

Decision \_\_\_\_\_

**BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA**

Application of Pacific Gas and Electric Company (U39E) for Review of Entries to the Energy Resource Recovery Account (ERRA) and Renewables Portfolio Standard Cost Memorandum Account (RPSMA), and Compliance Review of Fuel Procurement for Utility Retained Generation, Administration of Power Purchase Contracts, and Least Cost Dispatch of Electric Generation Resources for the Record Period of January 1, through December 31, 2010 and for Adoption of Electric Revenue Requirements and Rates Associated with the Market Redesign and Technology Upgrade (MRTU) Initiative.

Application 11-02-011  
(Filed February 15, 2011)

**(NOT CONSOLIDATED)**

Application of Southern California Edison Company (U338E) for a Commission Finding that its Procurement-Related and Other Operations for the Record Period January 1 Through December 31, 2010 Complied with its Adopted Procurement Plan; for Verification of its Entries in the Energy Resource Recovery Account and Other Regulatory Accounts; and for Recovery of \$25.613 Million Recorded in Three Memorandum Accounts.

Application 11-04-001  
(Filed April 1, 2011)

**(NOT CONSOLIDATED)**

Application of San Diego Gas & Electric Company (U902E) for Approval of: (i) Contract Administration, Least Cost Dispatch and Power Procurement Activities in 2010, (ii) Costs Related to those Activities Recorded to the Energy Resource Recovery Account and Transition Cost Balancing Account in 2010 and (iii) Costs Recorded in Related Regulatory Accounts in 2010.

Application 11-06-003  
(Filed June 6, 2011)

**(NOT CONSOLIDATED)**

## **DECISION GRANTING PETITION FOR MODIFICATION**

### **Summary**

This decision grants the uncontested Petition for Modification filed by Pacific Gas and Electric Company, Southern California Edison Company and San Diego Gas & Electric Company, (jointly, the Utilities). Decisions (D.) 15-05-005, D.15-05-006, and D.15-05-007 shall each be modified to provide clear guidance in future Energy Resource Recovery Account compliance proceedings regarding the showing that is required for the Utilities to demonstrate least cost dispatch of their respective electric supply portfolios.

These proceedings are closed.

### **1. Background and Procedural History**

Pub. Util. Code § 454.5(d)(2) provided for a procurement plan that would accomplish, among others, the following objective:

Eliminate the need for after-the-fact reasonableness reviews of an electrical corporation's actions in compliance with an approved procurement plan, including resulting electricity procurement contracts, practices, and related expenses. However, the commission may establish a regulatory process to verify and assure

that each contract, and contract dispute which may arise are reasonably resolved.

In Decision (D.) 02-10-062, the Commission implemented Section 454.5 (d) by establishing Energy Resource Recovery Account (ERRA) balancing accounts for Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE) and San Diego Gas & Electric Company (SDG&E) (jointly “the Utilities”). In doing so, the Commission required the Utilities to track fuel and purchased power revenues against actual recorded costs; the Commission reviews this information in an annual ERRA compliance review conducted for each Utility.

The Petition under review here has its origins in Commission decisions in the 2010 ERRA compliance reviews for PG&E, SCE and SDG&E: in 2015, the Commission issued decisions in each of the Utilities’ respective 2010 ERRA Compliance application proceedings.<sup>1</sup> Each decision adopted an identical methodology for addressing least-cost dispatch (LCD) in future ERRA compliance proceedings. As the Commission discussed in detail in its decisions on the Utilities’ applications covering the 2010 record period, least-cost dispatch refers to a situation in which the most cost-effective mix of total resources is used, thereby minimizing the cost of delivering electric services.

On August 6, 2015, the Utilities filed and served a petition for modification of D.15-05-005, D.15-05-006, and D.15-05-007 (the “LCD Decisions”).

The utilities state that the petition for modification is narrowly focused and intended to provide clarity to the LCD Decisions. The Utilities explain that in each of the decisions, the Commission adopted the Joint Utilities’ “Proposal for

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<sup>1</sup> D.15-05-005, D.15-05-006, and D.15-05-007.

the Demonstration of Least Cost Dispatch” (Joint IOUs’ Proposal), but also adopted four modifications proposed by the Commission’s Office of Ratepayer Advocates (ORA). Finally, the LCD Decisions also adopted certain metrics for economically-dispatched demand response programs that were proposed by ORA.

