APPENDIX A

PRELIMINARY SCOPING MEMO

A. Phase I Issue Areas

a. Standardized Resource Planning Practices, Assumptions & Analytical Techniques

Electric resource planning is inherently complex, uncertain and high-stakes, because the process guides multi-billion dollar decisions about enduring capital infrastructure investments whose economics depend on accurate predictions about an uncertain future. The investor-owned utilities (IOUs) face the very difficult task of sorting through these complexities and making reasonable recommendations to the Commission about which resource portfolios strike the best balance between countervailing objectives of low-cost, reliability, and environmental stewardship. In Rulemaking (R.) 06-02-013, the IOUs demonstrated, with varying degrees of ingenuity, that some (though not all) of this complexity could be synthesized and juxtaposed into explicit comparisons among candidate resource plans that, for example, trade total supply cost against increased reliability or more preferred resources. Despite these bright spots, in Decision (D.) 07-12-052 we identified opportunities for improvement in the IOUs' long-term procurement plan (LTPP) planning process. We signaled to the IOUs and stakeholders that the Commission intends to improve upon, and adopt a best-practices approach to, electric resource planning methods:

> In subsequent iterations of the long term procurement process, the IOUs will be expected in their resource planning to meet and exceed the high standards Californians expect as pacesetters on energy and environmental issues. We agree with parties that find areas that could be improved on throughout the IOUs' planning process from planning assumptions and scenario development, to candidate

portfolios and portfolio analysis, and ultimately, evaluation and final selection of a preferred portfolio.[1]

Because "we expect the IOUs to integrate the best, most recent planning methodologies and analytical techniques [in the LTPPs],"[2] this Order Instituting Rulemaking (OIR) provides a venue for the IOUs and other parties to come forward with proven, innovative, and effective proposals to build on California's rich legacy of resource planning leadership, while continuously improving its technical and analytical underpinnings.

In the 2007 Integrated Energy Policy Report (IEPR), the California Energy Commission (CEC) also concluded that the resource planning practices and techniques that the IOUs used to develop their LTPPs were insufficient to effectively analyze trade-offs between resource alternatives and to address certain long-term risk factors in the electric resource planning environment. During the 2007 IEPR proceeding, CEC staff reviewed the IOUs' LTPPs with a focus on risk management, including an assessment of the Commission's To Expiration Value at Risk (TEVaR) metric.[3] While the resulting report found that TEVaR is an appropriate tool to manage electric price risk and insulate from short-term fluctuations in market power and natural gas costs, according to the report, the same methodology does not readily apply to risk factors over the long-term time horizon. Among other recommendations, the IEPR calls for "a common portfolio analytic method, such as the application of, to the maximum

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[1] D.07-12-052, at pp. 6-7.

[2] *Id.*, at p. 6.

[3] CEC. (2007). *Portfolio Analysis and its Potential Application to Utility Long-term Planning*, Final Staff Report, CEC-200-2007-012-SF, August 2007. *See* Appendix 1.

extent practicable, common planning assumptions, particularly for key risk drivers such as natural gas price trends, greenhouse gas mitigation costs, and technology characteristics."[4] Further, the 2007 IEPR states:

> The Energy Commission will make the development of a common portfolio analytic methodology a core focus of the 2008 IEPR Update, with the clear objective of influencing the long-term procurement plans filed by the investor-owned utilities with the CPUC... This methodology should use common assumptions across utilities to the maximum extent practicable; extend over a 20-30 year period of analysis; discount future fuel costs at the same social discount rate used in standard-setting activities unless these costs are shown to be shareholder liabilities; and focus upon an "efficient frontier" from a consumer perspective utilizing a cost-based metric, with a sufficiently broad scope to incorporate environmental impacts.[5]

In essence, the CEC is calling for incorporating aspects of an integrated resource planning (IRP)[6] approach into the long-term procurement process, much as this Commission has indicated in past rulings. For example, in the 2006 LTPP OIR, we stated that "the long-term plan review process will reflect an [IRP]

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[4] CEC. (2007). *2007 Integrated Energy Policy Report,* CEC-100-2007-008-CTF, November 2007, at p. 67.

[5] CEC. (2007), 2007 Integrated Energy Policy Report, "Final Errata," December 5, 2007, at p. 4.

[6] Integrated resource planning (IRP) is a broadly used term to describe a planning process that evaluates supply and demand-side resource alternatives and optimizes the resource mix to serve electric load over a planning horizon under various cost/risk, reliability and environmental criteria.

approach to planning for the future of the state's electric system."[7] In general, parties' views on IRP exhibit a continuum of opinions from strictly regulated, utility-driven resource planning to loosely regulated, market-driven resource development. In the run up to the 2006 LTPP, some parties expressed concern over the concept of utilities' conducting IRP in conjunction with their long-term plan filings. For example, advocates for market competition stated that IRP is a term that only refers to vertically-integrated utilities and their internal tradeoffs between generation and transmission.[8] In R.01-10-024, parties "urged the Commission to develop a fully integrated resource planning process."[9] More recently, parties expressed concerns in R.06-02-013 that the IOUs' plans were hastily developed and/or lacked sufficient analytical rigor to quantify significant price risks to California ratepayers, such as carbon risk.[10] The utilities, in their own defense, complained that the 2006 LTPP schedule gave insufficient time to develop their plans to the extent that parties (and they themselves) would have liked.[11] The Commission intends to respond to this concern by scheduling at least six months in the 2010 LTPP cycle for IOUs to develop plans following the issuance of the 2010 LTPP scoping memo.

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[7] *Order Instituting Rulemaking to Integrate Procurement Policies and Consider Long-Term Procurement Plans*, dated February 23, 2006 at p. 9.

[8] *Id.*, at p. 14.

[9] D.02-08-071, at p. 13.

[10] For example, *see Opening Brief of the Division of Ratepayer Advocates*, R.06-02-013 Track III, filed August 1, 2007, at p. 41.

