September 30, 2014

The Honorable Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

Re: California Independent System Operator Corporation
Docket Nos. ER08-1178-000 and EL08-88-000
June 2014 Exceptional Dispatch Report (Chart 2 Data)

Dear Secretary Bose:

Pursuant to the orders issued in the above-referenced dockets on September 2, 2009 and May 4, 2010, the California Independent System Operator Corporation (CAISO) submits the attached report. The report provides Exceptional Dispatch information that the Commission directed be included in “Chart 2,” which is set forth in Appendix A to the September 2, 2009 order, as modified by the May 4, 2010 order.

The attached report provides Chart 2 data for the month of June 2014. The report also includes the price impact analysis for June 2014 required by paragraph 44 of the September 2, 2009 order. The CAISO was unable to complete the degree of mitigation analysis required by CAISO tariff section 34.9.4 for June 2014 due to changes in the manner in which data is recorded. The CAISO will include the degree of mitigation analysis for both June and July 2014 in its October 30 exceptional dispatch report.

Respectfully submitted,

By: */s/ Sidney M. Davies*

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Exceptional Dispatch Report

Table 2: June 2014

Market Quality and Renewable Integration September 30, 2014

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Introduction

This report is filed pursuant to FERC's September 2, 2009, and May 4, 2010, orders in ER08-1178. These orders require two monthly Exceptional Dispatch reports—one issued on the 15th of each month and one issued on the 30th of each month. This report provides data on the frequency, reasons and costs for Exceptional Dispatches issued in June 2014. On December 19, 2013, the ISO implemented a new exceptional dispatch tool. This tool improves the ISO's ability to automate the production of the report and provides more granularity and consistency concerning the reasons for the exceptional dispatch.

In addition, this report contains a price impact analysis as prescribed by FERC in its September 2 order. The price impact analysis for the month of June is presented in Appendix B. This report also includes the degree of mitigation analysis for June 2014 required by section 34.9.4 of the ISO tariff. As it has previously explained, the ISO indicated that it would start including the degree of mitigation analysis beginning with the month of August 2009 when the more limited Exceptional Dispatch bid mitigation took effect. This analysis will compare those Exceptional Dispatches subject to bid mitigation (i.e. Exceptional Dispatches to address noncompetitive constraints and Delta Dispatch), and determine the cost difference between the Exceptional Dispatch bid mitigation settlement rules and what the settlement amount would have been had the Exceptional Dispatches not been subject to bid mitigation. The Exceptional Dispatch bid mitigation analysis for June is presented in Appendix C.

The Nature of Exceptional Dispatch

The ISO can issue exceptional dispatch instructions for a resource as a pre-day-ahead unit commitment, a post day-ahead unit commitment or a real-time exceptional dispatch. A pre-day-ahead unit commitment is an exceptional dispatch instruction committing a resource at or above its physical minimum (Pmin) operating level in the day-ahead market. A post-day-ahead unit commitment is an exceptional dispatch instruction committing a resource at or above its (Pmin) operating level in the real-time market. A real-time exceptional dispatch instructs a resource to operate at or above its physical minimum operating point. For the purposes of this report, a real-time exceptional dispatch above the resource's day-ahead award is considered an incremental exceptional dispatch instruction and a real-time exceptional dispatch below the day-ahead award is considered a decremental dispatch instruction. The ISO issues exceptional dispatch instructions primarily to manage transmission constraints that are not modeled in the market software. In addition to constraints, the ISO also issues exceptional dispatch instructions relating to reliability requirements and, on occasion, software failures. Reliability requirements are calculated for both local area and the system wide needs, and are classified into various requirements including local generation, transmission management, non-modeled transmission outages, ramping and intertie emergency assistance.

Whenever the ISO issues an exceptional dispatch instruction, these instructions are logged by the operators into the scheduling and logging system (SLIC), including an associated reason for each exceptional dispatch instruction.

Most of the generation procedures are internal to the ISO and not available publically on the ISO website; however, all of the transmission procedures are available on the ISO website.[1]

The following additional reason for exceptional dispatch instructions in June 2014 was not related to specific generation or transmission operating procedures: Software Limitation, when an exceptional dispatch instruction was used to bridge schedules across days for resources with a minimum down time of 24 hours, as the ISO software does not handle multi day commitment. For instance, a resource has a day-ahead schedule from 0600 till 2300, and then is shut down in 2400. If this resource had a minimum down time of 24 hours and it is required the following day, then the ISO issues an exceptional dispatch to commit this resource in 2400 so that it can be dispatched economically in the following day. Software limitation reason was also used for exceptional dispatches to manually issue shut down instructions to a resource because of a temporary Automatic Dispatch System ("ADS") failure, or similar issues. There were a few other reasons used to explain exceptional dispatch instructions in June, which are self explanatory.

As mentioned earlier, the data shown in Table 1 is based on a template specified in the September 2009 order.[2] This table contains all the information published in Table 1 of the first report for June. In addition, it contains volume (MWh) and cost information. Each entry in Table 1 is a summary of exceptional dispatches classified by (1) the reason for the exceptional dispatch; (2) the location of the resource by Participating Transmission Owner (PTO) service area; (3) the Local Reliability Area (LRA) where applicable; (4) the market in which the exceptional dispatch occurred (day-ahead vs. real-time); and (5) the date of the exceptional dispatch. For each classification the following information is provided: (1) Megawatts (MW); (2) Commitment; (3) Inc or Dec; (4) Hours; (5) Begin Time; (6) End Time; (7) Total Volume (MWh); (8) Min Load Cost; (9) Start Up Cost; (10) CC6470; (11) ED Volume (MWh INC/DEC); (12) CC6470 INC; (13) CC6470 DEC; (14) CC6482; (15) CC6488; and (16) CC6620. Each column is defined as follows:

- The MW column shows the range of exceptional dispatch instruction in MW for the classification.

[1] A list of all of the ISO's Operating Procedures and all the publicly available Operating Procedures are available at the following link: **http://www.caiso.com/thegrid/operations/opsdoc/index.html**

[2] The data in Table 1 is principally SLIC information supplemented with data from the Market Quality System (MQS) and Settlements database. The volume and cost information is based on t+51B Recalculation Statements.

- The Commitment column specifies if there was a unit commitment for the classification.
- The INC/DEC/NA column specifies if there was an incremental dispatch (INC), a decremental dispatch (DEC), or only a unit commitment (NA). The Begin Time and End Time columns show the start and end time of exceptional dispatch for the classification respectively.
- The Hours column is the time difference between begin time and end time rounded up to the next hour.
- The total volume column shows the total MWh dispatch quantity dispatched for that classification. This quantity includes the minimum load quantity, the imbalance energy quantity, and the exceptional dispatch quantity.
- The Min-Load Cost column shows eligible minimum load cost for the classification.
- The Start-Up Cost column shows the eligible start up cost for the classification. Please note that the ISO does not explicitly pay resources for its start up and minimum load costs; however, it ensures that resources are compensated adequately through its bid cost recovery process.[3]
- The CC6470 column shows the total imbalance energy costs for the classification. This cost contains the portion of exceptional dispatch instruction that was settled as optimal energy by virtue of its bid price being less than the LMP in that specific settlement interval.
- The ED Volume MWh (MWh INC/DEC) column shows the incremental or the decremental portion of the real-time exceptional dispatch MWh for the classification. The CC6470-INC shows that portion of incremental exceptional dispatch instruction which is settled at the resource specific LMP.
- The CC6470-DEC column shows that portion of decremental exceptional dispatch instruction which is settled at the resource specific LMP. Both these charge codes are portion of the real-time instructed imbalance energy charge code (6470). [4]
- The CC6482 column shows the real-time excess cost for the classification.[5]
- The CC6488 column shows the real-time exceptional dispatch uplift settlement for the classification.[6] The CC6620 shows the bid cost recovery payment for the classification. This cost is shown for all pre-day-ahead unit commitments only.

[3] For further details regarding the Bid Cost Recovery process please refer to section 11.8 of the ISO tariff.

[4] For further details please refer to the BPM configuration Guide: Real-Time Instructed Imbalance Energy Settlement published on the ISO's website.

[5] For further details please refer to the BPM configuration Guide: Real Time Excess Cost for Instructed Energy Settlement published on the ISO's website.

[6] For further details please refer to the BPM configuration Guide: Real Time Exceptional Dispatch Uplift Settlement published on the ISO's website.

Charge codes 6470, 6470 INC, 6470 DEC, 6482 and 6488 are shown in Table 1 because all these charge codes pertain to real-time exceptional dispatch MWH quantities. The classification of data is further explained by way of example in Attachment A.

