STATE OF CALIFORNIA EDMUND G. BROWN JR., *Governor*

PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3298

Advice Letter: 4465-E

February 24, 2015

Pacific Gas and Electric Company
Attention: Meredith Allen
Senior Director, Regulatory Relations
77 Beale Street, Mail Code B10C
San Francisco, CA 94177

SUBJECT: Joint Utilities Compliance Advice Filing Addressing Reporting Template for Demand Response Dispatch Exceptions Pursuant to D.14-05-025

Dear Ms. Allen:

Advice Letter 4465-E is effective as of January 29, 2015, per Resolution E-4708 Ordering Paragraphs.

Sincerely,

Edward Randolph

Edward Randolph
Director, Energy Division

Date of Issuance: February 10, 2015

PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

ENERGY DIVISION **RESOLUTION E-4708**
January 29, 2015

R E S O L U T I O N

Resolution E-4708. Southern California Edison, San Diego Gas & Electric, and Pacific Gas and Electric Companies request approval of a reporting template for demand response dispatch exception.

PROPOSED OUTCOME:

- Approve, with modifications, the reporting template for demand response dispatch exception.

SAFETY CONSIDERATIONS:

- There is no new safety risk associated with implementing a reporting template for demand response dispatch exception.

ESTIMATED COST:

- There is no additional cost to ratepayers with implementing a reporting template for demand response dispatch exception.

By Advice Letter Southern California Edison (SCE) (AL) Filed on July 18, 2014 3081-E, San Diego Gas & Electric (SDG&E) AL 2624-E, and Pacific Gas and Electric (PG&E) AL 4465-E.

SUMMARY

This Resolution approves, with modifications, the request of Southern California Edison Company (SCE), Pacific Gas and Electric Company (PG&E), and San Diego Gas and Electric Company (SDG&E) (collectively the Utilities) to use the proposed reporting template to address weekly dispatch exception of demand response (DR) events.

Modifications to the proposed reporting template include the following: the Utilities are required to report both the forecast and actual trigger conditions, the highest price of a generating resource that is part of the Utilities' portfolio that was dispatched, the

actual value that met the trigger criteria, and certain confidential contract information. The Commission finds that this additional information is needed to improve transparency of the Utilities' administration of demand response programs, and to support future Commission analysis of any instances in which a demand response program was economic to dispatch but the utility instead decided to utilize a non-demand response resource.

The lessons-learned workshop ordered in D.14-05-025 (OP 3) is postponed. A first workshop should be held no later than May 1, 2015 and a second workshop should be held before December 31, 2015.

BACKGROUND

On May 19, 2014, the Commission issued Decision (D.) 14-05-025 that ordered the Utilities to provide weekly exception reporting to Energy Division and ORA to identify and describe each occurrence when a demand response program was economic to dispatch but the utility instead decided to utilize a non-demand response resource.[1] The decision further ordered the Utilities to file an advice letter proposing a reporting template for demand response dispatch exceptions and also directed the Utilities to organize a meeting to develop the reporting template with interested stakeholders including ORA, using the draft reporting template in Attachment A of the decision as a starting point.[2] Lastly, the decision directed Commission Staff to host a workshop to discuss lessons learned from the weekly exception reporting before December 31, 2014.[3]

On June 18, 2014, SCE hosted a conference call with Energy Division, PG&E, SDG&E, ORA and other stakeholders from the service list of R.13-09-011 and circulated the draft reporting template for comment on July 9, 2014. ORA submitted comments and proposed revisions to the Utilities' proposed reporting template on July 15, 2014.

On July 18, 2014, SCE, on behalf of itself, PG&E and SDG&E, filed a joint advice letter containing a proposed reporting template for demand response dispatch exceptions[4].

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[1] D.14-05-025, Ordering Paragraph (OP) 1.

[2] D.14-05-025, OP 2.

[3] D.14-05-025, OP 3.

[4] SCE AL 3081-E, SDG&E AL 2624-E, and PG&E AL 4465-E

The Utilities' proposed reporting template for DR dispatch exception consisted of 3 worksheets (see Appendix A of this Resolution for additional details):

Worksheet 1: Information on the weekly dispatch exceptions
Worksheet 2: Description of columns in Worksheet 1
Worksheet 3: Details on eligible DR programs, their availability and dispatch constraints.

NOTICE

Notice of SCE's AL 3081-E, SDG&E's AL 2624-E, and PG&E's AL 4465-E (collectively, the "Joint AL") were made by publication in the Commission's Daily Calendar. The Utilities state that a copy of the Joint AL was mailed and distributed in accordance with Section 4 of General Order 96-B.

PROTESTS

The Office of Ratepayer Advocates (ORA) timely protested the Joint AL on August 7, 2014. The Utilities filed a Response to ORA's protest on August 14, 2014.

The Discussion section of this resolution has a detailed summary of the major issues raised in the protest.

DISCUSSION

The purpose of the weekly reporting template is to improve transparency of the Utilities' administration of their DR programs, particularly the Utilities' dispatch of DR programs. Demand response programs are dispatched according to tariffs or contracts that set certain "trigger conditions," such as heat rate, energy prices, and high temperatures. However, the Utilities may use their discretion to *not* dispatch (withhold) their DR programs. Utilities dispatch decisions are currently not transparent to the Commission and ORA. The reporting template ordered in D.14-05-025 was intended to shed more light on the Utilities' decision-making process for dispatching their DR programs. Hence, we review ORA's protest with that objective in mind.

Data on When DR Program Trigger Conditions Are Actually Met

In their AL filing, the Utilities proposed a weekly reporting template. The proposed reporting template is limited to DR dispatched based on the Utilities' *forecast* trigger conditions, discloses whether the program is partially dispatched, and provides an explanation for non-dispatch (see Utilities' Proposed Reporting Template Headings below).

Utilities' Proposed Reporting Template Headings

1	2	3	4	5	6	7
Program or Contract	Forecasted Day	Forecasted Hour	[Forecast] Trigger Criteria Met	Load Impact Forecast	If Partial Dispatch, MWs Not Dispatched	Reason for Non-Dispatch

In its protest, ORA argues that the reporting template should identify both the *forecast* and when the *actual* trigger conditions are met (see ORA's Proposed Reporting Template Headings below). ORA states that the provision of actual trigger conditions is consistent with the decision's directive that the template demonstrate when demand response programs were economic to dispatch. Limiting the data to just forecasted trigger criteria will not always reveal when a demand response program was economic to dispatch, because forecasted and actual occurrences of trigger conditions do not always overlap.

ORA's Proposed Reporting Template Headings

1	2	3	4	5	6	7	8
Program or Contract	[Actual] Day and Hour Trigger was Met	Forecasted Day and Hour of Trigger	[Actual] Trigger Criteria Met	Trigger Criteria Forecasted to be Met	Load Impact Forecast	MW of the program/contract not dispatched	Reason for Non-Dispatch

In reply to ORA's protest, the Utilities argued that ORA's request goes beyond the scope of the compliance requirement in that the template should only show the information that the Utilities had at the time of dispatch (forecasted triggers) not an ex post review of whether the forecasted triggers were realized.