[11] For example, *see Comments of San Diego Gas & Electric Company (U902E) on Proposed Decision*, R.06-02-013 Track III, filed December 10, 2007, at p. 3.

We believe there is merit in developing tools that allow stakeholders (decision-makers, IOUs, market participants, environmental and ratepayer stewards) to better understand the economic, reliability, and environmental trade-offs between different resource choices – both across different types of supply- and demand-side "generation" and between generation and transmission. Many parties have identified the absence of any analysis of this type as a significant data gap in this proceeding, and we believe the planning principles that emerge from this effort will promote market goals of transparency, fairness, economic efficiency, and reduced costs to ratepayers.

A primary objective of this effort will be to provide greater transparency with regard to how resource planning decisions are made.[12] Allowing market participants to operate from a common understanding of planning assumptions should result in increased confidence in private investment in resources and projects that are most efficient and aligned with those assumptions.

We anticipate that one of the more challenging policy considerations we will face in developing this resource planning framework will be to balance the regulated aspects of a portfolio analysis methodology with our ongoing goal of developing a more functional competitive electricity market. We are confident that this balance can be struck, though, and we will welcome input from various stakeholders to assist us in structuring a methodology that is consistent with this goal.

Our task in this policy analysis will be to determine:

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[12] While protecting market sensitive information pursuant to D.06-06-066 and the Commission's confidentiality matrix in D.06-06-066, Appendix A.

(1) How electric resource planning in California ought to be conducted *in the next six to ten years,*[13]

(2) What transitional states are appropriate towards that end-state *in the next two to five years*; and

(3) What incremental steps are actionable *in the next two years*[14] given the current hybrid market structure.

While we by no means intend to predetermine the outcome of this important issue in the OIR, we do suggest a possible framework for considering refinements to resource planning methods in the LTPP arena. As a general theme, the Commission would like to see a planning framework emerge out of this process that balances two opposing objectives: standardization and flexibility. Standardization, so that (a) LTPPs can be compared to each other and work products from other proceedings, and (b) LTPP results can be aggregated to produce meaningful statewide assessments. Flexibility inspires creativity, allows planning methods to be adapted to IOUs' unique systems, and leverages the IOUs' formidable resources and knowhow in this area.

A starting point might be to establish a common format for loads and resources (L&R) tables and a master data request for populating the underlying inputs to the L&R tables. The master data request could clearly spell out minimum requirements (i.e., specific data sources that must be utilized in a base case run), flexible requirements (i.e., data sources that IOUs seek out to leverage

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[13] The approximate timeframe when Assembly Bill (AB) 32 framework will take effect and Department of Water Resources (DWR) contracts will expire, possibly reopening direct access (DA), both significant events that, if they occur, could radically affect how resource planning is done.

[14] The timeframe before new LTPPs are filed in the 2010 LTPP planning cycle.

market knowhow and demonstrate their "best guess" at the expected value of critical planning inputs), or both, depending on the data point in question. Examples of planning input variables include (but are not limited to):

- Supply curves or levelized cost;
- Capital cost or capacity payments;
- Fuel and other operating costs;
- Capacity credit (or firm capacity value);
- Integration cost (of intermittent renewables)
- Environmental regulatory compliance costs such as greenhouse gas (GHG); and
- Opportunity cost of generation from multi-use resources (*e.g.*, hydro).

With standardized L&R tables in place, the Commission could consider (also in the short-term) minimum and/or flexible requirements for scenario analysis. It is likely that a standard reference case scenario would be required, as well as certain sensitivity cases to test critical planning assumptions. In addition to these minimum requirements, utilities would be encouraged to develop their own planning scenarios to fill analytical gaps, apply the knowledge and expertise of utility resource planners, and propose innovative techniques to better evaluate cost-benefit and risk tradeoffs. Examples of planning assumptions that might be targeted under certain required scenarios include (but are not limited to):

- load migration;
- availability of energy efficiency (EE), demand response (DR), and other demand-side resources;
- New Qualifying Facility (QF) and QF recontracting;
- discount rates and other financial assumptions;

- viability of low-carbon technologies such as nuclear, carbon capture and sequestration, energy storage, and emerging technologies;
- power imports from Western Electricity Coordinating Council and their GHG and renewable content;
- GHG mitigation costs (see Section A.b.); and
- 33% renewable portfolio standard (RPS) (see discussion below).

Finally, the Commission might consider prescribing certain types of output variables that candidate resource portfolios should be evaluated against. With the proper analytical tools and modeling capabilities, candidate portfolios might be quantified in the following terms:

- Expected value or total supply cost (in levelized and/or absolute terms)
- Portfolio risk or variance of total supply cost;
- Rate impact (both expected value and variance);
- Reliability (Loss of Load Probability, Expected Unserved Energy, or other metrics)[15]
- Emissions of GHGs and other criteria pollutants (in absolute and per Megawatt-hours terms); and
- Energy mix and renewable content.

One area in particular that the Commission intends to highlight and address in this process is building analytical capability to assess the Energy Action Plan (EAP) goal of 33% renewables by 2020. The EAP called on all California load serving entities (LSEs) to "evaluate and develop implementation

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[15] We note that the forthcoming Planning Reserve Margin (PRM) rulemaking will likely shed some light on accepted reliability targets for long-term resource planning purposes.

paths for achieving [the 33% renewables goal] in light of cost-benefit and risk analysis."[16] In D.07-12-052, we found that "all three IOUs' 2006 LTPPs provided insufficient information for the Commission to accurately assess how the IOUs will achieve a 33% renewables target by 2020"[17] and "did not include the detail, integrated approach, or forward-thinking suggested in the [2006 LTPP] Scoping Memo."[18]

In general, we agreed with certain IOUs that "further analysis is needed regarding the feasibility and cost of a 33% renewables target,"[19] and we directed the parties "to work with ED staff to refine a methodology for resource planning and analysis that will allow them to adequately address the issue of a 33% renewables target by 2020 in subsequent LTPPs."[20]

The Commission, in conjunction with other state agencies and stakeholders, recently launched the California Renewable Energy Transmission Initiative (RETI), a statewide proposal to help identify the transmission projects needed to accommodate our clean energy goals, support future energy policy, and facilitate transmission corridor designation and transmission and generation siting and permitting.[21] Because RETI begins with a thorough assessment of the

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[16] *Energy Action Plan II*, Key Action #5, at p. 8.