Table 1: Exceptional Dispatches in June 2014

California Independent System Operator Corporation
Exceptional Dispatch Report
September 29, 2014

Chart 2: Table of Exceptional Dispatches for Period 01/June/2014 - 30/June/2014

Number	Market Type	Reason	Location	Local Reliability Area	Trade Date	MW	Commitment	INC_DEC	Hours	Begin Time	End Time	Total MWH	Min Load Cost	Start Up Cost	CC6470	ED MWH (INC/DEC)	CC6470 INC	CC6470 DEC	CC6482	CC6488	CC6620
1	RT	COI Overload	PG&E	Fresno	3-Jun-14	400	No	INC	1	22:15	22:59	-19.74	$9,545	$632	$1,516	0	$0	$0	$0	$0	$0
2	RT	Incomplete or Inaccurate Transmission	PG&E	Fresno	9-Jun-14	30- 64	No	INC	8	10:21	17:59	117.64	$25,842	$446	($8,920)	80	($5,660)	$0	$0	($739)	$0
3	RT	Incomplete or Inaccurate Transmission	PG&E	Fresno	20-Jun-14	83	No	INC	1	16:15	16:44	117.64	$25,842	$446	($8,920)	80	($5,660)	$0	$0	($739)	$0
4	RT	Incomplete or Inaccurate Transmission	PG&E	Fresno	21-Jun-14	50	No	INC	5	18:25	23:09	86.82	$18,923	$474	($4,536)	39	($1,568)	$0	$0	($469)	$0
5	RT	Incomplete or Inaccurate Transmission	PG&E	Fresno	21-Jun-14	50- 133	No	INC	5	18:45	23:29	117.64	$25,842	$446	($8,920)	80	($5,660)	$0	$0	($739)	$0
6	RT	Incomplete or Inaccurate Transmission	PG&E	Fresno	22-Jun-14	20	No	INC	3	2:30	5:14	117.64	$25,842	$446	($8,920)	80	($5,660)	$0	$0	($739)	$0
7	RT	Incomplete or Inaccurate Transmission	PG&E	Humboldt	30-Jun-14	0	No	INC	3	17:00	19:59	-19.87	($868)	$0	$1,213	(15)	$0	$956	$0	($2,392)	$0
8	RT	Incomplete or Inaccurate Transmission	PG&E	N/A	9-Jun-14	94	No	INC	9	11:39	19:59	-64.33	$0	$0	$2,872	(26)	$0	$1,289	$0	($1,254)	$0
9	RT	Incomplete or Inaccurate Transmission	PG&E	N/A	16-Jun-14	142	No	INC	16	8:25	23:59	-64.33	$0	$0	$2,872	(26)	$0	$1,289	$0	($1,254)	$0
10	RT	Incomplete or Inaccurate Transmission	PG&E	Sierra	21-Jun-14	20- 40	No	INC	10	14:15	23:59	5.56	$1,811	$0	($200)	0	$0	$0	$0	$0	$0
11	RT	Incomplete or Inaccurate Transmission	SCE	Big Creek-Ventura	10-Jun-14	50	No	INC	14	10:00	23:59	-15.85	$80,420	$0	$725	0	$0	$0	$0	$0	$0
12	RT	Incomplete or Inaccurate Transmission	SDG&E	San Diego-IV	6-Jun-14	21	No	INC	3	9:40	12:39	7.34	$9,106	$0	($360)	2	($12)	$0	$0	$0	$0
13	RT	Incomplete or Inaccurate Transmission	SDG&E	San Diego-IV	20-Jun-14	14	No	INC	5	10:50	14:59	7.34	$9,106	$0	($360)	2	($12)	$0	$0	$0	$0
14	RT	Load Forecast Uncertainty	PG&E	Bay Area	5-Jun-14	25	No	INC	6	12:15	17:29	-127.98	$20,635	$1,026	$6,850	0	$0	$0	($2)	$0	$0
15	RT	Load Forecast Uncertainty	PG&E	Bay Area	19-Jun-14	193	No	INC	2	15:55	16:59	-127.98	$20,635	$1,026	$6,850	0	$0	$0	($2)	$0	$0
16	RT	Load Forecast Uncertainty	PG&E	N/A	30-Jun-14	141	No	INC	9	6:00	14:21	-39.51	$57,256	$0	$3,631	(0)	$0	$0	$0	$0	$0
17	RT	Load Forecast Uncertainty	SCE	Big Creek-Ventura	9-Jun-14	20- 70	Yes	INC	16	8:00	23:59	-282.82	$50,509	$0	$16,462	0	$0	$0	$0	$0	$0
18	RT	Load Forecast Uncertainty	SCE	LA Basin	5-Jun-14	97- 146	No	INC	9	12:00	20:59	-355.45	$109,410	$33,107	$18,721	0	($5)	$0	($0)	$0	$0

Number	Market Type	Reason	Location	Local Reliability Area	Trade Date	MW	Commitment	INC_DEC	Hours	Begin Time	End Time	Total MWH	Min Load Cost	Start Up Cost	CC6470	ED MWH (INC/DEC)	CC6470 INC	CC6470 DEC	CC6482	CC6488	CC6620
19	RT	Load Forecast Uncertainty	SCE	LA Basin	9-Jun-14	10	Yes	INC	4	20:00	23:59	-355.45	$109,410	$33,107	$18,721	0	($5)	$0	($0)	$0	$0
20	RT	Load Forecast Uncertainty	SCE	LA Basin	30-Jun-14	25- 390	Yes	INC	19	5:00	23:59	-355.45	$109,410	$33,107	$18,721	0	($5)	$0	($0)	$0	$0
21	RT	Load Forecast Uncertainty	SDG&E	San Diego-IV	9-Jun-14	20- 40	Yes	INC	18	6:00	23:59	-232.28	$76,466	$0	$13,235	0	$0	$0	$0	$0	$0
22	RT	Load Forecast Uncertainty	SDG&E	San Diego-IV	30-Jun-14	20- 40	Yes	INC	18	6:00	23:59	-232.28	$76,466	$0	$13,235	0	$0	$0	$0	$0	$0
23	RT	Operating Procedure Number and Constraint	PG&E	Fresno	7-Jun-14	40- 334	No	INC	14	10:55	23:59	292.09	$27,858	$198	($21,495)	151	($8,060)	$0	$0	$0	$0
24	RT	Operating Procedure Number and Constraint	PG&E	Fresno	8-Jun-14	84- 272	No	INC	19	3:30	21:59	292.09	$27,858	$198	($21,495)	151	($8,060)	$0	$0	$0	$0
25	RT	Operating Procedure Number and Constraint	PG&E	Fresno	10-Jun-14	50	No	INC	1	8:15	8:29	292.09	$27,858	$198	($21,495)	151	($8,060)	$0	$0	$0	$0
26	RT	Operating Procedure Number and Constraint	PG&E	Fresno	15-Jun-14	20	No	INC	2	8:31	10:29	292.09	$27,858	$198	($21,495)	151	($8,060)	$0	$0	$0	$0
27	RT	Operating Procedure Number and Constraint	PG&E	Fresno	23-Jun-14	40- 200	No	INC	10	14:58	23:59	292.09	$27,858	$198	($21,495)	151	($8,060)	$0	$0	$0	$0
28	RT	Operating Procedure Number and Constraint	PG&E	Fresno	24-Jun-14	35- 118	No	INC	24	0:00	23:59	292.09	$27,858	$198	($21,495)	151	($8,060)	$0	$0	$0	$0
29	RT	Operating Procedure Number and Constraint	PG&E	Fresno	25-Jun-14	6- 231	No	INC	13	11:32	0:19	292.09	$27,858	$198	($21,495)	151	($8,060)	$0	$0	$0	$0
30	RT	Operating Procedure Number and Constraint	PG&E	Fresno	26-Jun-14	6- 92	No	INC	22	0:05	21:59	292.09	$27,858	$198	($21,495)	151	($8,060)	$0	$0	$0	$0
31	RT	Operating Procedure Number and Constraint	PG&E	Fresno	27-Jun-14	40- 50	No	INC	10	14:00	23:59	292.09	$27,858	$198	($21,495)	151	($8,060)	$0	$0	$0	$0
32	RT	Operating Procedure Number and Constraint	PG&E	Fresno	28-Jun-14	20- 198	No	INC	12	12:30	23:59	292.09	$27,858	$198	($21,495)	151	($8,060)	$0	$0	$0	$0
33	RT	Operating Procedure Number and Constraint	PG&E	Humboldt	1-Jun-14	15	No	INC	2	22:05	23:59	207.09	$12,691	$0	($11,976)	18	($1,167)	$0	$0	($2)	$0
34	RT	Operating Procedure Number and Constraint	PG&E	Humboldt	30-Jun-14	30- 75	No	INC	11	14:00	0:59	207.09	$12,691	$0	($11,976)	18	($1,167)	$0	$0	($2)	$0
35	RT	Operating Procedure Number and Constraint	PG&E	N/A	6-Jun-14	10- 120	No	INC	3	17:35	19:44	-28.03	$10,911	$640	$120	0	$0	$0	$0	$0	$0
36	RT	Operating Procedure Number and Constraint	PG&E	N/A	28-Jun-14	301	No	INC	6	14:55	20:29	-28.03	$10,911	$640	$120	0	$0	$0	$0	$0	$0
37	RT	Operating Procedure Number and Constraint	PG&E	NCNB	26-Jun-14	135- 150	No	INC	5	3:47	7:59	-12.42	$0	$0	($347)	(12)	$0	($360)	$0	$0	$0
38	RT	Operating Procedure Number and Constraint	PG&E	NCNB	27-Jun-14	75- 78	No	INC	17	3:00	19:59	-12.42	$0	$0	($347)	(12)	$0	($360)	$0	$0	$0
39	RT	Operating Procedure Number and Constraint	PG&E	Sierra	6-Jun-14	20- 222	No	INC	5	15:40	20:29	-49.10	$2,106	$0	$2,034	(49)	$0	$1,676	$0	$0	$0