We agree with ORA's argument that both the forecast and actual occurrence of the trigger conditions are needed in order to supply information necessary to address dispatch exception issues raised in D.14-05-025. The problem with the Utilities' reporting template is that it only shows one side of the story, the forecasted trigger conditions. The Utilities' decisions to dispatch demand response rely heavily on their forecasted trigger conditions. But, the actual trigger condition is also needed as a reference to see how well the Utilities forecast their demand response trigger conditions. Both the forecasted and the actual triggers are necessary to determine whether improvements are needed. Therefore, we adopt ORA's Proposed Reporting Template Headings.

In addition, we add two more columns to the template:

- Highest price of a generating resource that is part of the utilities' portfolio was *forecast* to be dispatched
- Highest price of a generating resource that is part of the utilities portfolio was *actually* dispatched

These two additional columns will enhance the Commission's understanding of the rationale and the extent to which the Utilities are dispatching generation resources before demand response resources. The Energy Action Plan "loading order" established that energy efficiency and demand response-side resources would be the first resource invested in meeting California energy needs, followed by renewable resources, and only then in clean conventional electricity supply.[5] .

Additionally Senate Bill 1414 (adopted in the 2014 Legislative session) directs the Commission to ensure "that investments are made in new and existing demand response resources that are cost effective and help to achieve electrical grid reliability and the state's goals for reducing emissions of greenhouse gases."[6] This broad directive further demonstrates the need for the Commission to understand the extent to which generation is dispatched instead of demand response.

[5] 2008 Energy Action Plan Update. http://www.cpuc.ca.gov/PUC/energy/Resources/Energy+Action+Plan/index.htm

[6] Public Utilities Code Section 380 (h)(6).

The Commission already has some data that peaker plants are being dispatched instead of demand response programs. Energy Division's report on *Lessons Learned From Summer 2012 Southern California Investor Owned Utilities' Demand Response Programs* (Staff Report) found that there has been an increase in peaker plant service hours while some DR program utilization decreased from 2006 to 2012.[7] The Commission should know to what extent, and why Utilities are using peaker plants at a higher rate than demand response programs.[8]

Specific Trigger Criteria Used for Dispatch of DR Programs/Contracts

In its protest, ORA argued that the Utilities should disclose the specific trigger used for dispatching DR programs, such as the exact energy price. In response, the Utilities requested this information be excluded from the weekly report, and instead, be included in the year-end report. The Utilities argued that this specific trigger data would require two set of weekly documents – a confidential version and a public version.

Demand response programs are dispatched according to tariffs or contracts that set certain "trigger conditions," such as heat rate, energy prices and high temperature. However, the Utilities have the ***discretion*** to dispatch their demand response programs in response to high wholesale energy prices. [9] Without knowing the exact price point of a high wholesale energy price, it is difficult to discern how the Utilities are making their decisions to dispatch or withhold their demand response programs. To maintain a comprehensive review, specific trigger information is needed on a weekly basis to ensure demand response is used to avoid high energy price and to facilitate the implementation of mid-cycle corrections if it is found the Utilities are not properly dispatching the DR programs. A year- end report might not give the Commission, and in effect the Utilities, enough time to make necessary adjustments to

[7] Staff Report, Pg 32.

[8] D.13-07-003, Conclusion of Law 1 .

[9] For example, SCE can dispatch its AC Cycling program in response to high wholesale energy prices, but is not required to. SCE tariff sheet Schedule D-SDP: Domestic Summer Discount Plan. https://www.sce.com/NR/sc3/tm2/pdf/ce342.pdf

the programs for the next demand response season. We adopt ORA's recommendation that Worksheet 3 of the exception report, which provides IOU-specific program information, shall include a column for "Available Trigger Criteria." This column should include the exact trigger criteria that the Utilities use to determine dispatch of the DR Programs/Contracts. In response to the Utilities' comments on the draft resolution, this column should also contain a description of the trigger condition value, and how the specific value is determined by the Utilities if it changes periodically. If the trigger is heat rate, the Utilities should state the exact heat rate. If the trigger is high CAISO wholesale energy prices, the Utilities should state the exact energy price.

The Utilities raise a concern of submitting two reports – one public, the other confidential. That will require some work on the part of the Utilities such as redacting the confidential document. While we recognize there is a burden with redacting, it is outweighed by our need for confidential information as described above. This issue should be re-evaluated in the lessons learned workshop at the end of 2015.

Confidentiality of the Utilities' Aggregated Managed Portfolio (AMP) Contracts
In the Joint AL filing, the Utilities proposed a single public version of the report. To ensure confidentiality of the Aggregator Managed Portfolio contracts, the Utilities proposed to aggregate its individual contracts into two sets of data points: Day-Ahead (DA) and Day-Of (DO). In its protest, ORA argues that the terms and conditions for each individual contract can vary and that disaggregation of the specific contract information is needed to do a thorough review of the exception report. In response, the Utilities argued that the single public report would reduce reporting workload and minimize the chance for errors.

We agree with ORA's recommendation to disclose specific information on the AMP contracts. Aggregating the individual contracts as proposed by the Utilities would not provide ORA and the Commission meaningful information about each AMP contract. With insufficient information, the Commission and/or ORA would likely issue data requests for the confidential information from each Utility whenever aggregated AMP information is reported. This creates an unnecessary burden to the Commission, ORA and the Utilities when the necessary information can be provided in the weekly reporting template. We have already addressed the issue of confidentiality earlier in this resolution. The Utilities shall provide contract specific information in a confidential version of the weekly report to Commission staff, including ORA. In Worksheet 1 and Worksheet 3, the Utilities shall report the name of each AMP contract, rather than aggregating the contracts to two sets: DA and DO, along with specific information required in the template.

Lessons-Learned Workshop
D.14-05-025 directed the Commission staff to host a lessons-learned workshop regarding the new reporting requirements no later than December 31, 2014. Because the reporting template has not yet been implemented, the first lessons-learned workshop was postponed to after the Utilities file the 2014 exception data but prior to the DR season (May 2015). ORA's proposal to host the first lessons-learned workshop is accepted. We appreciate ORA's offer to manage scheduling and notifying the workshop to all parties, facilitating workshop discussion, and circulating a draft workshop report for comments. Twenty days after the first workshop, ORA shall submit a final workshop report with parties' comments to the Commission. Commission staff shall host a second lessons-learned workshop no later than December 31, 2015. This workshop will focus on any lessons learned from 2015 so that improvements can be made to the template in preparation for 2016.

Exception Dispatch Year-End Review for 2014
ORA requests all the Utilities provide the exception reporting for all months in 2014 to allow for a comprehensive review in time for the lessons learned workshop. In response, the Utilities have no objection to ORA's request. The Utilities shall provide the exception reporting for all months in 2014 within 30 days of the approval of this Resolution. This information will be useful for the workshop.

Accordingly, we adopt the reporting template in Appendix B: Final Reporting Template, which reflects the modifications to the Utilities' proposed template approved in this Resolution. The Utilities shall implement the weekly reporting template for 2015 within 30 days of the approval of this Resolution.

<u>COMMENTS</u>

Public Utilities Code section 311(g)(1) provides that this resolution must be served on all parties and subject to at least 30 days public review and comment prior to a vote of the Commission. Section 311(g)(2) provides that this 30-day period may be reduced or waived upon the stipulation of all parties in the proceeding.