[17] D.07-12-052, at p. 255-256.

[18] *Id.*, at p. 256.

[19] *Id.*

[20] *Id.*

[21] www.energy.ca.gov/reti/index.html

renewable resource potential in California and neighboring regions, the output from RETI will be a critical input for the renewable procurement sections of the IOUs' future LTPPs.

RETI Phase I is targeted for completion by June 2008. We expect the data produced out of the RETI decision to be utilized in this proceeding. As stated in the 2006 LTPP decision, "we expect [the 33% renewables] sections to be much more robust in subsequent LTPPs, and expect that parties will work to make RETI more useful in this regard."[22]

We pose the following questions to parties with regard to the consideration of standardized resource planning practices, assumptions and analytical techniques in the development of LTPPs:

- What does IRP look like in a hybrid market?
- Are there any confidentiality issues that present themselves in the context of IRP, with regard to planning input assumptions, proprietary modeling tools, etc.?
- What aspects of portfolio analysis[23] are best suited to electric resource planning in California? What are the potential benefits and pitfalls of portfolio analysis? How should portfolio analysis techniques be incorporated into the LTPPs, if at all, to leverage its benefits and avoid any shortcomings?
- What are the gaps, if any, in the assessment of resource planning risks in the LTPPs? Why do the gaps exist? What can be done to close the gaps?

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[22] D.07-12-052, at p. 256.

[23] For a discussion of portfolio analysis in the context of electric resource planning in California, see the CEC publication, *Portfolio Analysis and its Potential Application to Utility Long-term Planning*, Final Staff Report, CEC-200-2007-012-SF, August 2007.

- How should reliability impacts of various resource types be integrated into the planning process?
- Are forward natural gas prices an appropriate planning input to evaluate the risk trade-offs of gas-fired generation against other resources? What comparable "fuel risk" metrics are need for renewables and other resources?

We expect that this planning approach, including a response to 2008 IEPR Update findings, will define the requirements of future LTPP filings.

b. Interim GHG Uncertainty Assessment

The Commission found, in D.07-12-052 that "the overarching problem in all three LTPPs is the absence of any scenario analysis regarding what types of resources the IOUs should use to fill their net short positions to best transition to the inevitably GHG-constrained world we are moving towards."[24] In order to strengthen future LTPP filings, the Commission stated that procurement plans ought to be "detailed enough to enable adequate analysis of fuel mix under various scenarios, overall cost to customers, risks faced by customers and environmental impact."[25] Apart from analyzing fuel risk, procurement plans should also assess the underlying technology risk, as the technologies selected to serve load pre-determine the fuel mix and operating cost of carbon-emitting resources.

One obstacle cited by the IOUs in their 2006 LTPP filings was the degree of uncertainty associated with GHG regulations at the time those filings were being completed. It is true that the Commission had only firmly announced its

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[24] D.07-12-052, at p. 5.

[25] D.07-12-052, at p. 245.

intention of establishing a load-based cap in April 2006.[26] Furthermore, the passage of AB 32 later that year added another layer of uncertainty to the future direction of GHG policies in California. While we maintain that uncertainty surrounding GHG policies at the time of the 2006 filings should not have prevented the IOUs from conducting a more thorough analysis of the implications of GHG constraint on their LTPPs, we acknowledge the difficulties these uncertainties imposed on IOUs. Many of the policy uncertainties noted by the IOUs will have been resolved by late 2008, and the decisions made by the Commission and the California Air Resource Board (ARB) should facilitate a more detailed treatment of GHG mitigation policies in subsequent LTPPs.

AB 32 designated ARB the lead agency on establishing and enforcing climate policies. It also set several important milestones for ARB related to the design of GHG policies. Two of these milestones are especially germane to the issues facing the IOUs as they prepare their LTPPs. The first directed ARB to approve mandatory GHG reporting protocols by January 1, 2008. On September 6, the California Public Utilities Commission (CPUC) issued a decision D.07-09-017 recommending a reporting protocol for the electricity sector. On December 6, 2007 the ARB approved this protocol, as well as protocols for other sectors developed by ARB staff.

The second milestone directs the ARB to issue a scoping plan by January 1, 2009 that lays out the major design elements of the GHG mitigation program ARB must implement to meet the requirements of AB 32. Additional CPUC and CEC decisions will be forthcoming in 2008 related to the scoping plan, and these

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[26] *See* R.06-04-009.

decisions will resolve other remaining issues. Another decision, expected in March 2008, will recommend that either electric utilities or electric generators be the point of regulation for ARB's GHG programs. This decision will also contain a broad recommendation on the question of allowance allocation in the electricity sector. In August or September 2008, the Commission and CEC will issue a more comprehensive set of recommendations to ARB covering all aspects of the GHG regulation for the electricity sector. This decision will give a more detailed recommendation on allowance allocation as well as recommendations related to offsets, banking and borrowing of allowances, the length of the compliance period, and other GHG program design issues.

Several factors will determine the costs of complying with AB 32 in the electricity sector and the distribution of those costs among utilities. These factors include population growth, natural gas prices, renewable technology prices, transmission developments, and the costs of implementing various energy efficiency measures across all sectors of the economy. Given the complexity of estimating these costs and devising plausible scenarios of how these factors may play out to 2020 and beyond, the Commission has hired a consulting firm, Energy and Environmental Economics, Inc. (E3), to perform a series of modeling runs at both the statewide and LSE levels to inform the August/September 2008 decision. Preliminary statewide results were presented to the public at a Commission workshop in November. These results will be further developed with new information from stakeholders and finalized in March 2008.

