeneration or renewable resources to generate electricity.

Split Wheeling Departing Load – That portion of the load of certain so-called "split-wheeling" customers which, for example, was served by PG&E under its retail tariffs prior to the expiration of PG&E's Contract 2948-A with WAPA but is now served by WAPA.

Stranded Costs – Costs related to utility investments in generation plants or long-term power contracts that are not economical in a competitive market.

Vintaging – The process of assigning a departure date to departing customers in order to determine those customers' generation resource obligations.

(END OF APPENDIX C)