The 30-day comment period for the draft of this resolution was neither waived or reduced. Accordingly, this draft resolution was mailed to parties for comments, and will be placed on the Commission's agenda no earlier than 30 days from today.

On December 19, 2014, the Draft Resolution was served on the service list for SCE Advice Letter 3081-E, SDG&E Advice Letter 2624-E, PG&E Advice Letter 4465-E, and R.13-09-011, released for public comment, and placed on the Commission's agenda for January 29, 2015. Comments were filed by ORA and jointly by the Utilities (SCE, SDG&E, and PG&E) on January 9, 2015. Those comments are summarized below.

Lessons Learned Workshop and 2014 Data

In its comments, ORA strongly supports the Draft Resolution with the exception of the postponement of the lessons-learned workshop. ORA requests the workshop be held between the time the Utilities file the 2014 exception reporting data and the beginning of the DR season (May 2015). ORA offers to host the workshop and submit a final workshop report with all parties' comments to the Commission.

We agree that it would be helpful to ORA, other interested parties, and this Commission to have an opportunity to learn from the Utilities 2014 DR dispatch exceptions and apply those lessons learned to the 2015 DR season. We therefore adopt ORA's recommendation for a workshop prior May 1, 2015. ORA's proposal to schedule, notice and facilitate the workshop and submit a final workshop report with all parties' comments is accepted. We also direct Commission staff to host a second workshop before December 31, 2015 to assess any lessons learned about the reporting template from the 2015 demand response season.

In their comments, the Utilities argued that it would be unreasonable to require the Utilities to provide the exception reporting for all months in 2014 within 30 days of the Final Resolution under the newly-revised reporting template. The Utilities had originally agreed to include the 2014 exception reporting data based on the template in their advice letter filing. We disagree that the request is unreasonable. Given that the Draft Resolution was issued in December 2014, Utilities should have had enough time to begin preparations to provide the data within 30 days of this resolution becoming effective.

Forecasting and DR Dispatch

In their comments, the Utilities argued that effective dispatch decisions and forecasting market and system condition are two distinct activities "that should be evaluated independently; an incorrect forecast should not imply a problem with the decision-making process around DR dispatches". We disagree. The decision on whether to dispatch DR relies on forecasting the market and system conditions as accurately as possible and therefore these two activities are tied together. We acknowledge the fact that forecasting is never a 100 percent accurate, but the Utilities should always be striving to improve their forecasting so that DR resources are dispatched when appropriate.

Supply Resource DR Exemption
In their comments, the Utilities argued that Supply Resource DR should be excluded from the reporting template because it is under the control of CAISO. Currently PG&E is bidding a small portion of its CBP and AMP[10] into the CAISO market and SCE is planning to begin bidding in 2015. It is too early to exclude any Supply Resource DR from the reporting template but the pre-May 2015 workshop should take up this issue in terms of how the Utilities should identify Supply Resource DR into the template for the 2015 DR season. In the future, we will consider excluding Supply Resource DR from the reporting template when bidding into the CAISO market becomes more prevalent.

Loading Order Vs. Least Cost Dispatch
In their comments, the Utilities argued that it is incorrect for the resolution to imply that the Energy Action Plan Loading Order should drive dispatch decisions for DR resources. The Utilities point out while the "Loading Order drives planning and investment decisions, such as procurement of new generation resources,[11]" when it comes to day-ahead and real-time operations, the Utilities are required to dispatch the lowest cost resource in the CAISO market, regardless of whether that resource is DR or a conventional resource. The Utilities state they are required to comply with the Commission's Standard of Conduct No.4 (SOC 4), which states:

> "The utilities shall prudently administer all contracts and generation resources and dispatch the energy in a least-cost manner. Our

[10] Approximately 20 MWs

[11] Utilities Comments on Draft Resolution, pg 3.

> definitions of prudent contract administration and least-cost dispatch are the same as our existing standard."[12]

In essence, the Utilities' dispatch decisions are made according to least-cost dispatch principles for real time market conditions, not the Loading Order. The Utilities elaborated further that least-cost dispatch principles apply to the use of peaker plants in that these plants should be dispatched prior to demand response resources if they have a lower dispatch cost.

We appreciate the Utilities' clarification that their current operating procedures are based on the least-cost dispatch principles and that the Loading Order has no direct relationship to their dispatch decisions. We will not debate the issue of the Loading Order versus least-cost dispatch principles in this resolution. Instead we direct the Utilities back to D.14-05-025 which states that the purpose of the reporting template is to identify when a demand response resource was economic to dispatch, but the utility decided to utilize a non-demand response resource instead. Presumably then, the Utilities' use of least-cost dispatch principles with particular regard to demand response will be demonstrated through the reporting template. This information will be helpful to the Commission in terms of future considerations of demand response policy.

However we disagree with the Utilities suggestion to modify the resolution to accurately reflect the usage of peaker plants. As stated in D.13-07-003, the Commission should know to what extent, and why the Utilities are using peaker plants at a higher rate than demand response programs.[13] If it turns out that the reporting template is insufficient in providing specific data about 2014 peaker plant usage versus demand response resources, then improvements to the template should be taken up in the pre-May 2015 workshop to address this issue.

Utilities' Suggested Revisions to the Reporting Template

In their comments, the Utilities suggest revisions to the Final Reporting Template in Appendix B to improve clarity. These revisions include (1) clarifying the distinction

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[12] D.12-02-10-062, Conclusion of Law 11.

1. [13] Conclusion of Law 1

between a trigger conditions and an actual condition; (2) including a new data field to capture both the trigger value itself as well as the value that the IOUs saw in either actual or forecasted conditions; and (3) linking the trigger values to the rationale behind how these values are developed. Specifically, the Utilities recommend that both trigger conditions and actual conditions be reported in a clearer manner in the template by creating two rows for every exception reported.

We agree that the Utilities' suggestions to revise the Final Reporting Template will provide clarity on the data. Columns 2 through 5 of Worksheet 1 of the Draft Resolution's Final Reporting Template are replaced by Columns 2 through 8 as illustrated in the table below titled "Utilities Proposed Final Reporting Template – Worksheet 1 – with example".

With the changes applied in Worksheet 1, the last column in Worksheet 3 "Available Trigger Condition" should disclose the trigger condition value and how the specific value is determined by the IOUs if it changes periodically.

Draft Resolution's Final Reporting Template – Worksheet 1

2	3	4	5
Day and Hour Trigger was *Actually* Met	Day and Hour Trigger *Forecasted* to be Met	Trigger Criteria was *Actually* Met	Trigger Criteria *Forecasted* to be Met

Utilities Proposed Final Reporting Template – Worksheet 1 – with example

2	3	4	5	6	7	8
Condition Type (Trigger Condion and/or Actual Condition	Potential Event Date	Potential Event Hour (HE)	Date condition was reached	Hour condition was reached	Trigger or Condition Value	Forecasted or Actual Value
Trigger Condition	08/06/14	HE17	08/05/2014	HE15	Forecasted Price of $65/MWh	$67/MWh
Actual	08/06/14	HE19	08/06/14	HE19	Actual	$71/MWh

Condition					Price of $65/MWh	

In their comments, the Utilities recommended that only information related to the Day-Ahead CAISO market for both Day-Ahead and Day-Of DR programs be captured in the last two columns of Worksheet 1 for the "Highest Price Generating Resource". The Utilities explained that the real-time market is extremely volatile and difficult to forecast. Limiting the last two columns to only Day-Ahead market data for a Day-Of program seems inconsistent and would not provide information we seek to understand dispatch decisions for Day-Of programs. If the Utilities do not forecast real-time markets, then they should insert a description of what they rely on to determine dispatch decisions for Day-Of programs for the forecast column (last column in Worksheet 1).