The three LCD Decisions attached the original Joint IOUs’ Proposal as Appendix A and ORA’s proposed metrics as Appendix B. In their Petition, the Utilities suggest that the LCD Decisions may be somewhat challenging to implement because ORA’s four modifications were described in a pleading filed by ORA in November 2014, but ORA did not specifically propose modifications to the language in the Joint IOUs’ Proposal. For this reason, implementing the LCD Decisions for the 2015 ERRA Compliance applications, which will be filed in 2016, will require the Utilities, ORA, and the Commission to go back and try to determine the specific changes to the Joint IOUs’ Proposal resulting from ORA’s proposed modifications.

## **2. The Petition for Modification**

In order to provide clarity to the parties and the Commission, the Utilities request that each of the LCD Decisions be modified to include a new Appendix C, which would provide the Joint IOUs’ Proposal with the modifications proposed by ORA and adopted by the Commission, as well as the Commission-adopted ORA demand response program metrics. This will provide parties and the Commission with a single document for use in future ERRA compliance proceedings, rather than having to refer to several documents and earlier ORA pleadings to determine what is required for an LCD demonstration in future ERRA compliance applications. The Utilities attached a copy of the proposed Appendix C to their August 6, 2015, petition. No parties

opposed this request by the Utilities, and they state that they provided a copy of this petition to ORA in advance and ORA did not express any disagreement with the Utilities' proposed revisions.

### **3. Discussion**

The Utilities provide a useful explanation of the challenges likely to be posed by the current format of the Commission's recently-adopted methodology for addressing least cost dispatch in future ERRA compliance proceedings. The Utilities' proposed solution should be adopted. D.15-05-005, D.15-05-006, and D.15-05-007 should each be modified by adding the proposed Appendix C to each decision, formatted to provide the Commission-adopted Joint IOUs' Proposal with the modifications proposed by ORA and adopted by the Commission, as well as the Commission-adopted ORA demand response program metrics. The version of Appendix C that is adopted today is provided in Attachment A of this decision.

### **4. Waiver of Comment Period**

This is an uncontested matter in which the decision grants the relief requested. Accordingly, pursuant to Section 311(g)(2) of the Public Utilities Code and Rule 14.6(c)(2) of the Commission's Rules of Practice and Procedure, the otherwise applicable 30-day period for public review and comment is waived.

### **5. Assignment of Proceeding**

Michel Peter Florio is the assigned Commissioner and Stephen C. Roscow is the assigned Administrative Law Judge in this proceeding.

### **Findings of Fact**

1. In D.15-05-005, D.15-05-006, and D.15-05-007 the Commission adopted a methodology for addressing least cost dispatch in future ERRA compliance proceedings. The methodology consists of (1) a Joint IOU Proposal, (2) several

modifications to that proposal that were proposed by ORA, and (3) several demand response program metrics that were proposed by ORA.

2. The current format of the recently-adopted methodology is likely to be a challenge to follow in future proceedings.

### **Conclusions of Law**

1. The current format of the Commission's recently-adopted methodology for addressing least cost dispatch in future ERRA compliance proceedings should be modified so that it will not be confusing in future proceedings.

2. D.15-05-005, D.15-05-006, and D.15-05-007 should each be modified by adding a new Appendix C to each decision, formatted to provide the Commission-adopted Joint IOU Proposal with the modifications proposed by ORA and adopted by the Commission, as well as the Commission-adopted ORA demand response program metrics.

## **ORDER**

**IT IS ORDERED** that:

1. Decision 15-05-005, Decision 15-05-006, and Decision 15-05-007 shall each be modified by adding a new Appendix C to each decision, formatted to provide the Commission-adopted Joint Investor-Owned Utility "Proposal for the Demonstration of Least Cost Dispatch" with the modifications proposed by the Office of Ratepayer Advocates (ORA) and adopted by the Commission, as well as the Commission-adopted ORA demand response program metrics. The adopted version of Appendix C is provided as Attachment A of this decision.