Once the statewide modeling runs are finalized, E3 will disaggregate the analysis at the LSE level. We expect the IOUs to work closely with E3 to help E3 deliver the most accurate results possible. Since E3 will be conducting what is essentially a long-run scenario analysis, the IOUs will be able to draw on E3's modeling results for information related to subsequent LTPP filings. Close cooperation among the IOUs, the Commission, and E3 will produce mutually acceptable results that facilitate analysis of the cost-effectiveness of IOU-specific GHG mitigation strategies given plausible developments in GHG prices and costs of GHG mitigation. Moreover, developing the scenarios and modeling runs in 2008 should provide valuable experience for assessing various approaches to designing a consistent methodology for GHG scenario analysis for future LTPPs.

In addition to the Commission's ongoing GHG modeling effort, the CEC conducted a Scenario Analysis Project, as part of the 2007 IEPR, to assess the GHG emissions consequences of policy strategies to support low-carbon resources. The study constructed and assessed various policy-driven scenarios, most with very high levels of EE and renewables, and evaluated their relative carbon emissions and cost of electricity against a reference case. The study also evaluated the sensitivity of cost and GHG emissions relative to natural gas prices and hydroelectric availability. Despite "scientific, technological and institutional uncertainties,"[27] the CEC maintains the 2007 IEPR scenario analysis produced certain indicative results. Notably, the CEC found that:

> Each of the policy-driven cases which increases the investment in efficiency and renewables *beyond current requirements* seems likely to fall within the range of 1990 CO_2 emissions [AB 32's 2020 goal]. The more intensive preferred resource scenarios would enable a *higher contribution* to AB 32's 2020 goals than attaining 1990 levels.[28]

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[27] 2007 IEPR, at p. 62.

[28] *Id.* (Emphasis added.)

Given these recent and ongoing initiatives to understand the cost and GHG emissions of low-carbon resource portfolio alternatives, the Commission believes the time is ripe to gather, evaluate, and consolidate these and other data sources as a basis for developing consistent interim requirements and/or guidelines for evaluating carbon cost and risk in future LTPP filings. Again as a general theme, similar to our vision of a standardized resource planning framework, what we expect to emerge from this effort will be some combination of minimum requirements and flexible guidelines for evaluating carbon cost and risk in subsequent LTPPs.

We pose several questions to initiate discussion of how a GHG scenario analysis component of the IOUs' LTPPs should be constituted:

- A review of recent utility resource plans indicates there are myriad techniques, both deterministic and probabilistic, that utilities might employ to assess GHG mitigation risk. Some utilities assign probabilities to discrete cost outcomes and run probabilistic simulations to develop cost and risk assessments. Others similarly test sensitivities at discrete cost levels, but make no attempt to divine their probabilities. Is there value in doing probabilistic analysis, in the absence of historical data to define the necessary frequency distribution of GHG costs, or do reasonable deterministic assessments provide the same quality of analysis?
- Parties in this proceeding have suggested possible process tools for estimating carbon risk in LTPPs, including the Delphi method[29] and nominal group technique.[30] Are these or other

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[29] The Delphi technique is a method for obtaining forecasts from a panel of independent experts over successive rounds of expert prediction, explanation and anonymous discussion to support or debate predictions, and averaging of final predictions. For further discussion, *see Opening Brief of the Division of Ratepayer Advocates*, R.06-02-013 Track III, filed August 1, 2007, at p. 42.

tools appropriate for the IOUs to consider or be required to utilize in their LTPP evaluation of carbon cost and risk?

- Should federal GHG regulation scenarios be evaluated, in addition to AB 32 scenarios? If so, how should these federal scenarios be assessed with respect to their structure, timing, and cost implications?
- Should the Commission require the IOUs to apply a GHG cost adder in their reference case LTPPs? If so, what should that cost be? Should it be fixed or escalating over the planning period?
- Should the Commission require the IOUs to assess high and low bandwidths and/or intermediate levels of GHG costs around an assumed reference case cost?
- What level of GHG uncertainty analysis would be reasonable and sufficient in the next round of LTPPs, given that real GHG cost data will not become available until after the AB 32 framework is implemented in 2012?
- What sort of Commission direction would most effectively foster IOU innovation and analytical ingenuity in the assessment of GHG uncertainty?

As an additional item, in response to the motion filed by the joint parties on December 11, 2007, we are requesting that the utilities prepare a report which provides the following required information for each of the relevant programs, which contribute to a reduction in GHG, listed below:

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[30] The nominal group technique is a decision-making method based on ranking various alternatives, 1st, 2nd, 3rd, 4th, and so on; explaining the rationale behind each group members' ranking; and tallying rank order votes, as opposed to all-or-nothing votes for 1st place. For further discussion, *see Opening Brief of the Division of Ratepayer Advocates*, R.06-02-013 Track III, filed August 1, 2007, at p. 42.

Required Information

1. All authorized revenue requirements or other charges;
2. The amounts collected over the past three years. For programs not in place for three calendar years, indicate the amounts collected since the program was authorized, and the time period;
3. The remaining authorized funding (revenue requirement or charges) and expiration, if any;
4. Identify any of these programs and cite where there is a pending request to increase or expand the program;
5. Describe specifically how greenhouse gases will be directly or indirectly reduced as a result of the program;
6. Quantify the annual reductions in greenhouse gases;
7. Cite the specific authorization or adoption of the program by the Commission; and
8. Identify either the expiration of rate authority or the evergreen status of the program.