In addition, the Utilities recommended the names of the last two columns be changed from "Highest Price Generating Resource…" to "Highest Incremental Cost Generating Resource…." The Utilities do not define what they mean by "incremental" and they do not explain why the change is necessary. We therefore deny the Utilities' recommendation to change the name for the last two columns in Worksheet 1.

FINDINGS

1. D.14-05-025 required Pacific Gas & Electric, Southern California Edison, and San Diego Gas & Electric (the Utilities) to provide a weekly exceptional dispatch report to Energy Division and ORA to identify and describe each occurrence when a demand response program was economic to dispatch but the utility decided to utilize a non-demand response resource instead.

2. D.14-05-025 ordered the Utilities to organize and meet with the ORA and interested stakeholders to develop an agreed-upon exceptional reporting template for providing weekly exception reporting, using the draft reporting template in Attachment A in D.14-05-025 as a starting point.

3. D.14-05-025 also directed the Utilities to submit an advice letter proposing a reporting template for the demand response dispatch exceptions.

4. The Office of Ratepayer Advocates (ORA) timely protested the Utilities' joint advice letter.

5. The Utilities' dispatch decisions are currently non-transparent to the Commission and ORA. The purpose of the weekly reporting template is to improve the transparency of the Utilities' administration of their DR programs, particularly the Utilities' dispatch of DR programs.

6. Reporting both the forecast and actual trigger conditions is within the scope of the compliance requirement because the actual trigger condition is used as a reference to see how well the Utilities forecast their demand response trigger conditions.

7. It is reasonable for the template to include the highest price of a generating resource that is part of the Utilities' portfolio that was *forecast* to be dispatched; and the highest price of a generating resource that is part of the Utilities' portfolio that was *actually* dispatched.

8. Disclosing the *specific* trigger criteria, such as the exact energy price, used for dispatching DR programs in the weekly report, as opposed to a year-end, is needed to ensure demand response is used effectively and to facilitate the implementation of mid-cycle corrections if it is found the Utilities are not properly dispatching their DR programs.

9. Aggregating the specific contract information would not provide sufficient data to do a thorough review of the exception report because the terms and conditions for each individual contract in Aggregated Managed Portfolio (AMP) can vary.

10. It is reasonable to postpone the lessons learned workshop to no later than May 1, 2015 to learn from the Utilities 2014 DR dispatch exception data and to make improvements for the 2015 DR season.

11. It is reasonable for Commission staff to facilitate a second workshop no later December 31, 2015 to determine if further improvements to the template are needed for the 2016 DR season.

12. It is reasonable for the Utilities to provide a exception dispatches for the 2014 year because it would help inform the pre-May 1, 2015 workshop.

THEREFORE IT IS ORDERED THAT:

1. Southern California Edison Company, San Diego Gas & Electric Company, and Pacific Gas and Electric Company's proposed weekly reporting template for demand response dispatch exception requested by Advice Letter 3081-E filed by SCE, Advice Letter 2624-E filed by SDG&E, and Advice Letter 4465-E filed by PG&E, are approved as modified in OP 2 and discussed herein.

2. The following modifications to the weekly reporting template are adopted: report both the forecast and actual occurrence of the trigger conditions, the actual value that met the trigger criteria, the highest price of a generating resource that is part of the utilities' portfolio in both the actual and forecast dispatched, and confidential information of their aggregated managed contracts. Appendix B of this resolution contains the Final Reporting Template that the Utilities shall use.

3. The first lessons- learned workshop is postponed to no later than May 1, 2015. ORA's proposal to host this workshop is approved. A second workshop shall be facilitated by Commission staff no later than December 31, 2015.

4. The Utilities are required to provide an exception dispatch year-end review for 2014 within 30 days of this resolution.

5. The Utilities shall begin reporting 2015 dispatch activity using the template in Appendix B within 30 days of this resolution.

This Resolution is effective today.

I certify that the foregoing resolution was duly introduced, passed and adopted at a conference of the Public Utilities Commission of the State of California held on January 29, 2015; the following Commissioners voting favorably thereon:

/s/_Timothy J. Sullivan____
TIMOTHY J. SULLIVAN
Executive Director

MICHAEL PICKER
President
MICHEL PETER FLORIO
CATHERINE J.K. SANDOVAL
CARLA J. PETERMAN
LIANE M. RANDOLH
Commissioners

Appendix A:

Utilities' Proposed Reporting Template

Worksheet 1 of Utilities Proposed Reporting Template

Worksheet 1 of the reporting template will be used to input the information of the weekly dispatch exceptions.

1	2	3	4	5	6	7
Program or Contract	Forecasted Day	Forecasted Hour	Trigger Criteria Met	Load Impact Forecast	If Partial Dispatch, MWs Not Dispatched	Reason for Non-Dispatch

Worksheet 2 of Utilities Proposed Reporting Template

Worksheet 2 of the reporting template is used to describe each of the columns from Worksheet 1.

Column #	Column Title	Description
1	Program or Contract	Economic DR program or contract that was forecasted to meet trigger criteria but was not dispatched or was partially dispatched (that is, only a portion of the total program was dispatched).
2	Forecasted Day	Day on which dispatch criteria was forecasted to be met (YYYY-MM-DD). That is, the date when the DR event would have occurred had the program been dispatched. If the same trigger applies to multiple programs or contracts, each program or contract should be reported on a separate row.
3	Forecasted Hour	Hour on which dispatch criteria was forecasted to be met (Hour Ending). That is, the hour when the DR event would have occurred had the program been dispatched. If the same trigger applies to multiple programs or contracts, each program or contract should be reported on a separate row.
4	Trigger Criteria Met	The type of dispatch criteria that the IOU forecasted that would be met (market prices, heat rates, IOU system load, temperature, other). Do not report actual values of triggers or forecasts; the rationale for non-dispatch or partial dispatch should be addressed in column 7.
5	Load Impact Forecast	Hourly load impact of the DR program as forecasted in the daily CAISO report.
6	If Partial Dispatch, MWs Not Dispatched	If the program was partially dispatched, report the number of MWs that were not dispatched.
7	Reason for Non-Dispatch	Reason the program or contract was not dispatched or was partially dispatched. Provide an explanation (tariff constraints, operational constraints, market conditions, etc.) that describes the IOU's reasoning.

BEGIN APPENDICES

Worksheet 3 of Utilities Proposed Reporting Template

Worksheet 3 of the reporting template will be unique for each IOU and will show eligible programs and their availability and dispatch constraints. Each of the IOUs worksheets are shown below.