Number	Market Type	Reason	Location	Local Reliability Area	Trade Date	MW	Commitment	INC_DEC	Hours	Begin Time	End Time	Total MWH	Min Load Cost	Start Up Cost	CC6470	ED MWH (INC/DEC)	CC6470 INC	CC6470 DEC	CC6482	CC6488	CC6620
40	RT	Operating Procedure Number and Constraint	PG&E	Sierra	7-Jun-14	210	No	INC	7	16:07	22:59	-49.10	$2,106	$0	$2,034	(49)	$0	$1,676	$0	$0	$0
41	RT	Operating Procedure Number and Constraint	PG&E	Sierra	8-Jun-14	544	No	INC	7	15:15	21:59	-49.10	$2,106	$0	$2,034	(49)	$0	$1,676	$0	$0	$0
42	RT	Operating Procedure Number and Constraint	SCE	Big Creek-Ventura	10-Jun-14	538	No	INC	4	17:25	21:14	113.37	$0	$0	($4,920)	118	($5,113)	$0	$0	$0	$0
43	RT	Operating Procedure Number and Constraint	SDG&E	San Diego-IV	13-Jun-14	243	No	INC	2	13:34	14:59	33.15	$0	$0	($1,288)	34	($1,290)	$0	$0	$0	$0
44	RT	Other Reliability Requirement	Intertie	N/A	6-Jun-14	50	No	INC	1	17:00	17:59	0.00	$0	$0	$0	0	$0	$0	$0	$0	$0
45	RT	Other Reliability Requirement	PG&E	Stockton	8-Jun-14	50	No	INC	1	16:26	16:59	0.01	$0	$0	($56)	0	$0	$0	$0	$0	$0
46	RT	Other Reliability Requirement	SCE	LA Basin	25-Jun-14	177- 387	No	INC	8	14:45	21:59	0.00	$16,054	$0	$0	0	$0	$0	$0	$0	$0
47	RT	Overgeneration	SCE	LA Basin	9-Jun-14	550	No	INC	2	3:03	4:44	145.17	$0	$0	($6,742)	(10)	$0	$387	$0	$0	$0
48	RT	Overgeneration	SDG&E	San Diego-IV	9-Jun-14	300	No	INC	2	3:01	4:43	57.21	$0	$0	($2,798)	(23)	$0	$849	$0	$0	$0
49	RT	Planned Transmission Outage and Constraint	PG&E	Fresno	2-Jun-14	92	No	INC	5	16:05	20:59	-78.80	$64,262	$1,067	$4,994	5	($154)	$0	$0	($640)	$0
50	RT	Planned Transmission Outage and Constraint	PG&E	Fresno	3-Jun-14	46	No	INC	5	2:35	7:29	-78.80	$64,262	$1,067	$4,994	5	($154)	$0	$0	($640)	$0
51	RT	Planned Transmission Outage and Constraint	PG&E	Fresno	4-Jun-14	20- 50	No	INC	16	8:55	23:59	-78.80	$64,262	$1,067	$4,994	5	($154)	$0	$0	($640)	$0
52	RT	Planned Transmission Outage and Constraint	PG&E	Fresno	5-Jun-14	50- 246	No	INC	20	1:50	20:59	-78.80	$64,262	$1,067	$4,994	5	($154)	$0	$0	($640)	$0
53	RT	Planned Transmission Outage and Constraint	PG&E	Fresno	20-Jun-14	80	No	INC	2	19:05	20:59	45.42	$5,779	$287	($3,128)	7	($326)	$0	$0	($36)	$0
54	RT	Planned Transmission Outage and Constraint	PG&E	Fresno	20-Jun-14	12- 770	No	INC	11	11:20	21:59	-78.80	$64,262	$1,067	$4,994	5	($154)	$0	$0	($640)	$0
55	RT	Planned Transmission Outage and Constraint	PG&E	Fresno	21-Jun-14	6- 56	No	INC	10	14:00	23:59	-78.80	$64,262	$1,067	$4,994	5	($154)	$0	$0	($640)	$0
56	RT	Planned Transmission Outage and Constraint	PG&E	Fresno	22-Jun-14	50- 96	No	INC	7	16:00	22:59	-78.80	$64,262	$1,067	$4,994	5	($154)	$0	$0	($640)	$0
57	RT	Planned Transmission Outage and Constraint	PG&E	Fresno	26-Jun-14	47	No	INC	2	22:55	23:59	-78.80	$64,262	$1,067	$4,994	5	($154)	$0	$0	($640)	$0
58	RT	Planned Transmission Outage and Constraint	PG&E	Fresno	30-Jun-14	20- 520	No	INC	11	11:05	21:59	-78.80	$64,262	$1,067	$4,994	5	($154)	$0	$0	($640)	$0
59	RT	Planned Transmission Outage and Constraint	PG&E	Humboldt	30-Jun-14	30	No	INC	13	6:40	18:59	33.82	$289	$0	($2,462)	8	($511)	$0	$0	($8)	$0
60	RT	Planned Transmission Outage and Constraint	PG&E	Humboldt	30-Jun-14	15- 60	No	INC	13	6:06	18:59	5.12	$0	$0	($303)	1	($85)	$0	$0	$0	$0

Number	Market Type	Reason	Location	Local Reliability Area	Trade Date	MW	Commitment	INC_DEC	Hours	Begin Time	End Time	Total MWH	Min Load Cost	Start Up Cost	CC6470	ED MWH (INC/DEC)	CC6470 INC	CC6470 DEC	CC6482	CC6488	CC6620
61	RT	Planned Transmission Outage and Constraint	PG&E	N/A	5-Jun-14	150- 775	No	INC	14	7:59	20:59	163.33	$136,775	$7,380	($13,576)	37	$6,497	$7	$0	($59,399)	$0
62	RT	Planned Transmission Outage and Constraint	PG&E	N/A	6-Jun-14	140- 282	Yes	INC	7	5:00	11:59	163.33	$136,775	$7,380	($13,576)	37	$6,497	$7	$0	($59,399)	$0
63	RT	Planned Transmission Outage and Constraint	PG&E	N/A	9-Jun-14	280- 600	Yes	INC	12	12:13	23:59	163.33	$136,775	$7,380	($13,576)	37	$6,497	$7	$0	($59,399)	$0
64	RT	Planned Transmission Outage and Constraint	PG&E	N/A	10-Jun-14	141- 284	No	INC	17	7:15	23:59	163.33	$136,775	$7,380	($13,576)	37	$6,497	$7	$0	($59,399)	$0
65	RT	Planned Transmission Outage and Constraint	PG&E	N/A	11-Jun-14	141	No	INC	18	6:50	23:59	163.33	$136,775	$7,380	($13,576)	37	$6,497	$7	$0	($59,399)	$0
66	RT	Planned Transmission Outage and Constraint	PG&E	N/A	12-Jun-14	250	No	INC	12	12:20	23:59	163.33	$136,775	$7,380	($13,576)	37	$6,497	$7	$0	($59,399)	$0
67	RT	Planned Transmission Outage and Constraint	PG&E	N/A	13-Jun-14	140- 206	No	INC	16	1:00	16:59	163.33	$136,775	$7,380	($13,576)	37	$6,497	$7	$0	($59,399)	$0
68	RT	Planned Transmission Outage and Constraint	PG&E	N/A	18-Jun-14	140- 300	No	INC	14	1:32	15:29	163.33	$136,775	$7,380	($13,576)	37	$6,497	$7	$0	($59,399)	$0
69	RT	Planned Transmission Outage and Constraint	PG&E	N/A	19-Jun-14	128- 356	No	INC	16	1:00	16:09	163.33	$136,775	$7,380	($13,576)	37	$6,497	$7	$0	($59,399)	$0
70	RT	Planned Transmission Outage and Constraint	PG&E	N/A	20-Jun-14	140- 450	No	INC	16	6:00	21:59	163.33	$136,775	$7,380	($13,576)	37	$6,497	$7	$0	($59,399)	$0
71	RT	Planned Transmission Outage and Constraint	PG&E	N/A	21-Jun-14	140	No	INC	19	5:00	23:59	163.33	$136,775	$7,380	($13,576)	37	$6,497	$7	$0	($59,399)	$0
72	RT	Planned Transmission Outage and Constraint	PG&E	N/A	30-Jun-14	0	No	INC	10	14:22	23:59	163.33	$136,775	$7,380	($13,576)	37	$6,497	$7	$0	($59,399)	$0
73	RT	Planned Transmission Outage and Constraint	PG&E	NCNB	1-Jun-14	60- 240	No	INC	23	1:50	23:59	-4.67	$0	$0	$41	(3)	$0	$148	$0	($28,499)	$0
74	RT	Planned Transmission Outage and Constraint	PG&E	NCNB	2-Jun-14	100- 185	No	INC	6	18:20	23:59	-4.67	$0	$0	$41	(3)	$0	$148	$0	($28,499)	$0
75	RT	Planned Transmission Outage and Constraint	PG&E	NCNB	3-Jun-14	50- 170	No	INC	23	1:30	23:59	-4.67	$0	$0	$41	(3)	$0	$148	$0	($28,499)	$0
76	RT	Planned Transmission Outage and Constraint	PG&E	NCNB	6-Jun-14	69- 204	No	INC	13	9:15	21:59	-4.67	$0	$0	$41	(3)	$0	$148	$0	($28,499)	$0
77	RT	Planned Transmission Outage and Constraint	PG&E	Sierra	2-Jun-14	60	No	INC	1	20:35	21:14	-32.01	$1,264	$0	$1,446	(6)	$0	$222	$0	($222)	$0
78	RT	Planned Transmission Outage and Constraint	PG&E	Sierra	4-Jun-14	20- 35	No	INC	3	18:45	21:29	-32.01	$1,264	$0	$1,446	(6)	$0	$222	$0	($222)	$0
79	RT	Planned Transmission Outage and Constraint	PG&E	Sierra	5-Jun-14	20- 40	No	INC	6	17:15	22:59	-32.01	$1,264	$0	$1,446	(6)	$0	$222	$0	($222)	$0
80	RT	Planned Transmission Outage and Constraint	PG&E	Stockton	8-Jun-14	191	No	INC	3	19:40	21:59	-63.74	$0	$0	$3,179	(2)	$0	$98	$0	($1,457)	$0
81	RT	Planned Transmission Outage and Constraint	PG&E	Stockton	9-Jun-14	14	No	INC	3	16:23	18:59	-0.31	$3,754	$0	$20	0	$0	$0	$0	$0	$0