2. Applications (A.) 11-02-011, A.11-04-001, and A.11-06-003 are closed.

This order is effective today.

Dated \_\_\_\_\_, at San Francisco, California.

## **ATTACHMENT A**

Adopted Version of Appendix C for Decision (D.) 15-05-005,  
D.15-05-006, and D.15-05-007

**Methodology for the Demonstration of Least Cost Dispatch  
in Energy Resource Recovery Account Compliance Proceedings**

In Pacific Gas and Electric Company's, Southern California Edison Company's, and San Diego Gas & Electric Company's (collectively "Joint Utilities") respective 2014 Energy Resource Recovery Account ("ERRA") Compliance applications (which will be filed in 2015) and in all subsequent ERRA Compliance applications, unless and until the requirements are changed by the Commission, the information described herein would be provided by the utility.

Providing this information satisfies the requirement that the Joint Utilities "develop proposed criteria that should be used to determine what constitutes least-cost dispatch compliance, and the resulting methodology [each utility] should follow to assemble a showing to meet its burden to prove such compliance."<sup>1</sup> Providing the material outlined below would satisfy a utility's burden of production regarding what constitutes adequate evidence to allow the Office of Ratepayer Advocates ("ORA") and the Commission to assess whether the utility complied with the Commission's least-cost dispatch ("LCD") requirements. To the extent that there are LCD exceptions (*e.g.*, a unit was not bid in at incremental costs for a specific period(s) of time during the Record Period), the utility would document such exceptions and quantify, where practicable, the cost impacts of such exceptions, or that customers were not otherwise negatively impacted as a result of the exceptions.

**Structure of 2014 ERRA Compliance Testimony****Testimony:**

6. Overview/narrative of LCD in the California Independent System Operator ("CAISO") markets.
7. Description of the utility's bidding and scheduling processes.
8. Summary reports/tables documenting aggregated annual exception rates for:
  - a. Incremental cost bid calculations.
  - b. Self-commitment decisions.
  - c. Master File data changes.
9. Narratives reviewing significant strategy changes, internal software and/or process changes, and CAISO market design changes during the Record Period, including documentation of the utility's review of market changes. Market changes may affect the need for, or content of, specific summary reports or workpapers, and any reports

or workpapers added, dropped, or modified due to such market changes will be detailed in this section.

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<sup>-1</sup> See Decision (“D.”) 13-10-041 at pp. 25-26 (PG&E’s 2010 ERRRA Compliance decision); D.13-11-005 at p. 26 (SCE’s 2010 ERRRA Compliance decision); and D.14-07-006 at p. 22 (SDG&E’s 2010 ERRRA Compliance decision).

10. Background summary table (identical to the table included as Item #5 in the workpapers).

**Workpapers:**

9. Summary reporting on thermal commitment and minimum load cost submission.<sup>2</sup> Detailed supporting data documents each decision to select proxy or registered cost, and value of registered cost if registered cost is chosen. Narrative explains how proxy and registered costs are calculated, and the reasons for selecting proxy or registered cost. A chart will be provided to indicate the frequency of calculations that differed from values submitted to CAISO, and the cost impacts, by month. For Record Periods 2015 and beyond, comparisons of the annual frequency of calculations that differed from values submitted to CAISO and total cost impacts will be made to previous years.

Monthly and annual tables will include summaries of:

- a. Number of times proxy and registered cost values were selected, and reason for selection.
  - b. Number of times proxy/registered cost calculations differed from values submitted to CAISO, or registered cost values were calculated and submitted to the CAISO incorrectly, based on documented procedure for this calculation.
  - c. Summary of cost impact from calculations that differed from values submitted to CAISO, based on an estimate of bid cost recovery (“BCR”) gains or losses calculated by comparing BCR credits from settlements invoices with calculated BCR using correctly calculated commitment costs.
10. Summary reporting on incremental bid cost calculations for dispatchable thermal resources.<sup>3</sup> Detailed supporting data documents all incremental bid cost calculations, including documentation of the fuel costs, heat rates, greenhouse gas costs, operations and maintenance costs, and any other costs used in this calculation. For Record Periods 2015 and beyond, comparisons of the annual frequency of incorrect calculations and total cost impacts will be made to previous years.