SCE's Worksheet 3

Abrev.	Program Name	Residential Non-Res	Months Available	Days Available	Hours Available	Program Hour Usage Limit	Day Ahead Day Of	Minimum Participant Notification Lead Time
AMP-DA	Aggregator Managed Program, Day-Ahead	Non-Res	Varies by contract	Weekdays (non-holiday)	Varies by contract	Varies by contract	DA	3 PM day ahead
AMP-DO	Aggregator Managed Program, Day-Of	Non-Res	Varies by contract	Weekdays (non-holiday)	Varies by contract	Varies by contract	DO	1 hour before event
CBP-DA	Capacity Bidding Program, Day-Ahead	Non-Res	All	Weekdays (non-holiday)	HE12 - HE19	30/month	DA	3 PM day ahead
CBP-DO	Capacity Bidding Program, Day-Of	Non-Res	All	Weekdays (non-holiday)	HE12 - HE19	30/month	DO	1 hour before event
SDP-C	Summer Discount Program, Commercial	Non-Res	All	All	All	6/day, 180/year	DO	None
SDP-R	Summer Discount Program, Residential	Residential	All	All	All	6/day, 180/year	DO	None
SPD	Save Power Day	Residential	All	Weekdays (non-holiday)	HE15 - HE20	None	DA	Day ahead (SCE tariff does not specify exact time)
DBP	Demand Bidding Program	Non-Res	All	Weekdays (non-holiday)	HE13 - HE20	None	DA	12 PM day ahead
SAI	Summer Advantage Incentive (Critical Peak Pricing)	Non-Res	All	Weekdays (non-holiday)	HE15 - HE18	Exactly 12 events required per year	DA	3 PM day ahead

SDG&E's Worksheet 3

Abrev.	Program Name	Residential Non-Res	Months Available	Days Available	Hours Available	Program Hour Usage Limit	Day Ahead Day Of	Minimum Participant Notification Lead Time
CBP-DA	Capacity Bidding Program- Day Ahead	Non-Res	May-Oct	Weekdays (non-holiday)	11-7 pm	Max of 44 hours a month	DA	Before 3 pm day ahead
CBP-DO	Capacity Bidding Program- Day Of	Non-Res	May-Oct	Weekdays (non-holiday)	11-7 pm	Year: No annual max Month: 44 hours Week: No limit Day: 1 event	DO	By 9 am
CPP-D	Critical Peak Pricing	Non-Res	All	All	11-6 pm	Year: 18 max events Month: No limit Week: No limit Day: 7 hours (11 am-6 pm)	DA	System load must meet triggers by 2:30pm or no event can be called Customer notification: Before 3 pm
DBP- DA	Demand Bidding Program	Non-Res	All	All	Must provide range of hours needed	No annual max	DA	Before 1 pm, when possible
DBP- DO	Demand Bidding Program- Day Of	Non-Res	All	All	Must provide range of hours needed	No annual max	DO	30 minute
RYU	Reduce Your Use Rewards	Res	All	All	11-6 pm	Year: No limit Month: No limit Week: No limit Day: 7 hours (11 am-6 pm)	DA	Before 3 pm (best practice)
Summer Saver	Summer Saver	Res & Non-Res	May-Oct	All	12-6 pm	Year: 120 hours or 15 events Month: 40 hours Week: 3 days max Day: No less than 2 hours but no more than 4 consecutive hours.	DO	None

PG&E's Worksheet 3

Abrev.	Program Name	Residential Non-Res	Months Available	Days Available	Hours Available	Program Hour Usage Limit	Day Ahead Day Of	Minimum Participant Notification Lead Time
AMP-DA	Aggregator Managed Portfolio Program, Day-Ahead	Non-Res	May - October	Weekdays (non-holiday)	HE12 - HE19	Min. 4 hrs. and up to 6 hrs./event; 80 hours/year	DA	3 PM day ahead
AMP-DO	Aggregator Managed Portfolio Program, Day-Of	Non-Res	May - October	Weekdays (non-holiday)	HE12 - HE19	Min. 4 hrs. and up to 6 hrs./event; 80 hours/yea	DO	30 mins. before event
CBP-DA	Capacity Bidding Program, Day-Ahead	Non-Res	May - October	Weekdays (non-holiday)	HE12 - HE19	Min. 1 hr. and Max. 8 hrs./event; 30 hrs./month	DA	3 PM day ahead
CBP-DO	Capacity Bidding Program, Day-Of	Non-Res	May - October	Weekdays (non-holiday)	HE12 - HE19	Min. 1 hr. and Max. 8 hrs./event; 30 hrs./month	DO	At least 3 hours before event
DBP	Demand Bidding Program	Non-Res	Year-round	Weekdays (non-holiday)	HE13 – HE20	None	DA	12 PM day ahead
SmartAC	SmartAC	Res and Non-Res	May - October	Daily	HE1 – HE24	Max. 6 hrs./event, 100 hrs./year	DO	None
PDP	Peak Day Pricing	Non-Res	Year-round	Daily	HE15 - HE18	9 to 15 events/year	DA	2 PM day ahead
SmartRate	SmartRate	Res	May - October	Weekdays (non-holiday)	HE15 – HE19	15 events/year	DA	3 PM day ahead

Appendix B: Final Reporting Template

Worksheet 1 of Final Reporting Template

Worksheet 1 of the reporting template will be used to input the information of the weekly dispatch exceptions.

1	2	3	4	5	6	7	8
Program or Contract	Condition Type (Trigger Condition and/or Actual Condition)	Potential Event Date	Potential Event Hour (HE)	Date condition was reached	Hour condition was reached	Trigger or Condition Value	Forecasted or Actual Value
CBP	Trigger Condition	8/6/2014	HE17	8/5/2014	HE15	Forecasted Price of $65/MWh	$67/MWh
CBP	Actual Condition	8/6/2014	HE19	8/6/2014	HE19	Actual Price of $65/MWh	$71/MWh

9	10	11	12	13
Load Impact Forecast	MW of the Program/Contract Not dispatched	Reason for Non-Dispatch	Highest Price Generating Resource *Actually* Dispatched	Highest Price Generating Resource *Forecasted to be* Dispatched

Worksheet 2 of Final Reporting Template

Worksheet 2 of the reporting template is used to describe each of the columns from Worksheet 1.