Number	Market Type	Reason	Location	Local Reliability Area	Trade Date	MW	Commitment	INC_DEC	Hours	Begin Time	End Time	Total MWH	Min Load Cost	Start Up Cost	CC6470	ED MWH (INC/DEC)	CC6470 INC	CC6470 DEC	CC6482	CC6488	CC6620
82	RT	Planned Transmission Outage and Constraint	SCE	Big Creek-Ventura	9-Jun-14	300- 550	No	INC	12	10:45	21:59	-29.43	$0	$0	($1,386)	0	$0	$0	$0	$0	$0
83	RT	Planned Transmission Outage and Constraint	SCE	LA Basin	2-Jun-14	20	No	INC	18	6:00	23:59	86.21	$46,526	$35,114	($4,180)	0	$0	$0	$0	$0	$0
84	RT	Planned Transmission Outage and Constraint	SCE	LA Basin	26-Jun-14	130	No	INC	13	7:25	19:59	86.21	$46,526	$35,114	($4,180)	0	$0	$0	$0	$0	$0
85	RT	Planned Transmission Outage and Constraint	SCE	N/A	21-Jun-14	40	Yes	INC	1	23:00	23:59	5.09	$0	$0	($613)	0	$0	$0	$0	$0	$0
86	RT	Planned Transmission Outage and Constraint	SDG&E	San Diego-IV	9-Jun-14	40- 800	No	INC	16	8:50	23:59	1660.88	$99,563	$29,697	($73,310)	719	($30,627)	($931)	$0	($22,053)	$0
87	RT	Planned Transmission Outage and Constraint	SDG&E	San Diego-IV	10-Jun-14	400	No	INC	9	14:38	22:59	1660.88	$99,563	$29,697	($73,310)	719	($30,627)	($931)	$0	($22,053)	$0
88	RT	Planned Transmission Outage and Constraint	SDG&E	San Diego-IV	11-Jun-14	20- 44	No	INC	11	0:00	10:59	1660.88	$99,563	$29,697	($73,310)	719	($30,627)	($931)	$0	($22,053)	$0
89	RT	Planned Transmission Outage and Constraint	SDG&E	San Diego-IV	12-Jun-14	40- 809	No	INC	14	6:00	19:59	1660.88	$99,563	$29,697	($73,310)	719	($30,627)	($931)	$0	($22,053)	$0
90	RT	Planned Transmission Outage and Constraint	SDG&E	San Diego-IV	13-Jun-14	20- 200	No	INC	14	6:00	19:59	1660.88	$99,563	$29,697	($73,310)	719	($30,627)	($931)	$0	($22,053)	$0
91	RT	Planned Transmission Outage and Constraint	SDG&E	San Diego-IV	14-Jun-14	20- 400	No	INC	14	10:45	23:59	1660.88	$99,563	$29,697	($73,310)	719	($30,627)	($931)	$0	($22,053)	$0
92	RT	Planned Transmission Outage and Constraint	SDG&E	San Diego-IV	17-Jun-14	58	No	INC	2	10:38	12:34	1660.88	$99,563	$29,697	($73,310)	719	($30,627)	($931)	$0	($22,053)	$0
93	RT	Planned Transmission Outage and Constraint	SDG&E	San Diego-IV	27-Jun-14	16	No	INC	9	9:35	17:59	1660.88	$99,563	$29,697	($73,310)	719	($30,627)	($931)	$0	($22,053)	$0
94	RT	Pump Management	PG&E	Fresno	14-Jun-14	-311	No	INC	2	6:55	8:14	0.00	$0	$0	$0	0	$0	$0	$0	$0	$0
95	RT	Shutdown	PG&E	Fresno	9-Jun-14	0	No	INC	3	3:45	6:09	-1.87	$500	$67	$0	(2)	$0	$0	$0	$0	$0
96	RT	Shutdown	SCE	LA Basin	9-Jun-14	0	No	INC	1	3:45	4:44	0.00	$0	$0	$0	0	$0	$0	$0	$0	$0
97	RT	Shutdown	SDG&E	San Diego-IV	20-Jun-14	0	No	INC	1	0:00	0:59	21.88	$0	$0	($867)	0	$0	$0	$0	$0	$0
98	RT	Software Limitation	PG&E	Bay Area	21-Jun-14	0	No	INC	5	1:15	5:54	0.00	$0	$0	($0)	0	$0	$0	$0	$0	$0
99	RT	Software Limitation	PG&E	Fresno	2-Jun-14	0	No	INC	3	3:05	6:04	-23.76	$315	$0	$1,694	0	$0	$0	$0	$0	$0
100	RT	Software Limitation	PG&E	Fresno	22-Jun-14	6- 92	No	INC	7	16:15	22:59	-23.76	$315	$0	$1,694	0	$0	$0	$0	$0	$0
101	RT	Software Limitation	PG&E	Humboldt	1-Jun-14	0	No	INC	1	22:00	22:59	20.42	($5,696)	$0	($1,334)	12	($1,311)	$393	$0	($1,757)	$0
102	RT	Software Limitation	PG&E	Humboldt	8-Jun-14	15	No	INC	2	22:15	23:59	20.42	($5,696)	$0	($1,334)	12	($1,311)	$393	$0	($1,757)	$0
103	RT	Software Limitation	PG&E	Humboldt	11-Jun-14	15	No	INC	17	7:30	23:59	20.42	($5,696)	$0	($1,334)	12	($1,311)	$393	$0	($1,757)	$0
104	RT	Software Limitation	PG&E	Humboldt	12-Jun-14	15	No	INC	1	23:40	23:59	20.42	($5,696)	$0	($1,334)	12	($1,311)	$393	$0	($1,757)	$0