Monthly and annual tables will include summaries of:

- a. Verification of source data of all incremental bid cost calculations.
- b. Number of significant (greater than \$0.10) variances between calculated and actual submitted bids.
- c. Cost impacts of significant variances.

<sup>-2</sup> See ORA's Comments on PG&E's workshop report submitted in Application ("A.") 11-02-011 on March 25, 2014 ("ORA Comments"), p. 3.

<sup>-3</sup> See ORA Comments, p. 4.

- d. Number of times resources were not bid into CAISO markets when available.
  - e. Percentage of times incremental energy was not awarded when incremental bid cost at the awarded megawatt (“MW”) level was lower than the locational marginal price (“LMP”) at the applicable node. Explanation and documentation of CIDI tickets submitted, and subsequent actions taken by the utility.
11. Summary reporting on daily self-commitment decisions for dispatchable thermal resources.<sup>4</sup> Detailed supporting data documents daily forecasts of schedules if bid or self-committed, forecast revenues and bid costs if bid or self-committed, and decision to self-commit or bid.

Monthly and annual tables will include summaries of:

- a. Number of self-commitments and the reasons (using reason codes to be developed by utilities).
- b. Total energy (MWh) self-committed or self-scheduled.
- c. For each day a resource was self-committed, excluding self-schedules for bridging periods and non-discretionary reasons (*e.g.*, for unit testing), provide:
  - i. The utility’s forecast energy schedule, estimated revenues, and estimated costs using the utility’s forecast LMPs and resource bid costs used in making the self-commitment decision.
  - ii. The resulting schedule, estimated revenues, and estimated costs of the self-commitment decision, using the actual LMP and resource bid costs.
  - iii. The estimated schedule, estimated revenues, and estimated costs of the resource had it been bid into the market rather than self-committed, using actual LMPs and resource bid costs.
  - iv. Calculation of the net difference between c.ii and c.iii.
- d. Number of days that each resource’s estimated revenues exceeded its estimated bid costs.
- e. Number of days when each self-committed resource’s revenue exceed its estimated bid cost (profit position) and the reserve situation when its bid costs exceeded its revenues (loss position).

12. Summary reporting on bidding and dispatch of dispatchable hydro and pumped storage resources.<sup>5</sup> Detailed supporting data documents daily bid calculations, actual LMPs, and

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<sup>-4</sup> See ORA Comments, p. 6.

<sup>-5</sup> See ORA Comments, p. 7.

market dispatch results, as well as output from the mid-term hydro planning models, and sorted lists of LMPs, from highest to lowest, relevant to each resource.

Monthly and annual tables will include summaries of:

- a. Total MWh dispatched.
- b. Average LMPs when each resource was dispatched.
- c. For the annual table, metric indicating what percentage of the 500 highest LMPs of the year at each resource location that resource, when available, was dispatched for either energy or ancillary services, excluding must take or short term balancing resources. Notes using codes to be developed.

13. A background summary table will be provided laying out baseline annual data,<sup>6</sup>

including:

- a. Total capacity<sup>7</sup> of the dispatchable (bid in) portfolio.
- b. Total dispatchable capacity lost due to planned or forced outages.<sup>8</sup>
- c. Total capacity of the non-dispatchable (exclusively self-scheduled) portfolio.
- d. Total non-dispatchable capacity lost due to planned or forced outages.
- e. Total energy awards (dispatchable and non-dispatchable) by resource type (hydro, pumped storage, thermal, etc.) and broken down by self-scheduled versus market awards.

14. Comparison of the utility's awarded day-ahead load and actual day-ahead prices versus actual load. A comparison of the accuracy of the utilities' forecast of prices in the day ahead markets compared to actual CAISO results. Specifically, an assessment of how accurate the utilities were on the 50 highest energy value days, and the days when resources were self-committed due to concerns about the CAISO cycling their resources in an uneconomic manner (based on the average daily distribution load aggregation point ("DLAP") prices for the utility).

15. Monthly and annual report documenting load bid structure and results (amount of forecast load cleared in day ahead market versus load cleared in real time market).

16. LCD business process and software documentation.

-<sup>6</sup> See ORA Comments, p. 10.