Column#	Column Title	Description
1	Program or Contract	Economic DR program or specific contract name that was actually/forecasted to meet trigger criteria but was not dispatched or was partially dispatched (that is, only a portion of the total program was dispatched).
2	Condition Type (Trigger Condition and/or Actual Condition)	Identify whether it is a trigger condition, actual condition, or both. Report trigger conditions when any of the following condition reach the trigger criteria, but the program was not dispatched: forecast weather condition, price, heat rate, or IOU system load. Actual condition should be reported when the actual condition reached the trigger criteria, but the program was not dispatched.
3	Potential Event Date	Day on which dispatch criteria was *forecasted* to be met (YYYY-MM-DD). That is, the date when the DR event would have occurred had the program been dispatched. If the same trigger applies to multiple programs or contracts, each program or contract should be reported on a separate row.
4	Potential Event Hour (HE)	Hour on which dispatch criteria was *forecasted* to be met. That is, the hour when the DR event would have occurred had the program been dispatched. If the same trigger applies to multiple programs or contracts, each program or contract should be reported on a separate row.
5	Date condition was reached	Day on which dispatch criteria was *actual* met (YYYY-MM-DD). That is, the date when the DR event would have occurred had the program been dispatched. If the same trigger applies to multiple programs or contracts, each program or contract should be reported on a separate row.
6	Hour condition was reached	Hour on which dispatch criteria was *actual* met. That is, the hour when the DR event would have occurred had the program been dispatched. If the same trigger applies to multiple programs or contracts, each program or contract should be reported on a separate row.
7	Trigger or Condition Value	Type of dispatch criteria are market prices, heat rates, IOU system load, temperature, and others. Report the value of the dispatch criteria.
8	Forecasted or Actual Value	Type of dispatch criteria are market prices, heat rates, IOU system load, temperature, and others. Report the value of dispatch criteria IOUs used in either actual or forecasted condition.
9	Load Impact Forecast	Hourly load impact of the DR program in the daily CAISO report.
10	MW of the Program/Contract Not dispatched	If the program was partially dispatched, report the number of MWs that were not dispatched.
11	Reason for Non-Dispatch	Reason the program or contract was not dispatched or was partially dispatched. Provide an explanation (tariff constraints, operational constraints, market conditions, etc.) that describes the IOU's reasoning.
12	Highest Price Generating Resource *Actually* Dispatched	Highest price of a generating resource that is part of the utilities' portfolio that was *actually* dispatched.
13	Highest Price Generating Resource *Forecasted to be* Dispatched	Highest price of a generating resource that is part of the utilities' portfolio that was *forecast* to be dispatched.

Worksheet 3 of Final Reporting Template

Worksheet 3 of the reporting template will be unique for each IOU and will show eligible programs and their availability and dispatch constraints.

Abrev.	Program Name	Residential Non-Res	Months Available	Days Available	Hours Available	Program Hour Usage Limit	Day Ahead Day Of	Minimum Participant Notification Lead Time	Available Trigger Criteria
AMP - DA [Insert Name of Contract]									
AMP - DO [Insert Name of Contract]									
:									

END APPENDICES

SOUTHERN CALIFORNIA EDISON
An EDISON INTERNATIONAL Company

Megan Scott-Kakures
Vice President, Regulatory Operations

July 18, 2014

ADVICE 3081-E
(Southern California Edison Company - U 338-E)

ADVICE 2624-E
(San Diego Gas & Electric Company - U 902-E)

ADVICE 4465-E
(Pacific Gas and Electric Company - U 39-E)

PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA
ENERGY DIVISION

SUBJECT: Joint Utilities Compliance Advice Filing Addressing Reporting Template for Demand Response Dispatch Exceptions Pursuant to Decision 14-05-025

PURPOSE

In compliance with Ordering Paragraph (OP) 2 of Decision (D.)14-05-025, Southern California Edison Company (SCE), on behalf of itself, San Diego Gas & Electric Company (SDG&E) and Pacific Gas and Electric Company (PG&E) (collectively the investor-owned utilities or IOUs), hereby submits this joint advice letter requesting approval of a reporting template to address weekly dispatch exceptions of demand response (DR) events.

BACKGROUND

On January 31, 2014, Assigned Commissioner Peevey and Administrative Law Judge (ALJ) Hymes issued a joint Ruling providing guidance to the IOUs regarding DR program improvement proposals for the 2015-2016 bridge funding period and allowed for all parties to file program improvements.

P.O. Box 800 8631 Rush Street Rosemead, California 91770 (626) 302-6855 Fax (626) 302-4829

On March 3, 2014, the IOUs and various parties filed DR program improvements. Included in the filings was a proposal by the Office of Ratepayer Advocates (ORA) that would require the IOUs to submit a weekly report identifying and describing “each occurrence when a demand response program was economic to dispatch but the utility decided to utilize a non-demand response resource instead.”[1]

On May 19, 2014, the California Public Utilities Commission (Commission) issued D.14-05-025 which agreed with the additional reporting requested by ORA and the IOUs’ concerns regarding confidentiality and duplication. OP 2 of D.14-05-025 directs the IOUs to organize and meet with the appropriate Commission Staff, ORA, and all other interested stakeholders to develop an agreed-upon reporting template using the draft reporting template in Appendix A as a starting point. In addition, OP 3 of D.14-05-025 directs Commission Staff to host a workshop by no later than December 31, 2014 to discuss lessons learned from the weekly exception reporting.

On June 18, 2014, pursuant to OP 2 of D.14-05-025, SCE hosted a conference call with Commission Staff, PG&E, SDG&E, ORA and other interested stakeholders from the service list of Rulemaking (R.)13-09-011. On July 9, 2014, SCE, on behalf of the IOUs, circulated for comment a draft reporting template. On July 15, 2014, ORA submitted comments and revisions to the IOUs’ proposed reporting template.

PROPOSED REPORTING TEMPLATE

The IOUs request approval of the proposed modifications contained herein to the draft reporting template in Appendix A of D.14-05-025. These modifications include ORA’s recommendations while maintaining transparency and minimizing redundant reporting. Should ORA require additional information than what is contained in the proposed reporting template, it can issue a discovery request for that information. Although the IOUs are not proposing to modify the frequency of the reporting requirement in this advice filing, they will address the issue as part of the workshop directed in OP 3 of D.14-05-025.

Exclusions and Limitations to the Reporting Template

The IOUs have excluded the Base Interruptible Program and Agricultural Pumping Program from the reporting template as it was found reasonable in D.14-05-025.[2] Additionally, to preserve the value of this report as a tool that evaluates decisions on the information available to the IOUs at the time of dispatch, the report’s scope is limited to forecasted conditions (rather than an after-the-fact review of actual market prices or temperatures). Finally, because the purpose of the report is to identify DR dispatch exceptions, the IOUs propose to limit the scope of reporting to hours when a DR program was available. For example, SCE’s Demand Bidding Program is only available from noon to 8 p.m. on weekdays, thus reporting that it was not used at 10 a.m. does not provide the Commission with meaningful information.

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[1] D.14-05-045, p.15.
[2] D.14-05-025, p.17.

<u>Timing of the Reporting Period</u>

The IOUs propose that the information contained in the weekly report follow a Thursday through Wednesday reporting period to align with information prepared for summer readiness calls. The information will be provided one week following the completion of the reporting period. The IOUs request an August 17, 2014 effective date for this advice letter and propose that the first reporting period begin the first Thursday after approval of the advice letter. For instance, if the advice letter is timely approved, the IOUs reporting period would begin on August 21 with the first report due September 4.

<u>Proposed Reporting Template</u>

The IOUs propose the following worksheets be included in the DR exception reporting template. An explanation of the variance between Attachment 1 of D.14-05-025 is discussed further below.

Worksheet 1 of Reporting Template

Worksheet 1 of the reporting template will be used to input the information of the weekly dispatch exceptions.

1	2	3	4	5	6	7
Program or Contract	Forecasted Day	Forecasted Hour	Trigger Criteria Met	Load Impact Forecast	If Partial Dispatch, MWs Not Dispatched	Reason for Non-Dispatch

Worksheet 2 of Reporting Template

Worksheet 2 of the reporting template is used to describe each of the columns from Worksheet 1.