Number	Market Type	Reason	Location	Local Reliability Area	Trade Date	MW	Commitment	INC_DEC	Hours	Begin Time	End Time	Total MWH	Min Load Cost	Start Up Cost	CC6470	ED MWH (INC/DEC)	CC6470 INC	CC6470 DEC	CC6482	CC6488	CC6620
105	RT	Software Limitation	PG&E	Humboldt	13-Jun-14	15	No	INC	1	0:00	0:29	20.42	($5,696)	$0	($1,334)	12	($1,311)	$393	$0	($1,757)	$0
106	RT	Software Limitation	PG&E	Humboldt	17-Jun-14	15	No	INC	21	3:00	23:59	20.42	($5,696)	$0	($1,334)	12	($1,311)	$393	$0	($1,757)	$0
107	RT	Software Limitation	PG&E	Humboldt	18-Jun-14	15- 90	No	INC	20	4:00	23:59	20.42	($5,696)	$0	($1,334)	12	($1,311)	$393	$0	($1,757)	$0
108	RT	Software Limitation	PG&E	Humboldt	19-Jun-14	30	No	INC	19	5:25	23:59	20.42	($5,696)	$0	($1,334)	12	($1,311)	$393	$0	($1,757)	$0
109	RT	Software Limitation	PG&E	Humboldt	20-Jun-14	15- 48	No	INC	5	19:40	23:59	20.42	($5,696)	$0	($1,334)	12	($1,311)	$393	$0	($1,757)	$0
110	RT	Software Limitation	PG&E	Humboldt	21-Jun-14	15- 16	No	INC	23	1:00	23:59	20.42	($5,696)	$0	($1,334)	12	($1,311)	$393	$0	($1,757)	$0
111	RT	Software Limitation	PG&E	Humboldt	22-Jun-14	15	No	INC	1	23:20	23:59	20.42	($5,696)	$0	($1,334)	12	($1,311)	$393	$0	($1,757)	$0
112	RT	Software Limitation	PG&E	Humboldt	28-Jun-14	15	No	INC	21	3:40	23:59	20.42	($5,696)	$0	($1,334)	12	($1,311)	$393	$0	($1,757)	$0
113	RT	Software Limitation	PG&E	Humboldt	30-Jun-14	15	No	INC	14	4:25	17:29	-7.45	$1,518	$0	$391	0	$0	$0	$0	$0	$0
114	RT	Software Limitation	PG&E	Humboldt	30-Jun-14	15	No	INC	4	20:00	23:59	20.42	($5,696)	$0	($1,334)	12	($1,311)	$393	$0	($1,757)	$0
115	RT	Software Limitation	SCE	LA Basin	1-Jun-14	0	No	INC	8	10:30	18:29	187.10	$0	$0	($9,670)	(6)	$0	$0	$0	$0	$0
116	RT	Software Limitation	SCE	LA Basin	9-Jun-14	0	No	INC	2	6:40	7:59	0.00	$2,200	$0	($0)	0	$0	$0	$0	$0	$0
117	RT	Software Limitation	SCE	LA Basin	9-Jun-14	20	No	INC	1	23:00	23:59	187.10	$0	$0	($9,670)	(6)	$0	$0	$0	$0	$0
118	RT	Software Limitation	SCE	N/A	4-Jun-14	0	No	INC	6	16:45	22:44	-53.19	$5,673	$0	$2,049	(30)	$0	$1,151	$0	$0	$0
119	RT	Software Limitation	SDG&E	San Diego-IV	21-Jun-14	281	No	INC	23	1:10	23:29	-59.88	$0	$0	$2,253	0	$0	$0	$0	$0	$0
120	RT	Startup	SDG&E	San Diego-IV	10-Jun-14	37	No	INC	13	8:40	20:59	1.11	$39,512	$0	($790)	0	$0	$0	$0	$0	$0
121	RT	Start-Up Instructions	PG&E	Bay Area	24-Jun-14	0	No	INC	5	1:00	5:54	-52.50	$0	$0	$261	(45)	$0	$0	$0	$0	$0
122	RT	Start-Up Instructions	PG&E	Fresno	9-Jun-14	0	No	INC	1	3:45	4:39	-78.67	$2,386	$750	$3,039	(21)	$0	$0	$0	$0	$0
123	RT	Start-Up Instructions	PG&E	Fresno	13-Jun-14	0	No	INC	1	0:00	0:59	-1.40	$94	$0	$67	0	$0	$0	$0	$0	$0
124	RT	Start-Up Instructions	PG&E	Fresno	23-Jun-14	0	No	INC	3	5:30	8:14	-1.40	$94	$0	$67	0	$0	$0	$0	$0	$0
125	RT	Start-Up Instructions	SCE	Big Creek-Ventura	9-Jun-14	0	No	INC	1	5:10	5:39	0.00	$0	$0	$0	0	$0	$0	$0	$0	$0
126	RT	Start-Up Instructions	SCE	LA Basin	8-Jun-14	20- 30	Yes	INC	23	1:00	23:59	-385.81	$58,944	$0	$44,129	0	$0	$0	$0	$0	$0
127	RT	Start-Up Instructions	SCE	LA Basin	9-Jun-14	0	No	INC	2	6:40	7:59	-33.32	($3,671)	$0	$1,321	(15)	$0	$295	$0	$0	$0
128	RT	Start-Up Instructions	SCE	LA Basin	21-Jun-14	0	No	INC	1	0:05	0:49	-385.81	$58,944	$0	$44,129	0	$0	$0	$0	$0	$0
129	RT	Start-Up Instructions	SCE	LA Basin	29-Jun-14	0	No	INC	3	18:19	20:59	-33.32	($3,671)	$0	$1,321	(15)	$0	$295	$0	$0	$0

Number	Market Type	Reason	Location	Local Reliability Area	Trade Date	MW	Commitment	INC_DEC	Hours	Begin Time	End Time	Total MWH	Min Load Cost	Start Up Cost	CC6470	ED MWH (INC/DEC)	CC6470 INC	CC6470 DEC	CC6482	CC6488	CC6620
130	RT	Start-Up Instructions	SDG&E	San Diego-IV	9-Jun-14	21	No	INC	3	11:15	13:19	4.55	$0	$0	$364	0	$0	$0	$0	$0	$0
131	RT	Start-Up Instructions	SDG&E	San Diego-IV	20-Jun-14	0	No	INC	2	14:55	16:19	-16.07	$1,119	$0	($235)	(24)	$0	$76	$0	$0	$0
132	RT	Start-Up Instructions	SDG&E	San Diego-IV	21-Jun-14	0	No	INC	2	17:20	18:44	0.05	$0	$0	($3)	0	$0	$0	$0	$0	$0
133	RT	Unit Testing	PG&E	Bay Area	11-Jun-14	48	No	INC	6	10:20	15:59	115.17	$41,483	$0	($5,769)	63	($2,473)	$0	$0	$0	$0
134	RT	Unit Testing	PG&E	Bay Area	25-Jun-14	270- 500	No	INC	17	7:55	23:59	115.17	$41,483	$0	($5,769)	63	($2,473)	$0	$0	$0	$0
135	RT	Unit Testing	PG&E	Bay Area	26-Jun-14	200-1000	No	INC	24	0:00	23:59	115.17	$41,483	$0	($5,769)	63	($2,473)	$0	$0	$0	$0
136	RT	Unit Testing	PG&E	Bay Area	27-Jun-14	200- 563	No	INC	24	0:00	23:59	115.17	$41,483	$0	($5,769)	63	($2,473)	$0	$0	$0	$0
137	RT	Unit Testing	PG&E	Fresno	4-Jun-14	334	No	INC	1	9:10	9:44	187.17	$16,102	$0	($13,471)	132	($11,853)	$0	$0	$0	$0
138	RT	Unit Testing	PG&E	Fresno	5-Jun-14	149	No	INC	1	9:10	9:19	187.17	$16,102	$0	($13,471)	132	($11,853)	$0	$0	$0	$0
139	RT	Unit Testing	PG&E	Fresno	19-Jun-14	45- 90	No	INC	11	8:20	18:39	187.17	$16,102	$0	($13,471)	132	($11,853)	$0	$0	$0	$0
140	RT	Unit Testing	PG&E	Fresno	24-Jun-14	792	No	INC	1	12:05	12:59	187.17	$16,102	$0	($13,471)	132	($11,853)	$0	$0	$0	$0
141	RT	Unit Testing	PG&E	Fresno	25-Jun-14	396- 792	No	INC	1	12:30	13:29	187.17	$16,102	$0	($13,471)	132	($11,853)	$0	$0	$0	$0
142	RT	Unit Testing	PG&E	Fresno	26-Jun-14	396	No	INC	2	12:20	13:24	187.17	$16,102	$0	($13,471)	132	($11,853)	$0	$0	$0	$0
143	RT	Unit Testing	PG&E	N/A	2-Jun-14	136- 250	No	INC	11	8:00	18:59	49.23	$0	$0	($2,357)	40	($2,097)	$0	$0	$0	$0
144	RT	Unit Testing	PG&E	N/A	14-Jun-14	200- 550	No	INC	9	8:15	16:44	49.23	$0	$0	($2,357)	40	($2,097)	$0	$0	$0	$0
145	RT	Unit Testing	PG&E	N/A	17-Jun-14	64- 96	No	INC	1	9:30	10:29	49.23	$0	$0	($2,357)	40	($2,097)	$0	$0	$0	$0
146	RT	Unit Testing	PG&E	N/A	18-Jun-14	243- 262	No	INC	2	9:25	10:29	49.23	$0	$0	($2,357)	40	($2,097)	$0	$0	$0	$0
147	RT	Unit Testing	PG&E	N/A	25-Jun-14	450	No	INC	6	10:35	15:59	49.23	$0	$0	($2,357)	40	($2,097)	$0	$0	$0	$0
148	RT	Unit Testing	PG&E	N/A	26-Jun-14	450	No	INC	6	10:25	15:59	49.23	$0	$0	($2,357)	40	($2,097)	$0	$0	$0	$0
149	RT	Unit Testing	PG&E	Sierra	6-Jun-14	140- 420	No	INC	2	9:05	10:24	-0.17	$0	$0	$7	0	$0	$0	$0	$0	$0
150	RT	Unit Testing	PG&E	Sierra	10-Jun-14	60- 221	No	INC	2	9:40	10:59	-0.17	$0	$0	$7	0	$0	$0	$0	$0	$0
151	RT	Unit Testing	PG&E	Sierra	19-Jun-14	22- 92	No	INC	1	9:05	10:04	-0.17	$0	$0	$7	0	$0	$0	$0	$0	$0
152	RT	Unit Testing	PG&E	Stockton	12-Jun-14	240	No	INC	2	13:00	14:04	46.59	$7,658	$0	($1,500)	46	($1,494)	$0	$0	$0	$0
153	RT	Unit Testing	PG&E	Stockton	18-Jun-14	91	No	INC	1	9:25	9:34	46.59	$7,658	$0	($1,500)	46	($1,494)	$0	$0	$0	$0
154	RT	Unit Testing	SCE	LA Basin	3-Jun-14	41- 42	No	INC	4	12:15	15:59	0.00	$2,722	$0	$0	0	$0	$0	$0	$0	$0
155	RT	Unplanned Outage	PG&E	Bay Area	8-Jun-14	180- 540	No	INC	6	16:10	21:59	43.65	$23,682	$0	($1,158)	7	($350)	$0	($231)	$0	$0