Relevant Programs

1. Energy Efficiency Program(s), including incentives costs and front-end loaded costs;
2. Demand Response Program(s);
3. California Solar Initiative;
4. Low-Income Energy Efficiency;
5. Renewables Portfolio Standard:
    i. RPS payments in excess of the Market Price Referent;
    ii. Costs of non-renewable generation needed to operate when intermittent renewables are not running; these costs would include those of additional California Independent System Operator (CAISO) ramping requirements and utility quick start and quick ramping fossil generation that are required to work around wind (in particular) and solar facilities;

6. Renewables Research, Development and Deployment;
7. Low Emission Vehicle Research, Development and Deployment;
8. Solar Water Heating;
9. Self-Generation Incentive Program incentives for reduction of GHG emissions associated with electricity consumption;
10. PG&E Climate Protection Tariff;
11. University of California Climate Research Proposal; and
12. Any other program which contributes to a reduction of greenhouse gases.

c. Quantifying EE in the CEC Load Forecast

In D.07-12-052 and previous decisions, we directed the IOUs to use the CEC 1-in-2 base load forecast in preparing their LTPPs. The CEC forecasting methodology distinguishes between committed and uncommitted effects to account for energy efficiency in the load forecast. According to the CEC, "committed programs are defined as programs that have already been implemented or for which funding has been approved…and only the effects of committed programs are included in the demand forecast."[31] These committed effects "may include some impacts associated with the historical and ongoing levels of programs to the extent they represent impacts associated with replacement of aging [or installation of new] building stock and equipment at efficiency levels that comply with current building and appliance standards."[32] Uncommitted effects on the other hand, are defined as "the *incremental* impacts

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[31] CEC. *California Energy Demand 2008-2018 Staff Revised Forecast*, CEC-200-2007-015-SF2, November 2007, at p. 25.

[32] *Id.*

of the level of future programs (for example, savings associated with new equipment that exceeds current standards or early replacement of existing stock) impacts of new programs, and impacts from expansions of current programs."[33]

Due to certain mechanics in the CEC's demand forecasting methodology, uncommitted[34] EE was reflected in one of two places in the 2006 LTPPs: either: (1) embedded as a reduction in the load forecast (to the extent that uncommitted EE *does* overlap with the CEC's concept of committed effects); or (2) forecasted as an available resource (to the extent that uncommitted EE does *not* overlap with the CEC's concept of committed effects). A question that this OIR must address is the degree of "overlap" between our post-2008 EE goals and the amount of savings from EE programs that are embedded in the CEC's demand forecast. A 100% overlap in uncommitted EE savings means that 100% of our EE goals are embedded in the CEC demand forecast.

According to the CEC, "a difficulty arises in correctly projecting uncommitted impacts versus…savings from…utility programs that are captured in forecast models. Building and appliance standards are modeled within the residential and commercial forecast models. The models account for building

[33] *Id.* (Emphasis added.)

[34] We clarify that the CEC's definitions of "committed" and "uncommitted" differs from this Commission's use of the same terms in the context of the LTPP. In this OIR, as in D.07-12-052, we define "committed EE" as only those savings attributed to the IOUs' most recent (2006-2008) and earlier EE program portfolios designed to meet or exceed Commission-adopted EE goals. We define "uncommitted" EE as the projected savings attributable to future EE program cycles (2009-2011 and beyond) designed to meet or exceed the Commission-adopted EE goals. Hereinafter, all references to "committed" or "uncommitted" EE savings refers to the Commission definition, unless otherwise noted.

decay, equipment replacement, and market-induced impacts."[35] Within the sector models, some utility program savings are attributed to more stringent building codes and standards or price effects, whereas others are modeled separately.[36] Further complicating the issue, "as models are calibrated to historical actual data, they implicitly account for effects of many years of energy efficiency programs."

The degree of overlap between the Commission's EE goals in a given year and the amount of EE that the CEC forecasting methodology considers committed in that year is, at present, unclear. In order for the Commission to have confidence that the adoption of future long-term plans does not result in over- or under-procurement of new generation, an in-depth examination of the issues and development of an accepted methodology to accurately account for the overlap may be publicly vetted and adopted in this proceeding. In its 2007 IEPR, the CEC recommended that this issue be addressed as part of the 2008 IEPR Update:

> As an early part of the 2008 IEPR Update, the Energy Commission will conduct a public process that includes CPUC staff, utilities, and other stakeholders to determine an effective method of better delineating the energy efficiency savings assumptions included in

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[35] CEC (2007). *California Energy Demand 2008-2018 Staff Revised Forecast*, CEC-200-2007-015-SF2, November 2007, at p. 25.

[36] Within the CEC's end-use forecasting model, conservation savings (EE) is quantified in two main places: (1) the sector models, including residential and commercial, which quantify EE attributable to codes and standards, market effects, and *some* utility program effects; and (2) a summary model, which incorporates CEC staff assessments of *additional* EE savings attributable to utility programs not already captured in the sector model (so-called "direct program adjustments"). (*See* the CEC's *Energy Demand Forecast Methods Report*, CEC-400-2005-036, June 2005.)

> the Energy Commission staff demand forecast, both from historic as well as future standards and programs. The Energy Commission recognizes the value that such a methodology can provide in future state planning efforts related to both energy policy and greenhouse gas emissions reduction.[37]

d. Long-Term Firm Capacity Projections for Demand-side Resources

In the 2006 LTPP Scoping Memo, the Commission directed the IOUs to "include expectations of the supply of various procurement resources, including, EE, DR, renewables, distributed generation (DG) and non-renewable generation over the *long-term* time horizon."[38] This emphasis on the long-term availability of various resource alternatives is particularly salient with respect to demand-side resources which are less predictable and dependent on voluntary customer participation. Whereas the project viability risk of supply-side resources can be mitigated by issuing replacement Request for Offers, or by over-contracting in the first place, demand-side resources are more subject to variations in consumer behavior that are often difficult to predict.

The Commission recognizes that a distinction needs to be made between (1) loading order resource goals established in resource-focused proceedings that IOUs must work to achieve, and (2) prudent resource planning assumptions that affect need determination, procurement authority, and ultimately system reliability across a six-plus-year time horizon. To the extent that prudent planning assumptions result in lower resource "counting," in terms of firm

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[37] California Energy Commission, *2007 Integrated Energy Policy Report*, "Final Errata," CEC-100-2007-008-CTF-ERRATA, December 5, 2007 at p. 3.