-<sup>7</sup> Total capacity is defined as the resource's PMAX in MWh.

-<sup>8</sup> For purposes of this proposal, "outage" is defined as a unit being off-line and unavailable.

**Master Data Requests:**

Because the agreed upon methodology and workpapers would constitute adequate evidence to allow ORA and the Commission to assess the utilities' compliance with LCD principles and Standard of Conduct 4, ORA would cease its Master Data Request process regarding LCD. Follow-up data requests would be to facilitate additional discovery on focused topics.

**Metrics for Demand Response Resources:**

The metrics below should be provided for dispatchable DR programs with an economic trigger:

1. An annual summary of the results of the reporting requirement (related to dispatch of DR resources) recently adopted in D.14-05-025.<sup>9</sup> At a minimum, the utilities should provide a summary of:
  - a. The times and duration that all programs were dispatched;
  - b. All cases where the DR program's trigger conditions were forecast to be met, and all cases where these trigger conditions were actually met;
  - c. A list of occurrences when DR resources should have been dispatched but were not (i.e. a DR resource's economic trigger conditions were forecast by a utility but it was not dispatched). Each occurrence should be accompanied by an explanation detailing the reason for non-dispatch;
2. In addition to the Reporting Requirement in D.14-05-025, a calculation should be provided of the number of hours when the utility forecasts that trigger criteria will be reached, as a percentage of hours in which trigger conditions were reached in the same time period (monthly and annual basis).

***Net cost of underutilizing resources***

3. The total energy actually dispatched as a proportion of maximum available energy for each DR program<sup>10</sup> under scope of the proceeding (monthly and annual breakdowns).<sup>11</sup> This comparison should be provided in both percentage and nominal (MWh) terms. An example of the format is provided below:

***Example - Metric 3***

- a. In 2014 record Year – utility A's CBP program dispatched 100 MWh. This compares to

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<sup>9</sup> D.14-05-025 at 16.

<sup>10</sup> In cases when trigger criteria were forecast in sufficient hours that these programs could have been dispatched to their maximum available amounts.

<sup>11</sup> If a DR resource is available for 10 hours in a month for 20 MW, its maximum available energy for dispatch in that month would be 100 MWh.

a total maximum available dispatch of 200 MWh for that program.<sup>12</sup>

- b. Therefore utility A's CBP program did not dispatch 100 MWh of its total maximum available energy.
  - c. In 2014 record Year, utility A dispatched 50% of the available energy in the CBP program.
4. For each event the full capacity was not dispatched, an explanation should be provided as to why the DR resource was not dispatched to its maximum availability during the record period.
  5. If the metrics in 3) above show that available energy was not dispatched for a program, provide an estimate of the net cost impact on overall resource dispatch of not calling DR programs up to their maximum available amounts when the program trigger has been forecast to be reached.<sup>13</sup> This metric should focus on the net cost of dispatching metric (3.)(b.). An example of the format is provided below:

*Example – Metric 5*

- If the non-dispatched energy available to utility A's CBP program (100 MW in the example above) was actually dispatched this would have led to a net impact of \$X on the overall cost of resource dispatch in Record year 2014.

**Selection of dispatch days**

6. Metrics should be provided by the utility to identify whether the selection of DR events called minimized the utility's overall portfolio costs of dispatching supply resources. This assessment should include the average hourly net cost impact on overall resource dispatch by program:
  - a. For events actually dispatched in the record year.
  - b. For all time periods when DR program triggers were forecast by the utility (whether dispatched or not)
  - c. Comparison of a) and b) in both percentage and nominal (MWh) terms. An example is provided below:

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<sup>12</sup> Numbers provides in this example are meant for illustrative purposes only.

<sup>13</sup> In cases when trigger criteria were forecast in sufficient hours that these programs could have been dispatched to their maximum available amounts.

*Example – Metric 6*

(A) Average hourly net cost from actual dispatch events (\$/MWh)	(B) Average hourly potential net cost from all times when trigger conditions were forecast (dispatched or not) (\$/MWh)	\$(A)-(B )	(A)/(B) (%)
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7. An explanation of how opportunity cost analyses are used to make the decision to call, or not call, an event. This should include an explanation of the opportunity cost methodology and a demonstration of its application.