Appendix A: Explanation by Example

All examples listed below are based on fictitious data. Many simplified assumptions are made to explain settlement charge codes, and not all assumptions are explicitly stated in these examples. For instance settlement charge codes are calculated based on metered quantities, whereas, in these examples the dispatch quantities are assumed to be equal to metered quantities. These assumptions have been made to simplify the understanding of settlements calculations.

Example 1: Exceptional Dispatch Instructions Prior to DAM

In this fictitious example the ISO issued an exceptional dispatch instruction for resource A to be committed at its Pmin of 50 MW from hours ending 5 through 10 for a generation procedure 7630. Similarly, the ISO issued additional instructions to resources B and C for the same reason as shown in Table 2. Generally exceptional dispatches prior to the day-ahead market are commitments to minimum load. In this case the dispatch levels are all at minimum load. Table 2 below also shows the commitment costs and the total volume (MWh) of exceptional dispatch instruction for each resource. The minimum load costs and start up costs, shown in Table 2 are the eligible minimum load and start up costs which are different from the bid-in minimum load and start up costs[7]. Only those quantities which are relevant to pre-day-ahead unit commitments are shown in this table.

Table 2: Instructions Prior to Day-Ahead Market

Date	Market	Resource	Location	Local Reliability Area (LRA)	Begin Time	End Time	Dispatch level (MW)	Reason	Total Volume (MWh)	Min-Load Cost	Start- Up Cost	CC6620 (BCR)
01-Jul-09	DA	A	SCE	LA BASIN	05:00	10:00	50	7630	300	$5000	$0	0
01-Jul-09	DA	B	SCE	LA BASIN	08:00	20:00	30	7630	390	$6000	$500	$4000
01-Jul-09	DA	C	SCE	LA BASIN	09:00	23:00	20	7630	300	$400	$1000	$1000

This data is summarized as shown in Table 3, which is the prescribed format specified in the FERC order on September 02, 2009. This summary classifies the data by reason, resource location, local reliability area, and trade date. The MW column in Table 3 is the range of MW; in this case the minimum instruction MW is 20 MW for resource C which occurs from hours ending 21 through 23. The maximum instruction occurs in hour ending 10. In this hour resource A is committed at 50 MW, resource B is committed at 30 MW and resource C is committed at 20 MW. This adds up to 100 MW. Thus the MW column shows the minimum and maximum of the overlaps of all the exceptional dispatch instructions. The Commitment column shows whether a resource was committed between the begin time and end time. Commitments are broken out separately from energy dispatches. In the day-ahead, however the exceptional dispatches are nearly always just commitments, as in this example. The Begin Time column shows hour ending 5 as this was the hour ending for first dispatch of the day, and the End Time column shows hour ending 23, as this was the hour with last dispatch. It is also possible that there might be some hours between the begin time and the end time where there might not be exceptional dispatch instructions for the given reason, meaning that the range between the begin time and end time can include null hours with no dispatch. The total volume (MWh) is the sum of MWh quantity for each resource, which adds up to 990 MWh. Similarly, all cost information is sum of individual resource costs. It is possible that some resources bid-in zero start-up cost; as seen in this example, resource A bid in zero for its start up cost. Since the ISO does not explicitly pay a resource for bid-in minimum load costs and start-up costs; these costs are recovered through the charge code CC6620 (Bid Cost Recovery), this table shows the summary of CC6620 for the classification. In this case, it is the sum of CC6620 for all three resources which adds up to $5000. This column shows the impact of exceptional dispatch on bid cost recovery for all pre-day-ahead exceptional dispatch commitments.

Table 3: FERC Summary of Instructions Prior to DAM

Number	Market Type	Reason	Location	Local Reliability Area (LRA)	Trade Date	MW	Commitment	INC/DEC	Hour	Begin Time	End Time	Total Volume (MWh)	Min-Load Cost	Start-Up Cost	CC6620
1	DA	7630	SCE	LA Basin	1-Jul-09	20-100	Yes	N/A	19	05:00	23:00	990	$11,400	$1,500	$5000

[7] Please refer to the BPM configuration Guide: Bid Cost Recovery Settlements published on the ISO's website for details about eligible minimum load and start up costs.

Example 2: Incremental Exceptional Dispatch Instructions in RTM

In this fictitious example the ISO issued an exceptional dispatch instruction to resource A to be committed at its Pmin of 30 MW from hours 6:00 through 11:00 after completion of the day-ahead market for the transmission procedure 7110. This resource did not have a day-ahead award in those hours. The ISO issued another exceptional dispatch instruction to resource B, to be dispatched at 40 MW from hours 7:00 through 9:00 in real-time for the transmission procedure 7110. This resource had a day-ahead schedule of 20 MW from the day-ahead market, which implies that this exceptional dispatch instruction was an incremental instruction and the exceptional dispatch MW was 20 MW. Similarly, the details of exceptional dispatch (ED) instruction for resource C is shown in Table 4. This table also shows volume (MWh) and various real-time charge codes associated with the exceptional dispatch instructions. The total MWh column for each resource shows the sum of all types of imbalance energy quantities for this resource between the begin time and end time which includes both the exceptional dispatch energy quantities and optimal energy quantities.

Resource A was committed at its Pmin so its total volume (MWh) is equal to its Pmin times the number of hours, which is calculated as 30 MW times 6 hours and is equal to 180 MWh. The resource Minimum load costs and the start up costs are its eligible commitment costs for that period. LMP at this resource is $10/MWh for hours, so the charge code CC6470 is calculated at (180 MWh *$10/MWh) and is equal to 1800. Since this resource is not dispatched above its Pmin, it has a zero volume (MWh) of exceptional dispatch. As a result, all charge codes associated with the exceptional dispatch increment or decrement quantities are zero.

Resource B is dispatched 20 MW above its day-ahead schedule, so its total volume (MWH) is calculated as 20 MW times 3 hours which is equal to 60 MWh. Since the resource was committed in the Day-Ahead Market there are no minimum load quantity and start up costs associated with this resource. The resource had a bid price of $100/MWh and the LMP at that resource was $10/MWh. All of 60 MWh is considered as exceptional dispatch incremental quantity which is shown in ED Volume (MWH INC/DEC) column. The charge code CC6470 INC is calculated as 60 MWh * resource LMP ($10/MWh) which is equal to $600. Since the only imbalance energy in this timeframe was the exceptional dispatch volume, the charge code CC6470 is equal to CC6470 INC. The charge code CC6488 is calculated as MWH quantity *(bid price – LMP), which is equal to $5400 (60 MWh *($10/MWh-$100/MWh)). Similarly, volumes and real-time charge codes are calculated for resource C.