Column #	Column Title	Description
1	Program or Contract	Economic DR program or contract that was forecasted to meet trigger criteria but was not dispatched or was partially dispatched (that is, only a portion of the total program was dispatched).
2	Forecasted Day	Day on which dispatch criteria was forecasted to be met (YYYY-MM-DD). That is, the date when the DR event would have occurred had the program been dispatched. If the same trigger applies to multiple programs or contracts, each program or contract should be reported on a separate row.
3	Forecasted Hour	Hour on which dispatch criteria was forecasted to be met (Hour Ending). That is, the hour when the DR event would have occurred had the program been dispatched. If the same trigger applies to multiple programs or contracts, each program or contract should be reported on a separate row.
4	Trigger Criteria Met	The type of dispatch criteria that the IOU forecasted that would be met (market prices, heat rates, IOU system load, temperature, other). Do not report actual values of triggers or forecasts; the rationale for non-dispatch or partial dispatch should be addressed in column 7.
5	Load Impact Forecast	Hourly load impact of the DR program as forecasted in the daily CAISO report.

6	If Partial Dispatch, MWs Not Dispatched	If the program was partially dispatched, report the number of MWs that were not dispatched.
7	Reason for Non-Dispatch	Reason the program or contract was not dispatched or was partially dispatched. Provide an explanation (tariff constraints, operational constraints, market conditions, etc.) that describes the IOU's reasoning.

Worksheet 3 of Reporting Template

Worksheet 3 of the reporting template will be unique for each IOU and will show eligible programs and their availability and dispatch constraints. Each of the IOUs worksheets are shown below.

<u>SCE's Worksheet 3</u>

Abrev.	Program Name	Residential Non-Res	Months Available	Days Available	Hours Available	Program Hour Usage Limit	Day Ahead Day Of	Minimum Participant Notification Lead Time
AMP-DA	Aggregator Managed Program, Day-Ahead	Non-Res	Varies by contract	Weekdays (non-holiday)	Varies by contract	Varies by contract	DA	3 PM day ahead
AMP-DO	Aggregator Managed Program, Day-Of	Non-Res	Varies by contract	Weekdays (non-holiday)	Varies by contract	Varies by contract	DO	1 hour before event
CBP-DA	Capacity Bidding Program, Day-Ahead	Non-Res	All	Weekdays (non-holiday)	HE12 - HE19	30/month	DA	3 PM day ahead
CBP-DO	Capacity Bidding Program, Day-Of	Non-Res	All	Weekdays (non-holiday)	HE12 - HE19	30/month	DO	1 hour before event
SDP-C	Summer Discount Program, Commercial	Non-Res	All	All	All	6/day, 180/year	DO	None
SDP-R	Summer Discount Program, Residential	Residential	All	All	All	6/day, 180/year	DO	None
SPD	Save Power Day	Residential	All	Weekdays (non-holiday)	HE15 - HE20	None	DA	Day ahead (SCE tariff does not specify exact time)
DBP	Demand Bidding Program	Non-Res	All	Weekdays (non-holiday)	HE13 - HE20	None	DA	12 PM day ahead
SAI	Summer Advantage Incentive (Critical Peak Pricing)	Non-Res	All	Weekdays (non-holiday)	HE15 - HE18	Exactly 12 events required per year	DA	3 PM day ahead

SDG&E's Worksheet 3

Abrev.	Program Name	Residential Non-Res	Months Available	Days Available	Hours Available	Program Hour Usage Limit	Day Ahead Day Of	Minimum Participant Notification Lead Time
CBP-DA	Capacity Bidding Program-Day Ahead	Non-Res	May-Oct	Weekdays (non-holiday)	11-7 pm	Max of 44 hours a month	DA	Before 3 pm day ahead
CBP-DO	Capacity Bidding Program-Day Of	Non-Res	May-Oct	Weekdays (non-holiday)	11-7 pm	Year: No annual max Month: 44 hours Week: No limit Day: 1 event	DO	By 9 am
CPP-D	Critical Peak Pricing	Non-Res	All	All	11-6 pm	Year: 18 max events Month: No limit Week: No limit Day: 7 hours (11 am-6 pm)	DA	System load must meet triggers by 2:30pm or no event can be called Customer notification: Before 3 pm
DBP- DA	Demand Bidding Program	Non-Res	All	All	Must provide range of hours needed	No annual max	DA	Before 1 pm, when possible
DBP- DO	Demand Bidding Program-Day Of	Non-Res	All	All	Must provide range of hours needed	No annual max	DO	30 minute
RYU	Reduce Your Use Rewards	Res	All	All	11-6 pm	Year: No limit Month: No limit Week: No limit Day: 7 hours (11 am-6 pm)	DA	Before 3 pm (best practice)
Summer Saver	Summer Saver	Res & Non-Res	May-Oct	All	12-6 pm	Year: 120 hours or 15 events Month: 40 hours Week: 3 days max Day: No less than 2 hours but no more than 4 consecutive hours.	DO	None

PG&E's Worksheet 3

Abrev.	Program Name	Residential Non-Res	Months Available	Days Available	Hours Available	Program Hour Usage Limit	Day Ahead Day Of	Minimum Participant Notification Lead Time
AMP-DA	Aggregator Managed Portfolio Program, Day-Ahead	Non-Res	May - October	Weekdays (non-holiday)	HE12 - HE19	Min. 4 hrs. and up to 6 hrs./event; 80 hours/year	DA	3 PM day ahead
AMP-DO	Aggregator Managed Portfolio Program, Day-Of	Non-Res	May - October	Weekdays (non-holiday)	HE12 - HE19	Min. 4 hrs. and up to 6 hrs./event; 80 hours/yea	DO	30 mins. before event
CBP-DA	Capacity Bidding Program, Day-Ahead	Non-Res	May - October	Weekdays (non-holiday)	HE12 - HE19	Min. 1 hr. and Max. 8 hrs./event; 30 hrs./month	DA	3 PM day ahead
CBP-DO	Capacity Bidding Program, Day-Of	Non-Res	May - October	Weekdays (non-holiday)	HE12 - HE19	Min. 1 hr. and Max. 8 hrs./event; 30 hrs./month	DO	At least 3 hours before event
DBP	Demand Bidding Program	Non-Res	Year-round	Weekdays (non-holiday)	HE13 – HE20	None	DA	12 PM day ahead
SmartAC	SmartAC	Res and Non-Res	May - October	Daily	HE1 – HE24	Max. 6 hrs./event, 100 hrs./year	DO	None
PDP	Peak Day Pricing	Non-Res	Year-round	Daily	HE15 - HE18	9 to 15 events/year	DA	2 PM day ahead
SmartRate	SmartRate	Res	May - October	Weekdays (non-holiday)	HE15 – HE19	15 events/year	DA	3 PM day ahead