[38] September 25, 2006 ACR/Scoping Memo, at p. 17.

capacity, than the goals established in these underlying proceedings, such a finding does nothing to undermine the preferred resource goals themselves, or the Commission's directives to achieve them. On the contrary, this exercise would have the intended effect of demonstrating the consequences to California of *not* achieving the goals, namely more backstop procurement of fossil generation to replace potential shortages in demand-side resource availability.

Although it is impossible to exactly predict firm capacities from demand-side resources on a 5-10 year forward-looking basis, it is precisely this prediction that this proceeding must make in order to make reasonable need determinations. The very real consequences of that prediction are either more or less procurement authority, well in advance (5-8 years) of the need date. In general, the trade-off continuum before us is between overprocuring resources (in a conservative view of firm capacity) at risk of crowding out preferred resources that have shorter development timelines (or causing excess ratepayer costs due to excess resources), or underprocuring resources at the risk of poorer environmental performance from more aging plant generation, higher costs and poorer environmental performance from "just-in-time" procurement resources, or reliability problems.

While we emphasize that this issue deserves consideration prior to the next LTPP filing, the LTPP proceeding is just one of several possible procedural venues for addressing it. The issue could be alternatively taken up in the individual resource proceedings or the upcoming PRM rulemaking. We make no determination at this time which the forum will be, other than to identify this proceeding as an option for addressing some or all of the resource alternatives.

e. Customer Risk Preference Study

Customer Risk Tolerance (CRT) and TEVaR are the metrics currently required by the Commission to monitor and manage rate level risk. The TEVaR represents an estimate, at a given confidence level, of the amount of electric rate increase that could occur due to changes in market conditions such as hydro-power availability risk, electricity spot market price volatility, and gas price volatility (which represents the single greatest historical source of price volatility). For example, TEVaR 95% measures the maximum rate increase beyond the expected value with a 95% confidence level (in other words, it is the 1-in-20 worst case scenario). CRT is essentially a Commission-adopted target limit on unforeseen electric rate increases looking 12 months into the future. This has been set by the Commission at one cent per kilowatt-hour (kWh). The current policy sets a notification trigger when utilities are required to consult with the Procurement Review Group (PRG), if TEVaR reaches 125% of the CRT (that is, TEVaR 95% $\geq$ 1.25 ¢/kWh). The Commission requires the utilities to submit to Energy Division Staff (ED) monthly reports on TEVaR 95% on a rolling 12-month basis. These monthly submissions also report the TEVaR 95% on a quarterly basis for months 13-24 looking forward, and on an annual basis for months 25-60.

The 2006 LTPP proceeding considered and resolved several issues related to risk management, as identified in Attachment A to the September 25, 2006 Scoping Memo. In their comments, replies, oral testimony, and briefs, parties addressed all of these questions, and raised additional outstanding ones. The 2006 LTPP Scoping Memo asked parties for their opinions on the following issues:

- Whether consistency in hedging across DWR and non-DWR portfolios is desirable;
- Whether to mandate hedging "best practices;"
- Whether to modify the CRT level; and
- Regarding TEVaR, whether to:
  - Standardize calculations;
  - Require tracking on 12-month rolling or calendar year basis;
  - Set "confidence level" at 99% or 95%; and/or
  - Use other metrics, such as TEVaR beyond one year, forward-start TEVaR, etc.

D.07-12-052 made determinations on many of these issues, including:

- Facilitating DWR and non-DWR portfolio risk management by allowing for them to better coordinate;
- Declining to establish "best practices" for hedges, or to establish preferred ratios of fixed price instruments (such as futures) to options;
- Declining to the modify the CRT level (set at 1 cent/kWh) or the trigger level which triggers PRG review (set at 1.25 cents/kWh) currently in place; and
- Regarding TEVaR:
  - Declining to standardize calculations;
  - Requiring a 12-month rolling TEVaR report, as opposed to a calendar year approach;
  - Changing TEVaR reporting from a 99% confidence level to a 95% level; and
  - Allowing use of metrics other than the 12-month TEVaR.

Outstanding issues not addressed by D.07-12-052 include:

- The study which D.02-10-062 ordered ED to administer to empirically determine electric customer risk preferences;
- A review and modification of CRT levels and TEVaR metrics based upon empirical customer preference data; and
- Aglet's argument (reply brief) that Black Model results are not being reported, contrary to D.02-12-074, Ordering Paragraph 10.

We note our previous commitment to completion of a customer risk preference study. In one scenario, ED could contract with a consultant who surveys customers across the state's various IOUs. In another scenario, each IOU could independently administer a survey, either with in-house expertise or with assistance from a consultant, all under the guidance of its respective PRG. An advantage of having one consultant perform the survey would be a uniform methodology applied state-wide. An advantage of having each utility perform or sponsor (with PRG oversight) its own study would be the significant easing of problems of confidentiality that likely would arise.

Related to this matter, we note that Section 1.8 of the Settlement Agreement (Public Version) for long-term core gas hedging program adopted in D.07-06-013 required Pacific Gas and Electric Company (PG&E) to consult with its core hedging advisory group, regarding

> … a market assessment study regarding the risk preferences of PG&E's core gas customers. The goal of such a study will be to obtain a quantitative estimate of the consumer risk tolerance of PG&E's core gas customers, or the amount PG&E's core customers might be willing to spend on hedging to mitigate the impacts of commodity price volatility.[39]

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[39] D.07-06-013, Attachment A, *Settlement Agreement (Public Version) Regarding PG&E Long-term Core Hedge Program Application (A.06-05-007), the Core Procurement Incentive*

Footnote continued on next page

It may be instructive to wait for this study to be completed and reported on prior to launching a comparable study or studies of electric customers' risk preference, although we are also reluctant to further delay this overdue work.