Table 4: Incremental Exceptional Dispatch Instructions in RTM

Date	Market	Resource	Location	Local Reliability Area (LRA)	Begin Time	End Time	Dispatch level (MW)	Day-Ahead Award (MW)	Commitment	INC/DEC	ED (MW)	Reason	Total MWH	Min Load Cost	Start Up Cost	CC6470	ED MWH (INC/DEC)	CC6470 INC	CC6470 DEC	CC6482	CC6488
1-Jul-09	RT	A	PG&E	Humboldt	6:00	11:00	30	0	Yes	INC	30	7110	180	1000	50	1800	0	0	0	0	0
1-Jul-09	RT	B	PG&E	Humboldt	7:00	9:00	40	20	No	INC	20	7110	60	0	0	600	60	600	0	0	5400
1-Jul-09	RT	C	PG&E	Humboldt	12:00	15:00	50	50	No	INC	0	7110	0	0	0	0	0	0	0	0	0
1-Jul-09	RT	C	PG&E	Humboldt	16:00	20:00	50	40	No	INC	10	7110	50	0	0	300	20	300	0	0	200

This data is summarized as shown in Table 5 and is classified by reason, resource location, local reliability area, and trade date. The MW column in Table 5 is the range of MW; in this case the minimum instruction MW is 0 MW for resource C which occurs from hours ending 13 through 15. The maximum instruction occurs in hours ending 8 & 9, as during these two hours both resources A and B have an ED MW of 30MW and 20MW, respectively. This adds up to 50 MW. Thus the MW column shows the minimum and maximum of the overlaps of all the exceptional dispatch instructions. The Commitment column shows whether a resource was committed between the begin time and end time. This column shows a commitment if there was a single commitment in the entire interval of exceptional dispatch. The Begin Time column shows the time of the first dispatch of the day. This is a time not a range. Similarly, the End Time column shows a time and not a range. Exceptional dispatches occurred between these two times. Since there was a commitment between the begin time and end time then the Commitment column displays yes for the summary. Similarly, the INC/DEC column shows an INC as there was an incremental dispatch between the begin time and end time. As mentioned in the previous example it is possible that there might be some hours between the begin time and end time where there were no exceptional dispatch instructions for the given reason. Both volume and cost information columns are simply the summation for all the respective columns for resource A, B and C. For instance the Total volume (MWh) column is calculated as summation of 180,60,0 and 50 which are the individual volumes (MWh) for resources A, B and C for time periods shown in Table 4 on the previous page.

Table 5: FERC Summary of ED Instructions in RTM

Number	Market Type	Reason	Location	Local Reliability Area (LRA)	Trade Date	MW	Commitment	INC/DEC	Hour	Begin Time	End Time	Total MWH	Min Load Cost	Start Up Cost	CC6470	ED MWH (INC/DEC)	CC6470 INC	CC6470 DEC	CC6482	CC6488
1	RT	7110	PG&E	Humboldt	1-Jul-09	0-50	Yes	INC	15	6:00	20:00	290	1000	50	1700	140	1500	0	0	11000

Please note that it is possible that the ISO would dispatch a particular resource for instance at 10 MW from hours ending 1 through 4, and all or part of its energy might settle as optimal energy. This situation occurs when the LMP at the resource pricing node is above the resource bid price. This cost will only be captured in charge code 6470. It is also possible that ISO issues an exceptional dispatch for the resource to operate at a minimum of 10 MW, which is its Pmin; however the market application might dispatch this resource above Pmin because the resource is economical. When this occurs, the charge code CC6470 and the total MWh quantity might overstate the actual exceptional dispatch MWh quantities. So, to best estimate the cost and volume (MWH) of exceptional dispatch it is appropriate to consider only the following columns: ED MWh (INC/DEC), CC6470 INC, CC6470 DEC, CC6482, CC6488.

Example 3: Decremental Exceptional Dispatch Instructions in RTM

This example highlights decremental exceptional dispatch instructions in the real-time market. In this fictitious example the ISO issued an exceptional dispatch instruction to resource A to be committed at its Pmin of 20 MW from hours ending 15 through 20 after completion of the day-ahead market for the transmission procedure 7430. The ISO issued additional exceptional dispatch instructions for resources B and C; details of those instructions are shown in Table 6. This table also includes volume (MWh) and cost information.

Resource A is committed in real-time at its Pmin, its total volume (MWh) is 20MW *6 hours which is equal to 120 MWh. This resource has a zero MW of incremental dispatch in all hours, so all other relevant cost and volume columns result in zeros. Resource B has a decremental MW of 20 MW in 3 hours, which results in 60 MWh of decremental volume. Since this resource is not committed in real-time, both the minimum load cost and start up costs are zero. This resource had a bid price of $50/MWh and LMP at the resource pricing node is $10/ MWh. Based on this information CC6470-Dec is calculated as 60 MWh *$10/MWh which is equal to $600. Since this resource has its ED volume (MWh) equal to its Total volume, CC6470 is equal to CC6470- DEC. The CC6488 is calculated as (60 MWh * ($50/MWh - $10/MWh)) which is equal to $2400. Resource C had a bid price of $10/MWh and the LMP at its pricing node is $50/MWh. Based on this information, volume and cost information is calculated for resource C.

Table 6: Decremental Exceptional Dispatch Instructions in RTM

Date	Market Type	Resource	Location	Local Reliability Area (LRA)	Begin Time	End Time	Dispatch level (MW)	Day-Ahead Award (MW)	Commitment	INC/DEC	ED (MW)	Reason	Total MWH	Min Load Cost	Start Up Cost	CC6470	ED MWH (INC/DEC)	CC6470 INC	CC6470 DEC	CC6482	CC6488
1-Jul-09	RT	A	PG&E	Fresno	15:00	20:00	20	0	Yes	INC	20	7430	120	$ 120	$ 100	$ -	0	$ -	$ -	$ -	$ -
1-Jul-09	RT	B	PG&E	Fresno	7:00	9:00	40	60	No	DEC	20	7430	(60)	$ -	$ -	$ 600	-60	$ -	$ 600	$ -	$2,400
1-Jul-09	RT	C	PG&E	Fresno	10:00	14:00	40	50	No	DEC	10	7430	(50)	$ -	$ -	$ 500	-50	$ -	$ 500	$ -	$2,000

This data is summarized according to FERC convention as shown in Table 7. This summary classifies the data by reason, resource location, local reliability area, and trade date. Please note that incs and decs are broken out separately. The inc entry is self-explanatory and similar to the previous example. Regarding the dec entry the MW column is the range of MW; in this case the minimum dec instruction is 10 MW (actually -10MW as it is a dec) for resource C which occurs from hours ending 10 through 14. The maximum instruction occurs from hours ending 7 through 9, when resource B was issued a dec instruction of 20 MW. Thus the MW column shows the minimum and maximum of the overlaps of all the exceptional dispatch instructions. The Commitment column shows whether a resource was committed between the begin time and end time. The volume and cost information are summarized by INC and DEC classification.

Table 7: FERC Summary of Decremental ED Instructions in RTM

Number	Market Type	Reason	Location	Local Reliability Area (LRA)	Trade Date	MW	Commitment	INC/DEC	Hour	Begin Time	End Time	Total MWH	Min Load Cost	Start Up Cost	CC6470	ED MWH (INC/DEC)	CC6470 INC	CC6470 DEC	CC6482	CC6488
1	RT	7430	PG&E	Fresno	1-Jul-09	20	Yes	INC	6	15:00	20:00	120	$ 120	$ 100	$ -	0	$ -	$ -	$ -	$ -
2	RT	7430	PG&E	Fresno	1-Jul-09	10-20	Yes	DEC	8	7:00	14:00	(110)	$ -	$ -	$ (1,100)	$ (110)	$ -	$ (1,100)	$ -	$ (4,400)

Appendix B: Price Impact Analysis

In the September 2 FERC order, FERC requested the ISO to perform price impact analysis on two distinct pricing nodes for the entire reporting period. The order also mentioned that the ISO must pick two pricing nodes for the entire reporting period that are most impacted by the exceptional dispatch instructions, and the two pricing nodes must belong to two different load aggregation points (LAPs).

Based on this requirement the ISO implemented a methodology to perform price impact analysis. First, the ISO identified a heavily impacted pricing node from each of the Pacific Gas & Electric (PGAE) LAP and Southern California Edison (SCE) LAP. These two pricing nodes had the maximum amount of exceptional dispatch volume (MWh) in their respective LAP. Point A is in PGAE LAP and point B is in SCE LAP. Please note these two points correspond to an actual pricing node in the ISO system. Only one resource was connected to each of these pricing nodes. For each resource the following input parameters were obtained to perform the analysis:

Exceptional dispatch information: constrained level, constraint type, start of exceptional dispatch instruction and end of exceptional dispatch instruction.
Real-Time LMPs for each of the five minute intervals for the month.
Real-Time hourly bid set for each trade hour.
Day-Ahead award for the resources.

The exceptional dispatch intervals have a begin time and an end time which can span as small as one minute to as large as 24 hours. Since the market application dispatches resources on five-minute basis, the exceptional dispatch instructions for each of these resources were broken down into five-minute intervals. If the begin time or end time for an instruction was in the middle of the five-minute interval, that instruction was rounded up to the next five-minute interval. These five-minute intervals were then coupled with resource five-minute LMPs calculated by the real-time market application. Also, the hourly bid information and the hourly day-ahead schedule were put together to create a dataset that had all the necessary information to perform price impact analysis.