Comparison of IOUs Proposed Reporting Template and Attachment 1 of D.14-05-025

Column # in original template (Attachment 1 of D.14-05-025)	Description	Disposition in Proposed Template
1	*Date Trigger Is Met*	Column 2
2	*Time Trigger Is Met*	Column 3
3	*Program or Contract Name*	Column 1. Individual contracts (for DRC/AMP) cannot be listed in order to preserve the report's value as a public resource that provides transparency. Note: The IOUs have already provided ORA with the terms of each contract.
4	*Lead Time for Notification*	Sheet 3 of the template.
5	*Date & time when program is eligible to be implemented*	Columns 2-3
6	*Specify the Type of Trigger Conditions Met*	Column 4
7	*Was Resource Dispatched when available – see column 5 (Y/N)?*	This column is not necessary because the report is limited to times when a program was available but was not dispatched.
8	*If No, explain the reason why not*	Column 7
9	*Forecasted availability of the program or contract, MW*	Column 5
10	*Actual MW dispatched of the program of contract*	Column 6
11	*Duration of dispatch*	This column is not necessary because the report is limited to times when a program was available but was not dispatched.
12	*Tariff-based constraints restricting availability*	Column 7
13	*Strategy-based constraints preventing dispatch*	Column 7
14	*Highest Price that a non-Demand Response resource that is part of the utilities' portfolio was forecast to be Dispatched*	Column 7 of the proposed template address the issues underlying non-dispatch of DR resources. The data requested in columns 14-17 of Attachment 1 are both confidential and generally unavailable, and hence should not be included in DR exception reports.
15	*Highest Price that a non-Demand Response resource that is part of the utilities' portfolio was actually Dispatched*	
16	*Was the resource noted in column 15 self scheduled?*	
17	*Please note all non-DR resources that are part of the utilities' portfolio that are forecast to have marginal commitment costs that are above the energy value of the DR program resource at the time they are available*	

The IOUs request timely approval of this advice letter so that reporting of the dispatch exceptions can be done during the summer 2014 event season.

TIER DESIGNATION

Pursuant to OP 2 of D.14-05-025, this advice letter is submitted with a Tier 2 designation.

EFFECTIVE DATE

This advice filing will become effective on August 17, 2014, the 30th calendar day after the date filed.

NOTICE

Anyone wishing to protest this advice filing may do so by letter via U.S. Mail, facsimile, or electronically, any of which must be received no later than 20 days after the date of this advice filing. Protests should be mailed to:

CPUC, Energy Division
Attention: Tariff Unit
505 Van Ness Avenue
San Francisco, California 94102
E-mail: EDTariffUnit@cpuc.ca.gov

Copies should also be mailed to the attention of the Director, Energy Division, Room 4004 (same address above).

In addition, protests and all other correspondence regarding this advice letter should also be sent by letter and transmitted via facsimile or electronically to the addresses shown below:

For SCE:

Megan Scott-Kakures
Vice President, Regulatory Operations
Southern California Edison Company
8631 Rush Street
Rosemead, California 91770
Facsimile: (626) 302-4829
E-mail: AdviceTariffManager@sce.com

Leslie E. Starck
Senior Vice President, Regulatory Policy & Affairs
c/o Karyn Gansecki
Southern California Edison Company
601 Van Ness Avenue, Suite 2030
San Francisco, California 94102
Facsimile: (415) 929-5544
E-mail: Karyn.Gansecki@sce.com

For SDG&E:

Attn: Megan Caulson
Regulatory Tariff Manager
8330 Century Park Court, Room 32C
San Diego, California 92123-1548
Facsimile: (858) 654-1879
E-mail: MCaulson@semprautilities.com

For PG&E:

Brian K. Cherry
Vice President, Regulatory Relations
Pacific Gas and Electric Company
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P.O. Box 770000
San Francisco, California 94177
Facsimile: (415) 973-7226
E-mail: PGETariffs@pge.com

There are no restrictions on who may file a protest, but the protest shall set forth specifically the grounds upon which it is based and shall be submitted expeditiously.

In accordance with Section 4 of General Order (GO) 96-B, SCE is serving copies of this advice filing to the interested parties shown on the attached GO 96-B, R.13-09-011, and A.11-03-001 et al. service lists. Address change requests to the GO 96-B service list should be directed by electronic mail to AdviceTariffManager@sce.com or at (626) 302-2930. For changes to all other service lists, please contact the Commission's Process Office at (415) 703-2021 or by electronic mail at Process_Office@cpuc.ca.gov.

Further, in accordance with Public Utilities Code Section 491, notice to the public is hereby given by filing and keeping the advice filing at SCE's corporate headquarters. To view other SCE advice letters filed with the Commission, log on to SCE's web site at https://www.sce.com/wps/portal/home/regulatory/advice-letters.

For questions, please contact David Lowrey at (626) 302-3446 or by electronic mail at david.lowrey@sce.com.

Southern California Edison Company

/s/ MEGAN SCOTT-KAKURES
Megan Scott-Kakures

MSK:dl:sq
Enclosures

CALIFORNIA PUBLIC UTILITIES COMMISSION

ADVICE LETTER FILING SUMMARY
ENERGY UTILITY

MUST BE COMPLETED BY UTILITY (Attach additional pages as needed)

Company name/CPUC Utility No.: Southern California Edison Company (U 338-E)

Utility type:	Contact Person: Darrah Morgan
☑ ELC ☐ GAS	Phone #: (626) 302-2086
☐ PLC ☐ HEAT ☐ WATER	E-mail: Darrah.Morgan@sce.com
	E-mail Disposition Notice to: AdviceTariffManager@sce.com

EXPLANATION OF UTILITY TYPE

ELC = Electric GAS = Gas
PLC = Pipeline HEAT = Heat WATER = Water

(Date Filed/ Received Stamp by CPUC)

Advice Letter (AL) #: 3081-E et al. Tier Designation: 2

Subject of AL: Joint Utilities Compliance Advice Filing Addressing Reporting Template for Demand Response Dispatch Exceptions Pursuant to Decision 14-05-025

Keywords (choose from CPUC listing): Compliance

AL filing type: ☐ Monthly ☐ Quarterly ☐ Annual ☑ One-Time ☐ Other

If AL filed in compliance with a Commission order, indicate relevant Decision/Resolution #:

D.14-05-025

Does AL replace a withdrawn or rejected AL? If so, identify the prior AL:

Summarize differences between the AL and the prior withdrawn or rejected AL:

Confidential treatment requested? ☐ Yes ☑ No

If yes, specification of confidential information:
Confidential information will be made available to appropriate parties who execute a nondisclosure agreement.
Name and contact information to request nondisclosure agreement/access to confidential information:

Resolution Required? ☐ Yes ☑ No

Requested effective date: 8/17/14 No. of tariff sheets: -0-

Estimated system annual revenue effect: (%):

Estimated system average rate effect (%):

When rates are affected by AL, include attachment in AL showing average rate effects on customer classes (residential, small commercial, large C/I, agricultural, lighting).

Tariff schedules affected: None

Service affected and changes proposed[1]:

Pending advice letters that revise the same tariff sheets:

[1] Discuss in AL if more space is needed.

Protests and all other correspondence regarding this AL are due no later than 20 days after the date of this filing, unless otherwise authorized by the Commission, and shall be sent to:

CPUC, Energy Division
Attention: Tariff Unit
505 Van Ness Avenue
San Francisco, California 94102
E-mail: EDTariffUnit@cpuc.ca.gov

Megan Scott-Kakures
Vice President, Regulatory Operations
Southern California Edison Company
8631 Rush Street
Rosemead, California 91770
Facsimile: (626) 302-4829
E-mail: AdviceTariffManager@sce.com

Leslie E. Starck
Senior Vice President, Regulatory Policy & Affairs
c/o Karyn Gansecki
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San Francisco, California 94102
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PG&E Gas and Electric
Advice Filing List
General Order 96-B, Section IV

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California State Association of Counties
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Western Manufactured Housing Communities Association (WMA)