Having already mandated, in D.07-12-052, the use of a 12-month rolling TEVaR set at a confidence level of 95%, there are no risk management guidelines that urgently need to be addressed. However, a review of the risk management guidelines, and the CRT level (and associated trigger level) in particular, will be useful once more information becomes available about customer risk preferences. Therefore, we will await the results of the customer risk preference study, or studies, before addressing these in a more thorough fashion. If there is time, then we will address these additional issues in the 2008 LTPP proceeding. If not, then we will review the overall risk management approach in a subsequent proceeding.

In this OIR, we seek parties' opinions as to how to proceed with the customer risk preference study, both as regards the method of execution and the timing.

f. Other Implementation Issues

Finally, experience to date implementing the LTPP program has demonstrated, in a variety of instances, that the LTPP proceeding must have sufficient flexibility to address additional procurement related implementation issues, on an as-needed basis. For example, review and adoption an "AB 57 Procurement Plan Implementation Manual," pursuant to D.07-12-052, may

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Mechanism (CPIM), and Transportation Capacity Held on Behalf of Core Customers, at pp. 2-3.

require the introduction of additional issues into the scope of this proceeding on an as-needed basis.

In addition, as discussed in D.07-12-052, we understand that when the Market Redesign Technology Update (MRTU) is implemented, some aspects of the IOUs' procurement plans may need to me modified. For example, the three IOUs already sought and obtained initial authority to acquire Congestion Revenue Rights (CRR) in the fall of 2007.[40] We note that ratepayers and LSEs may benefit from the development of more clarified and refined upfront standards regarding acquisition of CRRs.[41]

Also, the Commission recognized that ratepayers and LSEs may benefit from LSE participation in virtual or convergence bidding, which the CAISO expects to implement one year after MRTU startup. The IOUs' procurement plans would have to be modified to include upfront achievable standards for procurement of this new energy-related product.

Since it is anticipated that MRTU will be implemented during this LTPP cycle, we will assume that such MRTU related issues such as CRRs and virtual

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[40] *See e.g.*, Resolution E-4136, issued December 6, 2007, approving with criteria for implementation the request by SDG&E to amend its procurement plans to allow for procurement of CRRs with potential expense to ratepayers. CRRs are a financial tool designed to hedge the variable transmission costs expected under MRTU, and are akin to the currently used Firm Transmission Rights.

[41] For example, the quantities and durations of CRRs available to market participants will not necessarily exactly match the energy deliveries expected by LSEs. Thus, while the Commission granted LSEs permission to hedge their expected energy deliveries rather than speculate, LSEs may benefit from greater clarity regarding how to match hedges to their expected grid use without risking disallowances of CRR expenses that may arguably qualify as "speculative."

bidding are within the scope of the proceeding. If necessary, we will designate a separate Phase to deal with MRTU related issues when timely.

B. Phase II Issue Areas

a. System vs. Bundled Methodology

In D.07-12-052, we acknowledged comments from parties identifying gaps in the Commissions' rules with regard to the extent to which IOUs can elect the cost allocation mechanism (CAM) for new generation. The Commission heard at least two major concerns in the absence of a standard methodology or consistent practices for identifying system vs. bundled resource needs. First, "it is unclear how Southern California Edison Company (SCE) and San Diego Gas & Electric Company (SDG&E) will coordinate the identification of system need to ensure that they do not procure duplicate system resources."[42] Second, "there is no way to ensure whether an IOU election to utilize the CAM for a new resource is appropriate."[43] In other words, energy service provider (ESP) load may grow at a different rate than bundled load and there should not be a cross-subsidy between the two.

Therefore, in this proceeding, interested parties will be instructed to develop proposals for methodologies for identifying bundled- versus system-driven resource needs to:

- Coordinate the identification of system need to ensure that SCE and SDG&E do not procure duplicate system resources;

[42] D.07-12-052, at p. 117.

[43] *Id.*

- Capture respective growth trends of bundled and unbundled components of service area load;
- Identify how load growth trends and any resources ESPs are procuring to serve their own load can be included in this analysis, given the confidential nature of these data;
- Determine how to allocate the cost of new resources procured in the IOUs' RFOs to the bundled or system customers, based on this analysis (particularly given the "lumpiness" of resource procurement and the different types of resources procured in each solicitation). This could either take the form of a straightforward approximation or by importing an existing customer class allocation structure from the IOU General Rate Case proceedings, but should not take the form of the development of an entirely new customer class allocation structure for the CAM mechanism;
- Develop mechanisms that address instances in which any LSEs' development plans do not materialize and result in a greater amount of system resource needs than predicted; and
- Explore how re-opening of DA, or how Community Choice Aggregator or Electric Service Provider election to opt-out of CAM, would affect the proposed methodology (*i.e.*, can a sufficiently robust methodology be developed at this time, or will the methodology need to be revised, if and when DA is reopened).

b. Refinements to Bid Evaluation in Competitive Solicitations with Utility-Owned Generation (UOG) Bids

The 2006 LTPP decision (D.07-12-052) identified several concerns regarding whether the process for evaluating UOG bids against power purchase agreements bids is fair, just and reasonable. In particular, the decision identified the need to determine whether and how bid criteria can be developed that will provide meaningful, "apples-to-apples" comparisons of IOU and Independent

Power Producer (IPP) bids. Further, D.07-12-052 posed several questions that needed to be addressed in head-to-head RFOs with UOG bids:

- How IOU bid development costs would be addressed (*e.g.*, are these costs "at-risk" or are they ratepayer-guaranteed?);
- To the extent that penalty and reward components are added to UOG bids to make them more consistent with IPP bids, whether and how limits would be place on the participation of the IOU's ratebased resources on the proposed project (*i.e.*, what would prevent an IOU from re-directing its ratebased staff and other resources well in excess of the amounts estimated built in its winning bid); or
- What measures will be taken to prevent sharing of sensitive information between staff involved in developing utility bids and staff who create the bid evaluation criteria and select winning bids?