An exceptional dispatch instruction can be generally classified as a start up instruction, an instruction to be dispatched at or above the constrained level, an instruction to be dispatched at or below a constrained level, an instruction to be dispatched at a fixed constrained level, or a shut down instruction. In general, the Locational Marginal Price (LMP) is set by a resource which can provide the next incremental MW of energy. Based on this definition of LMP and the classification of exceptional dispatches based on constraint type, a resource is allowed to set the LMP in only those intervals in which the resource is eligible to move either up or down from its constrained level. Hence, in those intervals in which the resource was constrained up at its Pmax or, in other words, the resource was exceptionally dispatched to its Pmax and forced to generate at that level, the resource was considered ineligible to set the price as it had no room to move up. Similarly, if the resource was constrained down at its Pmin, then the resource was not eligible to set the price. All those intervals in which the resource was ineligible to set the price were dropped from the dataset under consideration. From this dataset of only eligible intervals, for both pricing nodes A and B, LMPs were calculated for all intervals based on the resource dispatch level and the its bid set. The calculated LMP is equal to that bid price corresponding to the constrained MW segment.

Table 8 shows the price impact analysis information for node A, which is located in the PGAE area. This table shows all the five minute intervals in which the resource at PNode A was issued an exceptional dispatch instruction. Out of the 8,064 five-minute intervals in June, this resource was issued exceptional dispatch instructions in 55 five-minute intervals. This resource was eligible to set the LMP in 51 intervals. Out of the 51 intervals, resource calculated LMP was larger than the market LMP in 46 intervals. In the 46 intervals, the average increase in five minute LMP was $29.92/MWh. Out of the 51 intervals, resource calculated LMP was less than the market LMP in 5 intervals. In the 5 intervals, the average decrease in five minute LMP was $16.42/MWh. This implies that if the ISO was able to model the constraint for this exceptional dispatch, then this resource and all other pricing nodes associated with that constraint would observe an average increase of $26.16/MWh.

Table 9 shows the price impact analysis information for node B, which is located in the SCE area. This table shows all the five minute intervals in which the resource at PNode B was issued an exceptional dispatch instruction. Out of the 8,064 five minute intervals, this resource was issued an exceptional dispatch instruction in 15 five minute intervals. This resource was eligible to set the LMP in all 15 intervals. Out of the 15 intervals, resource calculated LMP was larger than the market LMP in 3 intervals. In the 3 intervals, the average increase in five minute LMP was $7.82/MWh. Out of the 15 intervals, resource calculated LMP was less than the market LMP in 12 intervals. In the 12 intervals, the average decrease in five minute LMP was $57.64/MWh. This implies that if the ISO was able to model the constraint for this exceptional dispatch, then this resource and all other pricing nodes associated with that constraint would observe an average decrease of $44.54/MWh.

Table 8: Price Impact Analysis Information for Pricing Node A in PGAE LAP

Number	Trade Date	Trade Hour	Interval	Market LMP	Eligible Flag	Calculated LMP	Change in LMP
1	3-Jun-14	23	5	$68.20	Yes	$126.74	$58.54
2	3-Jun-14	23	10	$68.28	Yes	$126.74	$58.46
3	5-Jun-14	13	5	$48.33	Yes	$69.23	$20.90
4	5-Jun-14	13	10	$87.91	Yes	$69.23	($18.68)
5	5-Jun-14	14	5	$88.60	Yes	$69.23	($19.37)
6	5-Jun-14	14	10	$88.41	Yes	$69.23	($19.18)
7	7-Jun-14	17	5	$68.31	Yes	$93.16	$24.85
8	7-Jun-14	17	10	$68.25	Yes	$93.16	$24.91
9	7-Jun-14	18	5	$39.11	Yes	$93.16	$54.05
10	7-Jun-14	18	10	$39.13	Yes	$93.16	$54.03
11	7-Jun-14	20	5	$92.53	Yes	$80.07	($12.46)
12	7-Jun-14	20	10	$92.53	Yes	$80.07	($12.46)
13	7-Jun-14	21	5	$79.08	Yes	$80.07	$0.99
14	7-Jun-14	21	10	$78.97	Yes	$80.07	$1.10
15	9-Jun-14	4	5	$50.06	No	$69.23	$19.17
16	9-Jun-14	4	10	$50.06	No	$69.23	$19.17
17	9-Jun-14	5	5	$49.24	No	$69.23	$19.99
18	20-Jun-14	16	5	$40.87	Yes	$69.23	$28.36
19	20-Jun-14	17	5	$46.66	Yes	$69.23	$22.57
20	20-Jun-14	17	10	$58.15	Yes	$84.85	$26.70
21	20-Jun-14	18	5	$44.76	Yes	$84.85	$40.09
22	20-Jun-14	18	5	$44.76	Yes	$93.16	$48.40
23	20-Jun-14	18	5	$44.76	Yes	$107.47	$62.71
24	20-Jun-14	18	10	$42.40	Yes	$107.47	$65.07
25	20-Jun-14	19	5	$39.73	Yes	$97.83	$58.10
26	20-Jun-14	19	10	$39.54	Yes	$93.16	$53.62
27	20-Jun-14	19	10	$39.54	Yes	$97.83	$58.29
28	20-Jun-14	20	5	$58.27	Yes	$69.23	$10.96
29	20-Jun-14	20	5	$58.27	Yes	$84.85	$26.58
30	20-Jun-14	20	5	$58.27	Yes	$93.16	$34.89
31	20-Jun-14	20	10	$60.96	Yes	$69.23	$8.27
32	20-Jun-14	20	10	$60.96	Yes	$74.56	$13.60
33	20-Jun-14	21	5	$67.65	Yes	$69.23	$1.58
34	20-Jun-14	21	10	$67.64	Yes	$69.23	$1.59
35	21-Jun-14	23	5	$41.64	Yes	$69.23	$27.59
36	21-Jun-14	23	10	$37.10	Yes	$69.23	$32.13
37	23-Jun-14	19	5	$41.34	Yes	$74.56	$33.22
38	23-Jun-14	19	10	$41.08	Yes	$74.56	$33.48
39	23-Jun-14	20	5	$41.67	Yes	$74.56	$32.89
40	23-Jun-14	20	10	$40.33	Yes	$74.56	$34.23

41	23-Jun-14	21	5	$39.68	Yes	$74.56	$34.88
42	23-Jun-14	21	10	$39.69	Yes	$74.56	$34.87
43	23-Jun-14	22	5	$52.30	Yes	$74.56	$22.26
44	23-Jun-14	22	10	$48.88	Yes	$74.56	$25.68
45	23-Jun-14	23	5	$44.02	Yes	$74.56	$30.54
46	23-Jun-14	23	10	$50.62	Yes	$74.56	$23.94
47	24-Jun-14	13	5	$40.36	No	$126.74	$86.38
48	24-Jun-14	22	5	$51.51	Yes	$74.56	$23.05
49	24-Jun-14	22	10	$46.24	Yes	$74.56	$28.32
50	24-Jun-14	23	5	$58.53	Yes	$74.56	$16.03
51	24-Jun-14	23	10	$57.23	Yes	$74.56	$17.33
52	25-Jun-14	17	5	$37.37	Yes	$69.23	$31.86
53	25-Jun-14	17	10	$37.17	Yes	$69.23	$32.06
54	25-Jun-14	18	5	$67.78	Yes	$69.23	$1.45
55	25-Jun-14	18	10	$67.78	Yes	$69.23	$1.45

Table 9: Price Impact Analysis Information for Pricing Node B in SCE LAP

Number	Trade Date	Trade Hour	Interval	Market LMP	Eligible Flag	Calculated LMP	Change in LMP
1	9-Jun-14	11	10	$37.93	Yes	$41.76	$3.83
2	9-Jun-14	12	5	$44.12	Yes	$41.76	($2.36)
3	9-Jun-14	12	10	$44.07	Yes	$41.76	($2.31)
4	9-Jun-14	13	5	$45.69	Yes	$41.76	($3.93)
5	9-Jun-14	13	10	$47.87	Yes	$41.76	($6.11)
6	9-Jun-14	14	5	$47.26	Yes	$41.76	($5.50)
7	9-Jun-14	14	10	$45.06	Yes	$41.76	($3.30)
8	9-Jun-14	15	5	$48.82	Yes	$41.76	($7.06)
9	9-Jun-14	15	10	$54.02	Yes	$41.76	($12.26)
10	9-Jun-14	18	5	$41.80	Yes	$41.76	($0.04)
11	9-Jun-14	18	10	$41.80	Yes	$41.76	($0.04)
12	9-Jun-14	19	5	$371.21	Yes	$41.76	($329.45)
13	9-Jun-14	19	10	$361.10	Yes	$41.76	($319.34)
14	10-Jun-14	18	5	$33.89	Yes	$43.18	$9.29
15	10-Jun-14	18	10	$32.84	Yes	$43.18	$10.34

Appendix C: Exceptional Dispatch Bid Mitigation Analysis

Due to data issues, ISO could not update the exceptional dispatch bid mitigation analysis to this report. The exceptional dispatch table 2 report for the next month would include the bid mitigation analysis for both the months.

CERTIFICATE OF SERVICE

I hereby certify that I have served the foregoing document upon the parties listed on the official service lists in the above-referenced proceedings, in accordance with the requirements of Rule 2010 of the Commission's Rules of Practice and Procedure (18 C.F.R. § 385.2010).

Dated at Folsom, California this 30th day of September 2014.

/s/ Anna Pascuzzo
Anna Pascuzzo