Phase II of the 2008 LTPP proceeding may address these questions and any proposals on head-to-head competition methodology developed in response to D.07-12-052.

c. Other Issues In-Scope

Based on pre-workshop comments and outcomes from the Preliminary Scoping Memo workshop, the assigned Administrative Law Judge and assigned Commissioner may decide, by ruling, that additional issues brought by parties warrant inclusion in the scope of this proceeding.

(END OF APPENDIX A)

APPENDIX B

RESPONDENT LOAD SERVING ENTITIES
(Public Utilities Code Section 380(j))

Electric Corporations

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Raymond R. Lee (906)
Chief Operating Officer
Mountain Utilities
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Kirkwood, CA 95646

Brian Cherry (39)
Director, Regulatory Relations
Pacific Gas and Electric Company
B10C
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San Francisco, CA 94177

Douglas Larson (901)
Vice President, Regulation
PacifiCorp
201 S, Main
Salt Lake City, UT 84140

Robert Marshall (908)
General Manager
Plumas Sierra Rural Electric Coop.
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Portola, CA 96122-2000

Steve Rahon (902)
Director, Tariff & Regulatory
Accounts
San Diego Gas & Electric Company
CP32C
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San Diego, CA 92123-1548

Mary Simmons (903)
Rate Regulatory Relations
Sierra Pacific Power Company
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Reno, NV 89520-0026

Akbar Jazayeiri (338)
Director of Revenue & Tariffs
Southern California Edison
Company
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Ronald Moore (133)
Southern California Water Company
630 East Foothill Blvd.
San Dimas, CA 91773

Surprize Valley

Bear Valley

Electric Service Providers

Michael Mazur (1350)
3Phases Energy Services
2100 Sepulveda Blvd., Suite 37
Manhattan Beach, CA 90266

Frank Annunziato (1158)
American Utility Network (A.U.N.)
10705 Deer Canyon Drive
Alta Loma, CA 91737

Lili Shahriari (1355)
AOL Utility Corp.
12752 Barrett Lane
Santa Ana, CA 92705

Stacy Aguayo (1361)
APS Energy Services Company, Inc.
400 E. Van Buren Street, Suite 750
Phoenix, AZ 85004

Kevin Boudreaux (1362)
Calpine PowerAmerica-CA, LLC
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George Hanson (1367)
City of Corona
Department of Water and Power
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Inger Goodman (1092)
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Hank Harris (1360)
Coral Power, L.L.C.
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San Diego, CA 92121

Adrian Pye (1341)
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New West Energy
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Thomas Darton (1365)
Pilot Power Group, Inc.
9320 Chesapeake Drive, Suite 112
San Diego, CA 92123

Rick C. Noger (1370)
Praxair Plainfield, Inc.
2711 Centerville Road, Suite 400
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Megan Saunders (1364)
Sempra Energy Solutions
101 Ash Street, HQ09
San Diego, CA 92101-3017

Kerry Hughes (1351)
Strategic Energy, Ltd.
7220 Avenida Encinas, Suite 120
Carlsbad, CA 92209

In addition, any electric service provider that, subsequent to the date of the order instituting this rulemaking, becomes registered to provide services within the service territory of one or more of the respondent electric corporations through direct access transactions shall, upon such registration, become a respondent to this proceeding.

Community Choice Aggregators

Any community choice aggregator that, subsequent to the date of the order instituting this rulemaking, becomes registered to provide services within the service territory of one or more of the respondent electric corporations through community choice aggregation transactions shall, upon such registration, become a respondent to this proceeding.

David Orth
San Joaquin Valley Power Authority
886 East Jensen Avenue
Fresno, CA 93725

(END OF APPENDIX B)

APPENDIX C
PUBLICLY-OWNED LSEs

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Valerie O. Fong
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Alameda, CA 94501

California Department of Water Resources
Peter Garris
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Sacramento, CA 95821

California Department of Water Resources
Susan Lee
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Sacramento, CA 95821

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City of Anaheim
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City of Anaheim
Marci Edwards
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City of Azusa
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City of Banning
Fred Mason
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Banning, CA 92220

City of Burbank
Richard Corbi
164 W. Magnolia
Burbank, CA 91503

City of Colton, Public Utilities
Jeannette Olko
150 South 10th Street
Colton, CA 92324

City of Corona
George Hanson
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Corona, CA 92880

City of Glendale
Ignacio Troncoso
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Glendale, CA 91206

City of Palo Alto
Debra Lloyd
250 Hamilton Ave.
Palo Alto, CA 94301

City of Pasadena
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City of Riverside
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City of Riverside
Gary Nolff
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City of Riverside

LeeAnne Uhler
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City of Santa Clara, dba Silicon Valley Power
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City of Vernon
Jorge Somano
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CMUA
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Los Angeles Water & Power
Randy Howard
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Modesto Irrigation District
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Modesto, CA 95354

Metropolitan Water District Headquarters
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Turlock Irrigation District
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Western Area Power Administration
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Cerritos, CA 90703-3127

Coachella Valley Water District
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Coachella, CA 92236

City of Compton Water
205 S. Willowbrook Ave.
Compton, CA 90220
East Valley Water District
3654 E. Highland Avenue, Suite 18
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Eastern Municipal Water District
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Perris, CA 92572-8300

City of Hercules
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El Dorado Irrigation District
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Placerville, CA 95667

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Hemet, CA 92543

City of Inglewood Water
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Inglewood, CA 90301

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Oakland, CA 94623-1055

Gridley Municipal Utilities
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Gridley, CA 95948

Healdsburg Municipal Electric Dept.
401 Grove Street

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Healdsburg, CA 95448

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City & County of San Francisco
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San Francisco, CA 94103

Lodi Municipal Electric System
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Lompoc, CA 93438

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Ukiah Municipal Utility District
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Modesto, CA 95352

Shasta Dam Public Utilities District
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Central Valley, CA 96019

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Foresthill, CA 95631

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City of San Diego Water
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City of San Jose
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San Jose, CA 95113

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(END OF APPENDIX C)